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CHAPTER 8

ELECTRIC POWER

8.1 Introduction

8.1.1 Utility Grid Description

The operating company grid system and interconnections to other grid systems and generating stations are site-specific.

8.1.2 Onsite Power System Description

The onsite power system is comprised of the main ac power system and the dc power system. The main ac power system is a non-Class 1E system. The dc power system consists of two independent systems: Class 1E dc system and non-Class 1E dc system. The ac and dc onsite power system configurations are shown on Figures 8.3.1-1 and 8.3.2-1, -2 and -3, respectively.

The normal ac power supply to the main ac power system is provided from the station main generator. When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers. This is the preferred power supply. In addition, two non-Class 1E onsite standby diesel generators supply power to selected loads in the event of loss of both the normal and preferred power sources. There is also a maintenance source of power provided through a reserve auxiliary transformer. The maintenance source is site-specific.

The main generator is connected to the offsite power system by three single-phase stepup transformers. The normal power source for the plant auxiliary ac loads comes from the generator buses through two unit auxiliary transformers of identical rating. In the event of a loss of the main generator, the power is maintained without interruption from the preferred power supply by an autotrip of the main generator breaker. Power then flows from the switchyard to the auxiliary loads through the main and unit auxiliary transformers.

A spare single-phase main stepup transformer is provided in the transformer area. The spare can be placed in service upon failure of one phase of the main stepup transformers.

The onsite standby power system, powered by the two onsite standby diesel generators, supplies power to selected loads in the event of loss of other ac power sources. Loads that are priority loads for investment protection due to their specific functions (permanent nonsafety loads) are selected for access to the onsite standby power supply. Availability of the standby power source is not required to accomplish any safety function.

The maintenance power supply is provided at the medium voltage (6.9 kV) buses through normally open circuit breakers. Bus transfer to maintenance source is manual.

Four independent divisions of Class 1E 125 Vdc battery systems are provided for the Class 1E dc and UPS system. Divisions B and C have two battery banks; one battery bank is sized to supply power to safety-related loads for at least 24 hours and the other battery bank is sized to supply

power to a second set of safety-related loads for at least 72 hours following a design basis event (including the loss of all ac power). Divisions A and D have one 24-hour battery bank. The loads are assigned to each battery bank, depending on their required function, during the 72 hour coping period so that no manual or automatic load shedding is required for the first 24 hours. Two ancillary diesel generators are provided for power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and power to refill the PCS water storage tank and spent fuel pool if no other sources of ac power are available.

A single spare Class 1E battery bank is provided for both Class 1E and non-Class 1E battery systems and a separate spare charger is provided for each of the systems. In order to preserve independence of each Class 1E dc system division, plug-in locking type disconnects are permanently installed to prevent connection of more than one battery bank to the spare. In addition, kirk-key interlock switches are provided to prevent transfer operation of more than one switchboard at a time. The spare battery bank is located in a separate room and is capable of supplying power to the required loads on any battery being temporarily replaced with the spare.

The non-Class 1E 125 Vdc power system provides continuous, reliable power to the plant nonsafety-related dc loads. Operation of the non-Class 1E dc system is not required to accomplish any safety function.

Uninterruptible power supplies (UPS) to the four independent divisions of the Class 1E 120 Vac instrument buses are included in the Class 1E dc system. The normal power to the uninterruptible power supply comes from the respective Class 1E 125 Vdc bus. The backup power comes from the main ac power system through Class 1E 480-208Y/120V voltage regulating transformers. The same configuration applies for the uninterruptible power to the non-divisional, non-Class 1E 120 Vac instrument buses. The normal power to the non-Class 1E uninterruptible power supply comes from the non-Class 1E 125 Vdc bus and the backup power comes from the main ac power system through a voltage regulating transformer.

8.1.3 Safety-Related Loads

The safety-related loads requiring Class 1E power are listed in Tables 8.3.2-1, -2, -3 and -4. Safety-related loads are powered from the Class 1E 125 Vdc batteries and the associated Class 1E 120 Vac instrument buses.

8.1.4 Design Basis

8.1.4.1 Offsite Power System

Offsite power has no safety-related function due to the passive design of the AP1000. Therefore, redundant offsite power supplies are not required. The design provides a reliable offsite power system that minimizes challenges to the passive safety system.

8.1.4.2 Onsite Power System

8.1.4.2.1 Safety Design Basis

- The Class 1E dc and UPS power system meets the single failure criterion (GDC 17).

- The Class 1E dc and UPS system has sufficient capacity to achieve and maintain safe shutdown of the plant for 72 hours following a complete loss of all ac power sources without requiring load shedding for the first 24 hours.

- The Class 1E dc and UPS system is divided into four independent divisions. Any three-out-of-four divisions can shut down the plant safely and maintain it in a safe shutdown condition.

- Separation criteria preserve the independence of redundant Class 1E circuits as described in subsection 8.3.2.4 and no single credible event is capable of disabling redundant safety-related systems.

- Special identification criteria are applied for Class 1E equipment, cabling, and raceways as described in subsection 8.3.2.3.

- The Class 1E systems and equipment are designed to permit periodic inspection and testing (GDC-18).

- The Class 1E dc and UPS power system permits connection of any one 125 Vdc switchboard at a time to the spare battery and the spare battery charger. The spare battery and charger have sufficient capacity to permit continuous plant operation at 100-percent power in case of a failure or unavailability of one Class 1E battery bank and the associated battery charger.

- Two ancillary diesel generators provide ac power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and power to refill the PCS water storage tank and spent fuel pool if no other sources of power are available. The equipment used to perform this function is not safety-related because it is not needed for a prolonged period following a loss of ac and it is easily replaced with transportable generators.

8.1.4.2.2 Power Generation Design Basis

- The main ac power system is a non-Class 1E system and nonsafety-related. The normal power supply to the main ac power system comes from the station main generator through two identically rated unit auxiliary transformers.

- The onsite standby power system supplies ac power to the selected permanent nonsafety loads in the event of a main generator trip concurrent with the loss of preferred power source. The onsite standby diesel generators are automatically connected to the associated 6.9 kV buses upon loss of bus voltage only after the generator rated voltage and frequency is established. Loads that are important for orderly plant shutdown are sequentially connected as shown in subsection 8.3.1 during this event.

The permanent nonsafety loads are not required for the plant safe shutdown; therefore, the onsite standby power system is a nonsafety-related system and non-Class 1E.

- For continued operation of the plant, a spare single-phase main transformer can be placed in service upon failure of one phase of the main stepup transformers.

8.1.4.3 Design Criteria, Regulatory Guides, and IEEE Standards

Refer to Table 8.1-1 for guidelines, and their applicability to Chapter 8.

The offsite and onsite ac power systems have no safety function and, therefore, their conformance to General Design Criteria, Regulatory Guides and IEEE Standards is not required, except as indicated in Table 8.1-1.

The Class 1E dc power system design is based on the following:

- General Design Criteria (GDC)

  See Section 3.1 for a discussion of conformance to the General Design Criterion.

- Nuclear Regulatory Commission (NRC) Regulatory Guides

  See Section 1.9 for the list and details of conformance to the regulatory guides.

- IEEE Standards.

  The Class 1E dc power system design is based on the following IEEE Standards that are generally acceptable to the NRC as stated in the referenced Regulatory Guides:

  – IEEE 308-1991, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.32.

  – IEEE 317-1983, IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.63.

  – IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.89.

  – IEEE 338-1987, IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems. Refer to Regulatory Guide 1.118.

  – IEEE 344-1987, IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.100.

  – IEEE 379-2000, IEEE Standard Application of the Single Failure Criterion to Nuclear Power Generating Station Safety Systems. Refer to Regulatory Guide 1.53.

- IEEE 382-1996, IEEE Standard for Qualification of Actuators for Power Operated Valve Assemblies with Safety Related Functions for Nuclear Power Plants. Refer to Regulatory Guide 1.73.

- IEEE 383-1974, IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.131.

- IEEE 384-1981, IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits. Refer to Regulatory Guide 1.75.

- IEEE 450-1995, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications. Refer to Regulatory Guide 1.32.

- IEEE 484-1996, IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications. Refer to Regulatory Guide 1.128.

- IEEE 741-1997, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations. Refer to Regulatory Guide 1.63.

- IEEE 1202-1991, IEEE Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies.

8.1.5 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

Table 8.1-1 (Sheet 1 of 5)

CRITERIA AND GUIDELINES FOR ELECTRIC POWER SYSTEMS

Criteria			Applicability (DCD[(a)] Section/Subsection) 8.2	8.3.1	8.3.2	Remarks
1.	10CFR50 Appendix A – General Design Criteria (GDC) (See Section 3.1 for a discussion of conformance to each of the GDC).					
a.	GDC 2	Design Bases for Protection Against Natural Phenomena			A	
b.	GDC 4	Environmental and Missile Design Basis			A	
c.	GDC 5	Sharing of Structures, Systems, and Components				not applicable
d.	GDC 17	Electric Power Systems			A	
e.	GDC 18	Inspection and Testing of Electric Power Systems			A	
f.	GDC 50	Containment Design Basis		A	A	applicable to penetration design

Note:

(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2, Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 2 of 5)

CRITERIA AND GUIDELINES FOR ELECTRIC POWER SYSTEMS

Criteria			Applicability (DCD[(a)] Section/Subsection) 8.2	8.3.1	8.3.2	Remarks
2.	Regulatory Guide (See Section 1.9 for list and discussion of conformance to the Regulatory Guides).					
a.	RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems			G	
b.	RG 1.9	Selection, Design, and Qualification of Diesel Generator Units Used as Stand-by (Onsite) Electric Power Systems at Nuclear Power Plants				not applicable
c.	RG 1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Generating Stations			G	
d.	RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems			G	
e.	RG 1.63	Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants		G	G	

Note:

(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2, Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 3 of 5)

CRITERIA AND GUIDELINES FOR ELECTRIC POWER SYSTEMS

Criteria			Applicability (DCD[(a)] Section/Subsection) 8.2	8.3.1	8.3.2	Remarks
f.	RG 1.75	Physical Independence of Electric Systems			G	
g.	RG 1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants				not applicable
h.	RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves			G	
i.	RG 1.108	Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants				not applicable
j.	RG 1.118	Periodic Testing of Electric Power and Protection Systems			G	
k.	RG 1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants			G	
l.	RG 1.129	Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants				site-specific
m.	RG 1.131	Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants			G	The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202 or IEEE Standard 383 excluding the option to use the alternate flame source, oil or burlap.

Note:

(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2, Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 4 of 5)

CRITERIA AND GUIDELINES FOR ELECTRIC POWER SYSTEMS

Criteria			Applicability (DCD[(a)] Section/Subsection) 8.2	8.3.1	8.3.2	Remarks
3.	Branch Technical Position (BTP)					
a.	BTP ICSB 4 (PSB)	Requirements on Motor-Operated Valves in the ECCS Accumulator Lines			G	see DCD 1.9.2
b.	BTP ICSB 8 (PSB)	Use of Diesel-Generator Sets for Peaking				not applicable
c.	BTP ICSB 11 (PSB)	Stability of Offsite Power Systems				site-specific
d.	BTP ICSB 18 (PSB)	Application of the Single Failure Criterion to Manually Controlled Electrically-Operated Valves			G	see DCD 1.9.2
e.	BTP ICSB 21	Guidance for Application of RG 1.47			G	see also DCD 7.5
f.	BTP PSB 1	Adequacy of Station Electric Distribution System Voltages				not applicable
g.	BTP PSB 2	Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status				not applicable

Note:

(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2, Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 5 of 5)

CRITERIA AND GUIDELINES FOR ELECTRIC POWER SYSTEMS

Criteria	Applicability (DCD[(a)] Section/Subsection) 8.2	8.3.1	8.3.2	Remarks
4. NUREG Reports				
a. NUREG CR0660 Enhancement of Onsite Diesel Generator Reliability				not applicable

Note:

(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2, Table 8-1 (SRP). No letter denotes "Not Applicable."

8.2 Offsite Power System

8.2.1 System Description

The Combined License applicant is responsible for providing a transmission system to supply offsite ac energy for startup and normal shutdown through a site-specific transmission switchyard. This offsite ac power system is not required for plant safety.

[[A transformer area containing stepup transformers, unit auxiliary transformers, and the reserve auxiliary transformer is located next to the turbine building.]]

The normal ac power supply to the main ac power system is provided from the main generator. When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers. This is the preferred power supply. In addition, two non-Class 1E onsite standby diesel generators supply power to selected plant loads in the event of loss of both the normal and preferred power sources. There is also a maintenance source of power provided through a reserve auxiliary transformer to supply power to selected loads. The maintenance source is site specific. Maintenance power is provided at the medium voltage level (6.9 kV) through normally open circuit breakers. Bus transfer to the maintenance source is manual. Connection of the preferred and maintenance power supplies to the utility grid or other power sources is site-specific.

The main generator is connected to the offsite power system via three single-phase main stepup transformers. The normal power source for the plant auxiliary ac loads is provided from the isophase generator buses through the two unit auxiliary transformers of identical ratings. In the event of a loss of the main generator, the power is maintained without interruption from the preferred power supply by an auto-trip of the main generator breaker. Power then flows from the transformer area to the auxiliary loads through the main and unit auxiliary transformers.

The transmission system is site-specific.

The transmission line structures associated with the plant are designed to withstand standard loading conditions for the specific-site as provided in Reference 1.

Automatic load dispatch is not used at the plant and does not interface with safety-related action required of the reactor protection system.

8.2.1.1 Transmission Switchyard

The transmission switchyard is site specific and the responsibility of the Combined License applicant.

8.2.1.2 Transformer Area

The transformer area contains the main stepup transformers, the unit auxiliary transformers, and the reserve auxiliary transformer. Protective relaying and metering required for this equipment is located in the turbine building. The necessary power sources (480 Vac, 120 Vac, and 125 Vdc)

to the equipment are supplied from the turbine building. See subsection 9.5.1 for a discussion of fire protection associated with plant transformers.

One feeder connects the transformer area with the switchyard to supply power to/from the main stepup transformers for the unit. An arrangement is shown in Figure 8.3.1-1.

8.2.2 Grid Stability

The AP1000 is designed with passive safety-related systems for core cooling and containment integrity and, therefore, does not depend on the electric power grid for safe operation. This feature of the AP1000 significantly reduces the importance of the grid connection and the requirement for grid stability. The AP1000 safety analyses assume that the reactor coolant pumps can receive power from either the main generator or the grid for a minimum of 3 seconds following a turbine trip.

The AP1000 main generator is connected to the generator bus through the generator circuit breaker. The grid is connected to the generator bus through the main step-up transformers and the grid breakers. The reactor coolant pumps are connected to the generator bus through the reactor coolant pump breakers, the 6.9 kV switchgear, and the unit auxiliary transformers. During normal plant operation the main generator supplies power to the generator bus. Some of this power is used by the plant auxiliary systems (including the reactor coolant pumps); the rest of the power is supplied to the grid.

If, during power operation of the plant, a turbine trip occurs, the motive power (steam) to the turbine will be removed. The generator will attempt to keep the shaft rotating at synchronous speed (governed by the grid frequency) by acting like a synchronous motor. The reverse-power relay monitoring generator power will sense this condition and, after a time delay of at least 15 seconds, open the generator breaker. During this delay time the generator will be able to provide voltage support to the grid if needed. The reactor coolant pumps will receive power from the grid for at least 3 seconds following the turbine trip. The Combined License applicant will perform a grid stability analysis to show that, with no electrical system failures, the grid will remain stable and the reactor coolant pump bus voltage will remain above the voltage required to maintain the flow assumed in the Chapter 15 analyses for a minimum of 3 seconds following a turbine trip. In the Chapter 15 analyses, if the initiating event is an electrical system failure (such as failure of the isophase bus), the analyses do not assume operation of the reactor coolant pumps following the turbine trip. The Combined License applicant will set the protective devices controlling the switchyard breakers with consideration given to preserving the plant grid connection following a turbine trip.

If the turbine trip occurs when the grid is not connected (generator supplying plant house loads only), the main turbine-generator shaft will begin to slow down as the energy stored in the rotational inertia of the shaft is used to supply the house loads (including reactor coolant pumps). The system will coast down until the generator exciter can no longer maintain generator terminal voltage and the generator breaker is tripped on either generator under-voltage or exciter over-current. This coast down will last at least 3 seconds before the generator breaker trips.

The sequence of events following a loss-of-offsite-power event is the same as those described for grid-disconnected operation.

8.2.3 Conformance to Criteria

The offsite sources are not Class 1E. Commercial equipment is manufactured to the industrial standards listed in subsection 8.2.6. The design meets General Design Criterion 1. Unit trips occur at the generator breaker and do not cause the loss of the preferred power source to the plant electrical systems. The AP1000 does not require ac power sources for mitigating design basis events; Chapter 15.0 describes the design bases assumptions utilized for analysis of these events.

The AP1000 plant design supports an exemption to the requirement of GDC 17 for two physically independent offsite circuits by providing safety-related passive systems for core cooling and containment integrity, and multiple nonsafety-related onsite and offsite electric power sources for other functions. See Section 6.3 for additional information on the systems for core cooling.

A reliable dc power source supplied by batteries provides power for the safety-related valves and instrumentation during transient and accident conditions.

The Class 1E dc and UPS system is the only safety-related power source required to monitor and actuate the safety-related passive systems. Otherwise, the plant is designed to maintain core cooling and containment integrity, independent of nonsafety-related ac power sources indefinitely. The only electric power source necessary to accomplish these safety-related functions is the Class 1E dc and UPS power system which includes the associated safety-related 120V ac distribution switchgear.

Although the AP1000 is designed with reliable nonsafety-related offsite and onsite ac power that are normally expected to be available for important plant functions, nonsafety-related ac power is not relied upon to maintain the core cooling or containment integrity.

The nonsafety-related ac power system is designed such that plant auxiliaries can be powered from the grid under all modes of operation. During loss of offsite power, the ac power is supplied by the onsite standby diesel-generators. Preassigned loads and equipment are automatically loaded on the diesel-generators in a predetermined sequence. Additional loads can be manually added as required. The onsite standby power system is not required for safe shutdown of the plant.

Conformance with General Design Criterion 18 is provided by the test and inspection capability of the system.

8.2.4 Standards and Guides

In addition to the General Design Criteria, the industry guides and standards listed as Reference 2 through 4 are used as guides in the design and procurement of the offsite power system.

8.2.5 Combined License Information for Offsite Electrical Power

Combined License applicants referencing the AP1000 certified design will address the design of the ac power transmission system and its testing and inspection plan.

The Combined License applicant will address the technical interfaces for this nonsafety-related system listed in Table 1.8-1 and subsection 8.2.2. These technical interfaces include those for ac power requirements from offsite and the analysis of the offsite transmission system and the setting of protective devices.

8.2.6 References

1. ANSI C2-1997, National Electrical Safety Code.

2. ANSI C37.010-1999, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

3. ANSI C37.90-1989, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

4. ANSI C57.12.00-2000, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.

8.3 Onsite Power Systems

8.3.1 AC Power Systems

8.3.1.1 Description

The onsite ac power system is a non-Class 1E system comprised of a normal, preferred, maintenance and standby power supplies. The normal, preferred, and maintenance power supplies are included in the main ac power system. The standby power is included in the onsite standby power system. The Class 1E and non-Class 1E 208/120 Vac instrumentation power supplies are described in subsection 8.3.2 as a part of uninterruptible power supply in the dc power systems.

8.3.1.1.1 Onsite AC Power System

The main ac power system is a non-Class 1E system and does not perform any safety-related functions. It has nominal bus voltage ratings of 6.9 kV, 480 V, 277 V, 208 V, and 120 V.

Figure 8.3.1-1 shows the main generator, transformers, feeders, buses, and their connections. The ratings of major ac equipment are listed in Table 8.3.1-3.

During power generation mode, the turbine generator normally supplies electric power to the plant auxiliary loads through the unit auxiliary transformers. The plant is designed to sustain a load rejection from 100 percent power with the turbine generator continuing stable operation while supplying the plant house loads. The load rejection feature does not perform any safety function.

During plant startup, shutdown, and maintenance the generator breaker remains open. The main ac power is provided by the preferred power supply from the high-voltage switchyard (switchyard voltage is site-specific) through the plant main stepup transformers and two unit auxiliary transformers. Each unit auxiliary transformer supplies power to about 50 percent of the plant loads.

A maintenance source is provided to supply power through a reserve auxiliary transformer. The maintenance source and the associated reserve auxiliary transformer primary voltage are site specific. The reserve auxiliary transformer is sized so that it can be used in place of either of the unit auxiliary transformers, if needed.

The unit auxiliary transformers have two identically rated 6.9 kV secondary windings. Secondaries of the auxiliary transformers are connected to the 6.9 kV switchgear buses by nonsegregated phase buses. The primary of the unit auxiliary transformer is connected to the main generator isolated phase bus duct tap. The 6.9 kV switchgear designation, location, connection, and connected loads are shown in Figure 8.3.1-1. The buses tagged with odd numbers (ES1, ES3, etc.) are connected to one unit auxiliary transformer and the buses tagged with even numbers (ES2, ES4, etc.) are connected to the other unit auxiliary transformer. These 6.9 kV buses are provided with an access to the maintenance source through normally open circuit breakers connecting the bus to the reserve auxiliary transformer. Bus transfer to the maintenance source is manual.

The arrangement of the 6.9 kV buses permits feeding functionally redundant pumps or groups of loads from separate buses and enhances the plant operational flexibility. The 6.9 kV switchgear powers large motors, and the load center transformers. There are two switchgear (ES1 and ES2) located in the annex building, and four (ES3, ES4, ES5 and ES6) in the turbine building.

The main stepup transformers have protective devices for sudden pressure, neutral overcurrent, and differential current. The unit auxiliary transformers have protective devices for sudden pressure, overcurrent, differential current, and neutral overcurrent. If these devices sense a fault condition the following actions will be automatically taken:

- Trip high-side (grid) breaker
- Trip generator breaker
- Trip exciter field breaker
- Trip the 6.9 kV buses connected to the faulted transformer

The reserve auxiliary transformer has protective devices for sudden pressure, overcurrent, and differential current. The reserve auxiliary transformer protective devices trip the reserve supply breaker and any 6.9 kV buses connected to the reserve auxiliary transformer.

The onsite standby power system powered by the two onsite standby diesel generators supplies power to selected loads in the event of loss of normal, and preferred ac power supplies. Those loads that are priority loads for defense-in-depth functions based on their specific functions (permanent nonsafety loads) are assigned to buses ES1 and ES2. These plant permanent nonsafety loads are divided in two functionally redundant load groups (degree of redundancy for each load is described in the sections for the respective systems). Each load group is connected to either bus ES1 or ES2. Each bus is backed by a non-Class 1E onsite standby diesel generator. In the event of a loss of voltage on these buses, the diesel generators are automatically started and connected to the respective buses. The source incoming breakers on switchgear ES1 and ES2 are interlocked to prevent inadvertent connection of the onsite standby diesel generator and preferred/maintenance ac power sources to the 6.9 kV buses at the same time. The diesel generator however, is capable of being manually paralleled with the preferred power supply for periodic testing. Design provisions protect the diesel generators from excessive loading beyond the design maximum rating, should the preferred power be lost during periodic testing. The control scheme, while protecting the diesel generators from excessive loading, does not compromise the onsite power supply capabilities to support the defense-in-depth loads. See subsection 8.3.1.1.2 for starting and load sequencing of standby diesel generators.

The reactor coolant pumps (RCPs) are powered from the four switchgear buses located in the turbine building, one RCP per bus. Variable-speed drives are provided for RCP startup and for RCP operation when the reactor trip breakers are open. During normal power operation (reactor trip breakers are closed), 60 Hz power is provided directly to the RCPs and the variable-speed drives are not connected.

Each RCP is powered through two Class 1E circuit breakers connected in series. These are the only Class 1E circuit breakers used in the main ac power system for the specific purpose of satisfying the safety-related tripping requirement of these pumps. The reactor coolant pumps

connected to a common steam generator are powered from two different auxiliary transformers. The bus assignments for the reactor coolant pumps are shown in Figure 8.3.1-1.

The 480 V load centers supply power to selected 460 V motor loads and to motor control centers. Bus tie breakers are provided between two 480 V load centers each serving predominantly redundant loads. This intertie allows restoration of power to selected loads in the event of a failure or maintenance of a single load center transformer. The bus tie breakers are interlocked with the corresponding bus source incoming breakers so that one of the two bus source incoming breakers must be opened before the associated tie breaker is closed.

The 480 V motor control centers supply power to 460 V motors not powered directly from load centers, while the 480/277 V, and 208/120 V distribution panels provide power for miscellaneous loads such as unit heaters, space heaters, and lighting system. The motor control centers also provide ac power to the Class 1E battery chargers for the Class 1E dc power system as described in subsection 8.3.2.

Two ancillary ac diesel generators, located in the annex building, provide ac power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and pump power to refill the PCS water storage tank and the spent fuel pool, when all other sources of power are not available.

Each ancillary ac generator output is connected to a distribution panel. The distribution panel is located in the room housing the diesel generators. The distribution panel has incoming and outgoing feeder circuit breakers as shown on Figure 8.3.1-3. The outgoing feeder circuit breakers are connected to cables which are routed to the divisions B and C voltage regulating transformers and to the PCS pumps. Each distribution panel has the following outgoing connections:

- Connection for Class 1E voltage regulating transformer to power the post-accident monitoring loads, the lighting in the main control room, and ventilation in the main control room and divisions B and C I&C rooms.

- Connection for PCS recirculation pump to refill the PCS water storage tank and the spent fuel pool.

- Connection for local loads to support operation of the ancillary generator (lighting and fuel tank heating).

- Temporary connection for a test load device (e.g., load resistor).

  See Figure 8.3.1-3 for connections to post-72-hour loads.

8.3.1.1.1.1 Electric Circuit Protection

Protective relay schemes and direct acting trip devices on circuit breakers:

- Provide safety of personnel
- Minimize damage to equipment

- Minimize system disturbances
- Isolate faulted equipment and circuits from unfaulted equipment and circuits
- Maintain (selected) continuity of the power supply

Major types of protection systems employed for AP1000 include the following:

Medium Voltage Switchgear

Differential Relaying

Each medium voltage switchgear bus is provided with a bus differential relay (device 87B) to protect against a bus fault. The actuation of this relay initiates tripping of the source incoming circuit breaker and all branch circuit load breakers. The differential protection scheme employs high-speed relays.

Motors rated 1500 hp and above are generally provided with a high dropout overcurrent relay (device 50D) for differential protection.

Overcurrent Relaying

To provide backup protection for the buses, the source incoming circuit breakers are equipped with an inverse time overcurrent protection on each phase and a residually connected inverse time ground overcurrent protection.

Each medium voltage motor feeder breaker is equipped with a motor protection relay which provides protection against various types of faults (phase and ground) and abnormal conditions such as locked rotor and phase unbalance. Motor overload condition is annunciated in the main control room.

Each medium voltage power feeder to a 480 V load center has a multifunction relay. The relay provides overcurrent protection on each phase for short circuit and overload, and an instantaneous overcurrent protection for ground fault.

Undervoltage Relaying

Medium voltage buses are provided with a set of three undervoltage relays (device 27B) which trip motor feeder circuit breakers connected to the bus upon loss of bus voltage using two-out-of-three logic to prevent spurious actuation. In addition, a protective device is provided on the line side of incoming supply breakers of buses ES1 and ES2 to initiate an alarm in the main control room if a sustained low or high voltage condition occurs on the utility supply system. The alarm is provided so that the operator can take appropriate corrective measures.

480-V Load Centers

Each motor-feeder breaker in load centers is equipped with a trip unit which has long time, instantaneous, and ground fault tripping features. Overload condition of motors is annunciated in the main control room.

The circuit breakers feeding the 480V motor control centers and other non-motor loads have long time, short time, and ground fault tripping features.

Each load center bus has an undervoltage relay which initiates an alarm in the main control room upon loss of bus voltage.

Load center transformers have transformer winding temperature relays (device 49T) which give an alarm on transformer overload.

480-V Motor Control Center

Motor control center feeders for low-voltage (460 V) motors have molded case circuit breakers (magnetic or motor circuit protectors) and motor starters. Motor starters are provided with thermal units (overload heaters) or current sensors. Other feeders have molded case circuit breakers with thermal and magnetic trip elements for overload and short circuit protection.

Non-Class 1E ac motor operated valves are protected by thermal overload devices. Thermal overload devices are selected and sized so as to provide the necessary protection while minimizing the probability of spurious interruptions of valve actuation.

8.3.1.1.2 Standby AC Power Supply

8.3.1.1.2.1 Onsite Standby Diesel Generators

Two onsite standby diesel generator units, each furnished with its own support subsystems, provide power to the selected plant nonsafety-related ac loads. Power supplies to each diesel generator subsystem components are provided from separate sources to maintain reliability and operability of the onsite standby power system. These onsite standby diesel generator units and their associated support systems are classified as AP1000 Class D, defense-in-depth systems.

The onsite standby diesel generator function to provide a backup source of electrical power to onsite equipment needed to support decay heat removal operation during reduced reactor coolant system inventory, midloop, operation is identified as an important nonsafety-related function. The standby diesel generators are included in the Investment Protection Short-Term Availability Controls described in Section 16.3 and the Design Reliability Assurance Program described in Section 17.4.

Each of the generators is directly coupled to the diesel engine. Each diesel generator unit is an independent self-contained system complete with necessary support subsystems that include:

- Diesel engine starting subsystem
- Combustion air intake and engine exhaust subsystem
- Engine cooling subsystem
- Engine lubricating oil subsystem

- Engine speed control subsystem
- Generator, static exciter, generator protection, monitoring instruments and controls subsystems

The diesel-generator starting air subsystem consists of an ac motor-driven, air-cooled compressor, a compressor inlet air filter, an air-cooled aftercooler, an in-line air filter, refrigerant dryer (with dew point at least 10°F less than the lowest normal diesel generator room temperature), and an air receiver with sufficient storage capacity for three diesel engine starts. The starting air subsystem will be consistent with manufacturer's recommendations regarding the devices to crank the engine, duration of the cranking cycle, the number of engine revolutions per start attempt, volume and design pressure of the air receivers, and compressor size. The interconnecting stainless steel piping from the compressor to the diesel engine dual air starter system includes air filters, moisture drainers, and pressure regulators to provide clean dry compressed air at normal diesel generator room temperature for engine starting.

The diesel-generator combustion air intake and engine exhaust subsystem provides combustion air directly from the outside to the diesel engine while protecting it from dust, rain, snow and other environmental particulates. It then discharges exhaust gases from the engine to the outside of the diesel generator building more than 20 feet higher than the air intake. The combustion air circuit is separate from the ventilation subsystems and includes weather protected dry type inlet air filters piped directly to the inlet connections of the diesel engine-mounted turbochargers. The combustion air filters are capable of reducing airborne particulate material, assuming the maximum expected airborne particulate concentration at the combustion air intake. Each engine is provided with two filters as shown in Figure 8.3.1-4. A differential pressure gauge is installed across each filter to determine the need for filter replacement. The engine exhaust gas circuit consists of the engine exhaust gas discharge pipes from the turbocharger outlets to a single vertically mounted outdoor silencer which discharges to the atmosphere. Manufacturer's recommendations are considered in the design of features to protect the silencer module and other system components from possible clogging due to adverse atmospheric conditions, such as dust storms, rain, ice, and snow.

The diesel-generator engine cooling system is an independent closed loop cooling system, rejecting engine heat through two separate roof-mounted, fan-cooled radiators. The system consists of two separate cooling loops each maintained at a temperature required for optimum engine performance by separate engine-driven coolant water circulating pumps. One circuit cools the engine cylinder block, jacket, and head area, while the other circuit cools the oil cooler and turbocharger aftercooler. The cooling water in each loop passes through a three-way self-contained temperature control valve which modulates the flow of water through or around the radiator, as necessary, to maintain required water temperature. The temperature control valve has an expanding wax-type temperature-sensitive element or equivalent. The cooling circuit, which cools the engine cylinder blocks, jacket, and head areas, includes a keep-warm circuit consisting of a temperature controlled electric heater and an ac motor-driven water circulating pump.

The diesel-generator engine lubrication system is contained on the engine skid and includes an engine oil sump, a main engine driven oil pump and a continuous engine prelube system consisting of an ac and dc motor driven prelube pump and electric heater. The prelube system

maintains the engine lubrication system in service when the diesel engine is in standby mode. The lube oil is circulated through the engine and various filters and coolers to maintain the lube oil properties suitable for engine lubrication.

The diesel generator engine fuel oil system consists of an engine-mounted, engine-driven fuel oil pump that takes fuel from the fuel oil day tank, and pumps through inline oil filters to the engine fuel injectors and a separate recirculation circuit with a fuel oil cooler. The recirculation circuit discharges back to the fuel oil day tank that is maintained at the proper fuel level by the diesel fuel oil storage and transfer system.

The onsite standby diesel generators are provided with necessary controls and indicators for local or remote monitoring of the operation of the units. Essential parameters are monitored and alarmed in the main control room via the plant data display and processing system as described in Chapter 7. Indications and alarms that will be available locally and in the main control room are listed in Table 8.3.1-5.

The design of the onsite standby diesel generators does not ensure functional operability or maintenance access or support plant recovery following design basis events. Maintenance accessibility is provided consistent with the system nonsafety-related functions and plant availability goals.

The piping and instrumentation diagrams for the onsite standby diesel generator units and the associated subsystems are shown on Figures 8.3.1-4 and 8.3.1-5.

The onsite standby power supply system is shown schematically on one line diagram, Figure 8.3.1-1.

The onsite diesel generators will be procured in accordance with an equipment specification which will include requirements based upon the manufacturer's standards and applicable recommendations from documents such as NUREG/CR-0660 (Reference 15). Capability to detect system leakage and to prevent crankcase explosions will be based upon manufacturer's recommendations. Control of moisture in the starting air system by the equipment described above will be based upon manufacturer's recommendations. Dust and dirt in the diesel generator room is controlled by the diesel generator building ventilation system described in subsection 9.4.10. Personnel training is addressed as part of overall plant training in subsection 13.2.1. Automatic engine prelube by the equipment described above will be based upon manufacturer's recommendations. Testing, test loading and preventive maintenance is addressed as part of overall plant testing and maintenance in Chapter 13. Instrumentation to support diagnostics during operation are shown on Figure 8.3.1-4. The overall diesel building ventilation design is described in subsection 9.4.10 and the combustion air systems are described above. The fuel oil storage and handling system is described in subsection 9.5.4. High temperature insulation will be based upon manufacturer's recommendations. Response to the effects of engine vibration will be based upon manufacturer's recommendations. Diesel building floor coatings are described in subsections 6.1.2.1.4 and 6.1.3.2. The diesel generators will be procured to be consistent with the diesel generator building HVAC system described in subsection 9.4.10.

8.3.1.1.2.2 Generator

Each generator is a direct-shaft driven, air-cooled self ventilated machine. The generator enclosure is open drip-proof type that facilitates free movement of ventilation air. The generator component design is in compliance with the NEMA MG-1 (Reference 1) requirements.

Each generator produces its rated power at 6900 V, 60 Hz. Each generator continuous rating is based on supplying the electrical ac loads listed in Tables 8.3.1-1 or 8.3.1-2. The loads shown on Tables 8.3.1-1 and 8.3.1-2 represent a set of nonsafety-related loads which provide shutdown capability using nonsafety-related systems. The generators can also provide power for additional investment protection ac loads. The plant operator would normally provide power to these loads by de-energizing one of those system components that are redundantly supplied by both the diesel generators. The diesel generator design is compatible with the step loading requirements identified in Tables 8.3.1-1 and 8.3.1-2. The generator exciter and voltage regulator systems are capable of providing full voltage control during operating conditions including postulated fault conditions.

Each generator has a set of potential and current transformers for protective relaying and metering purposes.

The following generator protection functions are provided via relays that are mounted on the local generator control panel:

> Differential (87), overcurrent (50/51), reverse power (32), underfrequency (81), under/over voltage (27/59), loss of excitation (40), ground fault (51g), negative sequence (46), synchronization check (25), voltage balance (60).
>
> **Note**: The number in the parentheses identifies the ANSI device designation.

8.3.1.1.2.3 Onsite Standby Power System Performance

The onsite standby power system provides reliable ac power to the various plant system electrical loads shown on Tables 8.3.1-1 and 8.3.1-2. These loads represent system components that enhance an orderly plant shutdown under emergency conditions. Additional loads that are for investment protection can be manually loaded on the standby power supply after the loads required for orderly shutdown have been satisfied. The values listed in the "Operating Load (kW)" column of Tables 8.3.1-1 and 8.3.1-2 represent nominal values of the actual plant loads.

Both the diesel engine and the associated generator are rated based on 104°F ambient temperature at 1000 ft elevation as standard site conditions. The selected unit rating has a design margin to accommodate possible derating resulting from other site conditions.

The diesel generator unit is able to reach the rated speed and voltage and be ready to accept electrical loads within 120 seconds after a start signal.

Each generator has an automatic load sequencer to enable controlled loading on the generator. The automatic load sequencer connects selected loads at predetermined intervals. This feature allows recuperation of generator voltage and frequency to rated values prior to the connection of the next load.

For sequential and manual loading of the onsite standby diesel generator, see Tables 8.3.1-1 and 8.3.1-2.

To enable periodic testing, each generator has synchronizing equipment at a local panel as well as in the main control room.

The logic diagram for diesel generator initiating circuit is shown in Figure 8.3.1-2.

8.3.1.1.3 Ancillary ac Diesel Generators

Power for Class 1E post-accident monitoring, MCR lighting, MCR and divisions B and C I&C room ventilation and for refilling the PCS water storage tank and the spent fuel pool when no other sources of power are available is provided by two ancillary ac diesel generators located in the annex building. The ancillary generators are not needed for refilling the PCS water storage tank, spent fuel pool makeup, post-accident monitoring or lighting for the first 72 hours following a loss of all other ac sources.

The generators are classified as AP1000 Class D. The generators are commercial, skid-mounted, packaged units and can be easily replaced in the event of a failure. Generator control is manual from a control integral with the diesel skid package. These generators are located in the portion of the Annex Building that is a Seismic Category II structure. Features of this structure which protect the function of the ancillary generators are analyzed and designed for Category 5 hurricanes, including the effects of sustained winds, maximum gusts, and associated wind-borne missiles.

The fuel for the ancillary generators is stored in a tank located in the same room as the generators. The tank is Seismic Category II and holds sufficient fuel for 4 days of operation.

8.3.1.1.4 Electrical Equipment Layout

The main ac power system distributes ac power to the reactor, turbine, and balance of plant (BOP) auxiliary electrical loads for startup, normal operation, and normal/emergency shutdown.

The medium voltage switchgear ES1 and ES2 are located in the electrical switchgear rooms 1 and 2 of the annex building. The incoming power is supplied from the unit auxiliary transformers ET2A and ET2B (X windings) via nonsegregated buses. The nonsegregated buses are routed from the transformer yard to the annex building in the most direct path practical.

The switchgear ES3, ES4, ES5, and ES6 are located in the turbine building electrical switchgear rooms. The incoming power is supplied from the unit auxiliary transformers ET2A and ET2B (Y windings) via nonsegregated buses to ES3 and ES4 and from ET2A and ET2B (X windings) to ES5 and ES6.

The Class 1E medium voltage circuit breakers, ES31, ES32, ES41, ES42, ES51, ES52, ES61, and ES62, for four reactor coolant pumps are located in the auxiliary building.

The 480 V load centers are located in the turbine building electrical switchgear rooms 1 and 2 and in the annex building electrical switchgear rooms 1 and 2 based on the proximity of loads and the associated 6.9 kV switchgear.

The 480 V motor control centers are located throughout the plant to effectively distribute power to electrical loads. The load centers and motor control centers are free standing with top or bottom cable entry and front access. The number of stacks/cubicles vary for each location.

8.3.1.1.5 Heat Tracing System

The electric heat tracing system is nonsafety-related and provides electrical heating where temperature above ambient is required for system operation and freeze protection.

The electric heat tracing system is part of the AP1000 permanent nonsafety-related loads and is powered from the diesel backed 480 V ac motor control centers through 480 V - 208Y/120V transformers and distribution panels.

8.3.1.1.6 Containment Building Electrical Penetrations

The electrical penetrations are in accordance with IEEE 317 (Reference 2).

The penetrations conform to the same functional service level as the cables, (for example, low-level instrumentation is in a separate nozzle from power and control). The same separation requirements apply within inboard/outboard terminal boxes.

Individual electrical penetrations are provided for each electrical service level and follows the same raceway voltage grouping described in subsection 8.3.1.3.4. For modular-type penetrations (three penetration modules in one nozzle), it is permissible to assign:

- One module for low voltage power
- One module for 120/125V control and signal
- One module for instrumentation signal

It is possible to combine low voltage power with 120/125V control in the same module.

Penetrations carrying medium voltage power cables have thermocouples to monitor the temperature within the assembly at the spot expected to have the hottest temperature.

Electrical circuits passing through electrical penetrations have primary and backup protective devices. These devices coordinate with the thermal capability curves (I^2t) of the penetration assemblies. The penetrations are rated to withstand the maximum short-circuit currents available either continuously without exceeding their thermal limit, or at least longer than the field cables of the circuits so that the fault or overload currents are interrupted by the protective devices prior to a potential failure of a penetration. Penetrations are protected for the full range of currents up to the maximum short circuit current available.

Primary and backup protective devices protecting Class 1E circuits are Class 1E in accordance with IEEE 741 (Reference 10). Primary and backup protective devices protecting non-Class 1E circuits are non-Class 1E.

Penetration overcurrent protection coordination curves are generated based on the protection requirements specified by the penetration equipment manufacturer. When necessary, penetrations

are protected for instantaneous overcurrent by current limiting devices such as current-limiting fuses, current-limiting breakers, or reactors.

8.3.1.1.7 Grounding System

The AP1000 grounding system will comply with the guidelines provided in IEEE 665 (Reference 18) and IEEE 1050 (Reference 20). The grounding system consists of the following four subsystems:

- Station grounding grid
- System grounding
- Equipment grounding
- Instrument/computer grounding

The station grounding grid subsystem consists of buried, interconnected bare copper conductors and ground rods (Copperweld) forming a plant ground grid matrix. The subsystem will maintain a uniform ground potential and limit the step-and-touch potentials to safe values under all fault conditions.

The system grounding subsystem provides grounding of the neutral points of the main generator, main step-up transformers, auxiliary transformers, load center transformers, and onsite standby diesel generators. The main and diesel generator neutrals will be grounded through grounding transformers providing high-impedance grounding. The main step-up and load center transformer neutrals will be grounded solidly. The auxiliary (unit and reserve) transformer secondary winding neutrals will be resistance grounded.

The equipment grounding subsystem provides grounding of the equipment enclosures, metal structures, metallic tanks, ground bus of switchgear assemblies, load centers, MCCs, and control cabinets with two ground connections to the station ground grid.

The instrument/computer grounding subsystem provides plant instrument/computer grounding through separate radial grounding systems consisting of isolated instrumentation ground buses and insulated cables. The radial grounding systems are connected to the station grounding grid at one point only and are insulated from all other grounding circuits.

The design of the grounding grid system and the lightning protection system depends on the soil resistivity and lightning activity in the area. Therefore, the design of both systems is site-specific and is the responsibility of the combined license applicant.

8.3.1.1.8 Lightning Protection

The lightning protection system, consisting of air terminals and ground conductors, will be provided for the protection of exposed structures and buildings housing safety-related and fire protection equipment in accordance with NFPA 780 (Reference 19). Also, lightning arresters are provided in each phase of the transmission lines and at the high-voltage terminals of the outdoor transformers. The isophase bus connecting the main generator and the main transformer and the medium-voltage switchgear is provided with lightning arresters. In addition, surge suppressors are

provided to protect the plant instrumentation and monitoring system from lightning-induced surges in the signal and power cables connected to devices located outside.

Direct-stroke lightning protection for facilities is accomplished by providing a low-impedance path by which the lightning stroke discharge can enter the earth directly. The direct-stroke lightning protection system, consisting of air terminals, interconnecting cables, and down conductors to ground, are provided external to the facility in accordance with the guidelines included in NFPA 780. The system is connected directly to the station ground to facilitate dissipation of the large current of a direct lightning stroke. The lightning arresters and the surge suppressors connected directly to ground provide a low-impedance path to ground for the surges caused or induced by lightning. Thus, fire or damage to facilities and equipment resulting from a lightning stroke is avoided.

The design of direct-stroke lightning protection and the associated grounding depends on the lightning activity at the plant site and the soil resistivity of the ground. It is site specific and is the responsibility of the Combined License applicant.

8.3.1.2 Analysis

The ac power system is non-Class 1E and is not required for safe shutdown. Compliance with existing regulatory guides and General Design Criteria is covered in Table 8.1-1 of Section 8.1.

8.3.1.3 Raceway/Cable

8.3.1.3.1 General

The raceway system for non-Class 1E ac circuits complies with IEEE 422 (Reference 3) in respect to installation and support of cable runs between electrical equipment including physical protection. Raceway systems consist primarily of cable tray and wireway.

8.3.1.3.2 Load Groups Segregation

There are two nonsafety-related load groups associated with different transformers, buses, and onsite standby diesel generators. No physical separation is required as these two ac load groups are non-Class 1E and nonsafety-related.

8.3.1.3.3 Cable Derating and Cable Tray Fill

Cable Derating

The power and control cable insulation is designed for a conductor temperature of 90°C. The allowable current carrying capacity of the cable is based on the insulation design temperature while the surrounding air is at an ambient temperature of 65°C for the containment and 40 to 50°C for other areas. Power cables, feeding loads from switchgear, load centers, motor control centers, and distribution panels are sized at 125 percent of the full-load current at a 100-percent load factor.

The power cable ampacities are in accordance with the Insulated Cable Engineers Association publications (References 4 and 11), and National Electric Code (Reference 5). The derating is based on the type of installation, the conductor and ambient temperature, the number of cables in a raceway, and the grouping of the raceways. A further derating of the cables is applied for those cables which pass through a fire barrier. The method of calculating these derating factors is determined from the Insulated Cable Engineers Association publications and other applicable standards.

Instrumentation cable insulation is also designed for a conductor temperature of 90°C. The operating power of these cables is low (usually mV or mA) and does not cause cable overheating at the maximum design ambient temperature.

For circuits that are routed partly through conduit and partly through trays or underground ducts, the cable size is based on the ampacity in that portion of the circuit with the lowest indicated current carrying capacity.

Cable Tray Fill

Cable tray design is based on random cable fill of 40 percent of usable tray depth. If tray fill exceeds the above stated maximum fill, tray fill will be analyzed and the acceptability documented.

Conduit fill design is in compliance with Tables 1, 2, 3, and 4 of Chapter 9, National Electrical Code (Reference 5).

8.3.1.3.4 Raceway and Cable Routing

When cable trays are arranged in a vertical array they are arranged physically from top to bottom, in accordance with the function and voltage class of the cables as follows:

- Medium voltage power (6.9 kV)
- Low voltage power (480 Vac, 120 Vac, 125 Vdc)
- 120 Vac/125 Vdc signal and control (if used)
- Instrumentation (analog and digital)

480 Vac power cables may be mixed with 120 Vac/125 Vdc signal and control cables.

Separate raceways are provided for medium voltage power, low voltage power and control, as well as instrumentation cables.

Non-Class 1E raceways and supports installed in seismic Category I structures are designed and/or physically arranged so that the safe shutdown earthquake could not cause unacceptable structural interaction or failure of seismic Category I components.

Raceways are kept at a reasonable distance from heat sources such as steam piping, steam generators, boilers, high and low pressure heaters, and any other actual or potential heat source. Cases of heat source crossings are evaluated and supplemental heat shielding is used if necessary.

For Class 1E raceway and cable routing see subsection 8.3.2.

8.3.1.4 Inspection and Testing

Preoperational tests are conducted to verify proper operation of the ac power system. The preoperational tests include operational testing of the diesel load sequencer and diesel generator capacity testing.

8.3.1.4.1 Diesel Load Sequencer Operational Testing

The load sequencer for each standby diesel generator is tested to verify that it produces the appropriate sequencing signals within five (5) seconds of the times specified in Table 8.3.1-1 and 8.3.1-2. The five second margin is sufficient for proper diesel generator transient response.

8.3.1.4.2 Standby Diesel Generator Capacity Testing

Each standby diesel generator is tested to verify the capability to provide 4000 kW while maintaining the output voltage and frequency within the design tolerances of 6900±10% Vac and 60±5% Hz. The 4000 kW capacity is sufficient to meet the loads listed in Tables 8.3.1-1 and 8.3.1-2. The test duration will be the time required to reach engine temperature equilibrium plus 2.5 hours. This duration is sufficient to demonstrate long-term capability.

8.3.1.4.3 Ancillary Diesel Generator Capacity Testing

Each ancillary diesel generator is tested to verify the capability to provide 35 kW while maintaining the output voltage and frequency within the design tolerances of 480±10% Vac and 60±5% Hz. The 35 kW capacity is sufficient to meet the loads listed in Table 8.3.1-4. The test duration will be the time required to reach engine temperature equilibrium plus 2.5 hours. This duration is sufficient to demonstrate long-term capability.

8.3.2 DC Power Systems

8.3.2.1 Description

The plant dc power system is comprised of independent Class 1E and non-Class 1E dc power systems. Each system consists of ungrounded stationary batteries, dc distribution equipment, and uninterruptible power supply (UPS).

The Class 1E dc and UPS system provides reliable power for the safety-related equipment required for the plant instrumentation, control, monitoring, and other vital functions needed for shutdown of the plant. In addition, the Class 1E dc and UPS system provides power to the normal and emergency lighting in the main control room and at the remote shutdown workstation.

The Class 1E dc and UPS system is capable of providing reliable power for the safe shutdown of the plant without the support of battery chargers during a loss of all ac power sources coincident with a design basis accident (DBA). The system is designed so that no single failure will result in a condition that will prevent the safe shutdown of the plant.

The non-Class 1E dc and UPS system provides continuous, reliable electric power to the plant non-Class 1E control and instrumentation loads and equipment that are required for plant operation and investment protection and to the hydrogen igniters located inside containment. Operation of the non-Class 1E dc and UPS system is not required for nuclear safety. See subsection 8.3.2.1.2.

The batteries for the Class 1E and non-Class 1E dc and UPS systems are sized in accordance with IEEE 485 (Reference 6). The operating voltage range of the batteries is 105 to 140 Vdc. The maximum equalizing charge voltage for batteries is 140 Vdc. The nominal system voltage is 125 Vdc.

8.3.2.1.1 Class 1E DC and UPS System

8.3.2.1.1.1 Class 1E DC Distribution

The Class 1E dc distribution is in compliance with applicable General Design Criteria, IEEE standards, and Regulatory Guides listed in subsection 8.1.4.3. The scope of compliance encompasses physical separation, electrical isolation, equipment qualification, effects of single active component failure, capacity of battery and battery charger, instrumentation and protective devices, and surveillance test requirements. The Class 1E dc components are housed in seismic Category I structures. For system configuration and equipment rating, see Class 1E dc one-line diagram, Figure 8.3.2-1. Nominal ratings of major Class 1E dc equipment are listed in Table 8.3.2-5.

There are four independent, Class 1E 125 Vdc divisions, A, B, C, and D. Divisions A and D are each comprising one battery bank, one switchboard, and one battery charger. The battery bank is connected to Class 1E dc switchboard through a set of fuses and a disconnect switch. Divisions B and C are each composed of two battery banks, two switchboards, and two battery chargers. The first battery bank in the four divisions, designated as 24-hour battery bank, provides power to the loads required for the first 24 hours following an event of loss of all ac power sources concurrent with a design basis accident (DBA). The second battery bank in divisions B and C, designated as 72-hour battery bank, is used for those loads requiring power for 72 hours following the same event. Each switchboard connected with a 24-hour battery bank supplies power to an inverter, a 125 Vdc distribution panel, and a 125 Vdc motor control center. Each switchboard connected with a 72 hour battery bank supplies power to an inverter. No load shedding or load management program is needed to maintain power during the required 24-hour safety actuation period.

A single spare battery bank with a spare battery charger is provided for the Class 1E dc and UPS system. In the case of a failure or unavailability of the normal battery bank and the battery charger, permanently installed cable connections allow the spare to be connected to the affected bus by plug-in locking type disconnect along with kirk-key interlock switches. The plug-in locking type disconnect and kirk-key interlock switches permit connection of only one battery bank and battery charger at a time so that the independence of each battery division is preserved. The spare battery and the battery charger can also be utilized as a substitute when offline testing, maintenance and equalization of an operational battery bank is desired.

Each 125 Vdc Class 1E battery division and the spare battery bank are separately housed as described in subsection 8.3.2.1.3.

Each battery bank, including the spare, has a battery monitor system that detects battery open-circuit conditions and monitors battery voltage. The battery monitor provides a trouble alarm in the main control room. The battery monitors are not required to support any safety-related function. Monitoring and alarming of dc current and voltages is through the plant control system which includes a battery discharge rate alarm. AP1000 generally uses fusible disconnect switches in the Class 1E dc system. If molded-case circuit breakers are used for dc applications, they will be sized to meet the dc interrupting rating requirements.

The Class 1E dc switchboards employ fusible disconnect switches and have adequate short circuit and continuous-current ratings. The main bus bars are braced to withstand mechanical forces resulting from a short-circuit current. Fused transfer switch boxes, equipped with double pole double throw transfer switches, are provided to facilitate battery testing, and maintenance.

Battery chargers are connected to dc switchboard buses. The input ac power for the Class 1E dc battery chargers is supplied from non-Class 1E 480 Vac diesel generator backed motor control centers. The battery chargers provide the required isolation between the non-1E ac and the Class 1E dc electrical systems. The battery chargers are qualified as isolation devices in accordance with IEEE 384 (Reference 7) and Regulatory Guide 1.75. Each battery charger has an input ac and output dc circuit breaker for the purpose of power source isolation and required protection. Each battery charger prevents the ac supply from becoming a load on the battery due to a power feedback as a result of the loss of ac power to the chargers. Each battery charger has a built-in current limiting circuit, adjustable between 110 to 125 percent of its rating to hold down the output current in the event of a short circuit or overload on the dc side. The output of the charger is ungrounded and filtered. The output float and equalizing voltages are adjustable. The battery chargers have an equalizing timer and a manual bypass switch to permit periodic equalizing charges. Each charger is capable of providing the continuous demand on its associated dc system while providing sufficient power to charge a fully discharged battery (as indicated by the nominal load requirements in Tables 8.3.2-1 through 8.3.2-4) within a 24-hour period. The battery chargers are provided with a common failure/trouble alarm.

The Class 1E dc motor control centers operate at 125 Vdc nominal two wire, ungrounded system. The dc motor control centers provide branch circuit protection for the dc motor-operated valves. Motor-operated valves are protected by thermal overload devices in accordance with Regulatory Guide 1.106. Motor overload condition is annunciated in the main control room. The loads fed from the motor control centers are protected against a short-circuit fault by fusible disconnect switches. Reduced-voltage motor controllers limit the starting current to approximately 250 percent of rated current for motors equal to or larger than 5 HP.

The Class 1E dc distribution panels provide power distribution and tripping capability between the 125 Vdc power sources and the assigned safeguard loads indicated on Figure 8.3.2-1.

8.3.2.1.1.2 Class 1E Uninterruptible Power Supplies

The Class 1E UPS provides power at 208 Y/120 Vac to four independent divisions of Class 1E instrument and control power buses. Divisions A and D each consist of one Class 1E inverter associated with an instrument and control distribution panel and a backup voltage regulating transformer with a distribution panel. The inverter is powered from the respective 24-hour battery bank switchboard. Divisions B and C each consist of two inverters, two instrument and control distribution panels, and a voltage regulating transformer with a distribution panel. One inverter is powered by the 24-hour battery bank switchboard and the other by the 72-hour battery bank switchboard. For system configuration and equipment rating, see Figures 8.3.2-1 and 8.3.2-2. The nominal ratings of the Class 1E inverters and the voltage regulating transformers are listed in Table 8.3.2-5. Under normal operation, the Class 1E inverters receive power from the associated battery bank. If an inverter is inoperable or the Class 1E 125 Vdc input to the inverter is unavailable, the power is transferred automatically to the backup ac source by a static transfer switch featuring a make-before-break contact arrangement. The backup power is received from the diesel generator backed non-Class 1E 480 Vac bus through the Class 1E voltage regulating transformer. In addition, a manual mechanical bypass switch is provided to allow connection of backup power source when the inverter is removed from service for maintenance.

In order to supply power during the post-72-hour period following a design basis accident, provisions are made to connect a ancillary ac generator to the Class 1E voltage regulating transformers (divisions B and C only). This powers the Class 1E post-accident monitoring systems and the lighting in the main control room and ventilation in the MCR and divisions B and C I&C rooms. See subsection 8.3.1.1.1 for post-72-hour power distribution details, subsection 9.4.1 for post-72-hour ventilation, and subsection 9.5.3 for post-72-hour lighting details respectively.

8.3.2.1.2 Non-Class 1E DC and UPS System

The non-Class 1E dc and UPS system consists of the electric power supply and distribution equipment that provide dc and uninterruptible ac power to the plant non-Class 1E dc and ac loads that are critical for plant operation and investment protection and to the hydrogen igniters located inside containment. The non-class 1E dc and UPS system is comprised of two subsystems representing two separate power supply trains. The subsystems are located in separate rooms in the annex building. Figure 8.3.2-3, non-Class 1E dc and UPS system one line diagram represents the distribution configuration.

Each subsystem consists of separate dc distribution buses. These two buses can be connected by a normally open circuit breaker to enhance the power supply source availability.

Each dc subsystem includes battery chargers, stationary batteries, dc distribution equipment, and associated monitoring and protection devices.

DC buses 1, 2, and 3 (See Figure 8.3.2-3) provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E uninterruptible power supply ac system. An alternate regulated ac power source for the UPS buses is supplied from the associated regulating transformers. DC bus 4 supplies large dc motors and other dc panel loads but not inverter loads.

This configuration helps prevent the large motor starting disturbances affecting the sensitive electronics equipment fed from the inverters.

The onsite standby diesel generator backed 480 Vac distribution system provides the normal ac power to the battery chargers. Industry standard stationary batteries that are similar to the Class 1E design are provided to supply the dc power source in case the battery chargers fail to supply the dc distribution bus system loads. The batteries are sized to supply the system loads for a period of at least two hours after loss of all ac power sources.

The dc distribution switchboard houses the dc feeder protection device, dc bus ground fault detection, and appropriate metering. The component design and the current interrupting device selection follows the circuit coordination principles.

The non-Class 1E dc and UPS system is designed to meet the quality guidelines established by Generic Letter 85-06, "Quality Assurance Guidance for ATWS Equipment that is not Safety-Related."

Each non-Class 1E dc distribution subsystem bus has provisions to allow the connection of a spare non-Class 1E battery charger should its non-Class 1E battery charger be unavailable due to maintenance, testing, or failure.

The non-Class 1E dc system uses the Class 1E spare battery bank (Figure 8.3.2-1) as a temporary replacement for any primary non-Class 1E battery bank. In this design configuration, the spare Class 1E battery bank would be connected to the non-Class 1E dc bus but could not simultaneously supply Class 1E safety loads nor perform safety-related functions. Additionally, the design includes two current interrupting devices placed in series with the main feed from the spare battery that are fault-current activated. This will preserve the spare Class 1E battery integrity should the non-Class 1E bus experience an electrical fault. This arrangement will not degrade the electrical independence of the Class 1E safety circuits.

8.3.2.1.3 Separation and Ventilation

For the Class 1E dc system, the 24-hour and the 72-hour battery banks are housed in the auxiliary building in ventilated rooms apart from chargers and distribution equipment. The battery rooms are ventilated to limit hydrogen accumulation. Subsection 9.4.1 describes the ventilation system in the battery rooms. Each of the four divisions of dc systems are electrically isolated and physically separated to prevent an event from causing the loss of more than one division.

8.3.2.1.4 Maintenance and Testing

Components of the 125 Vdc systems undergo periodic maintenance tests to determine the condition of the system. Batteries are checked for electrolyte level, specific gravity, and cell voltage, and are visually inspected.

The surveillance testing of the Class 1E 125 Vdc system is performed as required by the Technical Specifications.

8.3.2.2 Analysis

Compliance with General Design Criteria (GDC) and Regulatory Guides is discussed in Sections 3.1 and 1.9, respectively. Refer to Table 8.1-1 of Section 8.1 for guidelines and applicability of GDC, Regulatory Guides and IEEE Standards. A failure modes and effects analysis for the Class 1E dc and UPS system is provided in Table 8.3.2-7.

In the event of a loss of offsite power coincident with a main generator trip, ac power to the battery charger is provided from two separate non-Class 1E onsite standby diesel generators. Divisions A and C chargers receive their ac power from one diesel generator, ZOS MG 02A, and division B and D chargers from the second diesel generator, ZOS MG 02B. Provisions are also made to power the post accident monitoring systems and the main control room lighting loads in divisions B and C from ancillary ac generators during the post 72-hour period as described in subsection 8.3.2.1.1.2.

The Class 1E battery chargers and Class 1E voltage regulating transformers are designed to limit the input (ac) current to an acceptable value under faulted conditions on the output side. They have built-in circuit breakers at the input and output sides for protection and isolation. The circuit breakers are coordinated and periodically tested to verify their current-limiting characteristics. They are qualified as isolation devices between Class 1E and non-Class 1E circuits in accordance with IEEE 384 and Regulatory Guide 1.75.

The four divisions are independent, located in separate rooms, cannot be interconnected, and their circuits are routed in dedicated, physically separated raceways. This level of electrical and physical separation prevents the failure or unavailability of a single battery, battery charger, or inverter from affecting adversely a redundant division.

The Class 1E dc and UPS system is designed in accordance with IEEE 308 (Reference 8) and IEEE 946 (Reference 9). Important system component failures are annunciated. The battery monitoring system detects battery open circuit condition and monitors battery voltage. The Class 1E 208Y/120Vac distribution panels are equipped with undervoltage protection. The set of fuses located in the 125 Vdc switchboards provide selective tripping of circuits for a fault to limit the effects of the abnormal condition, minimize system disturbance and protect the battery from complete accidental discharge through a short circuit fault. The Class 1E dc system is ungrounded, thus, a single ground fault does not cause immediate loss of the faulted system. Ground detections with alarms are provided for each division of power so that ground faults can be located and removed before a second ground fault could disable the affected circuit. A spare battery bank and charger enables testing, maintenance, and equalization of battery banks offline. This configuration provides the capability for each battery bank or battery charger to be separately tested and maintained (including battery discharge tests, battery cell replacement, battery charger replacement) without limiting continuous plant operation at 100-percent power.

Short circuit analyses will be performed in accordance with IEEE 946 (reference 9) and/or other acceptable industry standards or practices to determine fault currents. Circuit interrupting device coordination analyses will be performed in accordance with IEEE 141, 242 (References 16 and 17), and/or other acceptable industry standards or practices.

8.3.2.3 Physical Identification of Safety-Related Equipment

Each safety-related circuit and raceway is given a unique identification number to distinguish between circuits and raceways of different voltage level or separation groups. Each raceway is color coded with indelible ink, paint, or adhesive markers (adhesive markers are not used in the containment) at intervals of 15 feet or less along the length of the raceway and on both sides of floor or wall penetrations. Each cable is color coded at a maximum of 5 feet intervals along the length of the cable and cable markers showing the cable identification number are applied at each end of the cable.

The following color coding is used for identification purposes:

Division	Color Code
A	Brown
B	Green
C	Blue
D	Yellow

8.3.2.4 Independence of Redundant Systems

8.3.2.4.1 General

The routing of cable and the design of raceways prevents a single credible event from disabling a redundant safety-related plant function.

8.3.2.4.2 Raceway and Cable Routing

There are five separation groups for the cable and raceway system: group A, B, C, D, and N. Separation group A contains safety-related circuits from division A. Similarly, separation group B contains safety-related circuits from division B; group C from division C; group D from division D; and group N from nonsafety-related circuits.

Cables of one separation group are run in separate raceway and physically separated from cables of other separation groups. Group N raceways are separated from safety-related groups A, B, C and D. Raceways from group N are routed in the same areas as the safety-related groups according to spatial separation stipulated in Regulatory Guide 1.75 and IEEE 384 with the following exceptions:

- Within the main control room and remote shutdown room (nonhazard areas), the minimum vertical separation for open top cable tray is 3 inches and the minimum horizontal separation is 1 inch.
- Within general plant areas (limited hazard areas), the minimum vertical separation is 12 inches, and the minimum horizontal separation is 6 inches for open top cable trays with low-voltage power circuits for cable sizes <2/0 AWG. For configurations that involve

exclusively limited energy content cables (instrumentation and control), these minimum distances are reduced to 3 inches and 1 inch respectively.

- Within panels and control switchboards, the minimum horizontal separation between components or cables of different separation groups (both field-routed and vendor-supplied internal wiring) is 1 inch, and the minimum vertical separation distance is 6 inches.

- For configurations involving an enclosed raceway and an open raceway, the minimum vertical separation is 1 inch if the enclosed raceway is below the open raceway.

The exceptions to the guidance in Regulatory Guide 1.75 are based on test results used to support exceptions to the separation guidance for operating nuclear power plants. A summary of test results from ten electrical separation test programs is documented in Reference 13. These test programs support the AP1000 exceptions.

Non-Class 1E circuits are electrically isolated from Class 1E circuits, and Class 1E circuits from different separation groups are electrically isolated by isolation devices, shielding and wiring techniques, physical separation (in accordance with Regulatory Guide 1.75 for circuits in raceways), or an appropriate combination thereof.

When isolation devices are used to isolate Class 1E circuits from non-Class 1E circuits, the circuits within or from the Class 1E equipment or devices are identified as Class 1E and are treated as such. Beyond the isolation device(s) these circuits are identified as non-Class 1E and are separated from Class 1E circuits in accordance with the above separation criteria.

Power and control cables are installed in conduits, solid bottom trays, or ventilated bottom trays (ladder-type). Solid tray covers are used in outdoor locations and indoors where trays run in areas where falling debris is a problem. Instrumentation cables are routed in conduit or solid bottom cable tray with solid tray covers as required. The cables are derated for specific application in the location where they are installed as stated in subsection 8.3.1.3.3. The environmental design of electrical equipment including Class 1E cables under normal and abnormal operating conditions is discussed in Section 3.11.

Separate trays are provided for each voltage service level: 6.9 kV, low voltage power (480 Vac, 120 Vac, 125 Vdc), high-level signal and control (120 Vac, 125 Vdc), and low level signal (instrumentation). A tray designed for a single class of cables shall contain only cables of the same class except that low voltage power cables may be routed in raceways with high level signal and control cables if their respective sizes do not differ greatly and if they have compatible operating temperatures. When this is done in trays, the power cable ampacity is calculated as if all cables in the tray are power cable. Low voltage power cable and high level signal and control cable will not be routed in common raceways if the fault current, within the breaker or fuse clearing time, is sufficient to heat the insulation to the ignition point. Vertically stacked trays are arranged from top to bottom as stated in subsection 8.3.1.3.4. In general, a minimum of 12 inches vertical spacing is maintained between trays of different service levels within the stack.

The electrical penetrations are in accordance with IEEE 317 (Reference 2). Class 1E and non-Class 1E electrical penetration assemblies are maintained in a separate nozzle. The physical

separation of the Class 1E electrical penetration assemblies are in accordance with Regulatory Guide 1.75. The containment building penetrations are described in subsection 8.3.1.1.5.

Raceways installed in seismic Category I structures have seismically designed supports or are shown not to affect safety-related equipment should they fail. Trays are not attached rigidly to seismic Category I equipment. Conduits may be attached to seismic Category I equipment with flexible type connections.

8.3.2.4.3 Hazard Protection

Where redundant safety-related and nonsafety-related raceway systems traverse each other, separation in accordance with Regulatory Guide 1.75 and IEEE 384 is maintained.

Where hazards to safety-related raceways are identified, a predetermined minimum separation is maintained between the break and/or missile source and any safety-related raceway, or a barrier designed to withstand the effects of the hazard is placed to prevent damage to raceway of redundant systems. For details of missile protection and high-energy line break protection, see Sections 3.5 and 3.6, respectively.

Where redundant circuits, devices or equipment (different separation groups) are exposed to the same external hazard(s), predetermined spatial separation is provided. Where the spatial separation cannot be met, qualified barriers are installed. For details on fire protection, see subsection 9.5.1.

See Section 3.4 for protection of raceways and the associated equipment against flooding.

8.3.2.4.4 Control of Compliance with Separation Criteria during Design and Installation

The separation group identification described in subsection 8.3.2.3 provides for the maintenance of separation in the routing of cables and the connection of control boards and panels. The separation group designation on the cable or raceway is assigned to maintain compatibility with a single line diagram channel designation and other cables or raceways routed. The routing is verified during installation. Color identification of equipment and cabling (discussed in subsection 8.3.2.3) assists field personnel in this effort.

8.3.2.5 Inspection and Testing

Preoperational tests are conducted to verify proper operation of the dc power systems. The preoperational tests include MOV terminal voltage testing and capacity testing of the batteries, chargers, inverters and regulating transformers.

8.3.2.5.1 Class 1E 24-Hour Battery Capacity Testing

Each Class 1E 24-hour battery is tested to verify the capability to provide its load for 24 hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-5. Analysis will be performed based on the design duty cycle and testing will be performed with loads which envelope the analyzed battery bank design duty cycle. Each battery is

connected to a charger maintained at 135±1 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.2 Class 1E 72-Hour Battery Capacity Testing

Each Class 1E 72-hour battery is tested to verify the capability to provide its load for 72 hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-5. Analysis will be performed based on the design duty cycle and testing will be performed with loads which envelope the analyzed battery bank design duty cycle. Each battery is connected to a charger maintained at 135±1 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.3 Class 1E Spare Battery Capacity Testing

The Class 1E spare battery is tested to the same requirements as the most severe of the six division batteries.

8.3.2.5.4 Class 1E 24-Hour Inverter Capacity Testing

Each Class 1E 24-hour inverter is tested to verify the capability to provide 12 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-5. The 12 kW capacity is sufficient to meet the 24-hour inverter loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3, and 8.3.2-4. The inverter input voltage will be no more than 105 Vdc during the test to represent the conditions at the battery end of life.

8.3.2.5.5 Class 1E 72-Hour Inverter Capacity Testing

Each Class 1E 72-hour inverter is tested to verify the capability to provide 7 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-5. The 7 kW capacity is sufficient to meet the 72-hour inverter loads listed in Tables 8.3.2-2 and 8.3.2-3. The inverter input voltage will be no more than 105 Vdc during the test to represent the conditions at the battery end of life.

8.3.2.5.6 Class 1E 24-Hour Charger Capacity Testing

Each Class 1E 24-hour charger is tested to verify the capability to provide 300 A while maintaining the output voltage within the range specified in Table 8.3.2-5. The 300 A is sufficient to meet the 24-hour loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3, and 8.3.2-4 while maintaining the corresponding battery charged.

8.3.2.5.7 Class 1E 72-Hour Charger Capacity Testing

Each Class 1E 72-hour charger is tested to verify the capability to provide 250 A while maintaining the output voltage within the range specified in Table 8.3.2-5. The 250 A is sufficient to meet the 72-hour loads listed in Tables 8.3.2-2 and 8.3.2-3 while maintaining the corresponding battery charged.

8.3.2.5.8 Class 1E Regulating Transformer Capacity Testing

Each Class 1E regulating transformer is tested to verify the capability to provide 30 kW while maintaining the output voltage within the tolerance specified in Table 8.3.2-5. The 30 kW capacity is sufficient to meet the inverter loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3 and 8.3.2-4.

8.3.2.5.9 Motor-Operated Valves Terminal Voltage Testing

The operating voltage supplied to Class 1E motor-operated valves is measured to verify the motor starter input terminal voltage is above the minimum design value of 100 Vdc. The battery terminal voltage will be no more than 105 Vdc during the test to represent the conditions at the battery end of life.

8.3.2.5.10 Non-Class 1E Battery Capacity Testing

Each load group 1, 2, and 3 non-Class 1E battery is tested to verify the capability to provide 500 A for two hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-6. The 500 A is sufficient to meet the loads described in subsection 8.3.2.1.2. Each battery is connected to a charger maintained at 135±1 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.11 Non-Class 1E Inverter Capacity Testing

Each load group 1, 2, and 3 non-Class 1E inverter is tested to verify the capability to provide 35 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-6. The 35 kW capacity is sufficient to meet the loads described in subsection 8.3.2.1.2.

8.3.2.5.12 Non-Class 1E Charger Capacity Testing

Each load group 1, 2, and 3 non-Class 1E charger is tested to verify the capability to provide 550 A while maintaining the output voltage within the range specified in Table 8.3.2-6. The 550 A is sufficient to meet the loads described in subsection 8.3.2.1.2 while maintaining the corresponding battery charged.

8.3.3 Combined License Information for Onsite Electrical Power

Combined License applicants referencing the AP1000 certified design will address the design of grounding and lightning protection.

The Combined License applicant will establish plant procedures as required for:

- Clearing ground fault on the Class 1E dc system
- Checking sulfated battery plates or other anomalous conditions through periodic inspections

- Battery maintenance and surveillance (for battery surveillance requirements, refer to DCD Chapter 16, Section 3.8)
- Periodic testing of penetration protective devices
- Diesel generator operation, inspection, and maintenance in accordance with manufacturers' recommendations.

8.3.4 References

1. NEMA MG-1, "Motors and Generators," 1998.
2. IEEE Standard 317, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," 1983.
3. IEEE Standard 422, "Guide for the Design and Installation of Cable Systems in Power Generating Stations," 1986.
4. ICEA Standard Publication P-54-440, "Ampacities of Cables in Open-Top Cable Trays," 1986.
5. NFPA 70, "National Electrical Code (NEC)," 1999.
6. IEEE Standard 485, "IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications," 1997.
7. IEEE Standard 384, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits," 1981.
8. IEEE Standard 308, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," 1991.
9. IEEE Standard 946, "IEEE Recommended Practice for the Design of dc Auxiliary Power Systems for Generating Stations," 1992.
10. IEEE Standard 741, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations," 1997.
11. IPCEA Standard Publication P-46-426-1962, "Power Cable Ampacities, Volume I - Copper Conductors."
12. IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications," 1995.
13. Young, G. L. et al., "Cable Separation - What Do Industry Programs Show?," IEEE Transactions of Energy Conversion, September 1990, Volume 5, Number 3, pp 585-602.
14. Reference deleted.

15. NUREG/CR-0660, "Enhancement of On-Site Emergency Diesel Generator Reliability," February 1979.

16. IEEE Standard 141, "IEEE Recommended Practice for Electric Power Distribution for Industrial Plants" (IEEE Red Book), 1993.

17. IEEE Standard 242, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems" (IEEE Buff Book), 1986.

18. IEEE Standard 665, "IEEE Guide for Generating Station Grounding," 1995.

19. NFPA 780, “Standard for the Installation of Lightning Protection Systems,” 2000.

20. IEEE Standard 1050, “IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations,” 1996

Table 8.3.1-1 (Sheet 1 of 5)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02A NOMINAL LOADS

Automatic Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) (Note 4) At Power (Note 10)	Operating Load (kW) (Note 4) Shutdown (Note 10)
1.	0	D/G Start Signal is Initiated	-	-	-
2.	TBD	D/G Reaches IDLE Speed (Note 6)	-	-	-
3.	TBD	D/G Reaches Full Speed (Note 6)	-	-	-
4.	120	D/G Breaker Closes, Load Sequencer Starts	-	-	-
5.	120	Load Center Transformer EK11 (Note 7)	2500 kVA	7.5	7.5
6.	120	Load Center Transformer EK12 (Note 7)	2500 kVA	7.5	7.5
7.	120	Annex Bldg Lighting Panel (Note 8)	30 kVA	10	10
8.	120	Annex Bldg Lighting Panel (Note 8)	30 kVA	10	10
9.	120	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
10.	120	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
11.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
12.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
13.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
14.	120	D/G Bldg Lighting Panel (Note 8)	30 kVA	3	3
15.	120	D/G 2A AC/OC Radiator Fan	25 hp	21	21
16.	120	Diesel Oil Transfer Module Unit Heater A	15 kW	15	15

Table 8.3.1-1 (Sheet 2 of 5)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02A NOMINAL LOADS

Automatic Loads (Note 2)					
				Operating Load (kW) (Note 4)	
Item No.	**Time Seq. (sec)**	**Event or Load Description**	**Rating (hp/kW)**	**At Power (Note 10)**	**Shutdown (Note 10)**
17.	120	Diesel Oil Transfer Module Exhaust Fan A	0.5 hp	0.5	0.5
18.	120	D/G A Jacket Water Radiator Fan	25 hp	21	21
19.	120	Class 1E Div. A Regulating XFMR 1	45 kVA	15	15
20.	120	Class 1E Div. C Regulating XFMR 1	45 kVA	15	15
21.	120	Motor Operated Valves (Note 5)	-	-	-
22.	120	D/G A Fuel Oil Transfer Pump	3 hp	3	3
23.	120	D/G A Bldg Stdby Exhaust Fan 1A	3 hp	3	3
24.	120	D/G A Bldg Stdby Exhaust Fan 2A	3 hp	3	3
25.	120	D/G A Bldg Primary AHU MS 01A Fan	3 hp	3	3
26.	120	D/G A Fuel Oil Cooler Fan	2 hp	2	2
27.	140	Start-up Feed Water Pump A	800 hp	665	0
28.	160	Load Center Transformer EK13 (Note 9)	2500 kVA	7.5	7.5
29.	160	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
30.	160	Fuel Oil Day Tank Vault Exhaust Fan A	0.5 hp	0.5	0.5
31.	160	Diesel Fuel Oil Transfer Heater A	90 kW	90	90
32.	160	Service Water Pump A	350 hp	290	290
33.	180	Service Water Cooling Tower Cell Fan A	175 hp	150	150
34.	200	Component Cooling Water Pump A	900 hp	750	750

Table 8.3.1-1 (Sheet 3 of 5)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02A NOMINAL LOADS

Automatic Loads (Note 2)					
				Operating Load (kW) (Note 4)	
Item No.	**Time Seq. (sec)**	**Event or Load Description**	**Rating (hp/kW)**	**At Power (Note 10)**	**Shutdown (Note 10)**
35.	240	Normal Residual Heat Removal Pump A	200 hp	0	166
36.	240	RNS Pump Room Fan A	1.5 hp	0	1.5
37.	240	Annex Bldg Equipment Room Return/Exhaust Fan A (Note 12)	20 hp	17	17
38.	240	Annex Bldg Equipment Room AHU MS02A Fan (Note 12)	50 hp	42	42
39.	240	Annex Bldg Swgr Rm AHU MS 05A Fan (Note 12)	50 hp	42	42
40.	240	Annex Bldg Swgr Rm Ret/Exhaust Fan 06A (Note 12)	25 hp	21	21
41.	300	Non-1E Battery Charger EDS1-DC-1	117 kVA	88	88
42.	300	Non 1E Battery Room A Exhaust Fan	0.5 hp	0.5	0.5
43.	300	Containment Recirculation Fan A	150 hp	21	21
44.	360	Containment Recirculation Fan D	150 hp	21	21
45.	360	Non-1E Battery Charger EDS3-DC-1	117 kVA	88	88
46.	420	Div. A/C Class 1E Battery Room Exhaust Fan A	5 hp	5	5
		Total Automatically Sequenced Loads (kW)		**2504**	**2006.5**

Table 8.3.1-1 (Sheet 4 of 5)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02A NOMINAL LOADS

Manual Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)
47.		Class 1E Div. A Battery Charger 1 (Note 13)	78 kVA	26
48.	--	Class 1E Div. C Battery Charger 1 (Note 13)	78 kVA	26
49.	--	Class 1E Div. C Battery Charger 2	78 kVA	15
50.	--	Supplemental Air Filtration System Fan A	15 hp	15
51.	--	Supplemental Air Filtration System Electric Heater A	20 kW	20
52.	--	Backup Group 4A Pressurizer Heaters	246 kW	246
53.	--	CRDM Fan 01A	40 hp	33
54.	--	CRDM Fan 01B	40 hp	33
55.	--	Spent Fuel Cooling Pump A	250 hp	200
56.	--	Make-Up Pump A	600 hp	498
57.	--	Non-1E Regulating XFMR EDS1-DT-1	75 kVA	25
58.	--	Non-1E Regulating XFMR EDS3-DT-1	75 kVA	25
59.	--	Instrument Air Compressor A (Note 14)	200 hp	166
60.	--	Main Control Room AHU Supply Fan A (Note 11)	40 hp	34
61.	--	Main Control Room AHU Return Fan A (Note 11)	25 hp	21
62.	--	Div A/C Class 1E Electrical Room AHU Supply Fan A (Note 11)	40 hp	34
63.	--	Div A/C Class 1E Electrical Room Return Fan A (Note 11)	25 hp	21

Table 8.3.1-1 (Sheet 5 of 5)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02A NOMINAL LOADS

Manual Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)
64.	--	Div B/D Class 1E Electrical Room AHU Supply Fan D (Note 11)	25 hp	21
65.	--	Div B/D Class 1E Electrical Room Return Fan D (Note 11)	25 hp	21
66.	--	Air Cooled Chiller Pump 2 (Note 11)	20 hp	17
67.	--	Air Cooled Chiller 2 (Note 11)	375 kW	375
68.	--	CVS Pump Room Fan A (Note 11)	1.5 hp	1.5
		Total Manually Sequenced Loads (kW)		**1873.5**

Notes:

1. Loads listed are for diesel generator ZOS MG 02A.
2. Loads identified in the first portion of the table (AUTOMATIC LOADS) will be loaded without operator action. Loads identified in the second portion of the table (MANUAL LOADS) will be energized at operator discretion based on system needs. Automatic loads may not be started until there is a system need. Not all manually sequenced loads will be operated simultaneously.
3. Time Sequence is counted from the time a diesel generator receives the start signal.
4. The "Operating Load" column shows the load input power requirement from the diesel generator.
5. Motor operated valves (MOVs) pertaining to various systems will be energized on closure of the diesel generator breaker. Normally the MOV power requirement is for a very short duration (a few seconds); hence, the MOV load will not affect the diesel generator capacity rating.
6. On receipt of the diesel generator start signal, the engine accelerates to a set idle speed. The engine operates at the idle speed for a time to allow bearing oil pressure buildup, proper lubrication of the moving parts, and engine warmup. After a set time delay (to be determined based on vendor selection), the engine will ramp up to the rated operating speed.
7. On restoring the power supply to the diesel backed bus ES1 by closing the diesel generator incoming breaker, the associated unit substation ECS EK 11 and 12 load center transformers are energized. The transformers draw magnetizing current and the no load losses (approx. 0.3 percent of the rating) from the bus.
8. Only a part of the building lighting load is automatically connected to the diesel generator bus. The remaining lighting load is connected via manual action at the operator's discretion.
9. Load Center ECS EK 13 transformer no load losses and magnetizing current is approximately 0.3 percent of the transformer rating.

Notes:

10. The 'At Power' loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power and reactor trip from power; i.e., reactor coolant pressure above the residual heat removal system operating pressure. The 'Shutdown' loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power during a plant shutdown; i.e., reactor coolant pressure below the residual heat removal system operating pressure and the RNS isolation valves open.
11. Air cooled chiller VWS MS 03 is automatically loaded on diesel generator ZOS MG 02B along with the VAS and VBS fans associated with the cooling coils served by this chiller. The redundant air cooled chiller VWS MS 02 and its associated VAS and VBS fans can be manually loaded on diesel generator ZOS MG 02A in case of failures of VWS MS 03 or ZOS MG 02B.
12. Annex building ventilation fans are automatically loaded on diesel generator ZOS MG 02A. The redundant fans can be manually loaded on diesel generator ZOS MG 02B in case of diesel generator or fan failures.
13. To prevent spurious ADS actuation, the 24-hour Class 1E battery chargers should be manually loaded on the diesel generator within 22 hours; before the Automatic Depressurization Actuation (ADS) timer in the Protection and Safety Monitoring System actuates ADS on low battery charger input voltage.
14. Instrument air compressor CAS MS 01B is automatically loaded on diesel generator ZOS MG 02B. The redundant compressor CAS MS 01A can be manually loaded on diesel generator ZOS MG 02A in case of diesel generator or compressor failures.

Table 8.3.1-2 (Sheet 1 of 4)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02B NOMINAL LOADS

Automatic Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) At Power (Note 10)	Operating Load (kW) Shutdown (Note 10)
1.	0	D/G Start Signal is Initiated	-	-	-
2.	TBD	D/G Reaches IDLE Speed (Note 6)	-	-	-
3.	TBD	D/G Reaches Full Speed (Note 6)	-	-	-
4.	120	D/G Breaker Closes, Load Sequencer Starts	-	-	-
5.	120	Load Center Transformer EK21 (Note 7)	2500 kVA	7.5	7.5
6.	120	Load Center Transformer EK22 (Note 7)	2500 kVA	7.5	7.5
7.	120	Annex Bldg Lighting Panel (Note 8)	30 kVA	10	10
8.	120	Annex Bldg Lighting Panel (Note 8)	30 kVA	10	10
9.	120	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
10.	120	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
11.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
12.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
13.	120	Turbine Bldg Lighting Panel (Note 8)	40 kVA	7	7
14.	120	D/G Bldg Lighting Panel (Note 8)	30 kVA	3	3
15.	120	D/G 2B AC/OC Radiator Fan	25 hp	21	21
16.	120	Diesel Oil Transfer Module Unit Heater B	15 kW	15	15
17.	120	Diesel Oil Transfer Module Exhaust Fan B	0.5 hp	0.5	0.5
18.	120	D/G B Jacket Water Radiator Fan	25 hp	21	21

Table 8.3.1-2 (Sheet 2 of 4)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02B NOMINAL LOADS

Automatic Loads (Note 2)					
				Operating Load (kW)	
Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	At Power (Note 10)	Shutdown (Note 10)
19.	120	Class 1E Div. B Regulating XFMR 1	45 kVA	15	15
20.	120	Class 1E Div. D Regulating XFMR 1	45 kVA	15	15
21.	120	Motor Operated Valves (Note 5)	-	-	-
22.	120	D/G B Fuel Oil Transfer Pump	3 hp	3	3
23.	120	D/G B Bldg Stdby Exhaust Fan 1B	3 hp	3	3
24.	120	D/G B Bldg Stdby Exhaust Fan 2B	3 hp	3	3
25.	120	D/G B Bldg. Primary AHU MS 01B Fan	3 hp	3	3
26.	120	D/G B Fuel Oil Cooler Fan	2 hp	2	2
27.	140	Start-up Feed Water Pump B	800 hp	665	0
28.	160	Load Center Transformer EK23 (Note 9)	2500 kVA	7.5	7.5
29.	160	Aux Bldg Lighting Panel (Note 8)	60 kVA	15	15
30.	160	Fuel Oil Day Tank Vault Exhaust Fan B	0.5 hp	0.5	0.5
31.	160	Diesel Fuel Oil Transfer Heater B	90 kW	90	90
32.	160	Service Water Pump B	350 hp	290	290
33.	180	Service Water Cooling Tower Cell Fan B	175 hp	150	150
34.	180	Main Control Room AHU Supply Fan B	40 hp	34	34
35.	180	Main Control Room AHU Return Fan B	25 hp	21	21
36.	180	Div. B/D Class 1E Electrical Room AHU Supply Fan B	25 hp	21	21

Table 8.3.1-2 (Sheet 3 of 4)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02B NOMINAL LOADS

Automatic Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) At Power (Note 10)	Operating Load (kW) Shutdown (Note 10)
37.	180	Div B/D Class 1E Electrical Room Return Fan B	25 hp	21	21
38.	180	Div A/C Class 1E Electrical Room AHU Supply Fan C	40 hp	34	34
39.	180	Div A/C Class 1E Electrical Room Return Fan C	25 hp	21	21
40.	180	Air Cooled Chiller Pump 3	20 hp	17	17
41.	200	Component Cooling Water Pump B	900 hp	750	750
42.	220	Air Cooled Chiller 3	375 kW	375	375
43.	240	CVS Pump Room Fan B	1.5 hp	1.5	1.5
44.	300	Normal Residual Heat Removal Pump B	200 hp	0	166
45.	300	RNS Pump Room Fan B	1.5 hp	0	1.5
46.	300	Non-1E Battery Charger EDS2-DC-1	117 kVA	88	88
47.	300	Non-1E Battery Room B Exhaust Fan 09B	0.5 hp	0.5	0.5
48.	360	Containment Recirculation Fan B	150 hp	21	21
49.	360	Containment Recirculation Fan C	150 hp	21	21
50.	360	Non-1E Battery Charger EDS4-DC-1	117 kVA	88	88
51.	420	Div. B/D Class 1E Battery Room Exhaust Fan B	1.5 hp	1.5	1.5
52.	420	Instrument Air Compressor B	200 hp	166	166
		Total Automatically Sequenced Loads (kW)		**3090**	**2592.5**

Table 8.3.1-2 (Sheet 4 of 4)

ONSITE STANDBY DIESEL GENERATOR ZOS MG 02B NOMINAL LOADS

Manual Loads (Note 2)

Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)
53.	--	Class 1E Div. B Battery Charger 1	78 kVA	26
54.	--	Class 1E Div. B Battery Charger 2	78 kVA	15
55.	--	Class 1E Div. D Battery Charger 1	78 kVA	26
56.	--	Supplemental Air Filtration System Fan B	15 hp	15
57.	--	Supplemental Air Filtration System Electric Heater B	20 kW	20
58.	--	Backup Group 4B Pressurizer Heaters	246 kW	246
59.	--	CRDM Fan 01C	40 hp	33
60.	--	Spent Fuel Cooling Pump B	250 hp	200
61.	--	Make-Up Pump B	600 hp	498
62.	--	Non-1E Regulating XFMR EDS2-DT-1	75 kVA	25
63.	--	Annex Bldg Equipment Room Return/Exhaust Fan B	20 hp	17
64.	--	Annex Bldg Equipment Room AHU MS02B Fan	50 hp	42
65.	--	Annex Bldg Swgr Rm AHU MS 05B Fan	50 hp	42
66.	--	Annex Bldg Swgr Rm Ret/Exhaust Fan 06B	25 hp	21
		Total Manually Sequenced Loads (kW)		**1226**

Notes:

1. Loads listed are for diesel generator ZOS MG02B.
2. Loads identified in the first portion of the table (AUTOMATIC LOADS) will be loaded without operator action. Loads identified in the second portion of the table (MANUAL LOADS) will be energized at operator discretion based on system needs. Automatic loads may not be started until there is a system need . Not all manually sequenced loads will be operated simultaneously.
3. Time Sequence is counted from the time a diesel generator receives the start signal.
4. The "Operating Load" column shows the load input power requirement from diesel generator.
5. Motor operated valves (MOVs) pertaining to various systems will be energized on closure of the diesel generator breaker. Normally the MOV power requirement is for a very short duration (few seconds), hence the MOV load will not affect the diesel generator capacity rating.
6. On receipt of the diesel generator start signal, the engine accelerates to a set idle speed. Engine operates at the idle speed for a time period to allow bearing oil pressure build up, proper lubrication of the moving parts, and engine warmup. After a set time delay (to be determined based on vendor selection), the engine will ramp up to the rated operating speed.
7. On restoring the power supply to the diesel backed bus ES2 by closing diesel generator incoming breaker, the associated unit substation ECS EK 21 and 22 load center transformers are energized. The transformers draw magnetizing current and the no load losses (approx. 0.3 percent of the rating) from the bus.
8. Only a part of the building lighting load is automatically connected to the diesel generator bus. The remaining lighting load is connected via manual action at the operator's discretion.
9. Load Center ECS EK 23 transformer no load losses and magnetizing current is approximately 0.3 percent of the transformer rating.
10. The ‘At Power’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power and reactor trip from power; i.e., reactor coolant pressure above the residual heat removal system operating pressure. The ‘Shutdown’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power during a plant shutdown; i.e., reactor coolant pressure below the residual heat removal system operating pressure and the RNS isolation valves open.
11. Air cooled chiller VWS MS 03 is automatically loaded on diesel generator ZOS MG 02B along with the VAS and VBS fans associated with the cooling coils served by this chiller. The redundant air cooled chiller VWS MS 02 and its associated VAS and VBS fans can be manually loaded on diesel generator ZOS MG 02A in case of failures of VWS MS 03 or ZOS MG 02B.
12. Annex building ventilation fans are automatically loaded on diesel generator ZOS MG 02A. The redundant fans can be manually loaded on diesel generator ZOS MG 02B in case of diesel generator or fan failures.
13. To prevent spurious ADS actuation, the 24-hour Class 1E battery chargers should be manually loaded on the diesel generator within 22 hours; before the Automatic Depressurization Actuation (ADS) timer in the Protection and Safety Monitoring System actuates ADS on low battery charger input voltage.
14. Instrument air compressor CAS MS 01B is automatically loaded on diesel generator ZOS MG 02B. The redundant compressor CAS MS 01A can be manually loaded on diesel generator ZOS MG 02A in case of diesel generator or compressor failures.

Table 8.3.1-3

COMPONENT DATA - MAIN AC POWER SYSTEM
(NOMINAL VALUES)

1.	**Main Stepup Transformer**	
		3 single phase, FOA, 65°C rise, liquid filled
2.	**Unit Auxiliary Transformers (UATs)**	
		3 phase, 3 winding
		H = 70 MVA, OA, 65°C
		X = 35 MVA, OA, 65°C
		Y = 35 MVA, OA, 65°C
	Reserve Auxiliary Transformer (RAT)	
		3 phase, 3 winding
		H = 70 MVA, OA, 65°C
		X = 35 MVA, OA, 65°C
		Y = 35 MVA, OA, 65°C
3.	**6.9 kV Switchgear**	
		medium voltage metal-clad switchgear
		MVA Class - 500 MVA
		vacuum-type circuit breaker
4.	**480 V Load Centers**	
	Transformers - Indoor, Air-Cooled Ventilated Dry-Type, Fire Retardant:	2500 kVA, AA, 3 phase, 60 Hz 6900 - 480 V
	Main Bus Ampacity	4000 amperes continuous
	480V Breakers	metal enclosed draw-out circuit breaker or motor-starter (contactor)
		65,000 A RMS symmetrical interrupting rating
5.	**480 V Motor Control Centers**	
	Horizontal Bus	800 A continuous rating
		65,000 A RMS symmetrical bracing
	Vertical Bus	300 A continuous rating
		65,000 A RMS symmetrical bracing
	Breakers (molded case)	65,000 A RMS symmetrical interrupting rating

Table 8.3.1-4

POST-72 HOURS NOMINAL LOAD REQUIREMENTS

Item No.	Description of Loads	Ancillary AC Generator 1 Load (kW)	Ancillary AC Generator 2 Load (kW)
1.	Post-Accident Monitoring (PAM) Emergency and Panel Lighting (Division B) in Main Control Room and ancillary fans		6.5
2.	Post-Accident Monitoring (PAM) Emergency and Panel Lighting (Division C) in Main Control Room and ancillary fans	6.5	
3[(a)]	PCS Recirculation Pumps	19.3	19.3
4.	Ancillary Generator Room Lights	0.5	0.5
5.	Ancillary Generator Fuel Tank Heater	1.25 kW	1.25 kW
	Total	27.55 kW	27.55 kW

Note:

a. There are two PCS pumps; however, only one pump will be operating at any point in time on each generator. In case of fire fighting, two pumps (one on each generator) may be used.

Table 8.3.1-5

INDICATION AND ALARM POINTS
STANDBY DIESEL GENERATORS

Parameter	Indication		Alarm	
	Control Room	Local	Control Room	Local
Lube Oil Pressure Low	No	Yes	Yes	Yes
Lube Oil Temperature High	No	Yes	Yes	Yes
Lube Oil Sump Level Low	No	Yes	No	Yes
Cooling Water Temperature High	Yes	Yes	Yes	Yes
Cooling Water Pressure Low	No	Yes	Yes	Yes
DG Starting Air Pressure Low	Yes	Yes	Yes	Yes

Table 8.3.2-1

125V DC CLASS 1E DIVISION A BATTERY NOMINAL LOAD REQUIREMENTS

Load Description	Power Required (kW)	
	Momentary	**Continuous**
Bus IDSA DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	10.6
Emergency Lighting	0	0.3
Containment High Range Monitor	0	0.1
Subtotal	0	11.0
125 Vdc Panel		
Reactor Trip Swgr & Solenoid Valves	7	0.5
125 Vdc MCC		
Motor Operated Valves	240	
Total	247	11.5

Table 8.3.2-2

125V DC CLASS 1E DIVISION B BATTERY NOMINAL LOAD REQUIREMENTS

Load Description	Power Required (kW)	
	Momentary	**Continuous**
Bus IDSB DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	10.1
Emergency Lighting and Panel Lighting	0	0.5
Subtotal	0	10.6
125 Vdc Panel		
Reactor Trip Swgr, RCP Trip & Solenoid Valves	12	0.8
125 Vdc MCC		
Motor Operated Valves	165	
Total	177	11.4
BUS IDSB DS 2 (72 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	3.15
Emergency Lighting and Panel Lighting	0	0.63
Containment High Range Monitor	0	0.12
MCR Supply Duct Radiation Monitor	1.8	0.24
Total	1.8	4.14

Table 8.3.2-3

125V DC CLASS 1E DIVISION C BATTERY NOMINAL LOAD REQUIREMENTS

Load Description	Power Required (kW)	
	Momentary	**Continuous**
Bus IDSC DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	10.1
Emergency Lighting and Panel Lighting	0	0.5
Subtotal	0	10.6
125 Vdc Panel		
Reactor Trip Swgr, RCP Trip & Solenoid Valves	12	0.5
125 Vdc MCC		
Motor Operated Valves	75	
Total	87	11.1
BUS IDSC DS 2 (72 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	3.15
Emergency Lighting and Panel Lighting	0	0.63
Containment High Range Monitor	0	0.12
MCR Supply Duct Radiation Monitor	1.8	0.24
Total	1.8	4.14

Table 8.3.2-4

125V DC CLASS 1E DIVISION D BATTERY NOMINAL LOAD REQUIREMENTS

Load Description	Power Required (kW)	
	Momentary	**Continuous**
Bus IDSD DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	10.6
Emergency Lighting	0	0.3
Containment High Range Monitor	0	0.1
Subtotal	0	11.0
125 Vdc Panel		
Reactor Trip Swgr & Solenoid Valves	6	0.8
125 Vdc MCC		
Motor Operated Valves	150	
Total	156	11.8

Table 8.3.2-5

COMPONENT DATA - CLASS 1E DC SYSTEM (NOMINAL VALUES)

a. Battery Bank

2 - 125 Vdc 60 lead calcium cells, 2400 Ah. (8 hrs to 1.75 V per cell @ 77°F).

b. Charger

AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 400 A continuous; float voltage 2.20 to 2.25 V/cell; equalizing charge voltage 2.33 V/cell.

c. Switchboard

Main bus 1,200 A continuous, 100,000 A short circuit bracing; fuse disconnect switch 100,000 A interrupting rating, continuous ratings 400 and 600 A.

d. Motor Control Center

Main Bus 600 A continuous, vertical bus 300 A continuous, 50,000 A short circuit bracing.

e. Spare Battery Bank

2-125V dc 60 lead calcium cells, 2400 Ah. (8 hrs to 1.75 V per cell @ 77°F).

f. Spare Charger

AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 400 A continuous; float voltage 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.

g. Uninterruptible Power Supply (UPS)

i) Inverter

15 kVA with 125 Vdc input and 208Y/120 Vac, 3-phase, 4-wire, 60 Hz output; ac output voltage regulation of ±2% steady state; output frequency variation within 0.5% of nominal 60 Hz.

ii) Voltage Regulating Transformer

45 kVA, 480 V - 208Y/120V, 3-phase, 4-wire.

Note:
Refer to Figures 8.3.2-1 and 8.3.2-2 for the system component configuration.

Table 8.3.2-6

COMPONENT DATA - NON-CLASS 1E DC SYSTEM (NOMINAL VALUES)

a. Battery Bank

125 Vdc 60 lead calcium cells, 2400 Ah. (8 hrs to 1.75 V per cell @ 77°F).

b. Charger

AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 600 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.

c. Switchgear

Main bus 1,000 A continuous, 50,000 A short circuit bracing; breaker 1000A frame size.

d. Spare Charger

AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 600 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.

e. Uninterruptible Power Supply (UPS)

i) Inverter

50 kVA with 125 Vdc input and 208 Y/120 Vac, 3-phase, 4-wire, 60 Hz output; ac output voltage regulation of ±2% steady state; output frequency variation within 0.5% of nominal 60 Hz.

ii) Voltage Regulating Transformer

75 kVA, 480 V - 208 Y/120 V, 3-phase, 4-wire.

Note:
Refer to Figure 8.3.2-3 for the system component configuration.

Table 8.3.2-7 (Sheet 1 of 4)

CLASS 1E 125V DC AND CLASS 1E UNINTERRUPTIBLE POWER SUPPLIES FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
1.	Battery Charger Division A, IDSA DC 1 Division B, IDSB DC 1, 2 Division C, IDSC DC 1, 2 Division D, IDSD DC 1	Provide dc power when ac power available and maintain battery in a charged condition.	A,B	No output	Annunciator in main control room; battery charger failure alarm for ac power failure, dc output under/ over voltage, dc no charge, and input/output breaker open.	None; Battery can provide power for 24 and 72 hours without charger; other divisions available. Spare battery charger available for connection.	Failure of only one div. chgr. falls into single failure criteria and the other three div. are still available.
			C	No input	Same as above.	None; Battery can provide power for 24 and 72 hours without charger.	This component inoperable during blackout.
2.	Battery Division A, IDSA DB 1A,1B Division B, IDSB DB 1A,1B,2A,2B Division C, IDSC DB 1A,1B,2A,2B Division D, IDSD DB 1A,1B	Backup to battery charger during load cycling (in-rush current) and provide dc power for 24 and 72 hours without battery charger.	A,B	No output or low voltage	Battery monitor provides annunciation in main control room; switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Battery chargers (item 1) available; other divisions available. Spare battery available for connection.	Power still available with a single ground. Loss of entire battery function is single failure and the other divisions are available.
			C	No output or low voltage	Same as above.	None; Other divisions available; spare battery available.	
3.	Fused transfer switch box Division A, IDSA DF 1 Division B, IDSB DF 1,2 Division C, IDSC DF 1,2 Division D, IDSD DF 1	Provide circuit continuity and protection between Item 2 battery and Item 4 switchboard.	A,B,C	Inadvertent opening (blown fuse)	Switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Other divisions available.	

Table 8.3.2-7 (Sheet 2 of 4)

CLASS 1E 125V DC AND CLASS 1E UNINTERRUPTIBLE POWER SUPPLIES FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
4.	125V DC Switchboard Division A, IDSA DS 1 Division B, IDSB DS 1,2 Division C, IDSC DS 1,2 Division D, IDSD DS 1	Distribute power via fusible disconnects to loads from chargers and battery.	A,B,C	Bus ground fault	Switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Other divisions available.	
5.	Fusible disconnect Division A, for Charger 1 Division B, for Charger 1,2 Division C, for Charger 1,2 Division D, for Charger 1	Provide circuit continuity and protection between Item 1 and 4.	A,B	Inadvertent opening (blown fuse)	Alarm in main control room for charger failure (dc no charge).	None; Battery can provide power for 24 and 72 hours without chargers. Other divisions available.	
			C	Inadvertent opening (blown fuse)	Same as above.	None; Battery can provide power for 24 and 72 hours without chargers.	
6.	Fusible disconnect Division A, for Inverter 1 Division B, for Inverter 1,2 Division C, for Inverter 1,2 Division D, for Inverter 1	Provide circuit continuity and protection between Item 4 switchboard and Item 9 inverters.	A,B,C	Inadvertent opening (blown fuse)	Inverter trouble alarm in main control room for loss of dc input, loss of ac output, input, output and backup power supply breaker open.	None; System safety function can be met with loss of one division.	
7.	Fusible disconnect for DC MCC Division A Division B Division C Division D	Provide circuit continuity and protection between Item 4 switchboard and Item 13 DC MCC.	A,B,C	Inadvertent opening (blown fuse)	DC MCC trouble alarm in main control room for bus undervoltage.	None; Other divisions available.	

Table 8.3.2-7 (Sheet 3 of 4)

CLASS 1E 125V DC AND CLASS 1E UNINTERRUPTIBLE POWER SUPPLIES FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
8.	Fusible disconnect for DC dist panel Division A Division B Division C Division D	Provide circuit continuity and protection between Item 4 switchboard and Item 14 dc panel.	A,B,C	Inadvertent opening (blown fuse)	DC dist. panel trouble alarm in main control room for bus undervoltage.	None; Other divisions available.	
9.	Inverter Division A, IDSA DU 1 Division B, IDSB DU 1,2 Division C, IDSC DU 1,2 Division D, IDSD DU 1	Convert 125V DC to 208Y/120V AC and provide 120V AC power.	A,B,C	No output	Alarm in main control room for common UPS trouble, for loss of dc input, loss of ac output; input, output and backup power supply breakers open.	None; System safety function can be met with loss of one division.	
10.	Voltage regulating transformer Division A, IDSA DT 1 Division B, IDSB DT 1 Division C, IDSC DT 1 Division D, IDSD DT 1	Backup to inverter (Item 9) when it is bypassed for maintenance or malfunction (local manual switching at inverter).	A,B	No output	Alarm in main control room for input and output power supply breakers open. And bus undervoltage.	None; Other divisions available.	For single failure analysis: These components are redundant to Item 1. These components are redundant to Item 9.
			C	No input	Bus undervoltage.	None	This component cannot function during blackout.
11.	208Y/120V AC distr. panel Division A, IDSA EA 1 Division B, IDSB EA 1,3 Division C, IDSC EA 1,3 Division D, IDSD EA 1	Distribute power via breakers to loads	A,B,C	Ground and bus fault	Alarm in main control room for undervoltage.	None; System safety function can be met with loss of one division.	

Table 8.3.2-7 (Sheet 4 of 4)

CLASS 1E 125V DC AND CLASS 1E UNINTERRUPTIBLE POWER SUPPLIES FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
12.	208Y/120V AC Distr. Panel Div. A, IDSA EA 2 Div. B, IDSB EA 2 Div. C, IDSC EA 2 Div. D, IDSD EA 2	Backup to invertor (Item 9) when it is bypassed for maintenance or malfunction (local manual switching at inverter).	A,B	Ground and bus fault	Alarm in main control room for bus undervoltage.	None; Other divisions available.	
			C	No input	Bus under voltage.	None	This component cannot function during blackout.
13.	DC MCC DIV. A, IDSA DK 1 DIV. B, IDSB DK 1 DIV. C, IDSC DK 1 DIV. D, IDSD DK 1	Distribute power via fusible disconnect to loads.	A,B,C	Ground and bus fault	MCC trouble alarm per MCC in main control room for bus undervoltage and ground detection.	None; Other divisions available.	Power still available with a single ground.
14.	DC Distr. Panel Div. A, IDSA DD1 Div. B, IDSB DD1 Div. C, IDSC DD1 Div. D, IDSD DD1	Distribute power via fusible disconnect to loads.	A,B,C	Ground and bus fault	Panel trouble alarm per panel in main control room for bus undervoltage and ground detection.	None; Other divisions available.	Power still available with a single ground.

- Plant operating modes are represented as follows:

  A – Normal or preferred power available.
  B – Loss of normal power and loss of preferred power and onsite standby diesel generator available.
  C – Blackout (loss of all ac systems, except 208Y/120-V AC UPS system).

  System success criteria are as follows:

  125-V DC System – Three out of four (Division A, B, C or D) divisions required.
  208Y/120-V AC UPS System – Three out of four divisions required.

- The failure of any one fusible disconnect or opening of one circuit breaker under a fault condition results in only the loss of the associated division. The other redundant divisions still remain available.

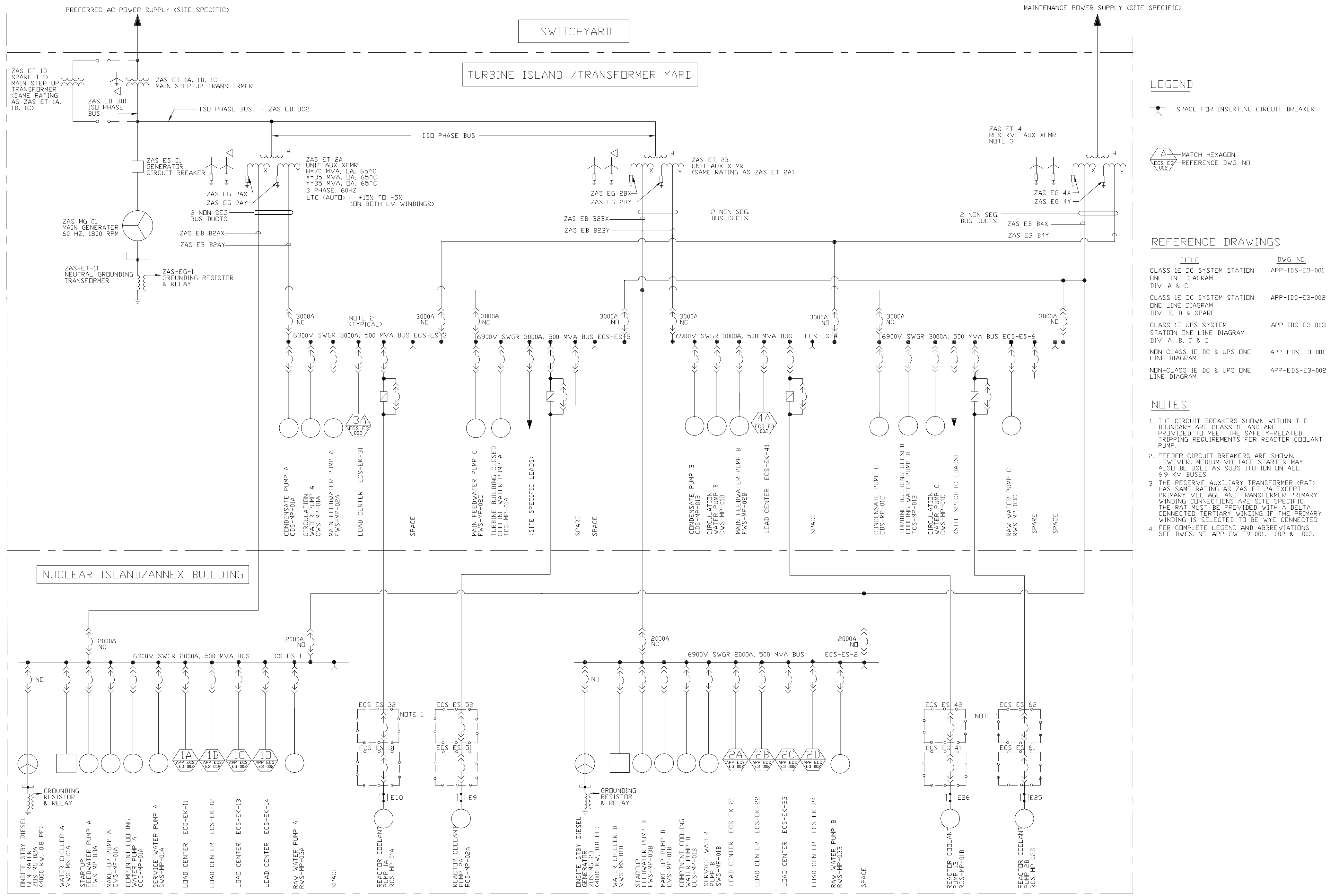


Figure 8.3.1-1

AC Power Station One Line Diagram

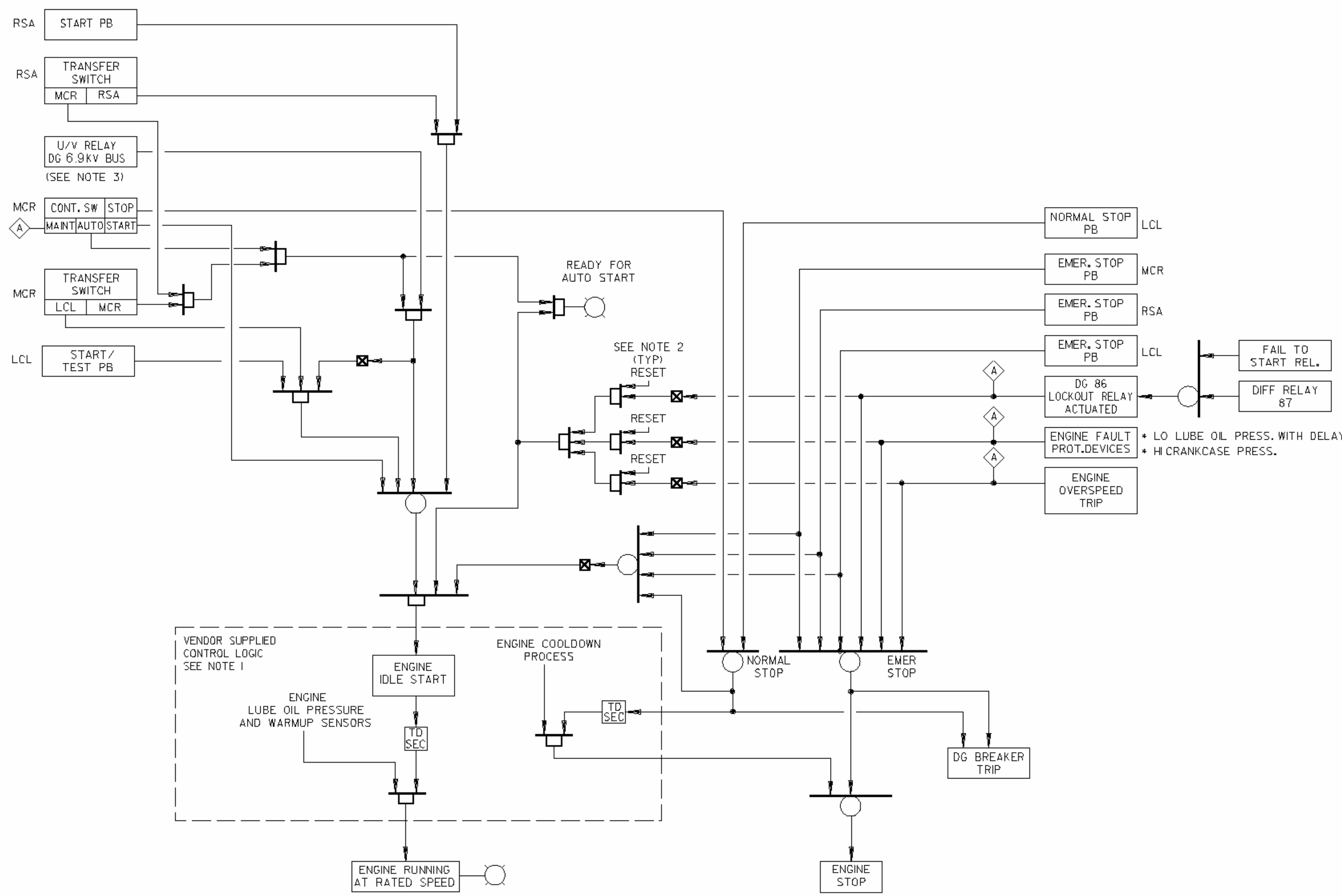


Figure 8.3.1-2

On-Site Standby Diesel Generator Initiating Circuit Logic Diagram

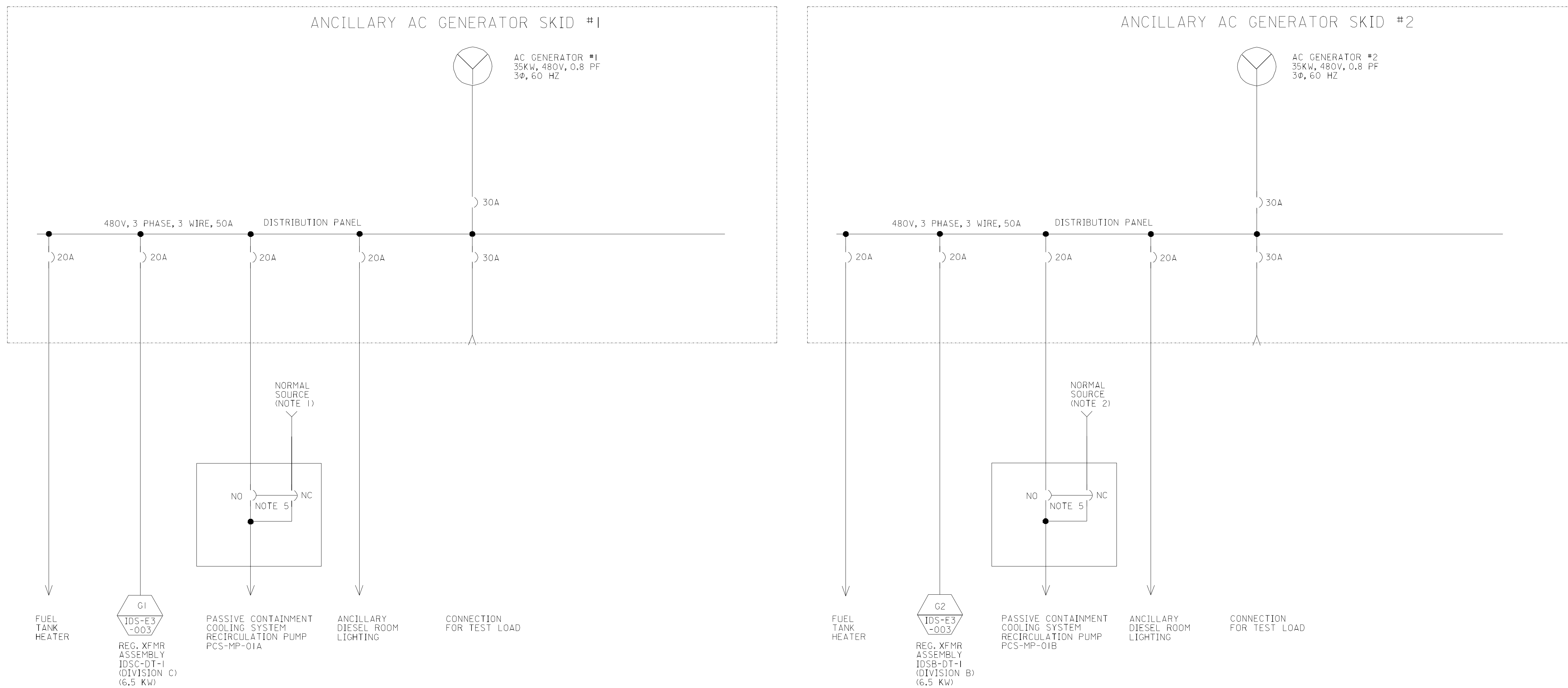
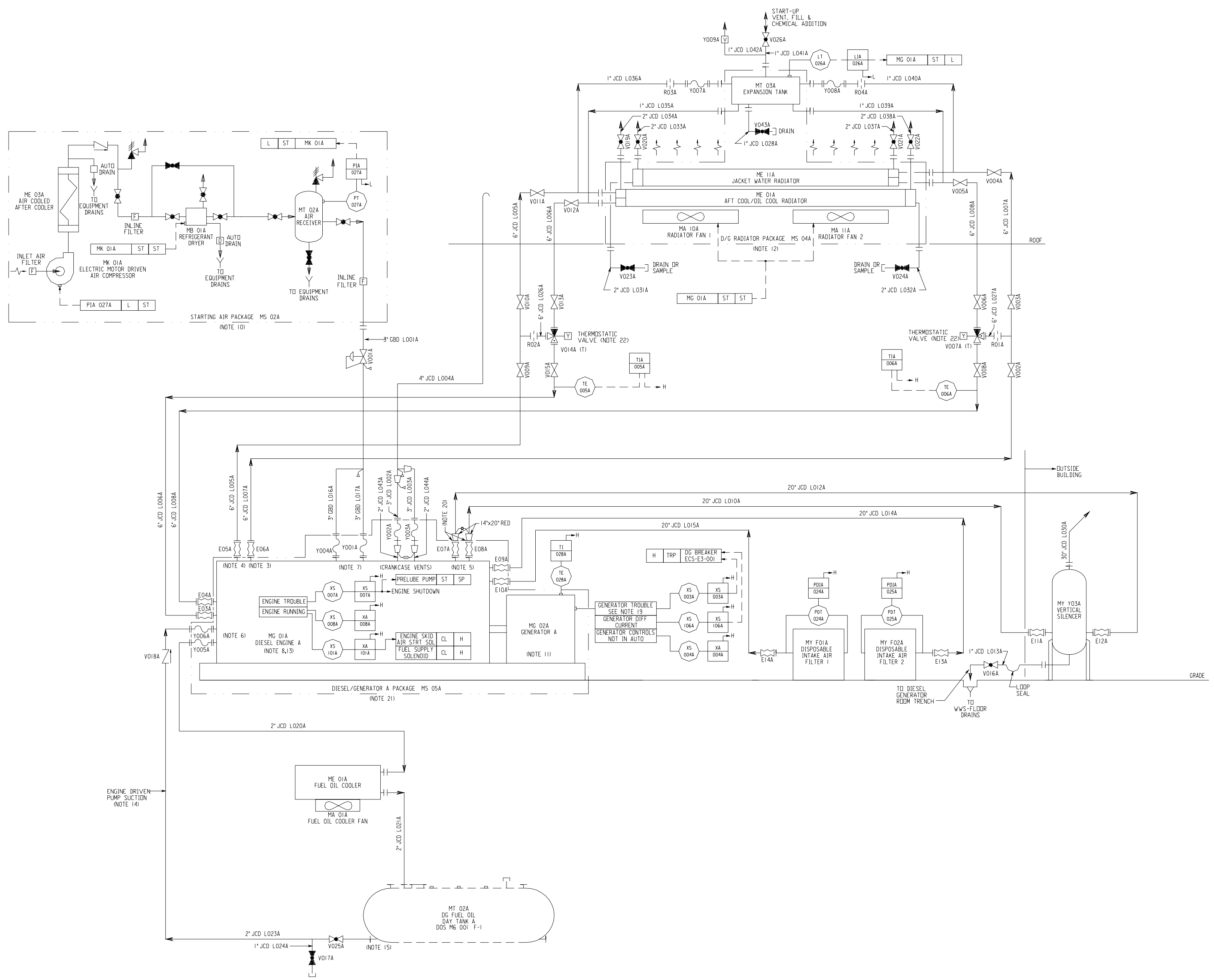


Figure 8.3.1-3

Post 72 Hour Temporary Electric Power One Line Diagram



NOTES

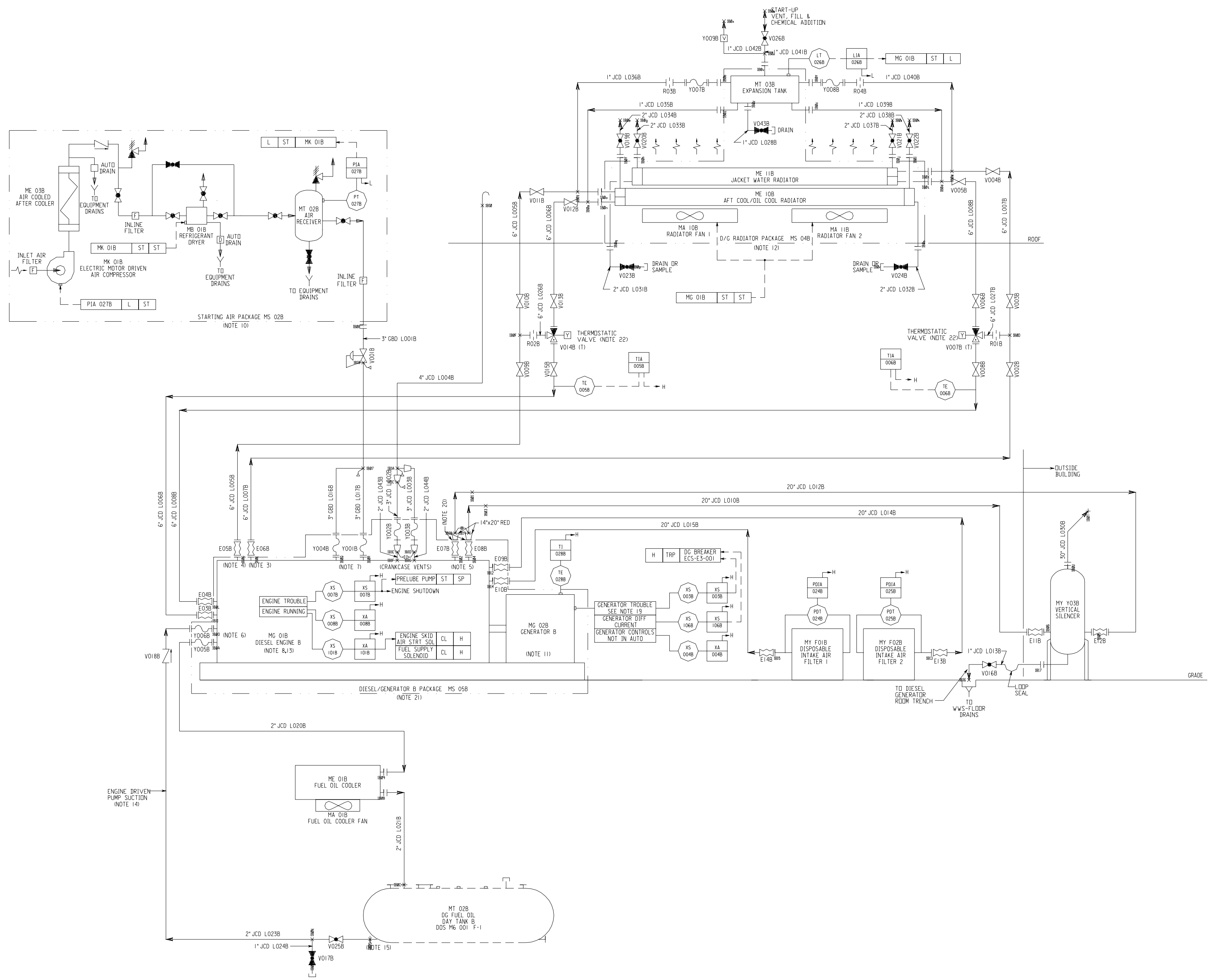
1. THIS DESIGN TYPICAL AND FUNCTIONAL FOR ANY OFFERED DIESEL GENERATOR MANUFACTURER.
2. THE SYSTEM LOCATOR CODE ZOS HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. EXCEPT FOR EQUIPMENT, THE COMPONENT TYPE CODE HAS ALSO BEEN OMITTED.
3. DIESEL ENGINE JACKET WATER COOLING CIRCUIT INCLUDES ENGINE DRIVEN JACKET WATER PUMP MP 05A AND SEPARATE KEEP WARM CIRCUIT WITH ELECTRIC MOTOR DRIVEN JACKET WATER HEATER PUMP MP 06A AND ELECTRIC JACKET WATER HEATER EH 01A.
4. DIESEL ENGINE AFTER COOLER/OIL COOLER CIRCUIT INCLUDES ENGINE DRIVEN AC/OC WATER PUMP MP 07A AND TURBO CHARGERS AFTER COOLER ME 02A AND LUBE OIL COOLERS ME 04A & ME 05A.
5. DIESEL ENGINE EXHAUST GAS DRIVEN TURBO CHARGERS MG 05A AND MG 06A COMPRESS COMBUSTION AIR TO THE DIESEL ENGINE.
6. DIESEL ENGINE FUEL OIL SYSTEM INCLUDES ENGINE DRIVEN FUEL OIL PUMP MP 04A.
7. DIESEL ENGINE STARTING AIR SYSTEM INCLUDES STARTING AIR MOTORS MG 03A AND MG 04A.
8. DIESEL ENGINE LUBE OIL SYSTEM INCLUDES ENGINE DRIVEN MAIN LUBE OIL PUMP MP 01A AND AC MOTOR PRELUBE OIL PUMP MP 02A, DC MOTOR PRELUBE PUMP MP 03A AND KEEP WARM LUBE OIL HEATER EH 02A.
9. EQUIPMENT VENDOR SHALL FURNISH ALL SMALL SPECIALITIES, VALVES ETC IN EITHER 1" OR 2" SIZE AS REQUIRED FOR SERVICE CONDITIONS.
10. STARTING AIR SYSTEM IS SKID MOUNTED PACKAGE.
11. GENERATOR IS EQUIPPED WITH A SPACE HEATER FOR FREEZE PROTECTION.
12. JACKET WATER AND AFT COOL/OIL COOL RADIATORS IS SKID MOUNTED PACKAGE. PACKAGE SHARES RADIATOR FANS 1 AND 2.
13. LOCAL AND REMOTE DIESEL GENERATOR ALARM AND ANNUNCIATION POINTS ARE AS RECOMMENDED BY VENDOR.
14. DIESEL FUEL LINE TO ENGINE IS ROUTED IN TRENCH.
15. FUEL OIL SUCTION CONNECTION FROM DAY TANK SIDE IS ABOVE POTENTIAL RESIDUE LEVEL.
16. ALL INSTRUMENTATION AND EQUIPMENT FOR SYSTEM PACKAGE IS FURNISHED BY DIESEL GENERATOR VENDOR.
17. SIGNAL INTERFACES ORIGINATING FROM THE DIESEL GENERATOR PACKAGES ARE IDENTIFIED IN SSD #ZOS E8 001.
18. TEST AND SAMPLE POINTS NOT SHOWN.
19. GENERATOR TROUBLE SIGNAL IS ACTIVATED ON OCCURANCE OF ANY OF THE FOLLOWING CONDITIONS. THE CONDITIONS ARE ALARMED THROUGH DCS.
    1. LOSS OF GENERATOR FIELD (40)
    2. GENERATOR OVERCURRENT (51V)
    3. GENERATOR NEG. SEQ. OVERCURRENT (46)
    4. GENERATOR REV. PWR ACTUATION (32)
20. EQUIPMENT CONNECTION FLANGE ONLY.
21. DIESEL ENGINE AND GENERATOR ARE SKID MOUNTED AS A SINGLE MECHANICAL PACKAGE.
22. SELF-CONTAINED, SELF-POWERED, THREE-WAY THERMOSTATIC VALVE

Inside Diesel Generator Building

Figure 8.3.1-4 (Sheet 1 of 2)

Diesel Generator System
Piping and Instrumentation Diagram

(REF) ZOS 001



NOTES

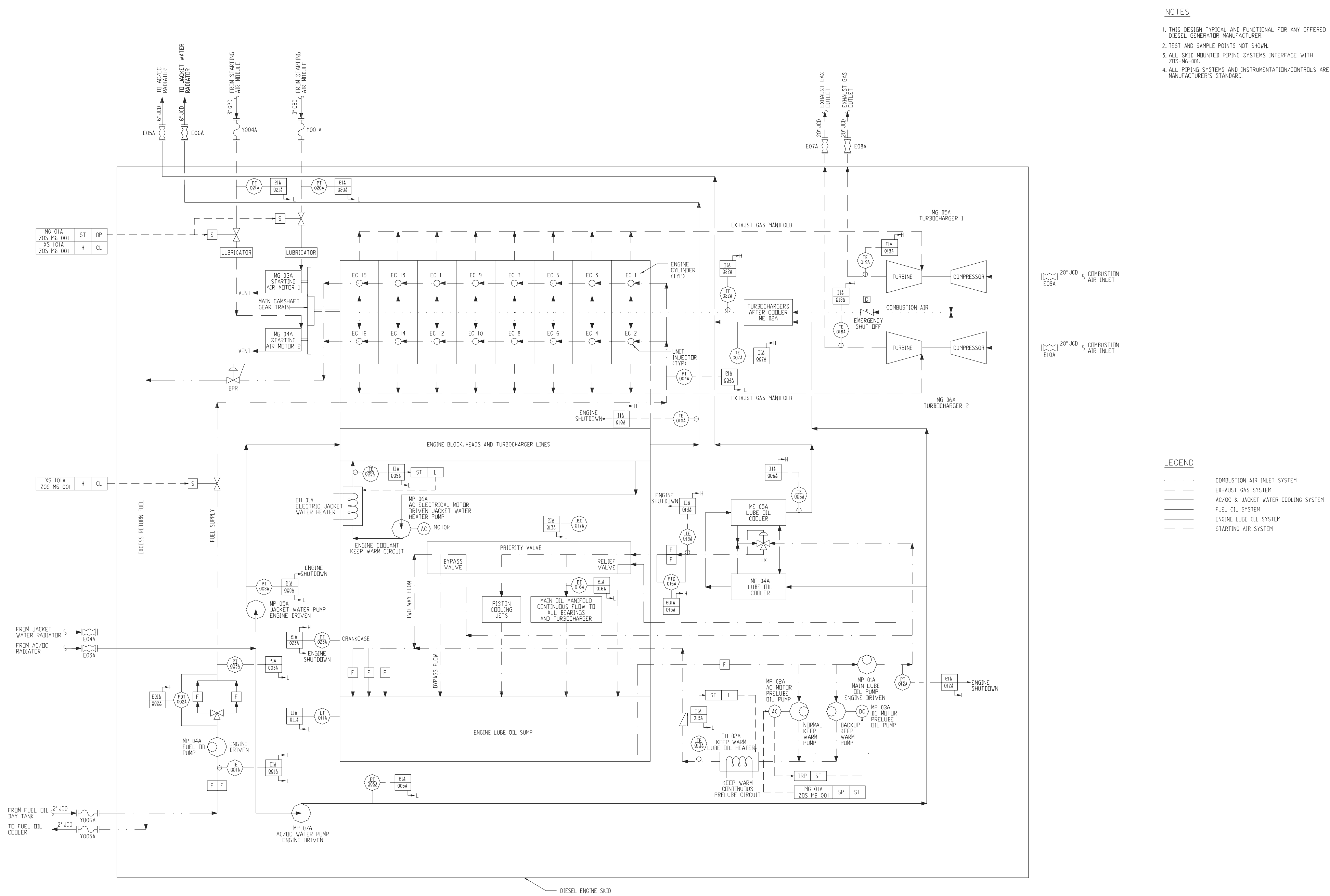
1. THIS DESIGN TYPICAL AND FUNCTIONAL FOR ANY OFFERED DIESEL GENERATOR MANUFACTURER.
2. THE SYSTEM LOCATOR CODE ZOS HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. EXCEPT FOR EQUIPMENT, THE COMPONENT TYPE CODE HAS ALSO BEEN OMITTED.
3. DIESEL ENGINE JACKET WATER COOLING CIRCUIT INCLUDES ENGINE DRIVEN JACKET WATER PUMP MP 05B AND SEPARATE KEEP WARM CIRCUIT WITH ELECTRIC MOTOR DRIVEN JACKET WATER HEATER PUMP MP 06B AND ELECTRIC JACKET WATER HEATER EH 01B.
4. DIESEL ENGINE AFTER COOLER/OIL COOLER CIRCUIT INCLUDES ENGINE DRIVEN AC/OC WATER PUMP MP 07B AND TURBO CHARGERS AFTER COOLER ME 02B AND LUBE OIL COOLERS ME 04B & ME 05B.
5. DIESEL ENGINE EXHAUST GAS DRIVEN TURBO CHARGERS MG 05B AND MG 06B COMPRESS COMBUSTION AIR TO THE DIESEL ENGINE.
6. DIESEL ENGINE FUEL OIL SYSTEM INCLUDES ENGINE DRIVEN FUEL OIL PUMP MP 04B.
7. DIESEL ENGINE STARTING AIR SYSTEM INCLUDES STARTING AIR MOTORS MG 03B AND MG 04B.
8. DIESEL ENGINE LUBE OIL SYSTEM INCLUDES ENGINE DRIVEN MAIN LUBE OIL PUMP MP 01B AND AC MOTOR PRELUBE OIL PUMP MP 02B, DC MOTOR PRELUBE PUMP MP 03B AND KEEP WARM LUBE OIL HEATER EH 02B.
9. EQUIPMENT VENDOR SHALL FURNISH ALL SMALL SPECIALITIES, VALVES ETC IN EITHER 1" OR 2" SIZE AS REQUIRED FOR SERVICE CONDITIONS.
10. STARTING AIR SYSTEM IS SKID MOUNTED PACKAGE.
11. GENERATOR IS EQUIPPED WITH A SPACE HEATER FOR FREEZE PROTECTION.
12. JACKET WATER AND AFT COOL/OIL COOL RADIATORS IS SKID MOUNTED PACKAGE. PACKAGE SHARES RADIATOR FANS 1 AND 2.
13. LOCAL AND REMOTE DIESEL GENERATOR ALARM AND ANNUNCIATION POINTS ARE AS RECOMMENDED BY VENDOR.
14. DIESEL FUEL LINE TO ENGINE IS ROUTED IN TRENCH.
15. FUEL OIL SUCTION CONNECTION FROM DAY TANK SIDE IS ABOVE POTENTIAL RESIDUE LEVEL.
16. ALL INSTRUMENTATION AND EQUIPMENT FOR SYSTEM PACKAGE IS FURNISHED BY DIESEL GENERATOR VENDOR.
17. SIGNAL INTERFACES ORIGINATING FROM THE DIESEL GENERATOR PACKAGES ARE IDENTIFIED IN SSD #ZOS E8 001.
18. TEST AND SAMPLE POINTS NOT SHOWN.
19. GENERATOR TROUBLE SIGNAL IS ACTIVATED ON OCCURANCE OF ANY OF THE FOLLOWING CONDITIONS. THE CONDITIONS ARE ALARMED THROUGH DCS.
    1. LOSS OF GENERATOR FIELD (40)
    2. GENERATOR OVERCURRENT (51V)
    3. GENERATOR NEG. SEQ. OVERCURRENT (46)
    4. GENERATOR REV. PWR ACTUATION (32)
20. EQUIPMENT CONNECTION FLANGE ONLY.
21. DIESEL ENGINE AND GENERATOR ARE SKID MOUNTED AS A SINGLE MECHANICAL PACKAGE.
22. SELF-CONTAINED, SELF-POWERED, THREE-WAY THERMOSTATIC VALVE

Inside Diesel Generator Building

Figure 8.3.1-4 (Sheet 2 of 2)

Diesel Generator System
Piping and Instrumentation Diagram

(REF) ZOS 002

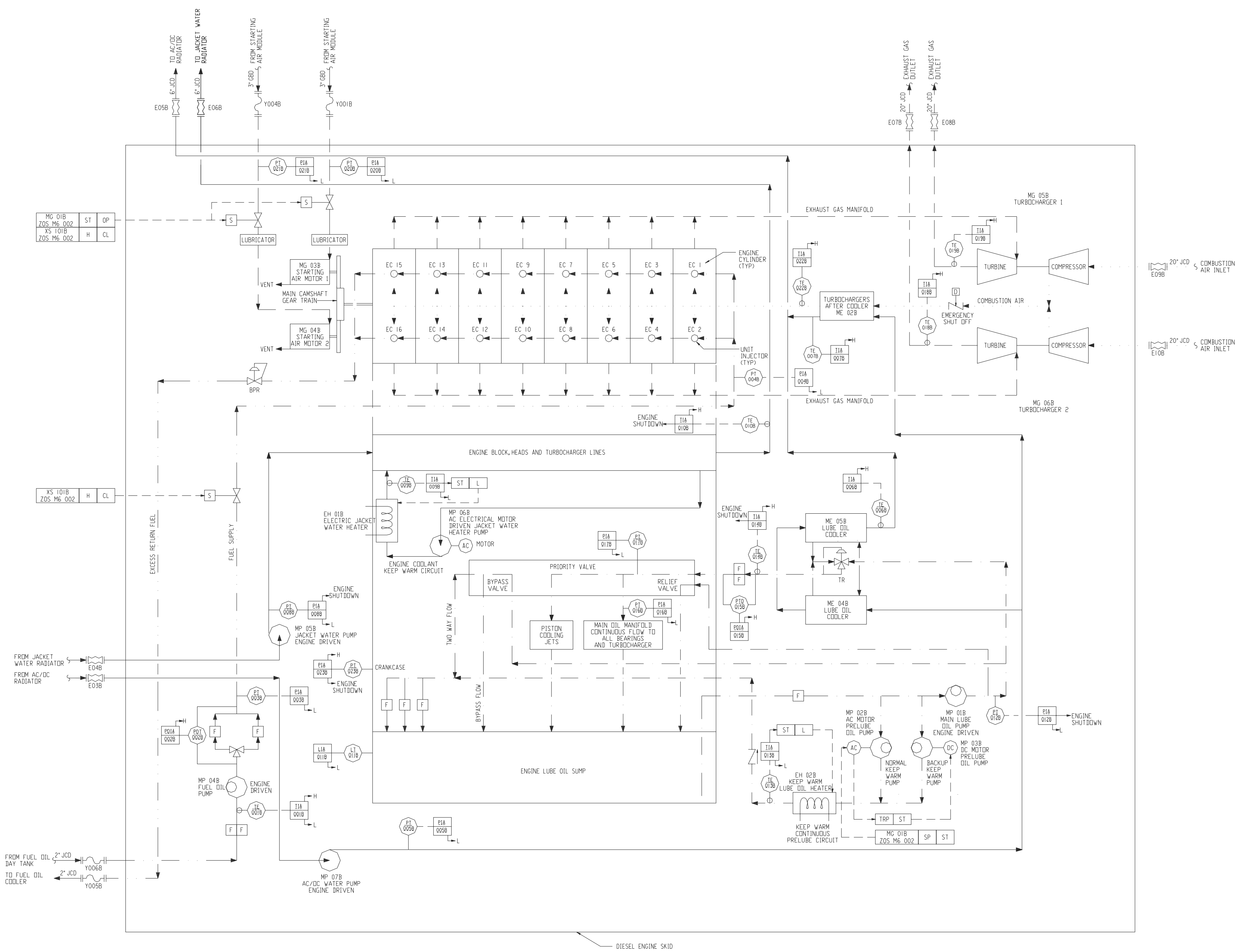


Inside Diesel Generator Building

Figure 8.3.1-5 (Sheet 1 of 2)

Diesel Engine Skid Mounted System

(REF) ZOS K001



NOTES

1. THIS DESIGN TYPICAL AND FUNCTIONAL FOR ANY OFFERED DIESEL GENERATOR MANUFACTURER.
2. TEST AND SAMPLE POINTS NOT SHOWN.
3. ALL SKID MOUNTED PIPING SYSTEMS INTERFACE WITH ZOS-M6-002.
4. ALL PIPING SYSTEMS AND INSTRUMENTATION/CONTROLS ARE MANUFACTURER'S STANDARD.

LEGEND

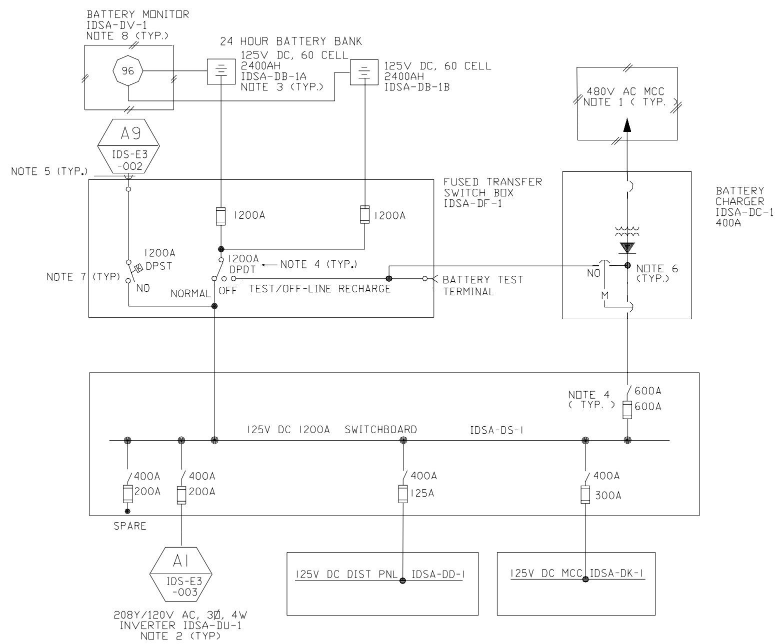
COMBUSTION AIR INLET SYSTEM
EXHAUST GAS SYSTEM
AC/OC & JACKET WATER COOLING SYSTEM
FUEL OIL SYSTEM
ENGINE LUBE OIL SYSTEM
STARTING AIR SYSTEM

Inside Diesel Generator Building

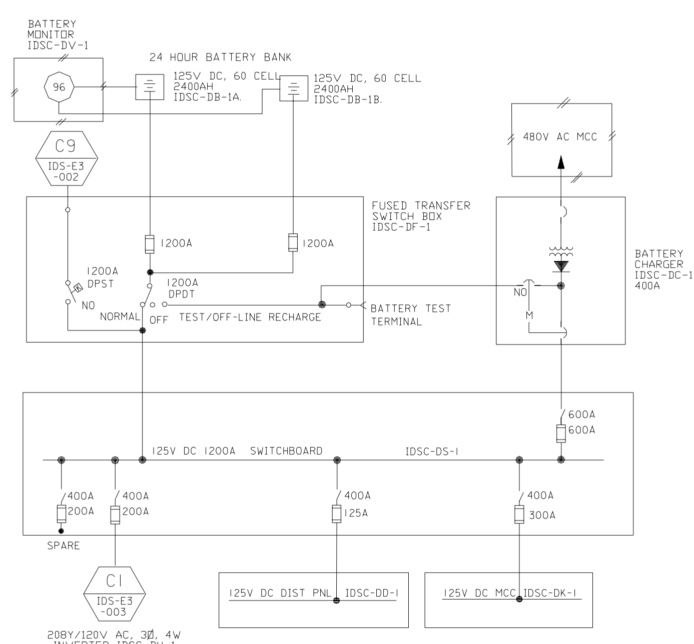
Figure 8.3.1-5 (Sheet 2 of 2)

Diesel Engine Skid Mounted System

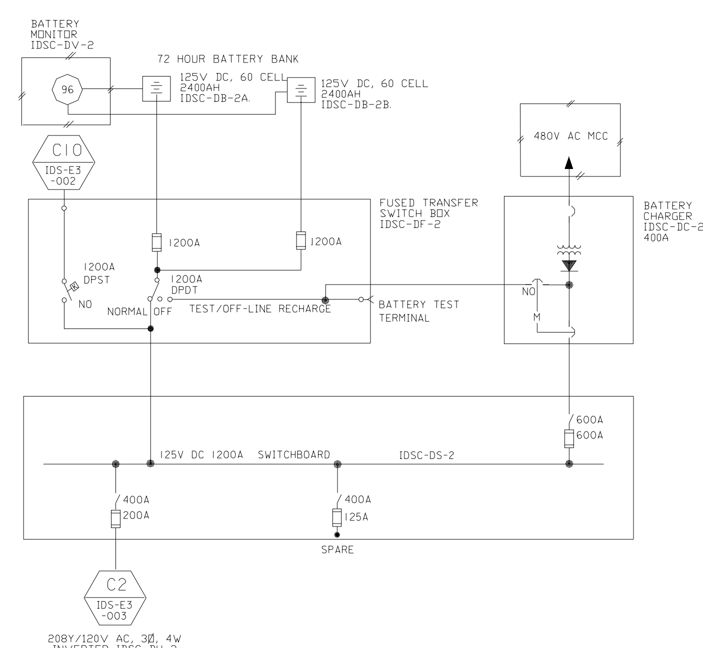
(REF) ZOS K002



24 HOUR BATTERY BANK (DIVISION A)



24 HOUR BATTERY BANK (DIVISION C)



72 HOUR BATTERY BANK (DIVISION C)

NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED MCC.
2. SEE DWG. NO. IDS-E3-003 FOR UPS CONFIGURATION.
3. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
4. ALL FUSIBLE DISCONNECT SWITCHES ARE RATED FOR 100 KA SHORT CIRCUIT RATING. THE 1200A SWITCH RATING IS CAPABLE OF CARRYING 2400A FOR UP TO 2 HOURS.
5. SPARE CLASS 1E BATTERY BANK WITH SPARE CLASS 1E BATTERY CHARGER IS UTILIZED FOR CLASS 1E DC SYSTEM AS A TEMPORARY REPLACEMENT FOR ANY 24 HR OR 72 HR BATTERY BANK ONE AT A TIME. SPARE CLASS 1E BATTERY BANK (WITHOUT SPARE CLASS 1E BATTERY CHARGER) CAN BE USED AS A TEMPORARY POWER SOURCE FOR NON-CLASS 1E DC SYSTEM.
6. MECHANICAL INTERLOCK IS PROVIDED TO PERMIT CLOSING ONLY ONE CIRCUIT BREAKER AT A TIME.
7. KIRK-KEY INTERLOCK SWITCH IS PROVIDED TO PREVENT TRANSFER OPERATION OF MORE THAN ONE SWITCHBOARD AT A TIME.
8. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, -002 AND -003.

REFERENCE DRAWINGS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAMS	ECS-E3-001 & 2
CLASS 1E DC SYSTEM - STATION ONE LINE DIAGRAM DIV. B,D & SPARE	IDS-E3-002
CLASS 1E UPS SYSTEM- STATION ONE LINE DIAGRAM DIV A,B,C & D	IDS-E3-003
CLASS 1E DC SYSTEM ONE LINE METER & RELAY DIAGRAMS	IDS-E3-004 THRU 010

Figure 8.3.2-1 (Sheet 1 of 2)

Class 1E DC System One Line Diagram

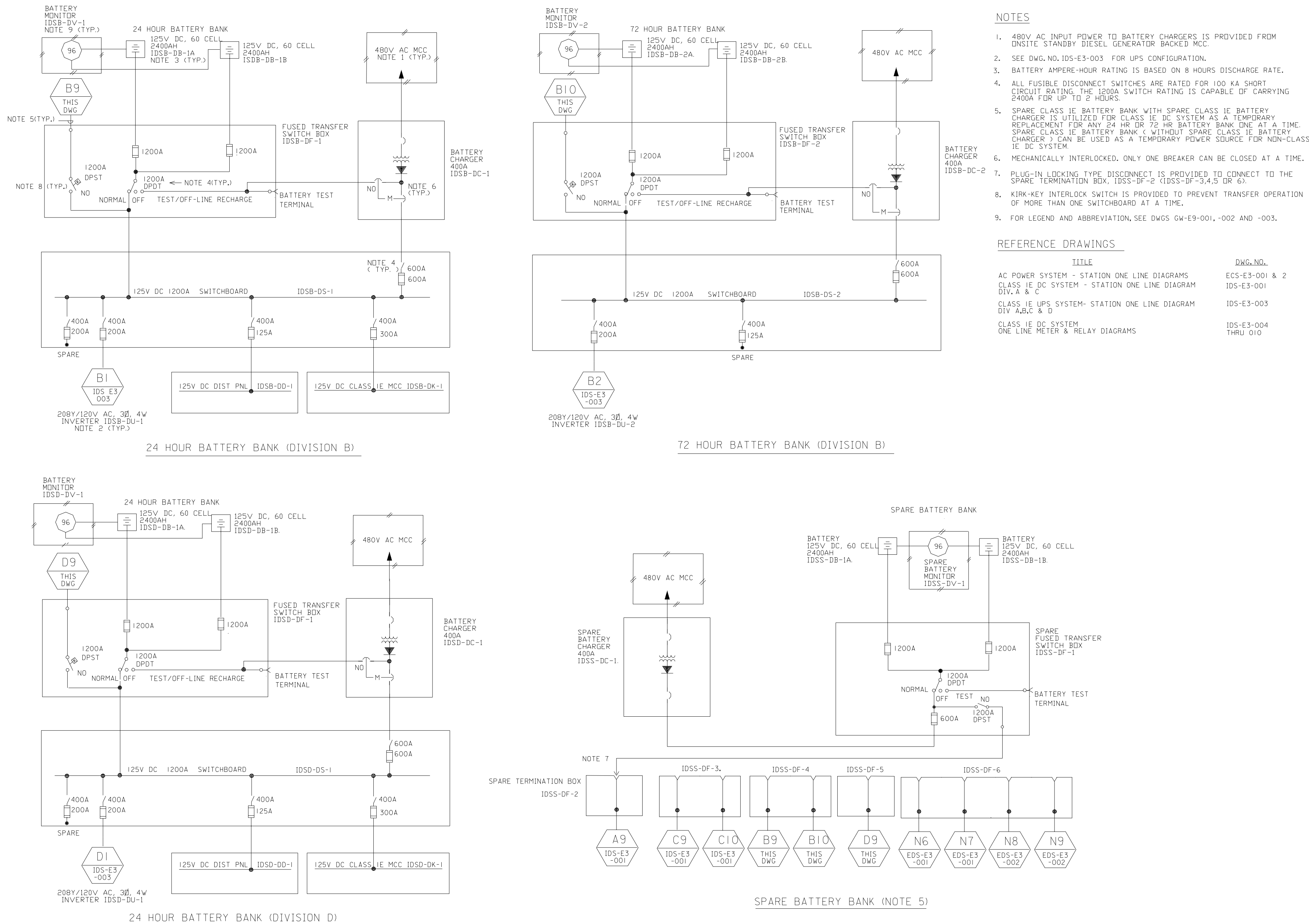


Figure 8.3.2-1 (Sheet 2 of 2)

Class 1E DC System One Line Diagram

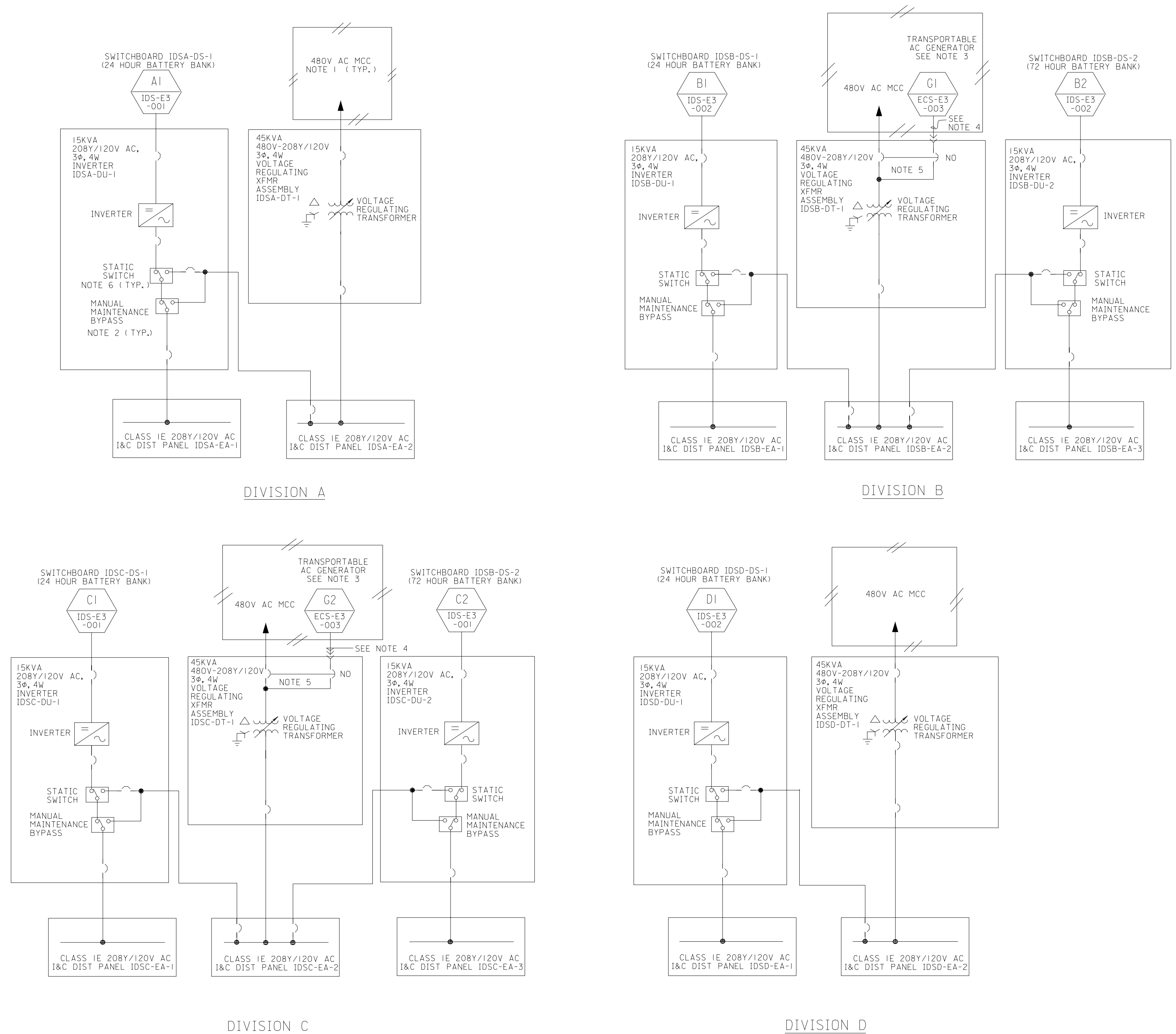


Figure 8.3.2-2

Class 1E 208y/120V UPS One Line Diagram

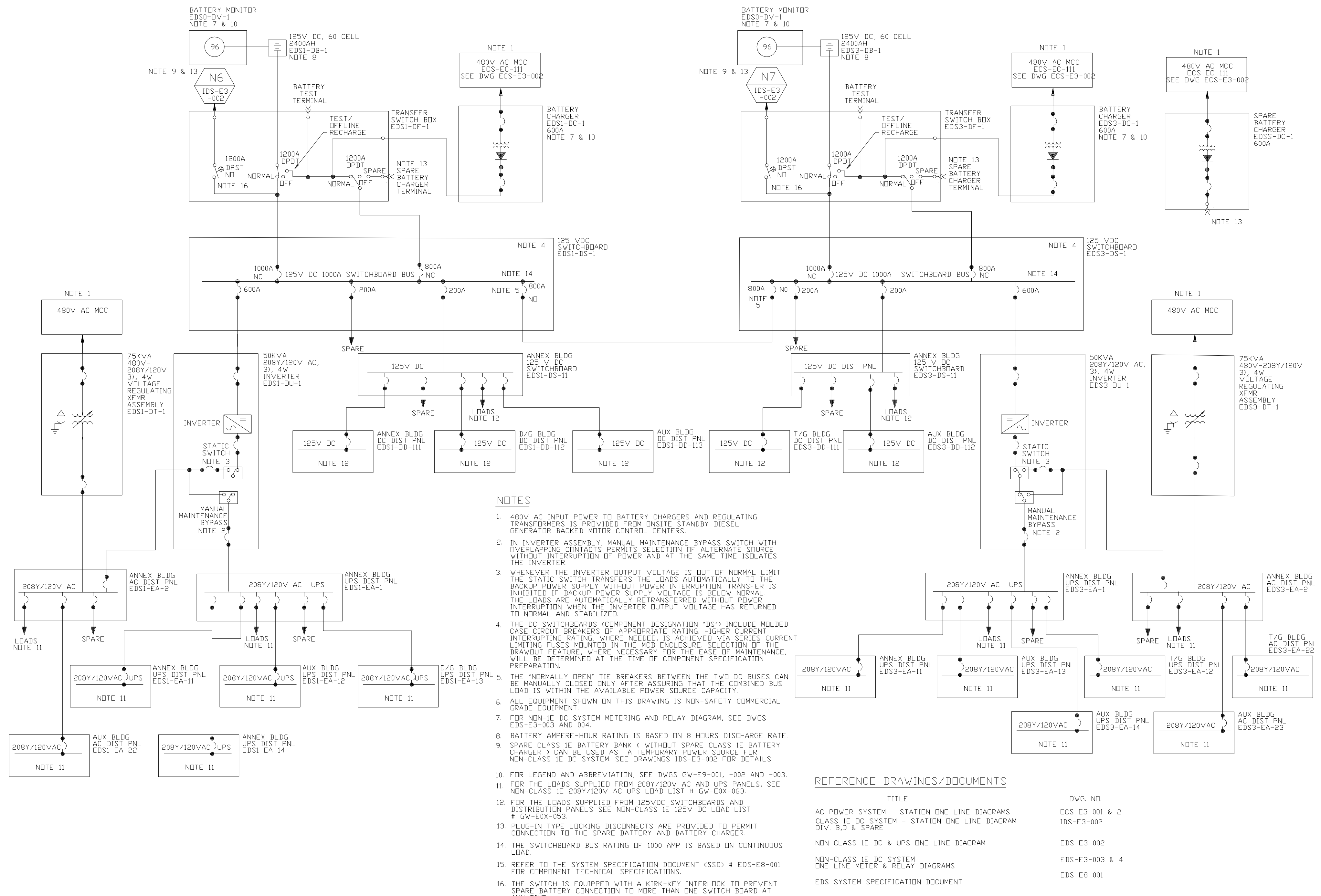
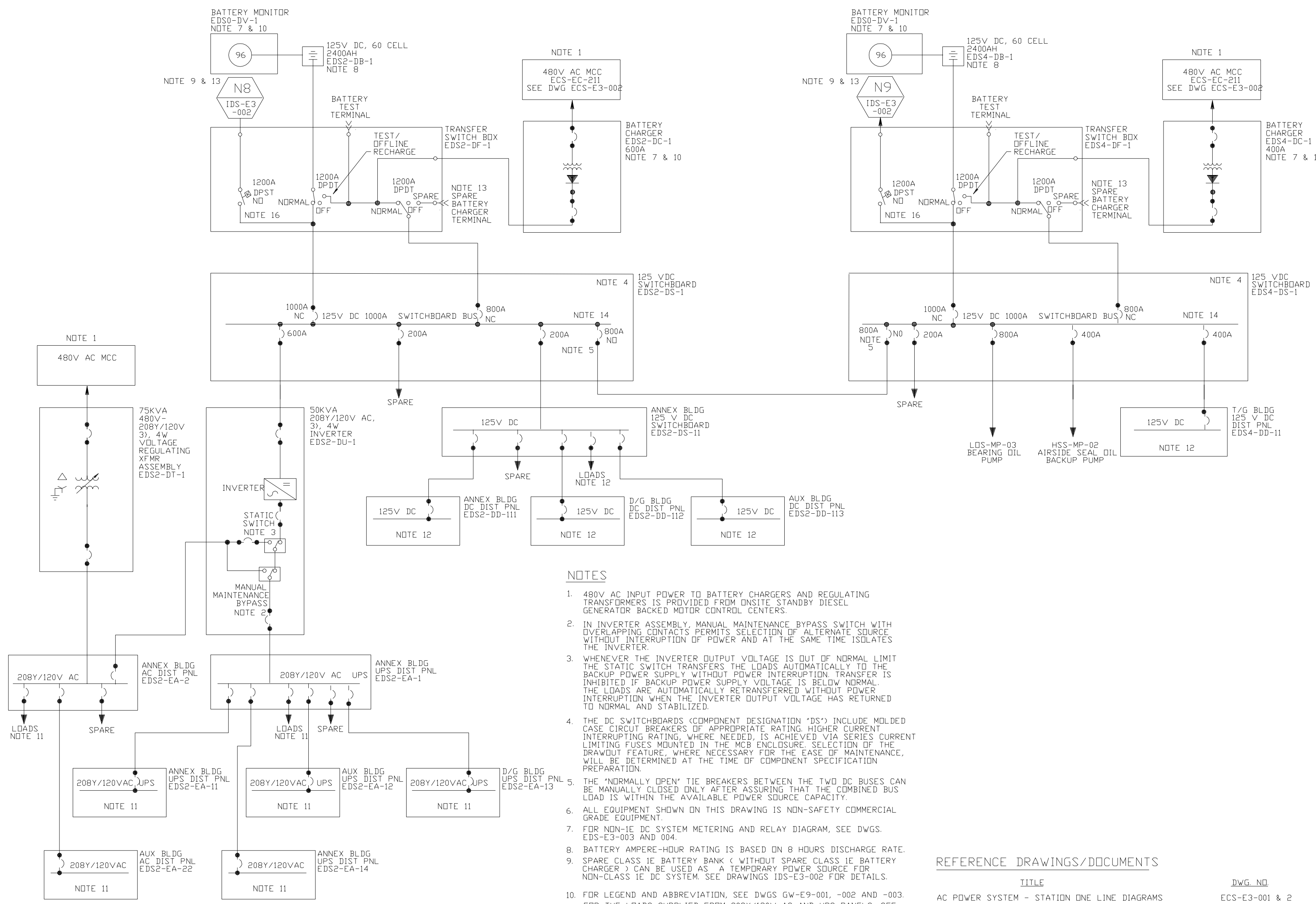


Figure 8.3.2-3 (Sheet 1 of 2)

Non-Class 1E DC & UPS System One Line Diagram



NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS AND REGULATING TRANSFORMERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED MOTOR CONTROL CENTERS.
2. IN INVERTER ASSEMBLY, MANUAL MAINTENANCE BYPASS SWITCH WITH OVERLAPPING CONTACTS PERMITS SELECTION OF ALTERNATE SOURCE WITHOUT INTERRUPTION OF POWER AND AT THE SAME TIME ISOLATES THE INVERTER.
3. WHENEVER THE INVERTER OUTPUT VOLTAGE IS OUT OF NORMAL LIMIT THE STATIC SWITCH TRANSFERS THE LOADS AUTOMATICALLY TO THE BACKUP POWER SUPPLY WITHOUT POWER INTERRUPTION. TRANSFER IS INHIBITED IF BACKUP POWER SUPPLY VOLTAGE IS BELOW NORMAL. THE LOADS ARE AUTOMATICALLY RETRANSFERRED WITHOUT POWER INTERRUPTION WHEN THE INVERTER OUTPUT VOLTAGE HAS RETURNED TO NORMAL AND STABILIZED.
4. THE DC SWITCHBOARDS (COMPONENT DESIGNATION "DS") INCLUDE MOLDED CASE CIRCUT BREAKERS OF APPROPRIATE RATING. HIGHER CURRENT INTERRUPTING RATING, WHERE NEEDED, IS ACHIEVED VIA SERIES CURRENT LIMITING FUSES MOUNTED IN THE MCB ENCLOSURE. SELECTION OF THE DRAWOUT FEATURE, WHERE NECESSARY FOR THE EASE OF MAINTENANCE, WILL BE DETERMINED AT THE TIME OF COMPONENT SPECIFICATION PREPARATION.
5. THE "NORMALLY OPEN" TIE BREAKERS BETWEEN THE TWO DC BUSES CAN BE MANUALLY CLOSED ONLY AFTER ASSURING THAT THE COMBINED BUS LOAD IS WITHIN THE AVAILABLE POWER SOURCE CAPACITY.
6. ALL EQUIPMENT SHOWN ON THIS DRAWING IS NON-SAFETY COMMERCIAL GRADE EQUIPMENT.
7. FOR NON-1E DC SYSTEM METERING AND RELAY DIAGRAM, SEE DWGS. EDS-E3-003 AND 004.
8. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
9. SPARE CLASS 1E BATTERY BANK (WITHOUT SPARE CLASS 1E BATTERY CHARGER) CAN BE USED AS A TEMPORARY POWER SOURCE FOR NON-CLASS 1E DC SYSTEM. SEE DRAWINGS IDS-E3-002 FOR DETAILS.
10. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, -002 AND -003.
11. FOR THE LOADS SUPPLIED FROM 208Y/120V AC AND UPS PANELS, SEE NON-CLASS 1E 208Y/120V AC UPS LOAD LIST # GW-E0X-063.
12. FOR THE LOADS SUPPLIED FROM 125VDC SWITCHBOARDS AND DISTRIBUTION PANELS SEE NON-CLASS 1E 125V DC LOAD LIST # GW-E0X-053.
13. PLUG-IN TYPE LOCKING DISCONNECTS ARE PROVIDED TO PERMIT CONNECTION TO THE SPARE BATTERY AND BATTERY CHARGER.
14. THE SWITCHBOARD BUS RATING OF 1000 AMP IS BASED ON CONTINUOUS LOAD.
15. REFER TO THE SYSTEM SPECIFICATION DOCUMENT (SSD) # EDS-E8-001 FOR COMPONENT TECHNICAL SPECIFICATIONS.
16. THE SWITCH IS EQUIPPED WITH A KIRK-KEY INTERLOCK TO PREVENT SPARE BATTERY CONNECTION TO MORE THAN ONE SWITCH BOARD AT ANY TIME.

REFERENCE DRAWINGS/DOCUMENTS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAMS	ECS-E3-001 & 2
CLASS 1E DC SYSTEM - STATION ONE LINE DIAGRAM DIV. B,D & SPARE	IDS-E3-002
NON-CLASS 1E DC & UPS ONE LINE DIAGRAM	EDS-E3-001
NON-CLASS 1E DC SYSTEM ONE LINE METER & RELAY DIAGRAMS	EDS-E3-003 & 4
EDS SYSTEM SPECIFICATION DOCUMENT	EDS-E8-001

Figure 8.3.2-3 (Sheet 2 of 2)

Non-Class 1E DC & UPS System One Line Diagram

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CHAPTER 9

AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

9.1.1.1 Design Bases

New fuel is stored in a high density rack which includes integral neutron absorbing material to maintain the required degree of subcriticality. The rack is designed to store fuel of the maximum design basis enrichment. The rack in the new fuel pit consists of an array of cells interconnected to each other at several elevations and to supporting grid structures at the top and bottom elevations. This rack module is not anchored to the pit floor, but lateral bracing to the pit wall structures is provided.

The new fuel rack includes storage locations for 72 fuel assemblies. The rack array center-to-center spacing is shown in Figure 9.1-1. This spacing provides a minimum separation between adjacent fuel assemblies which is sufficient to maintain a subcritical array even in the event the building is flooded with unborated water or fire extinguishant aerosols or during any design basis event. The design of the rack is such that a fuel assembly can not be inserted into a location other than a location designed to receive an assembly. An assembly can not be inserted into a full location. Surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel.

The requirements of ANS 57.1 are addressed in subsection 9.1.4. The rack is designed to withstand nominal operating loads and safe shutdown earthquake seismic loads defined in Table 9.1-1. The new fuel storage rack is designed to meet seismic Category I requirements of Regulatory Guide 1.29. Refer to subsection 1.9.1 for compliance with Regulatory Guides. The rack is also designed to withstand the maximum uplift force of the fuel handling jib crane.

AP1000 equipment, seismic and ASME Code classifications are discussed in Section 3.2. The requirements of ASME Code Section III, Division I, Article NF3000 are used as the criteria for evaluation of stress analysis. The materials are procured in accordance with ASME Code Section III, Division I, Article NF2000. Criticality analyses are performed in accordance with the requirements of ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors (Reference 1); and analysis codes are validated against the requirements of ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety (Reference 2).

9.1.1.2 Facilities Description

The new fuel storage facility is located within the seismic Category I auxiliary building fuel handling area. The facility is protected from the effects of natural phenomena such as earthquakes, wind, tornados, floods, and external missiles by the external walls of the auxiliary building. See Section 3.5 for additional discussion on protection from missiles. The facility is designed to

maintain its structural integrity following a safe shutdown earthquake and to perform its intended function following a postulated event such as fire, internal missiles, or pipe break. The walls surrounding the fuel handling area and new fuel storage pit protect the fuel from missiles generated inside the auxiliary building. The fuel handling area does not contain a credible source of missiles. Refer to subsection 1.2.4.3 for a discussion of the auxiliary building. Refer to Section 3.8 for a discussion of the structural design of the new fuel storage area. Refer to subsection 3.5.1 for a discussion of missile sources and protection.

The dry, unlined, approximately 17-feet deep reinforced concrete pit is designed to provide support for the new fuel storage rack. The rack is supported by the pit floor and laterally supported as required at the rack top grid structure by the pit wall structures. The walls of the new fuel pit are seismic Category I. The new fuel pit is normally covered to prevent foreign objects from entering the new fuel storage rack. Since the only crane that can access the new fuel pit does not have the capacity to lift heavy objects, as defined in subsection 9.1.5, the new fuel pit cover is not designed to protect the fuel assemblies from the effects of dropped heavy objects. Figures 1.2-7 through 1.2-10 show the relationship between the new fuel storage facility and other features of the fuel handling area.

The new fuel storage pit is drained by gravity drains that are part of the radioactive waste drain system (subsection 9.3.5), draining to the waste holdup tanks which are part of the liquid radwaste system (Section 11.2). These drains preclude flooding of the pit by an accidental release of water.

Nonseismic equipment in the vicinity of the new fuel storage racks is evaluated to confirm that its failure could not result in an increase of K_{eff} beyond the maximum allowable K_{eff}. Refer to subsection 3.7.3.13 for a discussion of the nonseismic equipment evaluation.

A jib crane is used to load new fuel assemblies into the new fuel rack and transfer new fuel assemblies from the new fuel pit into the spent fuel pool. The capacity of the jib crane is limited to 2000 lbs. The new fuel pit is not accessed by the fuel handling machine or by the cask handling crane. This precludes the movement of loads greater than fuel components over stored new fuel assemblies.

During fuel handling operations, a ventilation system removes gaseous radioactivity from the atmosphere above the new fuel pit. Refer to subsection 9.4.3 for a discussion of the fuel handling area HVAC system and Section 11.5 for process radiation monitoring. Security for the new fuel assemblies is described in Section 13.6.

9.1.1.2.1 New Fuel Rack Design

A. Design and Analysis of the New Fuel Rack

The new fuel storage racks are purchased equipment. The purchase specification for the new fuel storage racks will require the vendor to perform confirmatory dynamic and stress analyses. The seismic and stress analyses of the new fuel rack will consider the various conditions of full, partially filled, and empty fuel assembly loadings. The rack will be evaluated for the safe shutdown earthquake condition against the seismic Category I requirements. A stress analysis will be performed to verify the acceptability of the critical

load components and paths under normal and faulted conditions. The rack rests on the pit floor and is braced as required to the pit wall structures.

The dynamic response of the fuel rack assembly during a seismic event is the condition which produces the governing loads and stresses on the structure. The new fuel storage rack is designed to meet the seismic Category I requirements of Regulatory Guide 1.29.

Loads and Load Combinations

The applied loads to the new fuel rack are:

- Dead loads
- Live loads - effect of lifting the empty rack during installation
- Seismic forces of the safe shutdown earthquake
- Fuel assembly drop accident
- Fuel handling jib crane uplift - postulated stuck fuel assembly

Table 9.1-1 shows loads and load combinations considered in the analyses of the new fuel rack.

The margins of safety for the rack in the multi-direction seismic event are produced using loads obtained from the seismic analysis based on the simultaneous application of three statistically independent, orthogonal accelerations.

B. Fuel Handling Jib Crane Uplift Analysis

An analysis will be performed to demonstrate that the racks can withstand a maximum uplift load of 2000 pounds. This load will be applied to a postulated stuck fuel assembly. Resultant rack stresses will be evaluated against the stress limits and will be demonstrated to be acceptable. It will also be demonstrated that there is no change in rack geometry of a magnitude which causes the criticality criterion to be violated.

C. Fuel Assembly Drop Accident Analysis

In the unlikely event of dropping a fuel assembly, accidental deformation of the rack will be determined and evaluated in the criticality analysis to demonstrate that it does not cause the criticality criterion to be violated. The analysis considers only the case of a dropped new fuel assembly.

For the analysis of a dropped fuel assembly, two accident conditions are postulated. The first accident condition conservatively assumes that the weight of a fuel assembly and handling tool (1875 pounds total) impacts the top of the fuel rack from a drop height of 3 feet. Both a straight drop and an inclined drop will be included in the assessment. Calculations will be performed which demonstrate that the impact energy is absorbed by the dropped fuel assembly, the rack cells, and the rack base plate assembly.

The second accident condition assumes that the dropped assembly and tool (1875 pounds) falls straight through an empty cell and impacts the rack base plate from a drop height of

3 feet above the top of the rack. An analysis will be performed that will demonstrate the impact energy is absorbed by the fuel assembly and the rack base plate. The resulting rack deformations will be evaluated in the criticality analysis to demonstrate that the criticality criteria are not violated.

D. Failure of the Fuel Handling Jib Crane

The fuel handling jib crane is a seismic Category II component. The crane and the attachment to the building structure is evaluated to show that the crane does not fall into the new fuel storage pit during a seismic event.

E. Internally Generated Missiles

The fuel handling area does not contain any credible sources of internally generated missiles.

Stress analyses will be performed by the vendor using loads developed by the dynamic analysis. Stresses will be calculated at critical sections of the rack and compared to acceptance criteria referenced in ASME Section III, Division I, Article NF3000.

9.1.1.3 Safety Evaluation

The rack, being a seismic Category I structure, is designed to withstand normal and postulated dead loads, live loads, loads resulting from thermal effects, and loads caused by the safe shutdown earthquake event.

The design of the rack is such that K_{eff} remains less than or equal to 0.95 with new fuel of the maximum design basis enrichment. For a postulated accident condition of flooding of the new fuel storage area with unborated water, K_{eff} does not exceed 0.98.

The new fuel storage racks are purchased equipment. The purchase specification for the new fuel storage racks will require the vendor to perform a criticality analysis of the new fuel storage racks. The criticality evaluation will consider the inherent neutron absorbing effect of the materials of construction, including fixed neutron absorbing "poison" material.

The new fuel rack is located in the new fuel storage pit, which has a cover to protect the new fuel from debris. No loads are required to be carried over the new fuel storage pit while the cover is in place. The cover is designed such that it will not fall and damage the fuel or fuel rack during a seismic event. Administrative controls are utilized when the cover is removed for new fuel transfer operations to limit the potential for dropped object damage.

The racks are also designed with adequate energy absorption capabilities to withstand the impact of a dropped fuel assembly from the maximum lift height of the fuel handling jib crane. Handling equipment (spent fuel shipping cask crane) capable of carrying loads heavier than fuel components is prevented from traveling over the fuel storage area. The fuel storage racks can withstand an uplift force greater than or equal to the uplift capability of the fuel handling jib crane (2000 pounds).

Materials used in rack construction are compatible with the storage pit environment, and surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. Structural materials are corrosion resistant and will not contaminate the fuel assemblies or pit environment. Neutron absorbing "poison" material used in the rack design has been qualified for the storage environment. Venting of the neutron absorbing material is accomplished through the open corner design of the retaining "wrapper" plate.

The new fuel assemblies are stored dry. The rack structure is designed to maintain a safe geometric array for normal and postulated accident conditions. The fixed neutron absorbing "poison" material maintains the required degree of subcriticality for normal and postulated accident conditions such as flooding with pure water and low density optimum moderator "misting."

A discussion of the methodology used in the criticality analysis is provided in subsection 4.3.2.6.

9.1.2 Spent Fuel Storage

9.1.2.1 Design Bases

Spent fuel is stored in high density racks which include integral neutron absorbing material to maintain the required degree of subcriticality. The racks are designed to store fuel of the maximum design basis enrichment. Each rack in the spent fuel pool consists of an array of cells interconnected to each other at several elevations and to supporting grid structures at the top and bottom elevations. These rack modules are free-standing, neither anchored to the pool floor nor braced to the pool wall. The rack arrays center-to-center spacing is shown in Figures 9.1-2 and 9.1-3.

The spent fuel storage racks include storage locations for 619 fuel assemblies. The modified 10 x 7 rack module contains integral storage locations for five defective fuel storage containers as shown in Figure 9.1-4. The design of the rack is such that a fuel assembly can not be inserted into a location other than a location designed to receive an assembly. An assembly can not be inserted into a full location.

AP1000 equipment, seismic and ASME Code classifications are discussed in Section 3.2. The requirements of ASME Section III, Division I, Article NF3000 are used as the criteria for evaluation of stress analyses. The materials are procured in accordance with ASME Section III, Division I, Article NF2000. Criticality analyses are performed in accordance with the requirements of ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors (Reference 1); analysis codes are validated against the requirements of ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety (Reference 2); and overall requirements for fuel storage are in accordance with ANSI N210-76, Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations (Reference 3).

The spent fuel pool is designed to preclude inadvertent draining of the water from the pool.

9.1.2.2 Facilities Description

The spent fuel storage facility is designed to the guidelines of ANS 57.2 (Reference 4). The spent fuel storage facility is located within the seismic Category I auxiliary building fuel handling area. The walls of the spent fuel pool are an integral part of the seismic Category I auxiliary building structure. The facility is protected from the effects of natural phenomena such as earthquakes (subsection 3.7.2), wind and tornados (Section 3.3), floods (Section 3.4), and external missiles (Section 3.5).

The facility is designed to maintain its structural integrity following a safe shutdown earthquake and to perform its intended function following a postulated event such as a fire. Refer to subsection 1.2.4.3 for further discussions of the auxiliary building fuel handling area.

Nonseismic equipment in the vicinity of the spent fuel storage racks is evaluated to confirm that its failure could not result in an increase of K_{eff} beyond the maximum allowable K_{eff}. Refer to subsection 3.7.3.13 for a discussion of the nonseismic equipment evaluation.

The spent fuel pool provides storage space for spent fuel. The pool is approximately 42.5 feet deep and constructed of reinforced concrete and concrete filled structural modules as described in subsection 3.8.4. The portion of the structural modules in contact with the water in the pool is stainless steel and the reinforced concrete portions are lined with a stainless steel plate. The normal water volume of the pool is about 181,000 gallons of borated water (including racks without fuel at a water level 2 foot 6 inches below the operating deck) with a nominal boron concentration of 2500 ppm. Figures 1.2-7 through 1.2-10 show the spent fuel pool and other features of the fuel handling area.

The connections for the drain and makeup lines are located to preclude the draining of the spent fuel pool due to a break in a line or failure of a pump to stop. The connection for the spent fuel cooling pumps' suction is located below normal water level and above the level needed to provide sufficient water for shielding and for cooling of the fuel if the spent fuel pool cooling system is unavailable. Skimmers that normally follow the water level surface do not travel below the level of the spent fuel cooling suction. Connections for suction to the chemical volume and control system are located between the normal water level and the spent fuel cooling system pumps' suction connection level. Pipes which discharge into the spent fuel pool include a siphon break between the normal water level and the level of the spent fuel cooling system pumps' suction connection.

The piping which returns the water to the spent fuel pool from the spent fuel pool cooling system enters the pool at the opposite end from the spent fuel pool cooling system pumps' suction connection. The piping arrangement and location ensure thorough mixing of the cooled water into the pool to prevent stagnant or hot regions.

A gated opening connects the spent fuel pool and fuel transfer canal. The fuel transfer canal is connected to the in-containment refueling cavity by a fuel transfer tube. The spent fuel transfer operation is completed underwater, and the waterways are of sufficient depth to maintain a minimum of 10 feet of shielding water above the spent fuel assemblies. A metal gate with gasket assembly separates the spent fuel pool and fuel transfer canal. This allows the fuel transfer canal

to be drained without reducing the water level in the spent fuel pool. During normal operation, this gate remains open and is only closed to drain the canal. The bottom of the fuel transfer canal has a drain connected to safety-related piping and isolation valves which prevents inadvertent draining after a seismic event. Subsection 9.1.3 further addresses the minimum water level in the spent fuel pool.

Next to the spent fuel pool and accessible by another gated, gasketed opening is a cask loading pit. The cask pit is a lined reinforced concrete structure of the auxiliary building handling area. It is provided for underwater loading of fuel into a shipping cask and cask draining/decontamination prior to cask transshipment from the AP1000 site. The bottom of the cask loading pit has a drain connected to safety-related piping and isolation valve which prevents inadvertent draining after a seismic event. The gate between the spent fuel pool and the cask loading pit is normally closed and opened only for cask loading options. The cask loading pit can be used as a source of water for low pressure injection to the reactor coolant system via the normal residual heat removal pumps during an event in which the reactor coolant system pressure and inventory decrease.

The fuel handling machine traverses the spent fuel pool, the fuel transfer canal, and the cask loading pit. It is used in the movement of both new and spent fuel assemblies. A jib crane is used to transfer new fuel assemblies from the new fuel pit into the spent fuel pool. A new fuel elevator in the spent fuel pool lowers the new fuel to an elevation accessible by the fuel handling machine.

The cask handling crane is used for operations involving the spent fuel shipping cask. The cask handling crane traverses the auxiliary building and a portion of the fuel handling area. The cask handling crane's path is designed such that the cask cannot pass over the spent fuel pool, new fuel pit, or fuel transfer canal. This precludes the movement of loads greater than fuel components over stored fuel in accordance with Regulatory Guide 1.13.

During fuel handling operations, a ventilation system removes gaseous radioactivity from the atmosphere above the spent fuel pool. Refer to subsection 9.4.3 for a discussion of the radiologically controlled area ventilation system, Section 11.5 for process radiation monitoring, subsection 9.1.3 for the spent fuel pool cooling system, and subsection 12.2.2 for airborne activity levels in the fuel handling area.

9.1.2.2.1 Spent Fuel Rack Design

A. Design and Analysis of Spent Fuel Racks

The spent fuel storage racks are purchased equipment. The purchase specification for the spent fuel storage racks will require the vendor to perform confirmatory dynamic and stress analyses. The seismic and stress analyses of the spent fuel racks will consider the various conditions of full, partially filled, and empty fuel assembly loadings. The racks will be evaluated for the safe shutdown earthquake condition and seismic Category I requirements. A detailed stress analysis will be performed to verify the acceptability of the critical load components and paths under normal and faulted conditions. The racks rest on the pool floor and are evaluated to determine that under loading conditions they do not impact each other nor do they impact the pool walls.

The dynamic response of the fuel rack assembly during a seismic event is the condition which produces the governing loads and stresses on the structure.

Loads and Load Combinations

The applied loads to the spent fuel racks are:

- Dead loads
- Live loads - effect of lifting the empty rack during installation
- Seismic forces of the safe shutdown earthquake
- Fuel assembly drop analysis
- Fuel handling machine uplift - postulated stuck fuel assembly
- Thermal loads

Table 9.1-1 shows loads and load combinations that are considered in the analyses of the spent fuel racks including those given in Reference 5.

The margins of safety for the racks in the multi-direction seismic event are produced using loads obtained from the seismic analysis based on the simultaneous application of three statistically independent, orthogonal accelerations.

B. Fuel Handling Machine Uplift Analysis

An analysis will be performed to demonstrate that the racks can withstand a maximum uplift load of 5000 pounds. This load will be applied to a postulated stuck fuel assembly. Resultant rack stresses will be evaluated against the stress limits and will be demonstrated to be acceptable. It will also be demonstrated that there is no change in rack geometry of a magnitude which causes the criticality criterion to be violated.

C. Fuel Assembly Drop Accident Analysis

In the unlikely event of dropping a fuel assembly, accidental deformation of the rack will be determined and evaluated in the criticality analysis to demonstrate that it does not cause the criticality criterion to be violated. The analysis will consider only the case of a dropped spent, irradiated fuel assembly in a flooded pool and will take credit for dissolved boron in the water.

For the analysis of a dropped fuel assembly, two accident conditions are postulated. The first accident condition conservatively assumes that the weight of a fuel assembly, control rod assembly, and handling tool (3100 pounds total) impacts the top of the fuel rack from a drop height of 3 feet above the top of the rack. Both a straight drop and an inclined drop will be included in the assessment. Calculations will be performed which demonstrate that the impact energy is absorbed by the dropped fuel assembly, the rack cells, and the rack base plate assembly. Under these faulted conditions, credit is taken for dissolved boron in the pool water.

The second accident condition assumes that the dropped assembly and handling tool (3100 pounds) falls straight through an empty cell and impacts the rack base plate from a drop height of 3 feet above the top of the rack. The analysis will be performed which will demonstrate that the impact energy is absorbed by the fuel assembly and the rack base plate. At an interior rack location, base plate deformation is limited so that the pool liner is not impacted. At a support pad location, the stresses developed in the pool liner will be evaluated to be within allowable limits such that the liner integrity is maintained. Under these faulted conditions, credit is taken for dissolved boron in the pool water.

D. Fuel Rack Sliding and Overturning Analysis

Consistent with the criteria of Reference 5, the racks will be evaluated for overturning and sliding displacement due to earthquake conditions under the various conditions of full, partially filled, and empty fuel assembly loadings.

E. Failure of the Fuel Handling Jib Crane

The fuel handling jib crane is a seismic Category II component. The crane is evaluated to show that it does not collapse into the spent fuel pool as a result of a seismic event.

Stress analyses will be performed by the vendor using loads developed by the dynamic analysis. Stresses will be calculated at critical sections of the rack and compared to acceptance criteria referenced in ASME Section III, Division I, Article NF3000.

9.1.2.3 Safety Evaluation

The design and safety evaluation of the spent fuel racks is in accordance with Reference 5. The racks, being Equipment Class 3 and seismic Category I structures, are designed to withstand normal and postulated dead loads, live loads, loads resulting from thermal effects, and loads caused by the safe shutdown earthquake event.

The design of the racks is such that K_{eff} remains less than or equal to 0.95 under design basis conditions, including fuel handling accidents. Because of the close spacing of the cells, it is impossible to insert a fuel assembly in other than design locations. Inadvertent insertion of a fuel assembly between the rack periphery and the pool wall or placement of a fuel assembly across the top of a fuel rack is considered a postulated accident, and as such, realistic initial conditions such as boron in the pool water are assumed. These accident conditions have an acceptable K_{eff} of less than 0.95. The spent fuel storage racks are purchased equipment. The purchase specification for the spent fuel storage racks will require the vendor to perform a criticality analysis of the spent fuel storage racks. The criticality evaluation will consider the inherent neutron absorbing effect of the materials of construction, including fixed neutron absorbing "poison" material.

The racks are also designed with adequate energy absorption capabilities to withstand the impact of a dropped fuel assembly from the maximum lift height of the fuel handling machine. Handling equipment (cask handling crane) capable of carrying loads heavier than fuel components is prevented by design from carrying loads over the fuel storage area. The fuel storage racks can withstand an uplift force greater than or equal to the uplift capability of the fuel handling machine (5000 pounds).

Materials used in rack construction are compatible with the storage pool environment, and surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. Structural materials are corrosion resistant and will not contaminate the fuel assemblies or pool environment. Neutron absorbing "poison" material used in the rack design has been qualified for the storage environment. Venting of the neutron absorbing material is accomplished through the open corner design of the retaining "wrapper" plate.

Design of the spent fuel storage facility is in accordance with Regulatory Guide 1.13. A discussion of the methodology used in the criticality analysis is provided in subsection 4.3.2.6.

9.1.3 Spent Fuel Pool Cooling System

The spent fuel pool cooling system (SFS) is designed to remove decay heat which is generated by stored fuel assemblies from the water in the spent fuel pool. This is done by pumping the high temperature water from within the fuel pool through a heat exchanger, and then returning the water to the pool. A secondary function of the spent fuel pool cooling system is clarification and purification of the water in the spent fuel pool, the transfer canal, and the refueling water. A listing of the major functions of the spent fuel pool cooling system and the corresponding modes of operation is provided below:

- **Spent fuel pool cooling -** Remove heat from the water in the spent fuel pool during operation to maintain the pool water temperature within acceptable limits.

- **Spent fuel pool purification -** Provide purification and clarification of the spent fuel pool water during operation.

- **Refueling cavity purification -** Provide purification of the refueling cavity during refueling operations.

- **Water transfers -** Transfer water between the in-containment refueling water storage tank (IRWST) and the refueling cavity during refueling operations.

- **In-containment refueling water storage tank purification -** Provide purification and cooling of the in-containment refueling water storage tank during normal operation.

9.1.3.1 Design Basis

9.1.3.1.1 Safety Design Basis

The spent fuel pool cooling system has the safety-related function of containment isolation. See subsection 6.2.3 for the containment isolation system. Safety-related makeup to the spent fuel pool is discussed in subsection 9.1.3.4.3.

9.1.3.1.2 Power Generation Basis

The principal functions of the spent fuel pool cooling system are outlined above. The spent fuel pool cooling system is designed to perform its function in a reliable and failure tolerant manner. This reliability is achieved with the use of rugged and redundant equipment. The spent fuel pool

cooling system is not a safety-related system and is not required to operate following events such as earthquake, fire, passive failures or multiple active failures.

9.1.3.1.3 Spent Fuel Pool Cooling

9.1.3.1.3.1 Partial Core

The spent fuel pool cooling system is designed to remove heat from the spent fuel pool such that the spent fuel pool water temperature will be ≤ 120°F following a partial core fuel shuffle refueling. The system is designed to perform this function based on the following:

- The assumed heat load is based on the decay heat generated by the accumulated fuel assemblies stored in the fuel pool for 10 years plus 44% of a core (68 assemblies) being placed into the pool beginning at 120 hours after shutdown.
- Both trains of the spent fuel pool cooling system are assumed to be operating.
- The component cooling water system (CCS) supply temperature to the spent fuel pool cooling system heat exchangers is based on a service water system heat sink 1 percent exceedance ambient design wet bulb temperature of 80°F.

9.1.3.1.3.2 Full Core Off-Load

The AP1000 normal refueling basis heat load is from a full core off-load. The spent fuel pool cooling system is designed to remove heat from the spent fuel pool such that the spent fuel pool water temperature will be ≤ 120°F following a full core off-load based upon a service water heat sink 1 percent exceedance of 80°F ambient wet bulb temperature. The system is designed to perform this function based on the following:

- The assumed heat load is based on the decay heat generated by the accumulated fuel assemblies stored in the fuel pool for 10 years, plus one full core placed in the pool at 120 hours after shutdown. The time during the plant operating cycle at which the full core off-load occurs is chosen to maximize the required spent fuel pool cooling system heat load.
- The spent fuel pool cooling system is assumed to function with its full set of equipment available. One train of the normal residual heat removal system is also connected to the spent fuel pool and provides cooling as described in subsection 5.4.7.4.5.
- The component cooling water system supply temperature to the spent fuel pool cooling system heat exchangers is based on a service water system heat sink 1 percent exceedance ambient design wet bulb temperature of 80°F.

9.1.3.1.4 Spent Fuel Pool Purification

The spent fuel pool cooling system removes radioactive corrosion products, fission product ions and dust to maintain low spent fuel pool (SFP) activity levels and to maintain water clarity during all modes of plant operation. The spent fuel pool cooling system purification capability is such that the occupational radiation exposure (ORE) is minimized to support as-low-as-reasonably-

achievable (ALARA) goals. The spent fuel pool cooling system clarification capability is sufficient to permit necessary operations that must be conducted in the spent fuel pool area. The spent fuel pool cooling system is designed to perform its purification function in accordance with the following additional criteria:

- The spent fuel pool cooling system is designed to limit exposure rates at the surface of the spent fuel pool to less than 2.5 millirem per hour. This corresponds to an activity level in the water of approximately 0.005 microcurie per gram for the dominant gamma-emitting isotopes at the time of refueling.
- The spent fuel pool cooling system flow rate for one train shall be more than that necessary to provide two water volume changes in 24 hours for the spent fuel pool water.

9.1.3.1.5 Refueling Cavity Purification

The spent fuel pool cooling system removes radioactive corrosion products, fission product ions and dust to maintain low refueling cavity activity levels and to maintain water clarity during refueling operations. The spent fuel pool cooling system purification capability is such that the occupational radiation exposure is minimized to support ALARA goals. Furthermore, the spent fuel pool cooling system clarification capability is sufficient to permit necessary refueling operations that must be conducted in the refueling cavity. The spent fuel pool cooling system is designed to perform its purification function in accordance with the following additional criterion:

- The spent fuel pool cooling system is designed to limit exposure rates at the surface of the refueling cavity to less than 2.5 millirem per hour. This corresponds to an activity level in the water of approximately 0.005 microcurie per gram for the dominant gamma-emitting isotopes at the time of refueling.

9.1.3.1.6 Water Transfers

The spent fuel pool cooling system is designed to transfer water from the in-containment refueling water storage tank to the refueling cavity prior to a refueling and then back to the in-containment refueling water storage tank upon completion of the refueling operations. The spent fuel pool cooling system is designed to perform this function in accordance with the AP1000 refueling schedule.

9.1.3.1.7 In-Containment Refueling Water Storage Tank Purification

The spent fuel pool cooling system removes radioactive corrosion products and fission ions to maintain low in-containment refueling water storage tank activity levels during normal plant operation prior to a scheduled refueling. The spent fuel pool cooling system is designed to maintain the water in the in-containment refueling water storage tank consistent with activity requirements of the water in the refueling cavity during a refueling.

9.1.3.1.8 Spent Fuel Pool Water Tritium Concentration Control

The concentration of tritium in the spent fuel pool water is maintained at less than 0.5 μCi/g to provide confidence that the airborne concentration of tritium in the fuel handling area is within

10 CFR 20, Appendix B limits (see subsection 12.2.2). The tritium concentration in the spent fuel pool is reduced, if necessary, by transferring a portion of the spent fuel pool water to the liquid radwaste system for discharge and replacing it with non-tritiated water.

9.1.3.2 System Description

The spent fuel pool cooling system is a non-safety-related system. The safety-related function of cooling and shielding the fuel in the spent fuel pool is performed by the water in the pool. A simplified sketch of the spent fuel pool cooling system is included as Figure 9.1-5. The piping and instrumentation diagram for the spent fuel pool cooling system is Figure 9.1-6.

The spent fuel pool cooling system consists of two mechanical trains of equipment. Each train includes one spent fuel pool pump, one spent fuel pool heat exchanger, one spent fuel pool demineralizer and one spent fuel pool filter. The two trains of equipment share common suction and discharge headers. In addition, the spent fuel pool cooling system includes the piping, valves, and instrumentation necessary for system operation.

The spent fuel pool cooling system is designed such that either train of equipment can be operated to perform any of the functions required of the spent fuel pool cooling system independently of the other train. One train is continuously cooling and purifying the spent fuel pool while the other train is available for water transfers, in-containment refueling water storage tank purification, or aligned as a backup to the operating train of equipment.

Each train is designed to process spent fuel pool water. Each pump takes suction from the common suction header and discharges directly to its respective heat exchanger. The outlet piping branches into parallel lines. The purification branch is designed to process approximately 20% of the cooling flow while the bypass branch passes the remaining.

Each purification branch is routed directly to a spent fuel pool demineralizer. The outlet of the demineralizer is to a spent fuel pool filter. The outlet of the filter is then connected to the bypass branch which forms a common line that connects to the discharge header.

The spent fuel pool cooling system suction header is connected to the spent fuel pool at two locations. The main suction line connects to the spent fuel pool at an elevation 2 feet below the normal water level of the pool. Two skimmer connections take suction from the water surface of the spent fuel pool. This suction arrangement prevents the spent fuel pool from inadvertently being drained below a level that would prevent the water in the spent fuel pool from performing its safety-related function. This arrangement also eliminates the need for a separate skimmer circuit arrangement.

The spent fuel pool pump suction header is connected to the in-containment refueling water storage tank and the refueling cavity. This enables purification of the in-containment refueling water storage tank or the refueling cavity and allows for the transfer of water between the in-containment refueling water storage tank and the refueling cavity.

The spent fuel pool pump suction header is also connected to the fuel transfer canal and the cask loading pit. These connections are provided primarily for the transfer of water from the fuel

transfer canal to the cask loading pit. Water that is normally stored in the fuel transfer canal can be sent to the cask loading pit and vice versa.

The spent fuel pool is initially filled for use with water having a boron concentration of approximately 2500 ppm. Demineralized water can be added for makeup purposes, including replacement of evaporative losses, from the demineralized water transfer and storage system. Boron may be added to the spent fuel pool from the chemical and volume control system.

The spent fuel pool water may be separated from the water in the transfer canal by a gate. The gate enables the transfer canal to be drained to permit maintenance of the fuel transfer equipment.

9.1.3.3 Component Description

The general descriptions and summaries of the design requirements for the spent fuel pool cooling system components are provided below. See Table 9.1-2. The key equipment parameters for the spent fuel pool cooling system components are contained in Table 9.1-3. Additional information regarding the applicable codes and classifications is also available in Section 3.2.

9.1.3.3.1 Spent Fuel Pool Pumps

Two spent fuel pool pumps are provided. These pumps are single stage, horizontal, centrifugal pumps having a coupled pump motor shaft driven by an ac powered induction motor. A mechanical seal is used to prevent leakage to the atmosphere. The pumps have flanged suction and discharge nozzles.

Each pump is sized to provide the flow required by its respective heat exchanger for removal of its design basis heat load. The pumps are redundant for normal refueling heat loads.

9.1.3.3.2 Spent Fuel Pool Heat Exchangers

Two spent fuel pool heat exchangers are installed to provide redundant spent fuel heat removal capability for normal refueling heat loads. These heat exchangers are plate type heat exchangers constructed of austenitic stainless steel. Spent fuel pool water circulates through one side of the heat exchanger while component cooling water (CCW) circulates through the other side.

9.1.3.3.3 Spent Fuel Pool Demineralizers

Two mixed bed type demineralizers are provided to maintain spent fuel pool purity. The demineralizers are initially charged with a hydrogen type cation resin and hydroxyl type anion resin to remove fission and corrosion products. The demineralizers will be borated during initial operation with boric acid. Each demineralizer is sized to accept the maximum purification flow from its respective cooling train. The vessels are constructed of austenitic stainless steel.

9.1.3.3.4 Spent Fuel Pool Filters

Two spent fuel pool filters are provided, one downstream of each demineralizer in the purification branch line of each mechanical train. The filters are sized to collect small particulates and resin fines passed by the demineralizer. They are also sized to pass the maximum design purification

flow. The filter assembly is constructed of austenitic stainless steel with disposable filter cartridges.

9.1.3.3.5 Spent Fuel Pool Cooling System Valves

Spent fuel pool cooling system valves operate in low temperature and pressure service. Commercially available valves are used in accordance with the codes and standard of Section 3.2. The basic material of construction is stainless steel.

9.1.3.3.5.1 Locked-In-Position Valves

Refueling Cavity Drain Isolation Valve

There is one locked-open valve in the line from the refueling cavity to the steam generator 2 compartment. This valve is provided so that water in the refueling cavity cannot be trapped and be unavailable for passive recirculation cooling by the passive core cooling system (PXS) following an accident. This valve is locked-closed during refueling operations when the refueling cavity is flooded.

Refueling Cavity Connection for Containment Flooding Isolation Valve

There is one locked-open valve in the line that goes through the wall of the refueling canal to provide a water flow path between the refueling canal and the containment floodup water volume following an accident. This valve is locked open so that as the containment floods, the refueling canal will flood before the compartments that contain passive core cooling system components, which are used for safe shutdown. This valve is locked-closed during refueling operations when the refueling cavity is flooded.

Fuel Transfer Canal Drain Valve

There is one locked-closed valve in the bottom connection to the fuel transfer canal. This valve is provided to prevent inadvertent lowering of the spent fuel pool water level in the event that the gate between the fuel transfer canal and spent fuel pool is open during a seismic event that causes a break in the downstream piping.

9.1.3.3.5.2 Remotely-Operated Valves

Containment Isolation Valves

The spent fuel pool cooling system contains two lines which penetrate containment. They are the lines from the refueling cavity/in-containment refueling water storage tank to the spent fuel pool cooling system suction header and the return line to the refueling cavity/in-containment refueling water storage tank. Two remotely operated valves, one located inside and one outside containment, are provided in the line to the suction header. One remotely operated valve located outside containment and one check valve located inside containment are provided in the return line. These valves are normally closed and are opened only for purification or water transfers between the in-containment refueling water storage tank and the refueling cavity. They are controlled from the main control room. See subsection 6.2.3.

9.1.3.3.6 Piping Requirements

Spent fuel pool cooling system piping is made of austenitic stainless steel. Piping joints and connections are welded, except where flanged connections are required as indicated on the spent fuel pool cooling system piping and instrumentation diagram (Figure 9.1-6).

9.1.3.3.7 Reactor Cavity Seal Ring

The AP1000 reactor cavity seal ring is part of the fuel handling system and is a permanent welded seal ring used to provide the seal between the vessel flange and the refueling cavity floor. The reactor cavity seal ring does not use pneumatic seals and is not subject to a gross failure due to loss of a seal.

Leakage is not expected with this design. Leakage past or through the seal would not significantly affect the water level in the refueling canal and would be detected as an increase in water level in the containment sump. Water level in the sump is a key parameter in reactor coolant leak detection.

9.1.3.3.8 Reactor Cavity Connections

The spent fuel pool cooling system contains connections to the refueling cavity to prevent excessive holdup of water in the reactor cavity following an accident. The piping connection facilitates draining of the reactor cavity to the steam generator compartment following a postulated accident. The line connects at the bottom of the reactor cavity and discharges to a steam generator compartment, and contains a manual locked-open isolation valve and two check valves in series. The isolation valve is closed during refueling operations to facilitate flooding of the reactor cavity for refueling operations.

The spent fuel pool cooling system also contains a connection between the refueling cavity and Room 11300 to provide a water flow path following an accident. This connection is a single pipe through the wall of the refueling cavity and contains a manual locked-open isolation valve. This connection is provided so that as the containment floods, the refueling canal will flood before the compartments that contain passive core cooling system components, which are used for safe shutdown. Subsection 3.4.1.2.2.1 provides a discussion of post-accident containment flooding. The isolation valve is locked-closed during refueling operations to enable flooding of the reactor cavity for refueling operations.

Other connections are provided to the refueling cavity to facilitate proper draining, filling, and purification of the reactor cavity to support refueling operations.

9.1.3.4 System Operation and Performance

The operation of the spent fuel pool cooling system for the pertinent phases of plant operation are described in the following paragraphs.

9.1.3.4.1 Normal Operation

During normal plant operation, one spent fuel pool cooling system mechanical train of equipment is operating. The operating train is aligned to provide spent fuel pool cooling and purification. The other train is available to perform the other functions of the spent fuel pool cooling system such as water transfers or in-containment refueling water storage tank purification.

9.1.3.4.1.1 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media is ready to be transferred to the solid radwaste system, the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidizes in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system (WSS). Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

9.1.3.4.1.2 Filter Cartridge Replacement

Replacement of spent filter cartridges is performed as described in subsection 11.4.2.3.2.

9.1.3.4.2 Refueling

Both spent fuel pool mechanical trains are in operation during refueling. One train is aligned for spent fuel pool cooling and purification throughout the refueling. The other train performs various support functions during the refueling.

Initially the standby mechanical train is used to purify the water in the in-containment refueling water storage tank to prepare for the refueling. When the refueling cavity is ready to be flooded, the pump aligned for in-containment refueling water storage tank purification is stopped and valves are aligned to gravity drain the in-containment refueling water storage tank to the refueling cavity. Eventually the drain rate slows down and the in-containment refueling water storage tank and the refueling cavity have the same water level. At this time, the standby spent fuel pool pump is aligned to transfer the additional in-containment refueling water storage tank water into the refueling cavity.

This water transfer method improves water clarity in the refueling cavity during refueling operations as compared to conventional pressurized water reactors that have performed this function with their residual heat removal system by flooding up through the reactor vessel into the refueling cavity.

Once the refueling cavity is flooded, the standby mechanical train is re-aligned to cool and purify the refueling cavity. This mode of operation continues as needed. If the heat load is such that both pumps and heat exchangers are needed to cool the spent fuel pool, then the spent fuel pool cooling system can be aligned for that operation.

At the completion of the refueling, the standby spent fuel pool pump is used to transfer the water in the refueling cavity back to the in-containment refueling water storage tank. Once this is complete, the standby train can be aligned to cool the spent fuel pool or may be placed in standby.

9.1.3.4.3 Abnormal Conditions

The AP1000 spent fuel pool cooling system is not required to operate to mitigate design basis events. In the event the spent fuel pool cooling system is unavailable, spent fuel cooling is provided by the heat capacity of the water in the pool. Connections to the spent fuel pool are made at an elevation to preclude the possibility of inadvertently draining the water in the pool to an unacceptable level.

In the unlikely event of an extended loss of normal spent fuel pool cooling, the water level will drop. Low spent fuel pool level alarms in the control room will indicate to the operator the need to initiate makeup water to the pool. These alarms are provided from safety-related level instrumentation in the spent fuel pool. With the use of makeup water, the pool level is maintained above the spent fuel assemblies for at least 7 days. Initial spent fuel pool water level is controlled by technical specifications. During the first 72 hours any required makeup water is supplied from safety related sources. If makeup water beyond the safety related sources is required between 72 hours and 7 days, water from the passive containment cooling system ancillary water storage tank is provided to the spent fuel pool. The amount of makeup required to provide the 7 day capability depends on the decay heat level of the fuel in the spent fuel pool and is provided as follows:

- When the calculated decay heat level in the spent fuel pool is less than 2.3 MWt, no makeup is needed to achieve spent fuel pool cooling for at least 7 days.

- When the calculated decay heat level in the spent fuel pool is greater than or equal to 2.3 MWt and less than or equal to 2.8 MWt, safety related makeup from the cask washdown pit is sufficient to achieve spent fuel pool cooling for at least 7 days. A minimum level of 13.75 feet in the cask washdown pit is provided for this purpose. Availability of the makeup source is controlled by technical specifications.

- When calculated decay heat level in the spent fuel pool is greater than 2.8 MWt makeup from the passive containment cooling water storage tank or passive containment cooling ancillary water storage tank, or combination of the two tanks, is sufficient to achieve spent fuel pool cooling for at least 7 days.

- When the decay heat level in the reactor is less than 9 MW, the passive containment cooling water storage tank is not needed for containment cooling and this water can be used for makeup to the spent fuel pool. This tank provides safety related makeup for at least 72 hours. Between 72 hours and 7 days the tank continues to provide makeup water as required until it is empty. If the passive containment cooling water storage tank empties in less than 7 days, non-safety makeup water can be provided from the passive containment cooling ancillary water storage tank.

- When the decay heat level in the reactor is greater than 9 MW, the water in the passive containment cooling water storage tank is reserved for containment cooling. Safety related spent fuel pool cooling is provided for at least 72 hours from the pool itself and makeup water from the cask washdown pit. After 72 hours, non-safety related makeup can be provided from the passive containment cooling ancillary water storage tank.

- Minimum volume in the passive containment cooling water storage tank for spent fuel pool makeup is 756,700 gallons. Availability of this makeup source for the first 72 hours is controlled by technical specifications. Minimum volume in the passive containment ancillary water storage tank for spent fuel pool makeup is 175,000 gallons.

Table 9.1-4 provides the calculated timing and spent fuel pool water levels for several limiting event scenarios which would require makeup to the spent fuel pool.

Alignment of the cask washdown pit is accomplished by positioning manual valves located in the waste monitor tank room B (12365) in the auxiliary building. Alignment of the passive containment cooling water storage tank is accomplished by positioning manual valves located in the mid annulus access room (12345) and in the passive containment cooling valve room in the upper shield building. Because these alignments are made by positioning manual valves, they are not susceptible to active failures.

Gravity driven flow from the cask washdown pit to the spent fuel pool is provided as the cask washdown pit water level will follow the spent fuel pool level. Figures 9.1-5 and 9.1-6 show the connection of the cask washdown pit to the spent fuel pool.

Gravity driven flow from the passive containment cooling water storage tank is controlled by a manual throttle valve with local flow indication which is set to achieve the desired flow when the makeup is initiated. Figure 6.2.2-1 shows the flow path from the passive containment cooling water storage tank leading to the spent fuel pool and the tie-in to the spent fuel pool is also shown in Figure 9.1-6.

The flow from the passive containment cooling water storage tank (PCCWST) to the spent fuel pool, required to provide sufficient makeup to the spent fuel pool to keep the fuel covered as the pool water boils off, is 118 gpm. This is the maximum flow required at the initiation of makeup flow from the PCCWST during the worst case conditions in the pool, which is a full core offload. The makeup flow rate required decreases with time as the decay heat decreases.

After 72 hours, makeup water from the passive containment cooling ancillary water storage tank can either be pumped (with the passive containment cooling recirculation pumps) to the passive containment cooling water storage tank and then gravity fed to the spent fuel pool as discussed above, or the water can be pumped directly to the spent fuel pool. When the makeup water is pumped directly to the pool, the flow rate is controlled by the same manual throttle valve which is used to set the flow rate when providing gravity driven flow from the passive containment cooling water storage tank.

The flow provided from the passive containment cooling auxiliary water storage tank (PCCAWST) to the spent fuel pool by the recirculation pumps, required to provide sufficient

makeup to the spent fuel pool to keep the fuel covered as the pool water boils off, is 35 gpm. The plant condition associated with this flow is a loss of power combined with a seismic event when the plant is operating at full power, shortly after startup from a refueling outage. This condition results in the maximum flow required from the PCCAWST because cooling water must be supplied to both the PCCWST and the spent fuel pool to provide both containment and spent fuel cooling for a period of four days following the initial three days of passive systems operation.

Spent fuel pool level instrumentation is discussed in Subsection 9.1.3.7.

9.1.3.4.3.1 Failure of a Spent Fuel Pool Cooling System Pump

If a spent fuel pool cooling system pump fails when only one pump is operating, an alarm is actuated. Due to the heat capacity of the water in the spent fuel pool, sufficient time exists for the operators to manually align the standby spent fuel pool cooling system train of equipment (pump/heat exchanger) to cool the spent fuel pool.

9.1.3.4.3.2 Leakage from the Spent Fuel Pool Cooling System

The connections from the spent fuel pool cooling system to the pool are such that leakage in the spent fuel pool cooling system will not result in the pool water level falling to unacceptable levels. The heat capacity of the water in the pool is sufficient to allow the operators enough time to locate the leak and repair it. In the most probable scenario, cooling will be maintained by operation of the standby train of equipment. However, if spent fuel pool cooling must be terminated, sufficient time exists to allow for repairs of a leak in the system.

9.1.3.4.3.3 Loss of Offsite Power

The spent fuel pool cooling system pumps can be manually loaded on the respective onsite standby diesel generator in the event of a loss of offsite power. The spent fuel pool cooling system is capable of providing spent fuel pool cooling following this event.

9.1.3.4.3.4 Station Blackout

Following a loss of ac power (off-site power and both standby diesel generators), the heat capacity of the water in the pool is such that cooling of the fuel is maintained. Table 9.1-4 provides the times before boiling would occur in the pool following station blackout for various scenarios as well as the minimum levels of water that would be reached. Water vapor that evaporates from the surface of the spent fuel pool is vented to the outside environment through an engineered relief panel. This vent path maintains the fuel handling area at near atmospheric pressure conditions. The doses resulting from spent fuel pool boiling have been calculated and are included in Chapter 15. The release concentrations at the site boundary are small fractions of the limits specified in 10 CFR 20, Appendix B with no credit for removal of activity by building ventilation systems (which are not available during loss of ac power situations). The equipment in the fuel handling area, rail car bay\filter storage area, and spent resin equipment and piping areas exposed to elevated temperature and humidity conditions as a result of pool boiling does not provide safety-related mitigation of the effects of spent fuel pool boiling or station blackout. The fuel handling area, rail car bay, and spent resin area do not have connecting ductwork with other areas of the radioactively controlled area of the auxiliary building and connecting floor drains have a

water seal which prevents steam migration. The environment in these other areas during spent fuel pool steaming is mild with respect to safety-related equipment qualification and affords access for post-accident actions.

Spent fuel pool makeup for long term station blackout can be provided through seismically qualified safety-related makeup connections from the passive containment cooling system. These connections are located in an area of the auxiliary building that can be accessed without exposing operating personnel to excessive levels of radiation or adverse environmental conditions during boiling of the pool. Operating personnel are not required to enter the fuel handling area when normal cooling is not available, and are not required to enter the area to recover normal cooling.

9.1.3.4.3.5 Reactor Coolant System Makeup

During an event in which the reactor coolant system pressure and inventory decrease the normal residual heat removal system pumps are started to provide makeup water to the reactor coolant system when the primary system pressure is sufficiently reduced for injection to start. The AP1000 procedure for post-accident operation of the normal residual heat removal pumps is that the operators align the pumps to the cask loading pit. This is accomplished by the operator opening a motor operated isolation valve (see subsection 5.4.7.3.3.5) between the cask loading pit and the normal residual heat removal pump suction line. When the water in this pit nears empty, the pump suction is re-aligned to the IRWST/containment recirculation connection so that the pumps can continue to provide injection to the reactor coolant system. The refueling water from the cask loading pit provides additional water into containment (and thus additional driving head) for the post accident containment recirculation. The AP1000 emergency operating procedures will include a restriction on use of this injection method if the gate between the spent fuel pool and the cask loading pit is open at the initiation of the event. In this case the operators will be instructed to close the gate, if possible, before initiating the makeup flow with the normal residual heat removal pumps. Injection from the cask loading pit will only be initiated if the gate can be closed. The gate is normally in the closed position unless cask loading operations are in progress.

9.1.3.5 Safety Evaluation

The only spent fuel pool cooling system safety-related functions are containment isolation and emergency makeup connections to the spent fuel pool. Containment isolation evaluation is described in subsection 6.2.3. The following provides the evaluation of the design of the spent fuel pool as well as the spent fuel pool cooling system:

- The spent fuel pool is designed such that a water level is maintained above the spent fuel assemblies for at least 7 days following a loss of the spent fuel pool cooling system, using only onsite makeup water (see Table 9.1-4). The minimum water level to achieve sufficient cooling is the subcooled, collapsed level (without vapor voids) required to cover the top of the fuel assemblies.

- The maximum heat load is assumed to be the heat load for a full core off load immediately following a refueling in which 44 percent of the fuel assemblies were replaced.

- Safety-related makeup water can be supplied to the fuel pool from the fuel transfer canal, cask washdown pit, and passive containment cooling water storage tank.

- The spent fuel pool cooling system includes safety-related connections from the passive containment cooling system water storage tank in the passive containment cooling system to establish safety-related makeup to the spent fuel pool following a design basis event including a seismic event.

- In addition to the safety-related water sources, makeup water is also obtained from the passive containment cooling system ancillary water storage tank. Water from this tank can be pumped by the passive containment cooling system recirculation pumps either to the passive containment cooling water storage tank (and then gravity fed to the spent fuel pool), or directly to the spent fuel pool.

Radiation shielding normally provided by the water above the fuel is not required when normal spent fuel pool cooling is not available. Personnel are not permitted in the area when the level in the pool is below the minimum level.

The acceptability of the design of the spent fuel pool cooling system is based on specific General Design Criteria (GDCs) and Regulatory Guides as described in Sections 3.1 and 1.9.

9.1.3.6 Inspection and Testing Requirements

9.1.3.6.1 Preoperational Testing, Analysis, and Inspection

9.1.3.6.1.1 Pump Flow Capability Testing

Each spent fuel pool cooling system pump will be tested. The flow paths will be aligned for normal spent fuel pool cooling by one train of spent fuel pool cooling system components. The flow delivered to each spent fuel pool cooling system heat exchanger will be measured by a flow instrument at the spent fuel pool cooling system pump discharge. The testing confirms that the pumped flow is equal to or greater than the minimum value shown in Table 9.1-3. This is the minimum value for the spent fuel pool cooling system to meet its functional requirement of normal spent fuel pool cooling. The flow delivered to each spent fuel pool cooling system heat exchanger will be measured by a flow instrument at the spent fuel pool cooling system pump discharge. The testing confirms that the pumped flow is equal to or greater than the minimum value shown in Table 9.1-3. This is the minimum value for the spent fuel pool cooling system to meet its functional requirement of normal spent fuel pool cooling.

9.1.3.6.1.2 Heat Transfer Capability Analysis

An analysis will be performed on the spent fuel pool cooling system heat exchangers during heat exchanger design. The analysis is to confirm that the product of the overall heat transfer coefficient and effective heat transfer area, UA, of each heat exchanger is equal to or greater than the minimum value shown in Table 9.1-3. This is the minimum value for the spent fuel pool cooling system to meet its functional requirement of normal spent fuel pool cooling.

9.1.3.6.1.3 Dimensional Inspections

The contained volumes of water in the spent fuel pool, fuel transfer canal and the cask washdown pit are used for cooling the spent fuel by boiling after a prolonged loss of normal spent fuel pool cooling. The inspections are to confirm that the contained volumes are equal to or greater than the minimum values shown in Table 9.1-2. These are the minimum values for the spent fuel pool cooling system to meet its safety-related requirement of spent fuel pool cooling for 3 days after loss of normal cooling.

9.1.3.6.2 Routine Testing

Active components of the spent fuel pool cooling system are either in continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted.

No specific equipment tests are required since system components are normally in operation when spent fuel is stored in the fuel pool. Sampling of the fuel pool water for gross activity, tritium and particulate matter is conducted periodically.

9.1.3.7 Instrumentation Requirements

The instrumentation provided for the spent fuel pool cooling system is discussed in the following paragraphs. Alarms and indications are provided as noted.

A. Temperature

Instrumentation is provided to measure the temperature of the water in the spent fuel pool and to give indication as well as annunciation in the main control room when normal temperatures are exceeded.

Instrumentation is also provided to give indication of the temperature of the spent fuel pool water as it leaves either heat exchanger.

B. Pressure

Instrumentation is provided to measure and give indication of the pressures in the spent fuel pool pump suction and discharge lines. Instrumentation is also provided at locations upstream and downstream from the spent fuel pool filter and demineralizer so that pressure differential across this equipment can be determined. High differential pressure across the spent fuel pool filter and demineralizer is annunciated in the main control room.

C. Flow

Instrumentation is provided to measure and give remote indication of the spent fuel pool cooling loop flow downstream of the spent fuel pool pumps. Purification flow is also continuously measured.

D. Level

Safety-related instrumentation is provided to give an alarm in the main control room when the water level in the spent fuel pool reaches either the high-level or low-level setpoint. This instrumentation is used for post-accident monitoring on the spent fuel pool level. (See Table 7.5-1)

Non-safety related instrumentation is provided to give an alarm in the main control room when the water level in the cask loading pit reaches either the high-level or low-level setpoint. This instrumentation is used to alert the operator to a low level in the cask loading pit when injecting water from the pit into the reactor coolant system with the normal residual heat removal pumps.

9.1.4 Light Load Handling System (Related to Refueling)

The fuel handling and refueling system consists of equipment and structures used for conducting the refueling operation. This system conforms to General Design Criteria as defined in Section 3.1. The light load handling system meets the guidelines of American Nuclear Society (ANS) 57.1 (Reference 6). Figures 1.2-9 and 1.2-14 indicate the relationship between the light load handling system and the fuel handling areas.

9.1.4.1 Design Basis

9.1.4.1.1 Safety Design Basis

The following safety design basis apply to the light load handling system:

A. Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operation.

B. Handling equipment has provisions to avoid dropping of fuel handling devices during the fuel transfer operation.

C. Handling equipment used to raise and lower spent fuel has a limited maximum lift height so that the minimum required depth of water shielding is maintained.

D. The fuel transfer system, where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary.

E. Criticality during fuel handling operations is prevented by the geometrically safe configuration of the fuel handling equipment.

F. In the event of a safe shutdown earthquake (SSE), handling equipment cannot fail in such a manner as to prevent required function of seismic Category 1 equipment.

G. The inertial loads imparted to the fuel assemblies or core components during handling operations are less than potential damage causing loads.

H. Physical safety features are provided for personnel who operate handling equipment.

9.1.4.1.2 Power Generation Design Basis

Design criteria for the light load handling system are as follows:

A. The primary design requirement of the equipment is reliability. A conservative design approach is used for load bearing parts.

B. The refueling machine and fuel handling machine are designed and constructed in accordance with applicable portions of the Crane Manufacturers Association of America, Inc. (CMAA), Specification 70 for Class A-1 service (Reference 7).

C. The static design loads for the crane structures and lifting components are normal dead and live loads plus the fuel assembly weight.

D. The allowable stresses for the refueling machine and fuel handling machine structures supporting the weight of a fuel assembly are as specified in the American Institute of Steel Construction (AISC) Manual.

E. The design load on the wire rope hoisting cables does not exceed 0.20 times the average breaking strength. Two independent cables are used, and each is assumed to carry one half the load.

F. Components critical to the operation of the equipment are assembled with the fasteners restrained from loosening under vibration.

9.1.4.2 System Description

The light load handling system consists of the equipment and structures needed for the refueling operation. This equipment is comprised of fuel assemblies, core component and reactor component hoisting equipment, handling equipment, and a dual basket fuel transfer system. The structures associated with the fuel handling equipment are the refueling cavity, the transfer canal, the fuel transfer tube, the spent fuel pool, the cask loading area, the new fuel storage area, and the new fuel receiving and inspection area.

9.1.4.2.1 Fuel Handling Description

The fuel handling equipment is designed to handle the spent fuel assemblies underwater from the time they leave the reactor vessel until they are placed in a container for shipment from the site. Underwater transfer of spent fuel assemblies provides an effective and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. The boric acid concentration in the water is sufficient to preclude criticality.

The associated fuel handling structures may be generally divided into two areas: the refueling cavity which is flooded only during plant shutdown for refueling, and the spent fuel pool and transfer canal, which is kept full of water. See subsection 9.1.1.3 for new fuel assembly storage. The new and spent fuel storage areas are accessible to operating personnel. The refueling cavity and the fuel storage area are connected by the fuel transfer tube which is fitted with a quick opening hatch on the canal end and a valve on the fuel storage area end. The hatch is in place except during refueling to provide containment integrity. Fuel is carried through the tube on an underwater transfer car.

Fuel is moved between the reactor vessel and the fuel transfer system by the refueling machine. The fuel transfer system is used to move up to two fuel assemblies at a time between the containment building and the auxiliary building fuel handling area. After a fuel assembly is placed in the fuel container, the lifting arm pivots the fuel assembly to the horizontal position for passage through the fuel transfer tube. After the transfer car transports the fuel assembly through the transfer tube, the lifting arm at that end of the tube pivots the assembly to a vertical position so that the assembly can be lifted out of the fuel container.

In the fuel handling area, fuel assemblies are moved about by the fuel handling machine. Initially, a short tool is used to handle new fuel assemblies, but the new fuel elevator must be used to lower the assembly to a depth at which the fuel handling machine can place the new fuel assemblies into or out of the spent fuel storage racks.

Decay heat, generated by the spent fuel assemblies in the fuel pool is removed by the spent fuel pool cooling and cleanup system. After a sufficient decay period, the spent fuel assemblies are removed from the fuel racks and loaded into a spent fuel shipping cask for removal from the site.

9.1.4.2.2 Refueling Procedure

New fuel assemblies received for refueling are removed one at a time from the shipping container and moved into the new fuel assembly inspection area. After inspection, the accepted new fuel assemblies are stored in the new fuel storage racks. For the initial core load, some new fuel assemblies may be stored in the spent fuel pool.

Prior to initiating the refueling operation, the reactor coolant system (RCS) is borated and cooled down to refueling shutdown conditions as specified in the Technical Specifications. Criticality protection for refueling operations is specified in the Technical Specifications. The following significant points are addressed by the refueling procedure:

- The refueling water and the reactor coolant contain approximately 2500 ppm boron. This concentration is sufficient to keep the core five percent $\Delta k/k$ subcritical during the refueling operations.

- The water level in the refueling cavity is high enough to keep the radiation levels within acceptable limits when the fuel assemblies are removed from the core. Radiation monitoring is described in Section 11.5.

- Continuous communications are established and maintained between the main control room and the personnel engaged in fuel handling operations. One or more of the systems described in subsection 9.5.2 are used for this communication.

The refueling operation is divided into four major phases: preparation, reactor disassembly, fuel handling, and reactor assembly. A general description of a typical refueling operation through these phases is provided below.

9.1.4.2.2.1 Phase I - Preparation

The reactor is shut down, borated, and cooled to refueling conditions (≤ 140°F) with a final k_{eff} less than 0.95 (all rods in). Following a radiation survey, the containment building is entered. At this time, the coolant level in the reactor vessel is lowered to a point slightly below the vessel flange. The refueling machine console is removed from storage and placed on the refueling machine and cables are connected. Then, the fuel transfer equipment and refueling machine are checked for operation (subsection 9.1.4.4).

9.1.4.2.2.2 Phase II - Reactor Disassembly

Head cables are disconnected at the integrated head package (IHP) connector plate to allow removal of the vessel head. See subsection 3.9.7 for a discussion of the integrated head package. The refueling cavity is prepared for flooding by checking the underwater lights, tools, and fuel transfer system; closing the refueling cavity drain lines; and removing the hatch from the fuel transfer tube. With the refueling cavity prepared for flooding, the vessel head is unseated and raised above the vessel flange using the containment polar crane. See subsection 9.1.5 for requirements for the polar crane. Water from the in-containment refueling water storage tank (IRWST) is transferred into the refueling cavity by gravity and the spent fuel pool cooling system (See subsection 9.1.3). The vessel head and the water level in the refueling cavity are raised, keeping the water level just below the vessel head. When the water reaches a safe shielding depth (subsection 9.1.4.3.7), the vessel head is taken to its storage pedestal. The control rod drive shafts are disconnected. The internals lift rig is installed and the upper internals are removed from the vessel. See subsection 9.1.5 for discussion of lifting rig requirements and design. The fuel assemblies are now free from obstructions, and the core is ready for refueling.

9.1.4.2.2.3 Phase III - Fuel Handling

The refueling sequence is started with the refueling machine. The positions of partially spent assemblies are changed, and new assemblies are added to the core.

The general fuel handling sequence is as follows:

1. The refueling machine is positioned over a fuel assembly in the core.

2. The refueling machine mast is lowered over a fuel assembly and engages it.

3. The refueling machine withdraws a spent fuel assembly from the core and raises it to a pre-determined height sufficient to clear the vessel flange and still leave sufficient water covering the fuel assembly.

4. The fuel transfer system car containing a new fuel assembly in the fuel basket (which contains up to two fuel assemblies) is moved into the refueling cavity from the fuel storage area, and the fuel basket is pivoted to the vertical position by the lifting arm.

5. The refueling machine is moved to line up the fuel assembly with the empty fuel basket.

6. The refueling machine loads the spent fuel assembly into the empty fuel basket of the transfer car.

7. The refueling machine then moves to the new fuel assembly (in the remaining fuel basket) and withdraws it from the fuel transfer system.

8. The refueling machine then moves back over the core area and inserts the fuel assembly into the open location in the core prepared in step 3.

9. The fuel basket is pivoted to the horizontal position and the fuel transfer system container is moved through the fuel transfer tube to the fuel handling area by the transfer car and pivoted to the vertical position.

10. A new fuel assembly is taken from a storage rack and loaded into the empty fuel basket by the fuel handling machine. Note that new fuel was put in spent fuel racks prior to the start of refueling (new fuel elevator).

11. The spent fuel assembly is then unloaded from the fuel basket by the fuel handling machine.

12. The spent fuel assembly is placed in the spent fuel storage rack.

13. The fuel basket is pivoted to the horizontal position, moved back into the containment building and pivoted to the vertical position.

14. The refueling machine, which was concurrently relocating partially spent fuel in the vessel engages a spent fuel assembly, which is to be discharged, and returns to the fuel transfer system.

15. This procedure is repeated until refueling is completed.

9.1.4.2.2.4 Phase IV - Reactor Reassembly

Reactor reassembly, following refueling, is achieved by reversing the operations given in Phase II - Reactor Disassembly.

During a reassembly of the reactor, the vessel head and the water are lowered simultaneously until the vessel head engages the guide studs. At this point of the reassembly, the water is lowered to the top of the reactor vessel flange.

9.1.4.2.3 Spent Fuel Cask Loading

The spent fuel assemblies are normally stored in the spent fuel pool, until fission product activity is low enough to permit shipment. The spent fuel assemblies are then transferred to a shipping cask which is designed to shield radiation. Provisions for handling the spent fuel cask are discussed in subsection 9.1.5.

The following procedure briefly outlines the typical steps of this operation, assuming that the cask loading pit has been previously filled with water and the gate between the cask loading pit and the spent fuel pool has been removed:

1. A clean, empty cask is brought into the cask washdown pit and washed with demineralized water. The cask lid is removed and stored while the remainder of the cask is washed.

2. The clean empty cask is then properly positioned in the flooded cask loading pit.

3. The fuel handling machine is positioned over the specific fuel assembly to be shipped out of the spent fuel storage rack. The fuel assembly is picked up and transported into the cask loading pit. During the transfer process the fuel assembly is always maintained with the top of the active fuel at least 10 feet below the water surface. This provides confidence that the direct radiation from the fuel at the surface of the water is minimal.

4. Once the fuel transfer process is complete, the lid is placed on top of the cask to provide the required shielding.

5. The cask is then moved to the washdown pit and cleaned with demineralized water. Decontamination procedures can be started at this time.

6. When the cask is satisfactorily decontaminated, it is lifted out of the cask washdown pit and prepared for shipping.

During the operations, sufficient water is maintained between plant personnel and fuel assemblies that are being moved to limit dose levels to those acceptable for continuous occupational exposure.

9.1.4.2.4 Component Description

A. Fuel Transfer Tube

The fuel transfer tube penetrates the containment and spent fuel area and provides a passageway for the conveyor car during refueling. During reactor operation, the fuel transfer tube is sealed at the containment end and acts as part of the containment pressure boundary. See subsection 3.8.2.1.5 for discussion of the fuel transfer penetration.

B. Fuel Handling Machine

The fuel handling machine performs fuel handling operations in the fuel handling area. It also provides a means of tool support and operator access for long tools used in various service and handling functions.

C. New Fuel Assembly Handling Tool

The new fuel assembly handling tool is used to lift and transfer new fuel assemblies from the new fuel shipping containers to the new fuel storage racks. The tool is also used to transfer new fuel assemblies from the new fuel storage racks to the new fuel elevator.

D. Spent Fuel Assembly Handling Tool

The spent fuel assembly handling tool is used to lift and transfer spent fuel assemblies from the fuel transfer system to the spent fuel racks.

E. New Fuel Elevator Hoist

The new fuel elevator lowers new fuel assemblies from the fuel handling area operating floor into the spent fuel pool where they can be picked up by the fuel handling machine.

F. New Rod Cluster Control Handling Tool

The new rod cluster control handling tool is used to lift and transfer new control rods from their shipping containers to the new fuel assemblies, and between new assemblies in their storage racks.

G. Refueling Machine

The refueling machine performs fuel handling operations in the containment building. It also provides a means of tool support and operator access for long tools used for service, control rod latching and unlatching, and for various handling functions.

H. Burnable Poison Rod Assembly Handling Tool

The burnable poison rod assembly handling tool is used to lift and transfer burnable poison rod assemblies between assemblies and/or storage fixtures.

I. Burnable Poison Rod Assembly Rack Insert

The burnable poison rod assembly rack insert is used to store burnable poison rod assemblies or control rods in the spent fuel storage racks.

J. Fuel Transfer System

The fuel transfer system conveys fuel assemblies between the containment building and the fuel handling area.

K. Rod Cluster Control Storage Station

The rod cluster control (RCC) storage station is mounted on the reactor cavity wall and provides storage space for one rod cluster control. The rod cluster control assembly can be rotated for inspection purposes by an operator standing on the operating floor.

L. Control Rod Drive Shaft Unlatching Tool

The control rod drive shaft unlatching tool is used to latch and unlatch the control rod drive shafts from the rod cluster control assemblies. It is operated from the refueling machine walkway.

M. Control Rod Drive Shaft Handling Tool

The control rod drive shaft handling tool is used to latch and unlatch the control rod drive shafts (CRDS) from the rod cluster control assemblies.

N. Irradiation Sample Handling Tool

The irradiation sample handling tool is used to remove irradiated reactor vessel surveillance capsules in the holders located in the reactor internals. It is also used for removing and installing the irradiation sample access plugs in the reactor internals.

O. Irradiation Tube End Plug Seating Jack

The irradiation tube end plug seating jack is used to push the irradiation samples into the specimen guides for the last few inches.

P. Control Rod Drive Shaft Storage Racks

The control rod drive shaft storage racks are located on the refueling cavity wall and are used to store spare control rod drive shafts and any ones that might be removed from the upper internals during refueling.

Q. Jib Crane

The new fuel jib crane is located in the fuel handling area. It is a standard commercial jib crane with an "L" shaped frame and an electric operated hoist. It is used to move the new fuel from the new fuel storage position to the new fuel elevator. The jib crane is positioned so that it cannot reach the spent fuel storage positions. The jib crane capacity is limited to 2000 pound load.

9.1.4.3 Safety Evaluation

9.1.4.3.1 Refueling Machine

The refueling machine design includes the following provisions to provide for safe handling of fuel assemblies:

A. Safety Interlocks

Operations which could endanger the operator or damage the fuel, designated below by an asterisk (*), are prevented by mechanical or failure tolerant electrical interlocks or by redundant electrical interlocks. Other interlocks are intended to provide equipment protection and may be implemented either mechanically or by electrical interlock and are not required to be fail safe.

Fail safe electrical design of a control system interlock is applied according to the following rules:

1. Fail safe operation of an electrically operated brake is such that the brake engages on loss of power.

2. Fail safe operation of a relay is such that the de-energized state of the relay inhibits unsafe operation.

3. Fail safe operation of a switch, termination, or wire is such that breakage or high resistance of the circuit inhibits unsafe operation. The dominant failure mode of the mechanical operation of a cam-operated limit switch is sticking of the plunger in its depressed position. Therefore, use of the plunger-extended position (on the lower part of the operating cam) to energize a relay is consistent with fail safe operation.

Those parts of a control system interlock which are not or cannot be operated in a fail safe mode as defined in the preceding rules are supplemented by a redundant component or components to provide the requisite protection. Required fail safe operations are:

*1. The refueling machine can only place a fuel assembly in the core or fuel transfer system.

*2. When the refueling machine gripper is engaged, the machine can not traverse unless the gripper is fully withdrawn into the mast.

*3. When the refueling machine gripper is disengaged, the machine can not traverse unless the gripper is withdrawn into the mast.

*4. Simultaneous traversing and hoisting operations are prevented.

*5. The refueling machine is restricted to raising a fuel assembly or core component to a height at which the water provides a safe radiation shield.

*6. When a fuel assembly is raised or lowered, interlocks provide confidence that the refueling machine can only apply loads which are within safe operating limits.

*7. The fuel gripper is monitored by devices to confirm operation to the fully engaged or fully disengaged position. Alarms are actuated if both engage and disengage switches are actuated at the same time or if neither is actuated.

8. Lowering of the gripper is not permitted if slack cable exists in the hoist.

9. The gripper tube is prevented from lowering completely out of the mast.

10. Before the fuel gripper can release a fuel assembly, the fuel gripper must be in its down position in the core or in the fuel transfer system.

*11. The weight of the fuel assembly must be off the gripper before the fuel gripper can release a fuel assembly.

12. The fuel transfer system container is prevented from moving unless the engaged gripper is in the full up position or the disengaged gripper is withdrawn into the mast or unless the refueling machine is out of the fuel transfer zone. An interlock is provided from the refueling machine to the fuel transfer system to accomplish this.

B. Bridge and Trolley Hold-Down Devices

Both refueling machine bridge and trolley are horizontally restrained on the rails by guide rollers on either side of the rail. Hold down devices are used to prevent the bridge or trolley from leaving the rails in the event of a seismic event.

C. Main Hoist Braking System

The main hoist is equipped with two independent braking systems. The winch has a mechanically-operated load brake to prevent overhauling, and a solenoid activated motor brake. Both brakes are rated at 125 percent of the hoist design load.

D. Fuel Assembly Support System.

The main hoist system is supplied with redundant paths of load support such that failure of any one component will not result in free fall of the fuel assembly. Two wire ropes are anchored to the winch drum and carried to a load equalizing mechanism on the top of the gripper tube.

The fuel assembly gripper has four fingers gripping the fuel, any two of which will support the fuel assembly weight.

During each refueling outage and prior to removing fuel, the gripper and hoist system are routinely load tested to 125 percent of the maximum setting on the hoist load limit switch.

9.1.4.3.2 Fuel Transfer System

The following personnel safety features are provided for in the fuel transfer system:

A. Transfer Car Permissive Switch

The transfer car controls are located in the fuel handling area, and conditions in the containment are therefore not visible to the operator. The transfer car permissive switch allows the fuel transfer system containment operator to exercise some control over car movement if conditions visible to him warrant such control.

B. Lifting Arm - Transfer Car Position

An interlock on the fuel transfer system prevents the upender from being moved from the horizontal to the vertical position if the transfer car has not reached the end of its travel.

C. Transfer Car - Valve Open

An interlock on the transfer tube valve permits transfer car operation only when the transfer tube valve position switch indicates the valve is fully open.

D. Fuel Container - Refueling Machine

The fuel transfer system is interlocked with the refueling machine. Whenever the transfer car is located in the refueling cavity, the fuel transfer system cannot be operated unless the refueling machine mast is in the fully retracted position, the refueling machine is over the core, or the gripper is released and inside the core.

E. Lifting Arm - Fuel Handling Machine

On the spent fuel pool side, the fuel transfer system is interlocked with the fuel handling machine. The fuel transfer system cannot be operated until the fuel handling machine is moved away from the fuel transfer system area.

9.1.4.3.3 Fuel Handling Machine

The fuel handling machine is the same design as the refueling machine and includes the same safety features.

9.1.4.3.4 Fuel Handling Tools and Equipment

Fuel handling tools and equipment handled over an open reactor vessel are designed to prevent inadvertent decoupling from machine hooks; i.e., lifting rigs are pinned to the machine hook, and safety latches are provided on hook supporting tools.

Tools required for handling internal reactor components are designed with fail safe features that prevent disengagement of the component in the event of operating mechanism malfunction.

These safety features apply to the following tools:

A. Control Rod Drive Shaft Unlatching Tool

The air cylinders actuating the gripper mechanism are equipped with backup springs which close the gripper in the event of loss of air to the cylinder. Air-operated valves are equipped with safety locking rings to prevent inadvertent actuation.

B. New Fuel Assembly Handling Tool

When the fingers are latched, the actuating handle is positively locked, preventing inadvertent actuations. The tool is preoperationally tested at 125 percent of the weight of one fuel assembly.

9.1.4.3.5 Seismic Considerations

The equipment classifications for fuel handling and storage equipment are listed in Section 3.2, which provides criteria for the seismic design of the various components.

For safety and non-safety equipment, design for the safe shutdown earthquake (SSE) is considered if failure might adversely affect safety-related equipment.

9.1.4.3.6 Containment Pressure Boundary Integrity

The fuel transfer tube which connects the refueling cavity (inside the containment) and the fuel storage area (outside the containment) is closed on the refueling cavity side by a hatch except during refueling operations. Two seals are located around the periphery of the hatch with leak-check provisions between them.

9.1.4.3.7 Radiation Shielding

During spent fuel transfer, the gamma dose rate at the surface of the water is 20 millirem/hour or less. This is accomplished by maintaining a minimum of 10 feet of water above the top of the active fuel height during handling operations.

The three fuel handling devices used to lift spent fuel assemblies are the refueling machine, fuel handling machine, and the spent fuel handling tool. Both the refueling machine and fuel handling machine contain positive stops which prevent the fuel assembly from being raised above a safe shielding height.

9.1.4.4 Inspection and Testing Requirements

The test and inspection requirements for the equipment in the light load handling system are as follows:

A. Fuel Handling Machine, Refueling Machine, and New Fuel Elevator

The minimum acceptable tests include the following:

- Hoist and cable are load tested at 125 percent of the rated load.
- The equipment is assembled and checked for function and operation.

The following maintenance and checkout tests are recommended to be performed prior to refueling:

- Visual inspection for loose or foreign parts; maintenance to keep free of dirt and grease.
- Lubrication of exposed gears with proper lubricant.
- Visual inspection of hoist cables for worn or broken strands.
- Visual inspection of limit switches and limit switch actuators for any sign of damaged or broken parts.
- Inspection of the equipment for function and operation.

B. New Fuel Assembly Handling Tool

The minimum acceptable tests are as follows:

- The tool shall be load tested to 125 percent of the rated load.
- The tool is assembled and checked for operation.

The following maintenance and checkout tests are recommended to be performed prior to use of the tools:

- Visual inspection of the tool for dirt and loose hardware and for any signs of damage such as nicks and burrs.
- Check of the tool for operation.

C. Fuel Transfer System

The minimum acceptable test is that the system is assembled and checked for function and operation.

The following maintenance and checkout tests are recommended to be performed prior to refueling:

- Visual inspection for loose or foreign parts; maintenance to keep free of dirt and grease.
- Lubrication of exposed gears.
- Visual inspection of limit switches and limit switch actuators for any sign of damaged or broken parts.
- Check of system for function and operation.

9.1.5 Overhead Heavy Load Handling Systems

Heavy load handling systems consist of equipment which lift loads whose weight is greater than the combined weight of a single spent fuel assembly and its handling device. This equipment is part of the mechanical handling system (MHS) and is located throughout the plant. The principal equipment is the containment polar crane and the spent fuel shipping cask crane. Other such equipment includes the reactor coolant pump handling machine, bridge cranes, miscellaneous monorail hoists and fixed hoists. Table 9.1-5 lists the heavy load handling systems located in the safety-related areas of the plant, specifically the nuclear island.

For AP1000, a heavy load is a load whose weight is greater than the combined weight of a fuel assembly with rod cluster control, and the associated handling device, consisting of the inner mast of the fuel handling machine and the fuel gripper assembly. This combined weight is about 3100 pounds. Thus, a heavy load is defined as a load weighing more than 3100 pounds.

9.1.5.1 Design Basis

9.1.5.1.1 Safety Design Basis

Section 3.2 identifies safety and seismic classifications for mechanical handling system equipment. Heavy load handling systems are generally classified as nonsafety-related, nonseismic systems. The components of single-failure-proof systems necessary to prevent uncontrolled lowering of a critical load are classified as safety-related.

The polar crane and the equipment hatch hoists are single-failure-proof systems and are classified as seismic Category I. They are designed to support a critical load during and after a safe shutdown earthquake. Although not single-failure-proof, the maintenance hatch hoist is classified as seismic Category I. The equipment and maintenance hatches are required to be operational after a safe shutdown earthquake.

A critical load is a heavy load that, if dropped, could cause unacceptable damage to reactor fuel elements, or loss of safe shutdown or decay heat removal capability. The consequences of a postulated load drop are considered to be acceptable when the four evaluation criteria of NUREG-0612 (Reference 8), Paragraph 5.1, are satisfied.

Heavy loads handled in safety-related areas of the plant are classified as critical loads unless the consequences of a load drop have been evaluated and found to be within acceptable limits. (See subsection 9.1.5.3.)

Plant arrangement and the design of heavy load handling systems are based on the following criteria:

- To the extent practicable, heavy loads are not carried over or near safety-related components, including irradiated fuel and safe shutdown components. Safe load paths are designated for heavy load handling in safety-related areas.
- The likelihood of a load drop is extremely small (that is, the handling system is single failure proof), or the consequences of a postulated load drop are within acceptable limits.
- Single-failure-proof systems can stop and hold a critical load following the credible failure of a single component.
- Single-failure-proof systems can support a critical load during and after a safe shutdown earthquake.

9.1.5.1.2 Codes and Standards

The mechanical handling system conforms to the applicable codes and standards listed in Section 3.2. Overhead cranes are designed according to ASME NOG-1 (Reference 12). Other cranes and hoists handling heavy loads are designed according to the applicable ANSI standard.

NUREG-0612 references ANSI B30.2 (Reference 9) and CMAA-70 (Reference 7) for the design of cranes in safety-related areas, and references NUREG-0554 (Reference 11) for the design of single-failure-proof cranes. The design of AP1000 cranes is based on ASME NOG-1 (Reference 12) and complies with the requirements of NUREG-0612. ASME NOG-1 also provides design guidance consistent with that provided by NUREG-0554 for the design of single-failure-proof cranes.

The spent fuel shipping cask crane is designed according to the requirements of ASME NOG-1 for a Type III crane. The spent fuel shipping cask crane is also designed to meet the applicable requirements of ANSI/ANS-57.1 (Reference 6) and ANSI/ANS-57.2 (Reference 4), except as described in Table 9.1.5-1.

9.1.5.2 System Description

Table 9.1-5 lists heavy load handling systems in the nuclear island. The polar crane is designed according to the requirements of ASME NOG-1 for a Type I, single-failure-proof crane. A description of the polar crane is provided in this subsection. The equipment hatch hoist system incorporates single-failure-proof features based on NUREG-0612 guidelines. Based on the conservative design of these heavy load handling systems and associated special lifting devices, slings and load lift points (See subsection 9.1.5.2.3), a load drop of the critical loads handled by the polar crane or the equipment hatch hoist is unlikely. Except for the containment polar crane and the equipment hatch hoists, the heavy load handling systems are not single-failure-proof.

9.1.5.2.1 General Description

The containment polar crane is a bridge crane mounted on a circular runway rail supported by the containment structure. The bridge consists of two welded steel box girders held together with structural end beams. The two end beams are supported by wheeled trucks that travel on top of the runway rail.

The trolley is mounted on wheeled trucks which move by tractive power over rails secured to the crane girders. The trolley provides structural support for the crane hoisting machinery. Devices are installed to preclude derailment of the bridge or trolley under seismic loading.

Two electric-powered hoists are provided, a main hoist and an auxiliary hoist. Each hoist raises and lowers loads by reeving wire rope through upper and lower sheaves. The lower sheaves are an integral part of the load block. A hook is attached to each load block.

9.1.5.2.2 System Operation

The polar crane lifts a variety of loads for refueling and maintenance, such as the reactor vessel integrated head package, reactor internals, and the reactor coolant pump components. The crane is designed to withstand the containment environmental conditions during all modes of plant operation, including pressurization and depressurization of the containment. The crane is designed to operate only during shutdown periods.

Movements of the bridge, trolley, main, and auxiliary hoists can be controlled from the operator's cab or from a pendant suspended from the crane. Both the pendant and cab controls include a main power control switch. The pendant is equipped with a keylock switch that inhibits control from the cab. Motion control push buttons in the cab and on the pendant return to the OFF position when released.

Bridge, trolley, and hoist speeds, and speed controls are in accordance with ASME NOG-1. All speeds are variable. Speed controls permit precise positioning of the load.

The crane can be used for steam generator replacement. The structural design of the bridge is sufficient to support the steam generator, which is a noncritical load. A special hoist on a temporary trolley may be used for the steam generator replacement. Steam generator replacement is not intended to be accomplished with single-failure-proof equipment.

9.1.5.2.3 Component Descriptions

The polar crane is designed according to ASME NOG-1. Table 9.1.5-3 lists the design characteristics of these cranes. This subsection describes how the code requirements are implemented in the design of key safety-related components. Associated lifting devices and load lift points are also described.

Main Hoist Systems

The hoisting rope is wound around the drum in a single layer. If the rope becomes dislodged from its proper groove, the crane drives are automatically shut down and the brakes are set. Features are

also provided to contain the drum and prevent disengagement of the gearing in the event of drum shaft or bearing failure. A control brake and two redundant holding brakes are provided.

Two separate, redundant reeving systems are used, so that a single rope failure will not result in the dropping of the load. Two wire ropes are reeved side-by-side through the upper and lower sheaves. Each cable passes through an equalizer that adjusts for unequal cable length. The equalizer is also a load transfer safety system, eliminating sudden load displacement and shock to the crane in the unlikely event of a cable break. In the event of hook overtravel to the point where the load block contacts the crane structure, the ropes cannot be cut or crushed.

The load block provides two separate load attachment points; the main hook is a two-pronged, sister hook with safety latches.

Auxiliary Hoist System

The auxiliary hoist system is similar to that of the main hoist.

Special Lifting Devices

Special lifting devices for critical and non-critical loads are designed to meet the applicable requirements of ANSI N14.6 (Reference 14). The stress design safety factors are based on the combined maximum static and dynamic loads that could be imparted to the handling device, based on the characteristics of the crane. Special lifting devices used for the handling of critical loads are listed in Table 9.1.5-2.

Lifting Devices Not Specially Designed

Slings or other lifting devices not specially designed are selected in accordance with ANSI B30.9 (Reference 15), except that the load rating is based on the combined maximum static and dynamic loads that could be imparted to the sling.

For the handling of critical loads, dual or redundant slings are used, or a sling having a load rating twice that required for a non-critical load is used.

Load Lift Points

The design stress safety factors for heavy load lift points, such as lifting lugs or cask trunnions, are consistent with the safety factors used for special lifting devices. The design of lift points for critical loads is in accordance with NUREG-0612, Paragraph 5.1.6.(3).

9.1.5.2.4 Instrumentation Applications

Limit switches are used to initiate protective responses to:

- Hoist overtravel
- Hoist overspeed
- Hoist overload or unbalanced load

- Improper winding of hoist rope on the drum
- Bridge or trolley overtravel

Redundant limit switches are used with the main hoist and the auxiliary hoists to limit the extent of travel in both the hoisting and lowering directions. The primary protection for each hoist in each direction is a limit switch which interrupts power to the hoist motor via the control circuitry. Interruption of power to the hoist motor causes the hoist brakes to set. The hoist may be operated in the safe direction to back out of the overtravel condition.

The secondary protection for each hoist in the raising direction is a block-actuated limit switch which directly interrupts power to the hoist motor and the hoist brakes, causing the brakes to set. The secondary protection for each hoist in the lowering direction is a limit switch which is mechanically and electrically independent of the primary switch but also interrupts power to the hoist motor via the control circuitry. Actuation of the secondary limit switches prevents further hoisting or lowering until specific corrective action is taken.

A centrifugal-type limit switch, located on the drum shaft, provides overspeed protection for each hoist. Hoist speeds in excess of 115 percent of the rated lowering speed for a critical load cause the hoist motor to stop and the holding brakes to set.

A load-sensing system is used to detect overloading of the hoists. Hoisting motion is stopped when the overload setpoint is exceeded. Similarly, an unbalanced load is detected by a system that stops the hoist motion when there is excessive movement of the equalizer mechanism.

A level wind limit switch is provided to detect improper threading of the hoist rope in the drum grooves. This switch stops crane drive motors and sets the brakes. Further hoisting or lowering is prevented until specific corrective action is taken.

End-of-travel limit switches are provided for the trolley. These switches are set to trip just before the trolley comes into contact with the bumper, thus providing confidence that the kinetic energy of the trolley is within the energy-absorbing capacity of the bumpers.

9.1.5.3 Safety Evaluation

The design and arrangement of heavy load handling systems promotes the safe handling of heavy loads by one of the following means:

- A single-failure-proof system is provided so that a load drop is unlikely.

- The arrangement of the system in relationship to safety-related plant components is such that the consequences of a load drop are acceptable per NUREG 0612. Postulated load drops are evaluated in the heavy loads analysis.

The polar crane and the equipment hatch hoist systems are single failure proof. These systems stop and hold a critical load following the credible failure of a single component. Redundancy is provided for load bearing components such as the hoisting ropes, sheaves, equalizer assembly, hooks, and holding brakes. These systems are designed to support a critical load during and after a safe shutdown earthquake. The seismic Category I equipment and maintenance hatch hoist

systems are designed to remain operational following a safe shutdown earthquake. The polar crane is designed to withstand rapid pressurization of the containment during a design basis loss of coolant accident or main steam line break, without collapsing.

The spent fuel shipping cask storage pit is separated from the spent fuel pool. The spent fuel shipping cask crane cannot move over the spent fuel pool because the crane rails do not extend over the pool. Mechanical stops prevent the spent fuel shipping cask crane from going beyond the ends of the rails.

A heavy loads analysis is performed to evaluate postulated load drops from heavy load handling systems located in safety-related areas of the plant, specifically the nuclear island. No evaluations are required for critical loads handled by the containment polar crane or the equipment hatch hoists, since a load drop is unlikely.

The heavy loads analysis is to confirm that a postulated load drop does not cause unacceptable damage to reactor fuel elements, or loss of safe shutdown or decay heat removal capability.

9.1.5.4 Inservice Inspection/Inservice Testing

Preoperational inspection and testing of overhead cranes is governed by ASME NOG-1. Tests include operational testing with 100 percent load to demonstrate function and speed controls for bridge, trolley, and hoist drives and proper functioning of limit switches, locking, and safety devices. A rated load test is performed with a 125 percent load.

Following plant startup, inservice inspection of overhead cranes is governed by site-specific procedures in accordance with ANSI B30.2. Testing of crane modifications is governed by ASME NOG-1. Inservice inspection and testing of other cranes and hoists is in accordance with manufacturer's recommendations and applicable industry standards.

In-service inspection and testing of special lifting devices and slings used in safety-related areas of the plant are in accordance with ANSI N14.6 and ANSI B30.9.

9.1.6 Combined License Information for Fuel Storage and Handling

The Combined License applicant is responsible for a confirmatory structural dynamic and stress analysis for the new fuel rack, as described in subsection 9.1.1.2.1.

The Combined License applicant is responsible for a confirmatory criticality analysis for the new fuel rack, as described in subsection 9.1.1.3. This analysis should address the degradation of integral neutron absorbing material in the new fuel pool storage racks as identified in GL-96-04, and assess the integral neutron absorbing material capability to maintain a 5-percent subcriticality margin.

The Combined License applicant is responsible for a confirmatory structural dynamic and stress analysis for the spent fuel racks, as described in subsection 9.1.2.2.1. This includes reconciliation of loads imposed by the spent fuel racks on the spent fuel pool structure described in subsection 3.8.4.

The Combined License applicant is responsible for a confirmatory criticality analysis for the spent fuel racks, as described in subsection 9.1.2.3. This analysis should address the degradation of integral neutron absorbing material in the spent fuel pool storage racks as identified in GL-96-04, and assess the integral neutron absorbing material capability to maintain a 5-percent subcriticality margin.

The Combined License applicant is responsible for a program for inservice inspection of the light load handling system as specified in subsection 9.1.4.4 and the overhead heavy load handling system in accordance with ANSI B30.2, ANSI B30.9, ANSI N14.6, and ASME NOG-1 as specified in subsection 9.1.5.4.

The Combined License applicant/holder is responsible to ensure an operating radiation monitor is mounted on any crane or fuel handling machine when it is handling fuel.

9.1.7 References

1. ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors.

2. ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety.

3. ANSI N210-76, Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations.

4. ANS 57.2-1983, Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Plants.

5. Nuclear Regulatory Commission letter to All Power Reactor Licensees, from B. K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

6. ANS 57.1-1992, Design Requirements for Light Water Reactor Fuel Handling Systems.

7. Specifications for Electric Overhead Travelling Cranes CMAA, Specification 70 - 1999.

8. USNRC, "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, July 1980.

9. "Overhead and Gantry Cranes," ANSI/ASME B30.2-1990.

10. Deleted.

11. USNRC, "Single-Failure-Proof Cranes for Nuclear Power Plants," NUREG-0554, May 1979.

12. "Rules for Construction of Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder)," ASME NOG-1-1998.

13. Deleted.

14. "Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds or More," ANSI N14.6-1993.

15. "Slings," ASME/ANSI B30.9-1996.

Table 9.1-1

LOADS AND LOAD COMBINATIONS FOR FUEL RACKS

Load Combination
D + L
D + L + T_o
D + L + T_o + P_f
D + L + T_a + E'

Notes:

1. The abbreviations in the table above are those used in NUREG-0800, Section 3.8.4 of the Standard Review Plan (SRP) where each term is defined except for T_a and P_f.

   The term T_a is defined here as the thermal loads due to highest temperature associated with the postulated abnormal design conditions. The term P_f is the uplift force on the rack caused by a postulated stuck fuel assembly accident condition.

2. For the faulted load combination, thermal loads will be neglected when they are secondary and self limiting in nature and the material is ductile.

Table 9.1-2

SPENT FUEL POOL COOLING AND PURIFICATION SYSTEM DESIGN PARAMETERS

Spent fuel pool storage capacity	10 yrs spent fuel plus one core
Spent fuel pool water volume (including racks without fuel at water level of 2 foot 6 inch below the operating deck) (gallons)	181,000
Fuel transfer canal, including gate, water volume (gallons)	64,100
Minimum combined volume of spent fuel pool and fuel transfer canal above fuel to elevation 6 feet below the operating deck) (gallons)	46,700
Minimum volume of the cask washdown pit (gallons)	30,900
Nominal boron concentration of water (ppm)	2500
Maximum normal refueling case (full core offload) Water temperature with one spent fuel cooling system cooling train and one normal residual heat removal system cooling train in operation (°F)	<140
Maximum emergency core unload case Water temperature with both spent fuel cooling system cooling trains and one normal residual heat removal system cooling train in operation (°F)	<140

Table 9.1-3 (Sheet 1 of 2)

**COMPONENT DATA –
SPENT FUEL POOL COOLING AND PURIFICATION SYSTEM**

Spent Fuel Pool Pump		
Number		2
Design pressure (psig)		150
Design temperature (°F)		250
Nominal flow (gallons/minute)		1200
Minimum flow to support normal cooling (gpm)		900
Material		Stainless Steel
Spent Fuel Pool Heat Exchangers		
Number		2
Type		Plate
Design heat transfer (Btu/hour)		14.75×10^6
Design capacity (Btu/hour-°F)		24.0×10^5
Minimum capacity to support normal cooling (Btu/hour-°F)		22.0×10^5
	Side 1	**Side 2**
Design pressure (psig)	150	150
Design temperature (°F)	250	250
Nominal flow (pounds/hour)	6.23×10^5	5.94×10^5
Inlet temperature (°F), typ.	89.5	120
Outlet temperature (°F), typ.	113.3	95.1
Fluid circulated	Component cooling water	Spent fuel pool water
Material	Stainless steel	Stainless steel
Spent Fuel Pool Demineralizers		
Number		2
Design pressure (psig)		150
Design temperature (°F)		200
Nominal flow (gallons/minute)		250
Nominal resin volume (cubic feet)		75
Material		Stainless steel

Table 9.1-3 (Sheet 2 of 2)

**COMPONENT DATA –
SPENT FUEL POOL COOLING AND PURIFICATION SYSTEM**

Spent Fuel Pool Filter	
Number	2
Design pressure (psig)	150
Design temperature (°F)	250
Nominal flow (gallons/minute)	250
Filtration requirement	98% retention of particles above 5 μm
Material, vessel	Stainless steel

Table 9.1-4

STATION BLACKOUT/SEISMIC EVENT TIMES[(1)]

Event	Time to Saturation[(1)] (hours)	Height of Water Above Fuel at 72 Hours[(4)] (feet)	Height of Water Above Fuel at 7 Days[(4)] (feet)
Seismic Event[(2)] – Power Operation Immediately Following a 44% Core (68 Fuel Assemblies) Refueling	8.8	4.6	4.6[(6)]
Seismic Event[(8)] – Refueling, Immediately Following a 44% Core (68 Fuel Assemblies) Offload[(3)]	6.4	8.3[(5)]	8.3[(5)]
Seismic Event[(7)] – Refueling, Full Core Off-Load[(3)] Immediately Following a 44% Core (68 Fuel Assemblies) Refueling	2.5	8.3[(5)]	8.3[(6)]

Notes:

1. Times calculated neglect heat losses to the passive heat sinks in the fuel area of the auxiliary building.
2. Seismic event assumes water in the pool is initially drained to the level of the spent fuel pool cooling system connection simultaneous with a station blackout. Fuel cooling water sources are spent fuel pool, fuel transfer canal (including gate), and cask washdown pit for 72 hours. Between 72 hours and 7 days fuel cooling water provided from passive containment cooling system ancillary water storage tank.
3. Fuel movement complete, 150 hours after shutdown.
4. See subsection 9.1.3.5 for minimum water level.
5. Alignment of PCS water storage for supply of makeup water permits maintaining pool level at this elevation. Decay heat in reactor vessel is less that 9 MW, thus no PCS water is required for containment cooling.
6. Alignment of the PCS ancillary water storage tank and initiation of PCS recirculation pumps provide a makeup water supply to maintain this pool level or higher above the top of the fuel.
7. Seismic event assumes water in the pool is initially drained to the level of the spent fuel pool cooling system connection simultaneous with a station blackout. Fuel cooling water sources are spent fuel pool, fuel transfer canal (including gate), cask washdown pit, and passive containment cooling system water storage tank for 72 hours. Between 72 hours and 7 days fuel cooling water provided from passive containment cooling system water storage tank and passive containment cooling system ancillary water storage tank.
8. Seismic event assumes water in the pool is initially drained to the level of the spent fuel pool cooling system connection simultaneous with a station blackout. Fuel cooling water sources are spent fuel pool, fuel transfer canal (including gate), cask washdown pit, and passive containment cooling system water storage tank for 7 days.

Table 9.1-5

NUCLEAR ISLAND HEAVY LOAD HANDLING SYSTEMS[1]

Name	Crane/Hoist Type	Location (Building)	Maximum Load Rating (tons)
Containment Polar Crane	Overhead bridge	Containment	275[2]
Equipment Hatch Hoist	Fixed hoist	Containment	10
Maintenance Hatch Hoist	Fixed hoist	Containment	10
Spent Fuel Shipping Cask Crane	Overhead bridge	Auxiliary	150
MSIV Monorails Hoist A	Monorail hoists	Auxiliary	2
MSIV Monorails Hoist B	Monorail hoists	Auxiliary	2

Notes:
1. Nuclear island elevators are discussed in the heavy loads analysis.
2. Trolley maximum load rating for a critical load.

Table 9.1.5-1 (Sheet 1 of 2)

SPENT FUEL SHIPPING CASK CRANE
COMPLIANCE WITH ANSI/ANS-57.1 AND ANSI/ANS-57.2

The design of the spent fuel shipping cask crane meets the applicable provisions of ANSI/ANS-57.1-1992, R1998 and ANSI/ANS-57.2-1983, except as described below.

ANSI/ANS-57.1		Exceptions and Clarifications
6.3.1.1	Interlock Protection	Interlocks are provided in accordance with the applicable provisions of ASME NOG-1 for a Type III crane.
6.3.1.6	Emergency shutdown capability	A motor power circuit disconnect device is provided.
6.3.3.1	Parts retainers	Retaining devices are generally not provided because the crane cannot travel over the spent fuel pool.
6.3.3.2	Fastener locking devices	Fastener locking devices are provided in accordance with the applicable provisions of ASME NOG-1.
6.3.3.10	Lubricant Collection	Methods for lubricant collection are provided in accordance with the applicable provisions of ASME NOG-1.
6.3.3.22	Materials and design stresses	Material selection and allowable design stresses are in accordance with the applicable provisions of ASME NOG-1.
6.3.3.23	Joint and weld details	Joint and weld details are in accordance with the applicable provisions of ASME NOG-1.
6.3.4.1.9	Overload switch reset	Overload switch function not provided.
6.4.2.1.9	Wiring connections	Electrical wiring connections are provided in accordance with the applicable provisions of ASME NOG-1.

Table 9.1.5-1 (Sheet 2 of 2)

SPENT FUEL SHIPPING CASK CRANE
COMPLIANCE WITH ANSI/ANS-57.1 AND ANSI/ANS-57.2

ANSI/ANS-57.2		Exceptions and Clarifications
6.2.1	Codes and standards	The cask crane is designed in accordance with later industry standards as described in subsection 9.1.5.1.2.
6.2.2.8	Height limits	The height of a postulated cask drop is limited by the crane configuration. A hoist high limit switch is also provided.
6.2.4.1	Testing, maintenance & inspection	Applicable codes for inspection and testing are described in subsection 9.1.5.4.
6.2.5	Design documentation	Documentation maintenance and verification are in accordance with the applicable provisions of ASME NOG-1.
6.5.2.9	Spent fuel pool interlocks	The spent fuel shipping cask crane cannot move over the spent fuel pool because the crane rails do not extend over the pool. Mechanical stops prevent the spent fuel shipping cask crane from going beyond the ends of the rails.

Table 9.1.5-2

SPECIAL LIFTING DEVICES USED FOR THE HANDLING OF CRITICAL LOADS

Polar Crane Special Lifting Devices	Description
Integrated head package (IHP)	The IHP combines several separate components into an integral unit. It incorporates the lifting device that provides the interface between the polar crane and the reactor vessel head.
Reactor internals lifting rig	The reactor internals lifting rig is a three-legged carbon steel and stainless steel structure that is attached to the main hook for handling of the upper and lower reactor internals packages.
Reactor coolant pump (RCP)	The RCP handling machine is used for removal of the RCP motor and hydraulic elements from the pump casing. The pump/motor shell includes lifting lugs which are attached to a lifting device to allow the RCP motor and hydraulic elements to be handled by the polar crane auxiliary hook.

Table 9.1.5-3

POLAR CRANE COMPONENT DATA

Bridge	
Bridge span	See Figure 1.2-12
Travel speed	See Note 1
Braking systems (type)	Service, parking and emergency
Trolley	
Travel speed	See Note 1
Braking systems (type)	Service, parking and emergency
Main Hoist	
Approximate capacity	See Table 9.1-5
Hook speed	See Note 1
Approximate hook travel (elevation)	To reactor vessel internals
Load brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (two)
Auxiliary Hoist	
Approximate capacity	75 tons
Hook speed	See Note 1
Approximate hook travel (elevation)	To reactor coolant pump
Load brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (two)

Note:

1. Bridge, trolley and hoist speeds are within the recommended ranges of ASME NOG-1.

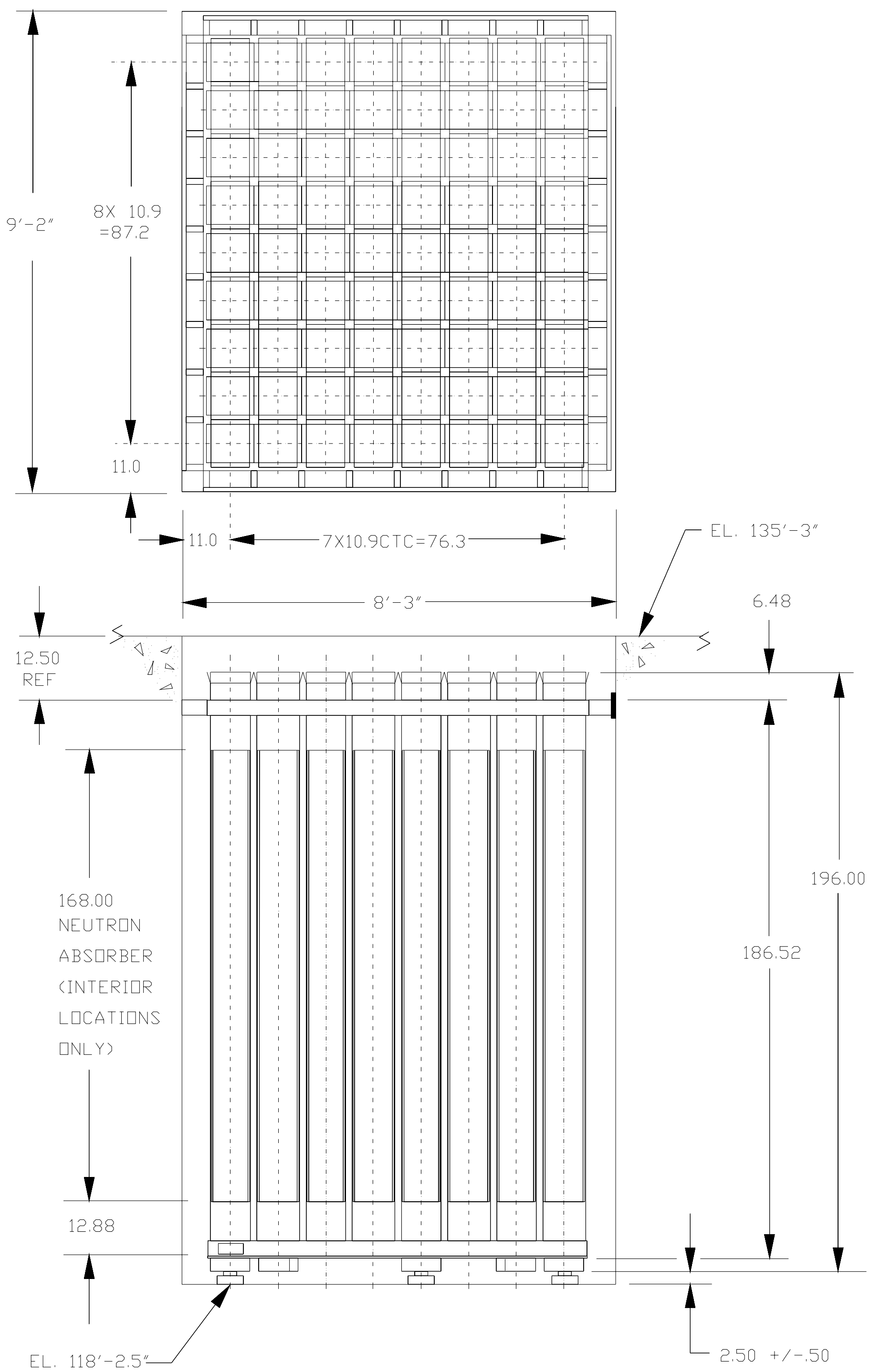


Figure 9.1-1

New Fuel Storage Rack Layout

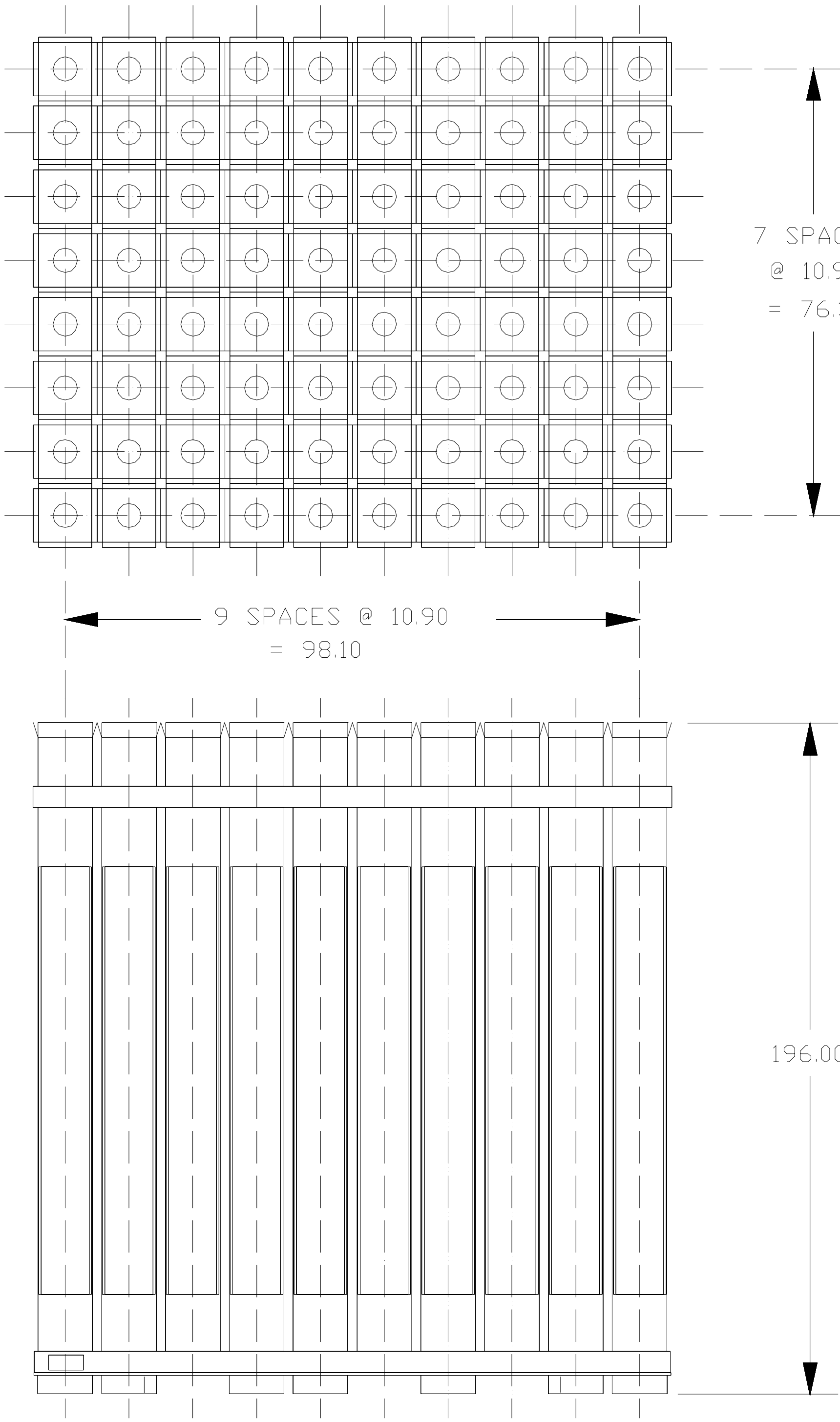


Figure 9.1-2 (Sheet 1 of 2)

Spent Fuel Storage Rack Array

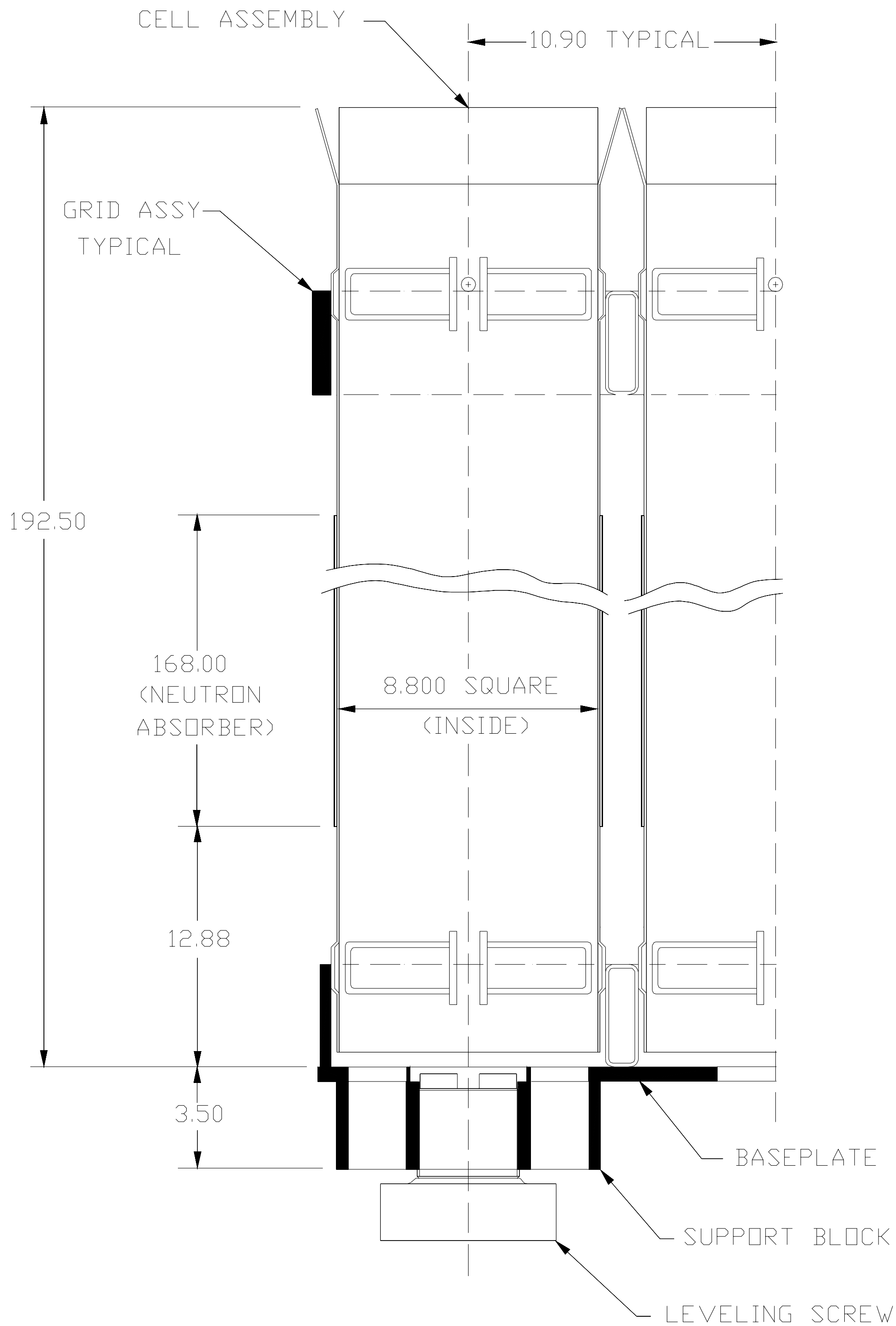


Figure 9.1-2 (Sheet 2 of 2)

Spent Fuel Storage Rack Array, Cross Section

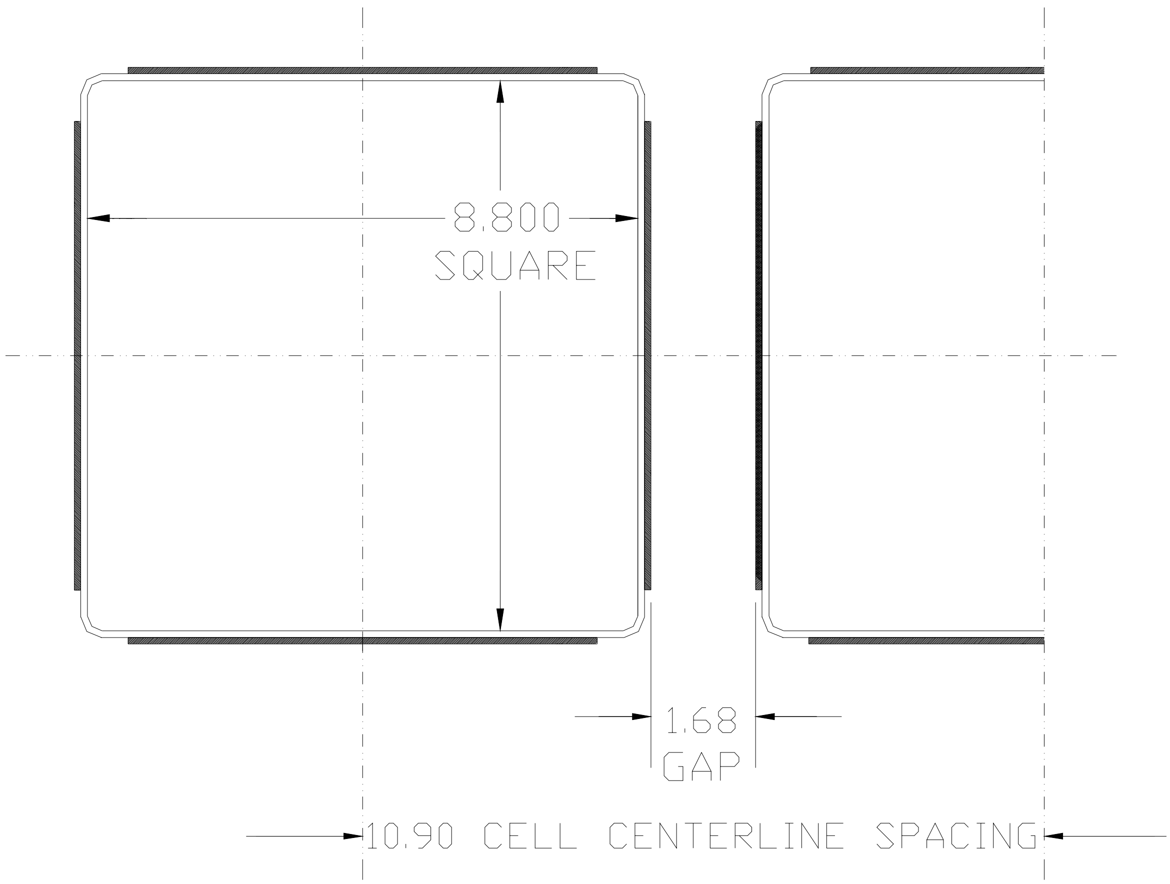


Figure 9.1-3

Spent Fuel Storage Rack Nominal Dimensions

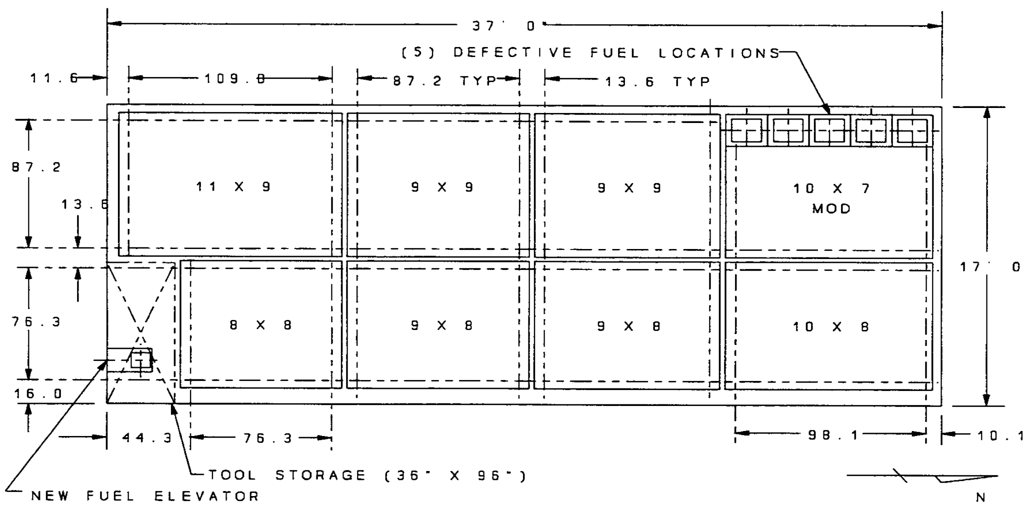


Figure 9.1-4

Spent Fuel Storage Pool Layout

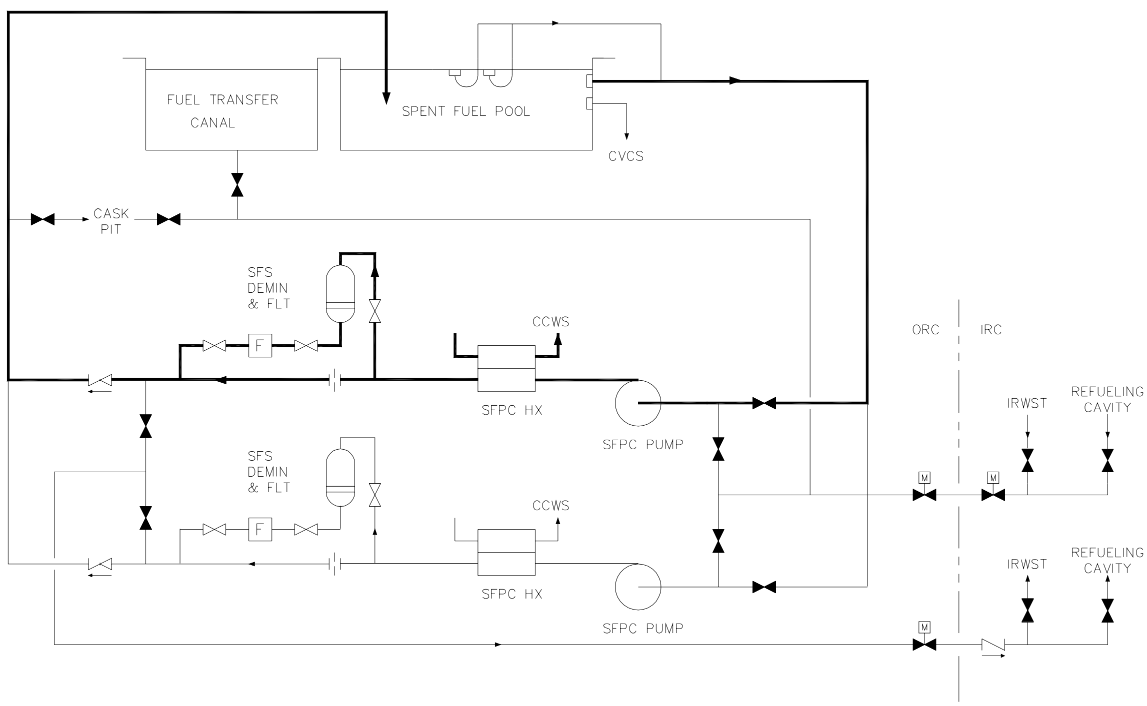


Figure 9.1-5

Spent Fuel Pool Cooling System (Normal Operation)

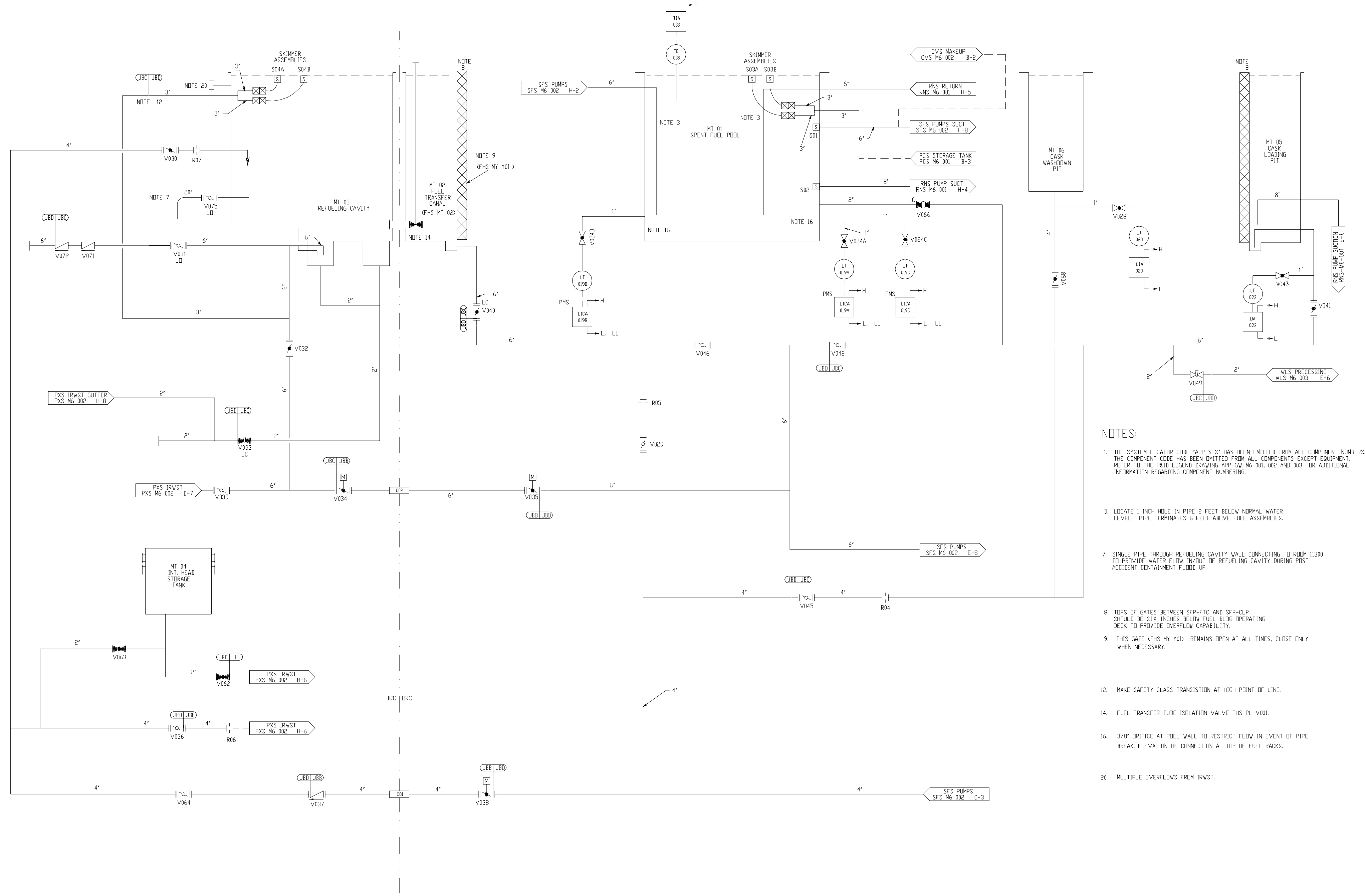
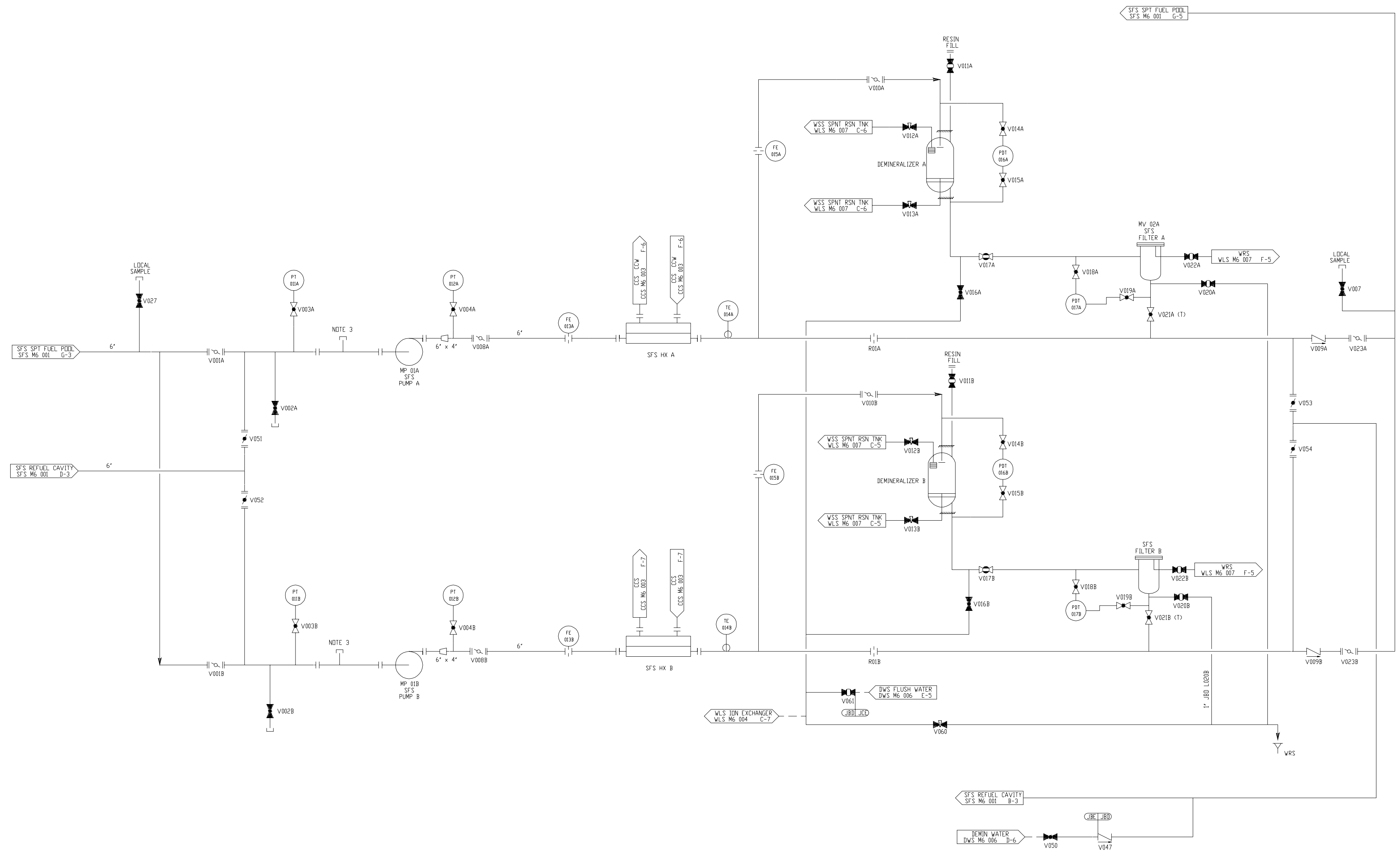


Figure 9.1-6 (Sheet 1 of 2)

Spent Fuel Pool Cooling System
Piping and Instrumentation Diagram

(REF) SFS 001



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-SFS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.
2. REFER TO SFS SYSTEM SPECIFICATION DOCUMENT FOR DETAILED DESCRIPTION OF INSTRUMENTATION, CONTROLS AND INTERLOCKS.
3. TEMPORARY STRAINER PLACED IN SPOOL PIECE FOR PRE-OPERATION FLUSHING. STRAINER AND SPOOL PIECE FURNISHED BY OTHERS. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE DURING FLUSHING OPERATIONS.
4. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP".

Figure 9.1-6 (Sheet 2 of 2)

Spent Fuel Pool Cooling System
Piping and Instrumentation Diagram

(REF) SFS 002

9.2 Water Systems

9.2.1 Service Water System

The service water system (SWS) supplies cooling water to remove heat from the nonsafety-related component cooling water system (CCS) heat exchangers in the turbine building.

9.2.1.1 Design Basis

9.2.1.1.1 Safety Design Basis

The service water system serves no safety-related function and therefore has no nuclear safety design basis.

Failure of the service water system or its components will not affect the ability of safety-related systems to perform their intended function.

9.2.1.1.2 Power Generation Design Basis

The service water system provides cooling water to the component cooling water system heat exchangers located in the turbine building.

During normal power operation, the service water system supplies cooling water at a maximum temperature of 89°F to one component cooling water heat exchanger.

During plant cooldown and refueling, the service water system supplies cooling water to both component cooling water heat exchangers to support the cooling requirements for the component cooling water system specified in subsection 9.2.2.1.2.

9.2.1.2 System Description

9.2.1.2.1 General Description

The service water system is shown in Figure 9.2.1-1. Classification of equipment and components is given in Section 3.2. The system consists of two 100-percent-capacity service water pumps, automatic backwash strainers, a two-cell cooling tower with a divided basin, and associated piping, valves, controls, and instrumentation.

The service water pumps, located in the turbine building, take suction from piping which connects to the basin of the service water cooling tower. Service water is pumped through strainers to the component cooling water heat exchangers for removal of heat. Heated service water from the heat exchangers then returns through piping to a mechanical draft cooling tower where the system heat is rejected to the atmosphere. Cool water, collected in the tower basin, flows through fixed screens to the pump suction piping for recirculation through the system.

A small portion of the service water flow is normally diverted to the circulating water system. This blowdown is used to control levels of solids concentration in the SWS. An alternate blowdown flow path is provided to the waste water system (WWS).

The service water system is arranged into two trains of components and piping. Each train includes one service water pump, one strainer, and one cooling tower cell. Each train provides 100-percent-capacity cooling for normal power operation. Cross-connections between the trains upstream and downstream of the component cooling water system heat exchangers allows either service water pump to supply either heat exchanger, and allows either heat exchanger to discharge to either cooling tower cell.

Temperatures in the system are moderate and the pressure of the service water system fluid is kept above saturation at all locations. This, along with other design features of the system arrangement and control of valves, minimizes the potential for thermodynamic or transient water hammer.

Service water system materials are compatible with the cooling water chemistry and the chemicals used for the control of long-term corrosion and organic fouling. Water chemistry is controlled by the turbine island chemical feed system (CFS).

Flooding of the turbine building resulting from a service water system failure is less severe than that for the circulating water system. Refer to subsection 10.4.5.2.3 for a description of flooding due to the circulating water system.

9.2.1.2.2 Component Description

Service Water Chemical Injection

The turbine island chemical feed system equipment injects the required chemicals into the service water system. This injection maintains a noncorrosive, nonscale forming condition and limits biological film formation. Chemicals are injected into service water pump discharge piping located in the turbine building.

The chemicals can be divided into six categories based upon function: biocide, algicide, pH adjustor, corrosion inhibitor, scale inhibitor, and silt dispersant. Specific chemicals used within the system, other than the biocide, are determined by the site water conditions. The pH adjustor, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. A sodium hypochlorite treatment system is provided for use as the biocide and controls microorganisms that cause fouling. The biocide application frequency may vary with seasons. Algicide is applied, as necessary, to control algae formation on the cooling tower. The impact of toxic material on main control room habitability is addressed in Section 6.4.

Chemical concentrations are measured through analysis of grab samples. Chlorine residual is measured to monitor the effectiveness of the biocide treatment. Addition of water treatment chemicals is performed by chemical feed system injection metering pumps and is adjusted as required.

Chemical injections are interlocked with each service water pump to prevent injection into a train when the associated service water pump is not running.

Cooling Tower

The cooling tower is a rectilinear mechanical draft structure.

The cooling tower is a counterflow, induced draft tower and is divided into two cells. Each cell utilizes one fan, located in the top portion of the cell, to draw air upward through the fill counter to the downward flow of water. Each fan is driven by a two speed electrical motor through a gear reducer. During normal power operation, one cell is inactive and water flow to that cell is shut off by a motor operated isolation valve. One operating service water pump supplies flow to the operating cell. When the service water system is used to support plant shutdown cooling, both tower cells are normally placed in service along with both service water pumps, for increased cooling capacity.

The cooling tower cold water temperature is normally automatically controlled by operation of the tower fans. The fan in an active cell will be either on high speed, low speed or off, depending on the temperature of the heated service water returning to the cooling tower. When necessary, the water flow to each cooling tower cell can be diverted directly to the basin, bypassing the tower internals. This is achieved by opening a full flow bypass valve. The bypass can be used during plant startup in cold weather to maintain service water system temperature above 40°F.

After transiting through the cooling tower, cooled service water is collected in a basin located below the tower structure. The basin is partitioned into two halves, with each half collecting the segregated flow from one tower cell. An opening in the partition normally allows the two basin halves to communicate, but a stoplog can be inserted to allow one half of the basin to remain full while the other half is drained for maintenance. Raw water is automatically supplied to the basin to makeup for evaporation, drift and blowdown losses. An alternate makeup water supply is available by gravity flow from one of the fire protection storage tanks, using water that is not dedicated to fire protection purposes. With no makeup to the cooling tower basin, the storage capacity of the basin allows continued system operation for at least 12 hours under limiting conditions, provided that blowdown flow is isolated.

Service Water Strainers

An automatic self-cleaning strainer is located in the service water supply piping to each component cooling water heat exchanger. The strainer is sized for a capacity compatible with the flow through the heat exchanger. When in service, each strainer will periodically backwash on a timed cycle, or will backwash if the differential pressure across the strainer exceeds a setpoint. The backwash cleaning features of the strainer can also be manually actuated. Backwash flow from the strainers is discharged to waste at the waste water retention basins.

Service Water Pumps

The service water system includes two service water pumps providing cooling water in the quantities and operating conditions listed in Table 9.2.1-1.

The service water pumps are vertical, centrifugal, constant speed, electric motor-driven pumps. The pumping elements of each pump are enclosed within a suction barrel which connects to supply piping from the cooling tower basin. The suction barrel of each pump is located in the

circulating water pipe trench area of the turbine building. The pumps are powered from the normal ac power system and are backed by the standby power source for occurrences of loss of normal ac power. Each pump provides 100 percent of the normal power operation flow requirements and is therefore capable of supporting normal power operation with one pump out of service for maintenance.

The starting logic for the service water pumps requires at least one of the cooling tower valves to be open prior to pump start to provide a flow path through the cooling tower or tower bypass. The pump starting logic also interlocks with the motor operated valve at the discharge of each pump. The pump starts with the discharge valve closed and the valve then opens at a controlled rate to slowly admit water to the system while maintaining pump minimum flow. This feature results in reduced fluid velocities during system start to minimize transient effects that may occur as the system sweeps out air that may be present and obtains a water solid condition.

Piping

Service water piping is made of carbon steel and is designed, fabricated, installed and tested in accordance with ANSI B31.1 Power Piping Code. Cooling water supply and return piping is accessible for inspection and/or wall thickness determination. Cooling water supply and return piping that runs in the yard is either routed within trenches or may be inspected from the inside.

The service water system is designed to accommodate transient effects that may be generated by the normal starting and stopping of pumps, opening and closing of valves, or other normal operating events. The system pumps water from the basin at the cooling tower, through piping and equipment, to a high point located at the cooling tower riser; the cooling water is then discharged in a spray fashion above the cooling tower basin. The system arrangement is such that high points in the system piping do not lead to the formation of vapor pressure voids upon loss of system pumping. Therefore, the potential for water hammer due to vapor collapse upon pump start is minimized.

Service Water System Valves

Manual isolation valves upstream and downstream of each component cooling water system heat exchanger can be used to isolate the heat exchanger and associated strainer from the service water system. The upstream valves are also normally used during power operation to align the service water system to the component cooling water heat exchanger in use by blocking flow to the inactive heat exchanger. Manual valves in the cross-connection lines between the two service water trains are normally open during power operation to allow the standby pump or standby cooling tower cell to quickly be placed in service if needed. The cross-connection valves are closed as necessary to isolate portions of the system for maintenance, and are normally closed when the system is configured for plant shutdown cooling with both trains in operation.

A motor operated isolation valve downstream of each pump automatically closes when the associated pump stops and automatically opens when the pump starts. Motor operated isolation valves are also used at the cooling tower to isolate flow to a cell that is inactive or out of service for maintenance. The motor operated valves for each train of service water pumps and cooling

tower cells are powered by the same onsite standby power source as the associated pump and cooling tower cell fan.

The service water strainers are provided with air-operated backwash valves which open during a backwash cycle. These valves fail closed upon loss of control air or electrical power.

An air operated control valve is provided in the cooling tower blowdown line. This valve allows the plant operator to set the blowdown flowrate. The valve also provides automatic isolation of blowdown flow upon loss of offsite power. The valve fails closed upon loss of control air or electrical power.

Heat Exchangers

The heat exchangers served by the service water system are part of the component cooling water system. For information concerning the component cooling water system heat exchangers refer to subsection 9.2.2.

9.2.1.2.3 System Operation

The service water system operates during normal modes of plant operation, including startup, power operation (full and partial loads), cooldown, shutdown, and refueling. The service water system is also available during loss of normal ac power conditions.

9.2.1.2.3.1 Service Water System Startup

For initial system startup, service water piping and equipment can be filled with raw water. Thereafter, at least one train normally remains in service. An inactive train is started by starting the associated pump and realigning valves as required.

9.2.1.2.3.2 Plant Startup

During plant startup, the service water system normally provides service to both component cooling water system heat exchangers. This requires that both service water pumps, strainers and cooling tower cells be in service. At the end of this phase of operation, when one of the component cooling water system heat exchangers is removed from service, one of the service water pumps, strainers and cooling tower cells may also be removed from service. Refer to subsection 9.2.2 for a description of plant startup operation and the conditions under which two component cooling water system heat exchangers may be required.

9.2.1.2.3.3 Power Operation

The service water system, during normal power operation, provides cooling water at a maximum temperature of 89°F to the component cooling water heat exchanger in service. One service water pump and one cooling tower cell are in service. The flow rate and heat load are shown in Table 9.2.1-1.

The standby service water pump is automatically started if the operating pump should fail, thereby providing a reliable source of cooling water. The system is designed so either pump can serve as the operating or standby pump.

9.2.1.2.3.4 Plant Cooldown/Shutdown

During the plant cooldown phase in which the normal residual heat removal system has been placed in service and is providing shutdown cooling, the service water cooling tower provides cooling water at a temperature of 88.5°F or less when operating at design heat load and at an ambient wet bulb temperature of no greater than 80°F (1 percent exceedance). Two service water pumps and two cooling tower cells are normally used for plant cooldown, and the cross-connection valves between trains are normally closed. The service water system heat load and flow rate are shown in Table 9.2.1-1. During these modes of operation the normal residual heat removal system and the component cooling water system remove sensible and decay heat from the reactor coolant system. In the event of failure of a service water system pump or cooling tower fan, the cooldown time is extended.

9.2.1.2.3.5 Refueling

During refueling, the service water system normally provides cooling water flow to both component cooling water system heat exchangers. Two service water pumps normally provide flow through the system for refueling modes.

9.2.1.2.3.6 Loss of Normal AC Power Operation

In the event of loss of normal ac power, the service water pumps and cooling tower fans, along with the associated motor operated valves, are automatically loaded onto their associated diesel bus. This includes isolation of cooling tower blowdown, which minimizes drain down of the system while both pumps are off. What drainage of system fluid that does occur is replaced by air without vapor cavities. The potential for water hammer on pump restart is minimized. Both pumps and both cooling tower cells automatically start after power from the diesel generator is available. Following automatic start, the operator may return the system to the appropriate configuration.

9.2.1.3 Safety Evaluation

The service water system has no safety-related functions and therefore requires no nuclear safety evaluation. If radioactive fluid is detected in the service water system, tower blowdown flow can be isolated by remote manual control. The tower blowdown valve fails closed upon loss of electrical power or instrument air.

9.2.1.4 Tests and Inspections

Preoperational testing is described in Chapter 14. The performance, structural, and leaktight integrity of system components is demonstrated by operation of the system.

9.2.1.5 Instrument Applications

Pressure indication, with low and high alarms, is provided for the discharge of each service water pump. A low pressure signal automatically starts the standby pump. Flow indication, with low and high alarms, is also provided for each service water pump. Due to the system configuration, pump flow indication can also normally be used to monitor flow through the heat exchanger or heat exchangers in service.

Temperature indication is provided for the service water supply to each component cooling water heat exchanger and for the discharge from each heat exchanger to determine the temperature differential across the heat exchanger. Heat exchanger inlet temperature indication also is used for performance monitoring of the service water cooling tower. Low and high heat exchanger inlet temperature alarms are provided. A high alarm is provided for the outlet temperature from each heat exchanger. Temperature instrumentation is provided for the service water return to each cooling tower cell to automatically control the operation of the associated cell fan.

Differential pressure measurement across each service water strainer is provided and will initiate backwash of the strainer on high differential. A high-high differential pressure alarm across the strainer is provided.

Power actuated valves in the SWS are provided with valve position indication instrumentation. In addition, the tower bypass valves are provided with position indication instrumentation.

Level indication is provided for the cooling tower basin along with high and low level alarms. The basin level signal is also used to control the normal makeup water supply valve to maintain the proper level in the cooling tower basin. Flow indication of cooling tower basin normal makeup is provided using instrumentation internal to the makeup valve.

A radiation monitor with a high alarm is provided to monitor the service water blowdown flow for detection of potentially radioactive leakage into the SWS from the component cooling water heat exchangers. Provisions are also available for taking local fluid samples. Flow indication of the blowdown flow is provided using instrumentation internal to the blowdown control valve.

9.2.2 Component Cooling Water System

The component cooling water system is a non-safety-related, closed loop cooling system that transfers heat from various plant components to the service water system during normal phases of operation. It removes heat from various components needed for plant operation and removes core decay heat and sensible heat for normal reactor shutdown and cooldown.

The AP1000 component cooling water system provides a barrier to the release of radioactivity between the plant components being cooled that handle radioactive fluid and the environment. The component cooling water system also provides a barrier against leakage of service water into primary containment and reactor systems.

9.2.2.1 Design Bases

9.2.2.1.1 Safety Design Basis

Failure of the component cooling water system or its components will not affect the ability of safety-related systems to perform their intended safety functions. The component cooling water system serves no safety-related function except for containment isolation and therefore has no nuclear safety design basis except for containment isolation (see subsection 6.2.3).

9.2.2.1.2 Power Generation Basis

The component cooling water system is designed to perform its operational functions in a reliable and failure tolerant manner. This reliability is achieved with the use of reliable and redundant equipment and with a simplified system design.

9.2.2.1.2.1 Normal Operation

The component cooling water system transfers heat from various plant components needed to support normal power operation with a single active component failure. The component cooling water system is designed for normal operation in accordance with the following criteria:

- The component cooling water supply temperature to plant components is not more than 95°F assuming a 0 percent exceedance ambient design wet bulb temperature of 81°F for service water cooling at normal operations (1 percent exceedance of 80°F for normal shutdown).

- The minimum component cooling water supply temperature to plant components is 60°F.

- The component cooling water system provides sufficient surge capacity to accept 50 gallons per minute leakage into or out of the system for 30 minutes before any operator action is required.

9.2.2.1.2.2 Normal Plant Cooldown

The first phase of plant cooldown is accomplished by transferring heat from the reactor coolant system via the steam generators to the main steam systems.

The component cooling water system, in conjunction with the normal residual heat removal system removes both residual and sensible heat from the core and the reactor coolant system and reduces the temperature of the reactor coolant system during the second phase of cooldown.

The component cooling water system reduces the temperature of the reactor coolant system from 350°F at approximately 4 hours after reactor shutdown to 125°F within 96 hours after shutdown by providing cooling to the normal residual heat removal system heat exchangers. This cooldown time is based on operation of both component cooling water system mechanical trains (one pump and one heat exchanger each), and a service water system supply temperature to the component

cooling water system heat exchangers resulting from a 1 percent exceedance ambient design wet bulb temperature of 80°F for service water cooling. In addition to the cooldown time requirements, other system design criteria during cooldown are:

- Operation is consistent with the established reactor coolant system cooldown rates while maintaining the component cooling water supply below 110°F.
- The system design prevents boiling in the component cooling water system during plant cooldown.
- A single failure of an active component during normal cooldown will not cause an increase in reactor coolant system temperature above 350°F. Such a single failure also will not cause the reactor coolant system to boil once the reactor vessel head has been removed and the refueling cavity flooded. The component cooling system continues to provide cooling water to the normal residual heat removal system throughout the shutdown after cooldown is complete.

9.2.2.1.2.3 Refueling

During fuel shuffling (partial core off-load) or a full core off-load, cooling water flow is provided to spent fuel pool heat exchangers to cool the spent fuel pool. For a full core off-load cooling water is also supplied to a normal residual heat removal heat exchanger as part of spent fuel pool cooling. The system design criteria during refueling are:

- System operation is with both component cooling water system mechanical trains available.
- The component cooling water system maintains the spent fuel pool water temperature below 120°F based on a one percent exceedance ambient design wet bulb temperature of 80°F for service water cooling.

9.2.2.1.3 Codes and Standards

The component cooling water system equipment applicable codes and standards are listed in Section 3.2. The containment penetrations, isolation valves, and the pipe between the isolation valves are Safety Class B. The remainder of the component cooling water system piping is designed to ANSI Standard B31.1.

9.2.2.2 System Description

The component cooling water system provides a reliable supply of cooling water to the various plant components listed in Table 9.2.2-2.

A simplified sketch of the component cooling water system is included as Figure 9.2.2-1. The details of the system are shown in the piping and instrumentation diagram for the component cooling water system which is included as Figure 9.2.2-2.

The component cooling water system is a closed loop cooling system that transfers heat from various plant components to the service water system cooling tower. It operates during normal

phases of plant operation including power operation, normal cooldown, and refueling. The system includes two component cooling water pumps, two component cooling water heat exchangers, one component cooling water surge tank and associated valves, piping, and instrumentation.

The system components are arranged into two mechanical trains. Each train includes one component cooling water pump and one component cooling water heat exchanger. The two trains of equipment take suction from a single return header. The surge tank is connected to the return header. Each pump discharges directly to its respective heat exchanger. A bypass line around each heat exchanger containing a throttle valve prevents overcooling the component cooling water. The discharge of each heat exchanger is to the common supply header.

Component cooling water is distributed to the components by this single supply/return header. Components are grouped in branch lines according to plant arrangement, with one branch line cooling the components inside containment. Loads inside containment are remotely isolated in response to a safety injection signal which also trips the reactor coolant pumps. Individual components, except the reactor coolant pumps, can be isolated locally to permit maintenance while supplying the remaining components with cooling water.

The component cooling water surge tank accommodates thermal expansion and contraction. It also accommodates leakage into or out of the component cooling water system until operators can isolate the leak. Water makeup to the surge tank is provided automatically on a low surge tank level signal by the demineralized water transfer and storage system. A line routed from the pump discharge header to the surge tank includes a mixing tank to add chemicals into the system to inhibit corrosion.

9.2.2.3 Component Description

General descriptions of the component cooling water system components are provided below. The nominal equipment parameters for the component cooling water system components are contained in Table 9.2.2-1.

9.2.2.3.1 Component Cooling Water Pumps

The two component cooling water pumps are horizontal, centrifugal pumps. They have a coupled pump shaft driven by an ac powered induction motor. Each pump provides the flow required by its respective heat exchanger for removal of its heat load. The pumps are redundant for normal operation heat loads. Both pumps are required for the cooldown; however, an extended cooldown can be achieved with only one pump in operation. One pump can be out of service during normal plant operation.

9.2.2.3.2 Component Cooling Water Heat Exchangers

Two component cooling water heat exchangers provide redundant cooling for normal operation heat loads. Both heat exchangers are required to achieve the design cooldown rate; however, an extended cooldown can be achieved with one heat exchanger in operation. Either heat exchanger can be aligned with either component cooling water pump allowing one heat exchanger to be out of service during normal plant operation.

The component cooling water heat exchangers are plate type heat exchangers. Component cooling water circulates through one side of the heat exchanger while service water circulates through the other side. Component cooling water in the heat exchanger is maintained at a higher pressure than the service water to prevent leakage of service water into the system.

9.2.2.3.3 Component Cooling Water Surge Tank

The component cooling water system has a single surge tank. The surge tank accommodates changes in component cooling water volume due to changes in operating temperature. The tank is designed to accommodate a 50 gallons per minute leakage into or out of the system for 30 minutes before any operator action is required.

The tank is a cylindrical, vertical unit constructed of carbon steel.

9.2.2.3.4 Component Cooling Water System Valves

Most of the valves in the component cooling water system are manual valves used to isolate cooling flow from components for which cooling is not required in a given plant operating mode.

Three motor operated isolations valves and a check valve provide containment isolation for the supply and return component cooling water system lines that penetrate the containment barrier. The motor-operated valves are normally open and are closed upon receipt of a safety injection signal. They are controlled from the main control room and fail as-is.

A motor operated isolation valve is located in the component cooling water discharge line from each reactor coolant pump. These valves, which are normally open, are closed on a high component cooling water flow signal. High flow in the component cooling water discharge line indicates significant reactor coolant leakage from the pump cooling coils or thermal barrier into the component cooling water system. Closing these valves prevents radioactive reactor coolant flow through the component cooling water system.

Relief valves are provided in the cooling water outlet line from each reactor coolant pump. These valves are sized to protect the pump motor cooling jacket (design pressure 150 psig) and the component cooling water piping in the event of a tube rupture in the pump motor cooling coil or thermal barrier. A relief valve in the cooling water outlet line from the letdown heat exchanger also protects the component cooling water piping in the event of a tube rupture in the heat exchanger. Small relief valves are included in the cooling water outlet line from the other components to relieve the volumetric expansion which occurs if the cooling water lines to the component are isolated and the water temperature rises.

9.2.2.3.5 Piping Requirements

Component cooling water system piping is made of carbon steel. Piping joints and connections are welded, except where flanged connections are required as indicated on the component cooling water system piping and instrumentation diagram (Figure 9.2.2-2).

9.2.2.4 System Operation and Performance

9.2.2.4.1 Plant Startup

Plant startup is the operation that brings the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

Normally both component cooling water system mechanical trains are operating during this post refueling period. Both trains are aligned to provide cooling to the required components as shown in Table 9.2.2-2.

When plant heatup is initiated, the reactor coolant pumps are started, and residual heat removal from the core is discontinued by stopping the residual heat removal pumps. The letdown heat exchanger is placed on automatic temperature control to maintain a constant letdown temperature. Throughout the plant startup, cooling water flows and temperatures are monitored to verify that the values are within the required limits. Once startup activities are complete, one component cooling water pump and one heat exchanger are taken out of service.

9.2.2.4.2 Normal Operation

During normal plant operation, one component cooling water system mechanical train of equipment is operating. The operating train is aligned to provide component cooling for the loads identified in Table 9.2.2-2. The other train is aligned to automatically start in case of a failure of the operating component cooling water pump. Figure 9.2.2-1 shows the valve alignment for the component cooling water system during normal plant operation.

During normal operation, leakage from the component cooling water system is replaced by automatic actuation of a valve in the makeup line on low surge tank level.

Periodically, a sample of the component cooling water is taken by the plant operator to ascertain that water chemistry specifications are met. If necessary, appropriate chemicals are added via the chemical addition tank and mixing is achieved through a recirculation line from the pump discharge header, through the surge tank to the pump suction line.

9.2.2.4.3 Plant Shutdown

Plant shutdown is the operation that brings the reactor plant from power operation to refueling conditions. During plant shutdown operations, both component cooling water system mechanical trains normally operate. The system is aligned to provide the cooling water flows to the appropriate equipment as shown on Table 9.2.2-2.

The initial phase of plant cooldown is the reactor coolant system cooldown and depressurization utilizing the steam generators and the main steam system. The second phase of plant cooldown is initiated by placing the normal residual heat removal system in service when the reactor coolant temperature and pressure have been reduced to 350°F and 400 to 450 psig, respectively (approximately 4 hours after reactor shutdown).

Prior to starting the residual heat removal pumps, the standby component cooling water pump and heat exchanger are placed in operation and component cooling water flow is initiated to the normal residual heat removal heat exchangers. Following this, the normal residual heat removal system can be placed into operation by properly aligning valves and starting a residual heat removal pump.

The component cooling water system, in conjunction with the normal residual heat removal system and service water system cools the reactor coolant system to 125°F within 96 hours after shutdown. During the cooldown period, the component cooling water inlet temperature to the various components does not exceed 110°F. Both component cooling water pumps and heat exchangers are required to meet the plant cooldown schedule. In the event of a failure of a component cooling water pump or heat exchanger, the cooldown time is extended.

9.2.2.4.4 Refueling

Both component cooling water system mechanical trains are in operation during refueling. The system is aligned to provide the required flow to the appropriate components as shown on Table 9.2.2-2.

For fuel shuffling (partial core off-load), cooling water flow is provided to both spent fuel pool heat exchangers to maintain the spent fuel pool water temperature below 120°F. With a full core off-load and 10 years accumulation of spent fuel in the pool, both spent fuel pool heat exchangers and one normal residual heat removal heat exchanger maintain the spent fuel pool water temperature below 120°F.

9.2.2.4.5 Abnormal Conditions

9.2.2.4.5.1 Failure of a Component Cooling Water Pump

If a component cooling water pump fails when one pump is in service, an alarm is actuated and the low header flow signal automatically initiates operation of the standby component cooling water pump. If a component cooling water pump fails during plant cooldown, the time to reach the cold shutdown condition is increased.

9.2.2.4.5.2 Leakage into the Component Cooling Water System from a High Pressure Source

Small leakage of reactor coolant into the component cooling water system is detected by a radiation monitor on the common pump suction header, by routine sampling, or by high level in the surge tank.

Flow measurement in the cooling water outlet line from each reactor coolant pump detects high leakage from a pump motor cooling coil or thermal barrier into the component cooling water system. A high flow signal automatically closes the valve on the cooling water outlet line on each reactor coolant pump to prevent reactor coolant flow throughout the component cooling water system. Both the flow signal and valves are nonsafety related. If the valve on the reactor coolant pump cooling water outlet line does not close, reactor coolant leakage from the pump can be retained inside containment by closing the safety-related component cooling water containment isolation valves. These valves can be closed manually by the operator after being alerted to a

reactor coolant pump leak by alarms from component cooling water system instrumentation or from the leaking reactor coolant pump instrumentation. A safety injection signal results if sufficient reactor coolant system inventory is lost through the leak. This signal will trip the reactor coolant pumps and automatically close the component cooling water containment isolation valves to prevent reactor coolant leakage outside containment. Overpressure protection of the reactor coolant pump motor cooling jacket and the component cooling water piping subjected to the reactor coolant system pressure is by means of a relief valve on the cooling water piping near the connection to the reactor coolant pump.

The operator is alerted to a large leak from the letdown heat exchanger by a high surge tank level or a high radiation alarm in the absence of high cooling water flow from any reactor coolant pump. The operator can isolate the reactor coolant flow to the letdown heat exchanger from the main control room by closing the letdown flow isolation valve in the chemical and volume control system. Overpressure protection for the component cooling water system in the case of a letdown heat exchanger tube rupture is provided by a relief valve in the component cooling water system piping near the heat exchanger outlet.

During a normal plant cooldown a normal residual heat removal heat exchanger tube leak or rupture could result in reactor coolant leakage into the component cooling water system. A check of the local flow measurements in the normal residual heat removal heat exchanger cooling water outlet lines will indicate the leaking heat exchanger. Reactor coolant flow to the faulty heat exchanger can be isolated by closing valves in the normal residual heat removal system.

9.2.2.4.5.3 Leakage from the Component Cooling Water System

Excessive leakage from the component cooling water system causes the water level in the component cooling water surge tank to drop and a low level alarm to be actuated. Makeup water is added automatically to the component cooling water system as required. After the leak is identified by visual inspection or by a change in individual component cooling water flow rate, the affected cooling water circuit containing the leak is isolated from the component cooling water system.

9.2.2.4.5.4 Loss of Normal AC Power

The component cooling water pumps are automatically loaded on the standby diesel in the event of a loss of normal ac power. The component cooling water system therefore continues to provide cooling of required components if normal ac power is lost.

9.2.2.4.5.5 Fire Leading to MODE 5, Cold Shut Down

In the event of a loss of normal component cooling system function the Fire Protection System can provide the source of cooling water for a Normal Residual Heat Removal System (RNS) heat exchanger and a RNS pump. Normally closed isolation valves between the Fire Protection System and the Component Cooling Water System are manually opened. An additional valve is manually closed to prevent supply of cooling water to other heat exchangers which are not needed to provide cooling for the Reactor Coolant System. A drain valve on the component cooling water return header is opened and the Fire Protection System water is released after passing through the

RNS heat exchanger. The flow rate of Fire Protection System water is controlled manually to conserve the supply.

9.2.2.5 Evaluation

The component cooling water system penetrates the containment boundary. The containment penetration lines are designed in accordance with the containment isolation criteria system specified in subsection 6.2.3. The containment isolation valve design evaluation and effects of failures are also presented in subsection 6.2.3.

The component cooling water system can remove the required heat load during a loss of normal ac power.

The acceptability of the design of the component cooling water system is based on specific General Design Criteria (GDCs) and regulatory guides. The design of the component cooling water system has been compared to the criteria set forth in subsection 9.2.2, "Reactor Auxiliary Cooling Water System," Revision 3, of the NRC's Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan section are General Design Criteria 2, 4, 5, 44, 45 and 46. Additionally, Regulatory Guide 1.29 was reviewed to determine the degree of compliance of the AP1000 design with the criteria. Branch Technical Position ASB 3-1 and IEEE 279 were also reviewed as appropriate. The compliance of the component cooling water system design with the applicable General Design Criteria and regulatory guides is discussed in Section 3.1 and subsection 1.9.1, respectively.

9.2.2.6 Inspection and Testing Requirements

9.2.2.6.1 Preoperational Inspection and Testing

Preoperational testing of the component cooling water system is performed to verify that the system is installed in accordance with plans and specifications. The system is hydrostatically tested and is also tested to verify that proper sequence of valve positions and pump starting occurs on the appropriate signals. The pumps are tested to verify performance and the required flows to the individual components are obtained by proper orifice installation and/or valve setting.

9.2.2.6.1.1 Pump Flow Capability Testing

Each component cooling water system pump will be tested during hot functional testing. The flow paths will be aligned for shutdown cooling by one train of component cooling water system components. The flow delivered to one normal residual heat removal system heat exchanger and one spent fuel pool cooling system heat exchanger, as well as the total component cooling water system flow, will be measured by flow instruments at the normal residual heat removal system heat exchanger, spent fuel pool cooling system heat exchanger, and component cooling water system pump discharge header.

9.2.2.6.1.2 Heat Transfer Capability Analysis

An analysis will be performed on the component cooling water system heat exchangers during heat exchanger design. The analysis is to confirm that the product of the overall heat transfer coefficient and effective heat transfer area, UA, of each heat exchanger is equal to or greater than the minimum value shown in Table 9.2.2-1. This is the minimum value for the component cooling water system to meet its functional requirement of shutdown heat removal and spent fuel pool cooling.

9.2.2.6.2 Routine Testing and Inspection

During normal operation, the standby pump and heat exchanger are periodically tested for operability, or alternatively, placed in normal operation in place of the train which had been operating.

Component cooling water system supply and return containment isolation valves are routinely tested during refueling outages. Descriptions of the testing and inspection programs for these valves are provided in subsections 3.9.6 and 6.2.3, and Section 6.6.

9.2.2.7 Instrumentation Requirements

Instruments are provided for monitoring system parameters. Essential system parameters are monitored in the main control room. Low flow in the discharge header automatically starts the backup component cooling water pump. A radiation monitor alarms in the main control room if reactor coolant leaks into the component cooling water system.

Level instrumentation on the surge tank provides both high- and low-level alarms in the main control room. Also, at a low-tank level, a valve in the makeup water line is automatically actuated to provide makeup flow from the demineralized water transfer and storage system into the component cooling water system.

High flow from a leak from the reactor coolant pump motor cooling coil or thermal barrier into the component cooling water system is alarmed in the main control room. The signal also actuates a motor operated valve which prevents reactor coolant flow from the pump with the high-flow signal into the component cooling water system. Component cooling water flow instrumentation is provided in the outlet line from the remaining components as shown in Figure 9.2.2-2.

9.2.3 Demineralized Water Treatment System

The demineralized water treatment system (DTS) receives water from the raw water system (RWS), processes this water to remove ionic impurities, and provides demineralized water to the demineralized water transfer and storage system (DWS). The demineralized water transfer and storage system is described in subsection 9.2.4.

9.2.3.1 Design Basis

9.2.3.1.1 Safety Design Basis

The demineralized water treatment system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.3.1.2 Power Generation Design Basis

- The demineralized water treatment system provides makeup and fill water to the demineralized water storage tank.
- The capacity of the demineralized water treatment system is sufficient to supply the plant makeup demand during startup, shutdown, and power operation.
- The quality of the water produced by the demineralized water treatment system is in accordance with the guidelines specified in Table 9.2.3-1.

9.2.3.2 System Description

9.2.3.2.1 General Description

Component and equipment classification for the demineralized water treatment system is given in Section 3.2. The system consists of the following major components:

- Two reverse osmosis (RO) feed pumps
- Two 100-percent reverse osmosis units normally operating in series for primary demineralization
- One electrodeionization unit for secondary demineralization

9.2.3.2.2 Component Description

Cartridge Filter

Two 100-percent capacity, cartridge-type filters arranged in a parallel configuration are provided upstream of the reverse osmosis units. These filters remove particulate such as silt or pipe scale which can plug the reverse osmosis membranes. Normally one filter is in service with the other used as a standby.

Reverse Osmosis Feed Pumps

The design consists of one full-capacity, high-pressure centrifugal feed pump for each reverse osmosis unit. The pumps maintain the required flow and pressure through the reverse osmosis membranes as the membrane performance is affected by the water temperature.

Reverse Osmosis Unit

Each reverse osmosis unit consists of two stages or arrays of membranes. Each array contains thin film composite membranes enclosed in fiberglass reinforced plastic pressure vessels. The reverse osmosis membrane assembly is of modular construction and is capable of being expanded. The piping arrangement of the individual pressure vessels permits one or more rows of an array to be out of service, while the remainder of the array is in service.

Manual isolation valves are furnished on the product and feed lines of each array and the reject brine lines between arrays. Sample valves are furnished on product and brine streams from each pressure vessel.

PVC piping may be used in low pressure portions of the system. Corrosion-resistant low alloy steel is used in higher pressure portions of the system. A pressure sensor, located on the product manifold, protects the membranes from overpressurization by alarming and shutting down the reverse osmosis unit.

Cleaning connections are provided on each stage of the reverse osmosis equipment.

Electrodeionization Unit

Electrodeionization (EDI) is used for secondary demineralization and the removal of dissolved carbon dioxide gas. The electrodeionization unit consists of multiple component stacks. Each stack component contains cell pairs of stacked membranes. One cell pair consists of an ion-diluting flow (product) channel located between a cation and an anion membrane with an ion concentrating (brine) flow channel located alternately between the cell pairs. A DC potential is maintained across the electrode plates which are located on opposite ends of the stacked membranes. Ion exchange resin is contained within the product flow channel, acting as an ion selective medium in the electrodeionization process. Isolation valves are provided for each stack component to allow for maintenance of a stack without removing the electrodeionization unit from service.

The electrodeionization unit includes two centrifugal brine pumps which maintain a constant flow in the closed loop brine system and flushes the ionic impurities from the brine channels in the stacks.

9.2.3.2.3 System Operation

After receiving water from the raw water system, the filtered water is pumped to the demineralized water treatment system. The demineralized water treatment system is a water purification system consisting of filters, pumps, reverse osmosis units, an electrodeionization unit, and associated piping, valves, and instrumentation.

A pH adjustment chemical is added upstream of the cartridge filters to adjust the pH of the reverse osmosis influent. The pH is maintained within the operating range of the reverse osmosis membranes to inhibit scaling and corrosion.

A dilute antiscalant, which is chemically compatible with the pH adjustment chemical feed, is metered into the reverse osmosis influent water to increase the solubility of salts (that is, decrease scale formation on the membranes). Antiscalant feed rate is controlled by a signal to the metering pump based on the demineralized water flow. Antiscalant chemicals are considered toxic materials for industrial facilities. The impact of toxic materials on the plant main control room habitability is addressed in Section 6.4.

Both the pH adjustment chemical and antiscalant are injected into the demineralized water treatment process from the turbine island chemical feed system. Refer to subsection 10.4.11 for a further discussion of the chemical feed system.

The reverse osmosis influent passes through the cartridge filter which removes any particulate carried over from the raw water system and provides mixing for the upstream chemical feed systems.

Primary demineralization is achieved by a two-pass reverse osmosis system which consists of two identical reverse osmosis units which normally operate in series. The influent to the reverse osmosis unit is pumped from the raw water system through the cartridge filters to the suction of the reverse osmosis feed pump. The feed pump moves the water through the first unit of reverse osmosis membranes where approximately 90 percent of the ionic impurities are removed. The product water from the first unit flows to the suction of the feed pump associated with the second reverse osmosis unit. Approximately 90 percent of the remaining ionic impurities is removed by the second reverse osmosis unit. A level signal from the demineralized water storage tank controls the operation of the reverse osmosis feed pumps. The pumps are started when the tank level is low and continue to run until the tank is full and the pumps are stopped.

Each reverse osmosis unit has two stages or arrays of pressure vessels; the membranes are contained within the vessels. A section of an array can be isolated for cleaning and maintenance of the membranes with the reverse osmosis unit in service. The reject flow or brine from the first reverse osmosis unit is discharged to the waste water system. The brine flow from the second unit is recycled to the suction of the feed pump of the first unit to improve the fluid recovery rate of the reverse osmosis process.

One reverse osmosis unit can be out of service, without affecting the demineralized water treatment effluent water quality. Operation with only one reverse osmosis unit results in the electrodeionization unit operating at a higher ionic loading.

The product water from the second reverse osmosis unit flows to the electrodeionization system for secondary demineralization. The electrodeionization unit removes approximately 90 percent of the remaining ionic impurities and also chemically removes dissolved carbon dioxide gas. The water flows through the electrodeionization stacks where a DC voltage across the electrode plates attracts ions of opposite charge. The alternately stacked membranes allow the ions to penetrate the membrane only in one direction, thereby concentrating the ions in the brine flow channel. The resin serves as an ion selective medium to aid migration of the ions through the membranes. Regeneration of the resin is performed by the DC voltage potential across the stack. The brine feed pumps maintain flow through the closed loop brine system, flushing the concentrated ions from the stacks. Approximately 5 percent of the brine flow is blowdown, which is recycled to the

suction of the second reverse osmosis unit feed pump. Makeup to the brine flow is provided from the influent to the electrodeionization unit. The brine makeup flow also provides a continuous flow to each stack for flushing deposits and crud from the electrode plates. The electrode waste is collected in the electrode waste drain tank and is normally recycled to the inlet of the first reverse osmosis feed pump. A degas blower draws ambient air through the waste drain tank to prevent the accumulation of hazardous gases in the tank.

After this water processing, demineralized water leaves the demineralized water treatment system and is supplied to the demineralized water storage tank. Refer to subsection 9.2.4 for further discussion of the demineralized water transfer and storage system.

9.2.3.3 Safety Evaluation

The demineralized water treatment system has no safety-related function and therefore requires no nuclear safety evaluation.

There are no potential sources of radioactive contamination within the demineralized water treatment system. Backflow prevention is addressed in the demineralized water transfer and storage system, subsection 9.2.4.

The effects of flooding due to demineralized water treatment system component failures are described in Section 3.4.

9.2.3.4 Tests and Inspections

The demineralized water treatment system is functionally tested under anticipated operating conditions prior to initial plant startup. This verifies that system components and controls function properly. Proper system performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.3.5 Instrumentation Applications

Pressure and flow instrumentation is provided to monitor the operation of the reverse osmosis process. The reverse osmosis feed pump discharge pressure and the effluent flow from the reverse osmosis units provide indication and control for the primary demineralization process. A pH analyzer, located upstream of the reverse osmosis units, maintains the pH level in the water to the reverse osmosis units by adjusting the stroke of the chemical feed pumps. Flow is measured downstream of the RO units and a permissive signal is sent to the chemical feed pumps. Pressure, conductivity, and flow is measured at each interval of the water treatment process.

Tank level from the demineralized water storage tank controls the operation of the system feed pumps. This level indication is described in subsection 9.2.4.

Parameters measured such as tank level indication, pressure differentials across filters, system and pump pressures, system flow, and water conductivity outputs are displayed to the data display and processing system.

9.2.4 Demineralized Water Transfer and Storage System

The demineralized water transfer and storage system receives water from the demineralized water treatment system, and provides a reservoir of demineralized water to supply the condensate storage tank and for distribution throughout the plant. Demineralized water is processed in the demineralized water transfer and storage system to remove dissolved oxygen. In addition to supplying water for makeup of systems which require pure water, the demineralized water is used to sluice spent radioactive resins from the ion exchange vessels in the chemical and volume control system (as described in subsection 9.3.6), the spent fuel pool cooling system (as described in subsection 9.1.3), and the liquid radwaste system (as described in section 11.2) to the solid radwaste system.

The demineralized water treatment system is described in subsection 9.2.3.

9.2.4.1 Design Basis

9.2.4.1.1 Safety Design Basis

The demineralized water transfer and storage system serves no safety-related function other than containment isolation, and therefore has no nuclear safety-related design basis except for containment isolation. See subsection 6.2.3 for the containment isolation system.

9.2.4.1.2 Power Generation Design Basis

- The demineralized water transfer and storage system provides demineralized water through the demineralized water storage tank to fill the condensate storage tank and to meet required demands and usages of demineralized water in other plant systems.

- The demineralized water transfer pumps provide adequate capacity and head for the distribution of demineralized water.

- The demineralized water storage tank supplies a source of demineralized water to the chemical and volume control makeup pumps during startup and required boron dilution evolutions. The demineralized water transfer and storage system supplies the required amount of water to the chemical and volume control system for reactor water makeup.

- The oxygen content of water supplied to the demineralized water distribution system from the demineralized water storage tank is 100 ppb or less.

- Sufficient storage capacity is provided in the condensate storage tank to satisfy condenser makeup demand based on maximum steam generator blowdown operation during a plant startup duration.

- The condensate storage tank provides the water supply for the startup feedwater pumps during startup, hot standby, and shutdown conditions.

- The condensate storage tank provides a sufficient supply of water to the startup feedwater system to permit 8 hours of hot standby operation, followed by an orderly plant cooldown from normal operating temperature to conditions which permit operation of the normal residual heat removal system over a period of approximately 6 hours.

- The piping from the condensate storage tank to the startup feedwater pumps allows adequate net positive suction head (NPSH) at maximum tank water temperature and minimum water level.

- The condensate storage tank serves as a reservoir to supply or receive condensate as required by the condenser hotwell level control system.

- The oxygen content of water stored in the condensate storage tank is 100 ppb or less.

9.2.4.2 System Description

9.2.4.2.1 General Description

Component and equipment classification for the demineralized water transfer and storage system is given in Section 3.2.

9.2.4.2.2 Component Description

Demineralized Water Storage Tank

The demineralized water storage tank has a capacity of approximately 100,000 gallons. The tank is a vertical cylindrical tank constructed of stainless steel. The tank is provided with level and temperature instrumentation; level controls the operation of the demineralized water treatment system and sends a signal to the reverse osmosis feed pumps to start and stop, thus supplying water to the storage tank. Tank temperature is monitored and controls an immersion-type electric heater to keep the tank contents from freezing.

Demineralized Water Transfer Pump

Two motor-driven, centrifugal, horizontal pumps, located near the demineralized water storage tank, provide the plant demineralized water distribution system pressure and capacity. Each pump provides full flow recirculation through the catalytic oxygen reduction unit as well as providing the required system demand.

Catalytic Oxygen Reduction Units

Oxygen control of the demineralized water is performed by catalytic oxygen reduction units. Two catalytic oxygen reduction units are used in the AP1000 plant. One unit is provided for the demineralized water distribution system as water is pumped from the tank to the distribution system. The second unit is provided at the condensate storage tank to maintain a low oxygen content within the tank and is used in a recirculation path around the tank.

Each catalytic oxygen reduction unit consists of a mixing chamber, a catalytic resin vessel, and a resin trap. The mixing chamber is a stainless steel, in-line, static mixer where dissolution of the reducing agent occurs. Dissolved oxygen is removed chemically by mixing the effluent from the storage tank with hydrogen gas. Hydrogen is supplied from the plant gas system. The resin vessel is a rubber lined, carbon steel vessel containing catalytic resin. The stainless steel resin trap contains a cartridge filter to collect resin fines discharged from the resin vessel.

Condensate Storage Tank

The condensate storage tank has a capacity of 485,000 gallons and is a vertical cylindrical tank constructed of stainless steel. Level and temperature instrumentation are provided with the tank level controlled by the makeup valve. Freeze protection is supplied by immersion-type electric heaters.

9.2.4.3 System Operation

9.2.4.3.1 Normal Operation

The water level in the demineralized water storage tank controls the demineralized water treatment system. When the level in the demineralized water storage tank falls to a preset level, the pumps in the demineralized water treatment system start automatically. High water level in the tank stops operation of the demineralized water treatment system. This action, along with the capacitance in the tank, maintains the desired volume to supply the expected demands for demineralized water during normal plant operation.

The demineralized water transfer pumps, taking suction from the demineralized water storage tank, supply water through a catalytic oxygen reduction unit to the demineralized water distribution header. From this header, demineralized water is supplied to the condensate storage tank, is supplied as makeup to the chemical and volume control system pumps, and is distributed throughout the plant. The demineralized water distribution header pressure is maintained by the operation of one transfer pump. This pump recirculates water that exceeds system demand to the demineralized water storage tank. Controls are provided to automatically start the second pump upon failure of the first to maintain system pressure and demand. A low level alarm on the demineralized water storage tank signals the plant operator to isolate demands on the tank other than chemical and volume control system supply. Demineralized water is distributed to the containment, auxiliary, radwaste, annex, and turbine buildings for system usage.

The condensate storage tank level is maintained by a level control valve in the tank supply line. The valve opens when the water level in the tank drops to a specified level and closes when the level increases to a specified setpoint. When high oxygen levels exist in the condensate storage tank, an oxygen analyzer signal starts the catalytic oxygen reduction unit pump. The pump is shut off when low levels of oxygen are detected. Low oxygen demineralized water is circulated from the tank outlet connection, through the catalytic oxygen reduction unit, and is returned to the tank via the normal inlet supply line of the tank. An orifice controls the recirculation pressure and flow returning to the tank.

Changes in the condensate system inventory are controlled by the condenser hotwell level system. As level falls in the hotwell, makeup from the condensate storage tank is supplied to the hotwell

by the makeup control valve. As level rises in the hotwell, condensate is rejected to the condensate storage tank via the condensate pump's discharge control valve. Subsection 10.4.1 describes the function of the condenser hotwell level system.

In the event the main feedwater system is unavailable to supply water to the steam generators during startup, hot standby, or shutdown, the startup feedwater pumps may be activated and require water from the condensate storage tank. Subsection 10.4.9 describes the startup feedwater system function and operation.

Water supplied from the condensate storage tank to the auxiliary steam supply system is described in subsection 10.4.10.

9.2.4.4 Safety Evaluation

The demineralized water transfer and storage system has no safety-related function other than for containment isolation (see Figure 9.2.4-1), and therefore requires no nuclear safety evaluation, other than containment isolation which is described in subsection 6.2.3.

Failure of system components has no impact on safety-related systems, structures, or components. Flooding due to demineralized water transfer and storage system component failures which may affect safe shutdown equipment are described in Section 3.4.

The condensate storage tank normally contains no significant radioactive contaminants.

A check valve or atmospheric gap, in conjunction with a block valve or control valve, is used to prevent backflow of fluids from systems that interface with the demineralized water transfer and storage system. For interfacing systems that have a higher operating pressure than the demineralized water transfer and storage system and that normally do not require a supply of demineralized water during plant operations, a check valve with a normally closed block valve is used. For interfacing systems that have a higher operating pressure than the demineralized water transfer and storage system and that normally require demineralized water during plant operations, a check valve is used to prevent backflow into the demineralized water transfer and storage system. For interfacing systems with a lower operating pressure than the demineralized water transfer and storage system, system operating pressure prevents backflow into the demineralized water transfer and storage system; when the demineralized water transfer and storage system is shut down for maintenance, the check valve, closed block or control valve, or atmospheric gap is relied upon to prevent backflow into the demineralized water transfer and storage system.

9.2.4.5 Tests and Inspections

Proper system performance and integrity during normal plant operation are confirmed by system operation and visual inspections.

Grab samples may be taken from the demineralized water storage tank or the condensate storage tank to verify water chemistry is maintained within acceptable limits. Grab samples are taken to the secondary sampling laboratory for analysis. Water chemistry specifications for demineralized water supplied to the demineralized water transfer and storage system are described in subsection 9.2.3.

9.2.4.6 Instrumentation Applications

Water level is measured and automatically controlled and alarmed in the demineralized water and condensate storage tanks.

Instrumentation is provided to control the recirculation and distribution of demineralized water from the storage tank through the pumps and to the supply header and condensate storage tank. Controls are provided for automatic starting of the demineralized water transfer and storage system pumps.

An oxygen analyzer signal starts and stops the condensate storage tank catalytic oxygen reduction unit pump on low and high oxygen levels.

Monitoring of instrumentation is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication, display and manual control are available in portable displays which may be connected to the data display and processing system. See Chapter 7.

9.2.5 Potable Water System

9.2.5.1 Design Basis

The potable water system (PWS) is designed to furnish water for domestic use and human consumption. It complies with the following standards:

- Bacteriological and chemical quality requirements as referenced in EPA "National Primary Drinking Water Standards," 40 CFR Part 141.

- The distribution of water by the system is in compliance with 29 CFR 1910, Occupational Safety and Health Standards, Part 141.

9.2.5.1.1 Safety Design Basis

The potable water system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.5.1.2 Power Generation Design Basis

- Potable water is supplied to provide a quantity of 100 gallons/person/day for the largest number of persons expected to be at the station during a 24-hour period during normal plant power generation or outages.

- Water heaters provide a storage capacity equal to the probable hourly demand for potable hot water usage and provide hot water for the main lavatory, shower areas, and other locations where needed.

- A minimum pressure of 20 psig is maintained at the furthermost point in the distribution system.
- No interconnections exist between the potable water system and any potentially radioactive system or any system using water for purposes other than domestic water service.

9.2.5.2 System Description

9.2.5.2.1 General Description

Classification of components and equipment for the potable water system is given in Section 3.2.

The source of water for the potable water system is the raw water system. The potable water system consists of a potable water storage tank, two potable water pumps, a jockey pump, a distribution header around the power block, hot water storage heaters, and necessary interconnecting piping and valves. Disinfection is provided upstream of the potable water storage tank (see subsection 10.4.11, turbine island chemical feed system for details).

9.2.5.2.2 Component Description

Potable Water Storage Tank

The potable water storage facility consists of a carbon steel tank with capacity less than 10,000 gallons and coated interior which stores water for distribution throughout the plant.

Potable Water Pumps

Each of the two motor-driven potable water pumps takes suction from the potable water storage tank and discharges to the domestic water distribution header. The pumps are operated as required to meet the potable water demand in the plant at a minimum supply pressure of 20 psig.

Jockey Pump

A continuously operated jockey pump is used to supply potable water to the distribution header and maintains the pressure of the system during low-flow requirement periods. This motor-driven pump takes suction from the potable water system storage tank and pumps water through the distribution system. A recirculation line to the potable water system storage tank is provided to allow continuous running of the jockey pump when the system demand is low.

Hot Water Heaters

Electric immersion heating elements located inside the potable water hot water tank are used to produce hot water. This hot water is routed to the shower and toilet areas and to other plumbing fixtures and equipment requiring domestic hot water service. Point of use, inline electric water heating elements are used to generate hot water for the main control room and the turbine building secondary sampling laboratory.

9.2.5.3 System Operation

Filtered water from the raw water system is stored in the top portion of one of the two fire water tanks which act as a clearwell for the raw water. This filtered water is pumped to the potable water system. Low water level instrumentation in the potable water storage tank generates a signal to activate the clearwell pumps supplying makeup to the potable water system storage tank. High water levels in the potable water system storage tank produce a signal which stops the clearwell pumps.

Prior to entering the potable water system storage tank, supply water is disinfected. A minimum residual chlorine level of 0.5 ppm is maintained in the system prior to entering the potable water system storage tank. The chlorination system is activated and deactivated by a flow signal generated by the fill valve located upstream of the potable water system storage tank.

Two potable water pumps and a system jockey pump are used to supply potable water throughout the plant. The potable water system pumps are activated sequentially to maintain an appropriate pressure throughout the distribution system. A pressure transmitter is provided downstream of the potable water system pumps to control their start/stop sequences. The jockey pump operates continuously to maintain system pressure.

Potable water is supplied to areas that have the potential to be contaminated radioactively. Where this potential for contamination exists, the potable water system is protected by a reduced pressure zone type backflow prevention device.

No interconnections exist between the potable water system and any system using water for purposes other than domestic water service including any potentially radioactive system. The common supply from the onsite raw water system is designed to use an air gap to prevent contamination of the potable water system from other systems supplied by the raw water system.

9.2.5.4 Safety Evaluation

The potable water system has no safety-related functions and therefore requires no nuclear safety evaluation.

9.2.5.5 Tests and Inspections

The potable water system is hydrostatically tested for leak-tightness in accordance with the Uniform Plumbing Code. Inspection of the system is in compliance with the Uniform Plumbing Code or governing codes having jurisdiction. The system is then disinfected, flushed with potable water, and placed in service. The presence of residual chlorine can be confirmed through laboratory tests of samples at the potable water storage tank and at other sampling points as required. Tests for microbiological and bacteria presence in potable water are conducted periodically.

9.2.5.6 Instrumentation Applications

Thermostats, high-temperature limit controls, and temperature indication are installed on the potable water system hot water tank. Thermostats and high-temperature limit controls are installed on the inline water heaters. Pressure regulators are employed in those parts of the distribution system where pressure restrictions are imposed.

Control signals for the chlorinator (located in the turbine island chemical feed system) are provided by flow instrumentation associated with the potable water system tank fill valve.

Instrumentation on the potable water system storage tank provides level indication for the tank, alarm signals, and control signals for the fill valve and the potable water system pumps. Should the potable water system storage tank become depleted, the potable water system pumps are tripped.

A pressure transmitter located downstream of the potable water system pumps controls the stop/start sequence of the pumps. The jockey pump runs continuously to maintain system pressure. If the jockey pump is unable to maintain system pressure, a potable water system pump is started. The second potable water system pump starts if the distribution system flow rates are such that all three pumps are required to maintain an acceptable system pressure.

9.2.6 Sanitary Drainage System

The sanitary drainage system (SDS) is designed to collect the site sanitary waste for treatment, dilution and discharge.

9.2.6.1 Design Basis

9.2.6.1.1 Safety Design Basis

The sanitary drainage system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.6.1.2 Power Generation Design Basis

The sanitary drainage system within the scope of the plant covered by Design Certification is designed to accommodate 25 gallons/person/day for up to 500 persons during a 24-hour period.

9.2.6.2 System Description

9.2.6.2.1 General Description

The sanitary drainage system collects sanitary waste from plant restrooms and locker room facilities in the turbine building, auxiliary building, and annex building, and carries this waste to the treatment plant where it is processed.

The sanitary drainage system does not service facilities in radiologically controlled areas (RCA).

Although this sanitary drainage system transports sanitary waste to the waste treatment plant, the waste treatment plant is site specific and is outside the scope of the standard AP1000 certification. This system description provides a conceptual basis for the site interface design.

9.2.6.2.2 Component Description

Trunk Line

The trunk line is the primary line that the sanitary drainage system piping connects into for transport of the sanitary drainage to the site treatment plant.

Branch Lines

Branch lines are the sanitary drainage lines that connect the restroom facilities to the trunk line.

Manholes

Manholes are required in the trunk line at the connection of the branch lines into the trunk line, at the change in direction of the trunk line, or at the change in slope or direction of the trunk line. Quantity and location are site specific.

Lift Stations

Lift stations are required in the trunk line when the uniform slope of the trunk line results in excessively deep and costly excavation. Quantity and location are site specific.

9.2.6.3 Safety Evaluation

The sanitary drainage system has no safety-related function and therefore requires no nuclear safety evaluation. There are no interconnections between this system and systems having the potential for containing radioactive material. Potentially radioactive drains are addressed in subsection 9.3.5 dealing with the radioactive waste drain system.

9.2.6.4 Test and Inspection

The sanitary drainage system is tested by water or air and established to be watertight in accordance with the Uniform Plumbing Code Section 318. System inspection is performed in compliance with the Uniform Plumbing Code Section 318 or governing codes specific to the site.

9.2.6.5 Instrument Application

The instruments associated with this system are part of the waste treatment plant which is site specific. Sufficient instrumentation for operation is provided with the treatment plant.

9.2.7 Central Chilled Water System

The plant heating, ventilation, and air conditioning (HVAC) systems require chilled water as a cooling medium to satisfy the ambient air temperature requirements for the plant. The central chilled water system (VWS) supplies chilled water to the HVAC systems and is functional during reactor full-power and shutdown operation.

9.2.7.1 Design Basis

9.2.7.1.1 Safety Design Basis

The central chilled water system serves no safety-related function other than containment isolation, and therefore has no nuclear safety design basis except for containment isolation. See subsection 6.2.3 for the containment isolation system.

9.2.7.1.2 Power Generation Design Basis

The central chilled water system provides chilled water to the cooling coils of the supply air handling units and unit coolers of the plant HVAC systems. It also supplies chilled water to the liquid radwaste system, gaseous radwaste system, secondary sampling system, and the temporary air supply units of the containment leak rate test system.

9.2.7.1.3 Codes and Standards

The central chilled water system is designed to the applicable codes and standards listed in Section 3.2.

9.2.7.2 System Description

9.2.7.2.1 General Description

The system consists of two closed loop subsystems: a high cooling capacity subsystem and a low cooling capacity subsystem. The high capacity subsystem is the primary system used to provide chilled water to the majority of plant HVAC systems and other plant equipment requiring chilled water cooling. The low capacity subsystem is dedicated to the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers. The low capacity subsystem is illustrated in Figure 9.2.7-1.

The high capacity subsystem consists of two 100-percent capacity chilled water pumps, two 100-percent capacity water-cooled chillers, a chemical feed tank, an expansion tank, and associated valves, piping, and instrumentation. The subsystem is arranged in two parallel mechanical trains with common supply and return headers. Each train includes one pump and one chiller. A cross-connection at the discharge of each pump allows for either pump to feed a given chiller. A bypass line maintains a constant chiller flow rate as the load demand changes. The chiller condensers are supplied with cooling water from the component cooling water system. The high capacity subsystem components are located in the turbine building.

The low capacity subsystem consists of two 100-percent capacity chilled water loops. Each loop consists of a chilled water pump, an air-cooled chiller, an expansion tank, and associated valves, piping, and instrumentation. The subsystem is arranged in two independent trains with separate supply and return headers. The subsystem is provided with a common chemical feed tank. The subsystem provides a reliable source of chilled water to the main control room (MCR) and technical support center (TSC) HVAC subsystem, and the Class 1E electrical equipment room HVAC subsystem. This system configuration provides 100-percent redundancy during normal plant operation and following the loss of offsite power. The air-cooled chillers of the low capacity subsystem are located on the auxiliary building roof. The chilled water pumps and expansion tanks are located in the auxiliary building below the chillers.

9.2.7.2.2 Component Description

The general descriptions and summaries of the design requirements for the central chilled water system components are provided below. The piping inside containment has a design pressure of 200 psig and a design temperature of 320°F to accommodate both cooling and heating service. The key equipment parameters for the central chilled water system components are contained in Table 9.2.7-1.

Pumps

Four central chilled water system pumps are provided. These pumps are single-stage, horizontal, centrifugal pumps. These pumps have an integral pump motor shaft driven by an ac-powered induction motor. The central chilled water system pumps are constructed of cast iron and have flanged suction and discharge nozzles. Each pump is sized to provide the maximum water flow required by its respective chiller unit for removal of its associated design heat load.

Water-Cooled Chillers

Two water cooled liquid chillers are provided. Each chiller unit consists of a compressor, condenser, evaporator, and associated piping and controls. Environmentally safe refrigerants will be used in these chillers.

Air-Cooled Chillers

Two air-cooled liquid chillers are provided. Each chiller unit consists of a compressor, condenser, evaporator, and associated piping and controls. Environmentally safe refrigerants will be used in these chillers.

Expansion Tank

One open and two closed expansion tanks are provided to maintain the pressure above saturation. The high capacity subsystem uses an open expansion tank which is located sufficiently above the high point of the system and connected to the suction side of the pump. The low capacity subsystem uses nitrogen charged expansion tanks on the suction side of the chilled water pumps. The expansion tanks maintain a positive suction pressure for the pumps. The tanks are sized to accommodate the volume of water expansion providing a space into which the noncompressible

liquid can expand or contract as the liquid undergoes volumetric changes with changes in temperature.

Chemical Feed Tank

The chemical feed tanks and the associated piping are used to add chemicals to each chilled water subsystem stream to maintain proper water quality. Antifreeze solution is added to the low capacity subsystem to prevent freezing during cold weather operation.

Valves

Isolation valves are provided upstream and downstream of each pump/chiller train. These valves are butterfly valves and are used to isolate a train of the subsystem for maintenance. An interlock is provided between the downstream isolation valve and the pump/chiller controls.

An isolation valve is provided in the line that cross-connects the pump discharge lines in the high capacity subsystem. This manual butterfly valve is normally closed and can be manually aligned to operate the standby chiller with the operating pump of either train.

An air-operated isolation valve and check valve are provided in the chilled water supply and two air-operated isolation valves are provided in the chilled water return line that penetrates containment. The air-operated containment isolation valves automatically close upon receipt of a containment isolation signal. This isolation signal can be bypassed by the MCR operator to be able to restore containment recirculation system cooling with the containment isolated.

Isolation valves are provided at the interconnection with the hot water heating system to provide hot water through the coils of the containment recirculation cooling system for heating during refueling, maintenance, and testing activities under cold weather conditions.

High capacity subsystem temperature control valves are located upstream of each cooling coil or group of coils, except for the containment recirculation cooling system coils. The containment recirculation cooling system coils are provided with three-way modulating valves. These valves bypass chilled water flow around the containment recirculation cooling system coils, as needed, to maintain the temperature within the design conditions. The flow control valves fail open upon loss of control air or electrical power. A pressure control valve is installed on the bypass line around the chiller system to maintain a constant chiller flow rate as the load demand changes. The bypass valve fails closed upon loss of control air or electrical power.

Low capacity subsystem three-way modulating temperature control valves are provided for each group of nuclear island nonradioactive ventilation system cooling coils. These valves bypass chilled water flow around the coils, as needed, to maintain the temperature within the design conditions.

The modulating control valves provide process parameters such as flow rate, temperature, and pressure to the plant control system. From this data, the plant control system calculates the required process variables.

9.2.7.2.3 Instrumentation Requirements

The chiller and pumps are operable from the plant control system. The following describes the instrumentation employed for monitoring the operation of the central chilled water system components.

- Compressor trip and malfunction alarm
- Pump trip alarm
- Flow indication and low-flow alarm
- Temperature indication and high-temperature alarm
- System low/high pressure alarm

A low pressure interlock is provided on the pump suction and a low-low flow interlock is provided on the pump discharge to protect the pumps. Level instrumentation measures expansion tank level and provides signals to low- and high-level alarms to the plant control system and to open and close the makeup supply valve.

9.2.7.2.4 System Operation

The central chilled water system operating modes are described below.

Normal Operation

The high capacity subsystem capacity is based on the ambient design temperatures of 100°F dry bulb/77°F coincident wet bulb maximum and -10°F minimum. The high capacity subsystem operates during normal modes of plant operation, supplying chilled water to plant components at a normal temperature of 40°F. The capacity of the low capacity subsystem is based on the ambient design temperatures of 115°F dry bulb/80°F coincident wet bulb maximum. The low capacity subsystem is designed to operate during all normal modes of operation, supplying chilled water to the nonradioactive ventilation system components at a normal temperature of 40°F. The low capacity system also supplies chilled water to the make-up pump and normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. The low capacity subsystem uses anti-freeze solution in the chilled water loop to protect the chilled water from freezing.

During normal operation of the high capacity subsystem, one pump and one chiller operate to supply chilled water to the following plant HVAC systems:

- Radiologically controlled area ventilation system (subsection 9.4.3)
- Containment recirculation cooling system (subsection 9.4.6)
- Containment air filtration system (subsection 9.4.7)
- Health physics/control access area HVAC system (subsection 9.4.11)
- Radwaste building ventilation system (subsection 9.4.8)

- Annex/auxiliary building nonradioactive ventilation system (subsection 9.4.2)

- In addition, they also supply chilled water to the liquid radwaste system (subsection 11.2), the gaseous radwaste system (subsection 11.3), the containment leak rate test system (subsection 6.2.5) components, the portable and mobile radwaste system (subsection 11.4) components, the secondary sampling system (subsection 9.3.4) components, the electrical switchgear room, and the personnel work area air handling units of the turbine building ventilation system (subsection 9.4.9).

In the event that either the pump or chiller of the operating train becomes inoperable, the standby train would be manually aligned to provide chilled water service.

During normal operation of the low capacity subsystem, one pump and one chiller operate to supply chilled water to the associated cooling coils of the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. One train provides chilled water to the A and D air handling unit of the Class 1E electrical equipment room HVAC subsystem, the A air handling unit of the main control room/technical support center HVAC subsystem, and the A makeup pump and the A and B normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. The other train provides chilled water to the B and C air handling unit of the Class 1E electrical equipment room HVAC subsystem, the B air handling unit of the main control room/technical support center HVAC subsystem, the B makeup pump and the A and B normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. In the event that one train of the low capacity subsystem is inoperable, the operator can align the standby train to provide cooling to the standby nuclear island nonradioactive ventilation system air handling units and the makeup pump and the normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system.

During plant shutdown in cold weather conditions, the supply and return piping to the containment recirculation cooling system cooling coils may be isolated to permit manual alignment of the hot water heating system to the containment.

The central chilled water system is designed to permit use of the chilled water piping inside containment to the containment recirculation air handling units for containment heating when the plant is shutdown during cold weather. Remote manual realignment to the heating mode, utilizing the hot water system and the same containment recirculation air handling unit coils as the cooling mode, is performed outside containment and the procedure is administratively controlled. During this mode of operation, the high capacity subsystem is functional to meet the demand of those remaining HVAC systems and other equipment requiring chilled water.

Abnormal Operation

The high cooling capacity subsystem piping penetrates the containment to supply chilled water to the containment recirculation system fan coil units. The containment isolation valves, located on the chilled water supply and return lines, close on receipt of containment isolation signals. A bypass mode with main control room indication is provided to restore the containment

recirculation cooling system cooling during containment isolation. The remainder of the chilled water system continues to operate normally following containment isolation provided that power is available.

The central chilled water system is designed to remain operable following a loss of offsite power by providing standby onsite ac power.

The low capacity subsystem chillers, pumps, and other electrical components are connected to the plant standby diesel generator bus in accordance with the automatic electrical load sequencing. The low capacity subsystem is configured such that the operation is similar to that described above for normal operation. Following the loss of offsite power, one diesel generator and one train of the low capacity subsystem operate to supply chilled water to the associated cooling coils of the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers as shown in Table 9.2.7-1.

The high capacity subsystem chillers, pumps, and other electrical components are connected to the plant standby diesel generator bus in accordance with the optional electrical load sequencing and can be energized at the option of the operator for investment protection after evaluation of the diesel generator available capacity.

The high capacity subsystem can be used in conjunction with the containment recirculation cooling system to remove heat from the containment atmosphere following certain plant transients, if the systems are available.

9.2.7.3 Safety Evaluation

The central chilled water system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation which is described in subsection 6.2.3.

The central chilled water system components located in safety-related areas of the plant are designed such that a failure in the system will not unacceptably impact the operation of safety-related components.

9.2.7.4 Inservice Inspection/Inservice Testing

The central chilled water piping circuits are hydrostatically tested and balanced to provide design flowrates and temperatures. Periodic inspections are performed to verify proper performance of system components. Specific test requirements and intervals are contained in the plant operating procedures.

9.2.8 Turbine Building Closed Cooling Water System

The turbine building closed cooling water system (TCS) provides chemically treated, demineralized cooling water for the removal of heat from nonsafety-related heat exchangers in the turbine building and rejects the heat to the circulating water system.

9.2.8.1 Design Basis

9.2.8.1.1 Safety Design Basis

The turbine building closed cooling water system has no safety-related function and therefore has no nuclear safety design basis.

9.2.8.1.2 Power Generation Design Basis

The turbine building closed cooling water system provides corrosion-inhibited, demineralized cooling water to the equipment shown in Table 9.2.8-1 during normal plant operation.

During power operation, the turbine building closed cooling water system provides a continuous supply of cooling water to turbine building equipment at a temperature of 95°F or less assuming a circulating water temperature of 90°F or less.

The cooling water is treated with a corrosion inhibitor and uses demineralized water for makeup. The system is equipped with a chemical addition tank to add chemicals to the system.

The heat sink for the turbine building closed cooling water system is the circulating water system. The heat is transferred to circulating water through plate type heat exchangers which are components of the turbine building closed cooling water system.

A surge tank is sized to accommodate thermal expansion and contraction of the fluid due to temperature changes in the system.

One of the turbine building closed cooling system pumps or heat exchangers may be unavailable for operation or isolated for maintenance without impairing the function of the system.

The turbine building closed cooling water pumps are provided ac power from the 6900V switchgear bus. The pumps are not required during a loss of normal ac power.

9.2.8.2 System Description

9.2.8.2.1 General Description

Classification of equipment and components is given in Section 3.2. The system consists of two 100-percent capacity pumps, three 50-percent capacity heat exchangers (connected in parallel), one surge tank, one chemical addition tank, and associated piping, valves, controls, and instrumentation. Heat is removed from the turbine building closed cooling water system by the circulating water system via the heat exchangers.

The pumps take suction from a single return header. Either of the two pumps can operate in conjunction with any two of the three heat exchangers. Discharge flows from the heat exchangers combine into a single supply header. Branch lines then distribute the cooling water to the various coolers in the turbine building. The flow rates to the individual coolers are controlled either by flow restricting orifices or by control valves, according to the requirements of the cooled systems. Individual coolers can be locally isolated, where required, to permit maintenance of the cooler

while supplying the remaining components with cooling water. A bypass line with a manual valve is provided around the turbine building closed cooling water system heat exchangers to help avoid overcooling of components during startup/low-load conditions or cold weather operation.

The system is kept full of demineralized water by a surge tank which is located at the highest point in the system. The surge tank connects to the system return header upstream of the pumps. The surge tank accommodates thermal expansion and contraction of cooling water resulting from temperature changes in the system. It also accommodates minor leakage into or out of the system. Water makeup to the surge tank, for initial system filling or to accommodate leakage from the system, is provided by the demineralized water transfer and storage system. The surge tank is vented to the atmosphere.

A line from the pump discharge header back to the pump suction header contains valves and a chemical addition tank to facilitate mixing chemicals into the closed loop system to inhibit corrosion in piping and components.

A turbine building closed cooling water sample is periodically taken and analyzed to verify that water quality is maintained.

9.2.8.2.2 Component Description

Surge Tank

A surge tank accommodates changes in the cooling water volume due to changes in operating temperature. The tank also temporarily accommodates leakage into or out of the system. The tank is constructed of carbon steel.

Chemical Addition Tank

The chemical addition tank is constructed of carbon steel. The tank is normally isolated from the system and is provided with a hinged closure for addition of chemicals.

Pumps

Two pumps are provided. Either pump provides the pumping capacity for circulation of cooling water throughout the system. The pumps are single stage, horizontal, centrifugal pumps, are constructed of carbon steel, and have flanged suction and discharge nozzles. Each pump is driven by an ac powered induction motor.

Heat Exchangers

Three heat exchangers are arranged in a parallel configuration. Two of the heat exchangers are in use during normal power operation and turbine building closed cooling water flow divides between them.

The heat exchangers are plate type heat exchangers. Turbine building closed cooling water circulates through one side of the heat exchanger while circulating water flows through the other side. During system operation, the turbine building closed cooling water in the heat exchanger is

maintained at a higher pressure than the circulating water so leakage of circulating water into the closed cooling water system does not occur. The heat exchangers are constructed of titanium plates with a carbon steel frame.

Valves

Manual isolation valves are provided upstream and downstream of each pump. The pump isolation valves are normally open but may be closed to isolate the non-operating pump and allow maintenance during system operation. Manual isolation valves are provided upstream and downstream of each turbine building closed cooling water heat exchanger. One heat exchanger is isolated from system flow during normal power operation. A manual bypass valve can be opened to bypass flow around the turbine building closed cooling water heat exchangers when necessary to avoid low cooling water supply temperatures.

Flow control valves are provided to restrict or shut off cooling water flow to those cooled components whose function could be impaired by overcooling. The flow control valves are air operated and fail open upon loss of control air or electrical power. An air operated valve is provided to control demineralized makeup water to the surge tank for system filling and for accommodating leakage from the system. The makeup valve fails closed upon loss of control air or electrical power.

Piping

System piping is made of carbon steel. Piping joints and connections are welded, except where flanged connections are used for accessibility and maintenance of components.

9.2.8.2.3 System Operation

The turbine building closed cooling water system operates during normal power operation. The system does not operate with a loss of normal ac power.

Startup

The turbine building closed cooling water system is placed in operation during the plant startup sequence after the circulating water system is in operation but prior to the operation of systems that require turbine building closed cooling water flow. The system is filled by the demineralized water transfer and storage system through a fill line to the surge tank. The system is placed in operation by starting one of the pumps.

Normal Operation

During normal operation, one turbine building closed cooling water system pump and two heat exchangers provide cooling to the components listed in Table 9.2.8-1. The other pump is on standby and aligned to start automatically upon low discharge header pressure.

During normal operation, leakage from the system will be replaced by makeup from the demineralized water transfer and storage system through the automatic makeup valve. Makeup can be controlled either manually, or automatically upon reaching low level in the surge tank.

Shutdown

The system is taken out of service during plant shutdown when no longer needed by the components being cooled. The standby pump is taken out of automatic control, and the operating pump is stopped.

9.2.8.3 Safety Evaluation

The turbine building closed cooling water system has no safety-related function and therefore requires no nuclear safety evaluation.

9.2.8.4 Tests and Inspections

Pre-operational testing is described in Chapter 14. The performance, structural, and leaktight integrity of system components is demonstrated by operation of the system.

9.2.8.5 Instrument Applications

Parameters important to system operation are monitored in the main control room. Flow indication is provided for individual cooled components as well as for the total system flow.

Temperature indication is provided for locations upstream and downstream of the turbine building closed cooling water system heat exchangers. High temperature of the cooling water supply alarms in the main control room. Temperature test points are provided at locations to facilitate thermal performance testing.

Pressure indication is provided for the pump suction and discharge headers. Low pressure at the discharge header automatically starts the standby pump.

Level instrumentation on the surge tank provides level indication and both low- and high-level alarms in the main control room. On low tank level, a valve in the makeup water line automatically actuates to provide makeup flow from the demineralized water transfer and storage system.

9.2.9 Waste Water System

The waste water system collects and processes equipment and floor drains from nonradioactive building areas.

9.2.9.1 Design Basis

9.2.9.1.1 Safety Design Basis

The waste water system serves no safety-related function and therefore has no safety-related design basis.

9.2.9.1.2 Power Generation Design Basis

The power generation design basis is:

- Remove oil and/or suspended solids from miscellaneous waste streams generated from the plant.
- Collect system flushing wastes during startup prior to treatment and discharge.
- Collect and process fluid drained from equipment or systems during maintenance or inspection activities.
- Direct nonradioactive equipment and floor drains which may contain oily waste to the building sumps and transfer their contents for proper waste disposal. The radioactive equipment and floor drain system is described in subsection 9.3.5.

9.2.9.2 System Description

9.2.9.2.1 General Description

The waste water system is capable of handling the anticipated flow of waste water during normal plant operation and during plant outages. The classification of components and equipment is given in Section 3.2.

Wastes from the turbine building floor and equipment drains (which include laboratory and sampling sink drains, oil storage room drains, the main steam isolation valve compartment, auxiliary building penetration area and the auxiliary building HVAC room) are collected in the two turbine building sumps. Drainage from the diesel generator building sumps, the auxiliary building sump – north (a nonradioactive sump) and the annex building sump is also collected in the turbine building sumps. The turbine building sumps provide a temporary storage capacity and a controlled source of fluid flow to the oil separator. In the event radioactivity is present in the turbine building sumps, the waste water is diverted from the sumps to the liquid radwaste system (WLS) for processing and disposal. A radiation monitor located on the common discharge piping of the sump pumps provides an alarm upon detection of radioactivity in the waste water. The radiation monitor also trips the sump pumps and the waste water retention basin pumps on detection of radioactivity to isolate the contaminated waste water. Provisions are included for sampling the sumps.

The turbine building sump pumps route the waste water from either of the two sumps to the oil separator for removal of oily waste. The diesel fuel oil area sump pump also discharges waste water to the oil separator. A bypass line allows for the oil separator to be out of service for maintenance. The oil separator has a small reservoir for storage of the separated oily waste which flows by gravity to the waste oil storage tank. The waste oil storage tank provides temporary storage prior to removal by truck for offsite disposal.

The waste water from the oil separator flows by gravity to the waste water retention basin for settling of suspended solids and treatment, if required, prior to discharge. The waste water basin

transfer pumps route the basin effluent to either the circulating water cooling tower basin or to the plant outfall, depending on the quality of the water in the waste water retention basin.

The condenser waterbox drains are routed directly to the waste water retention basins.

9.2.9.2.2 Component Description

Turbine Building Sumps

The two sumps collect waste water from the floor and equipment drains, laboratory drains, sampling waste drains, and plant washdowns from the turbine building. Selected drains from both the annex and auxiliary buildings are also collected in these sumps.

Turbine Building Sump Pumps

Each sump has one pneumatic, double diaphragm pump which routes the waste water to the oil separator. Interconnecting piping between the suction of the sump pumps allows for either pump to transfer waste water from either or both sumps. The plant service air system provides the supply of air for operation of the pumps. Operation of the pump is automatic based on sump level with controls provided for manual operation.

Oil Separator

The oil separator has internal, vertical coalescing tubes for removal of oily waste and an oil holdup tank. Sampling provisions are included on the oil holdup tank to confirm that the oil does not require handling and disposal as a hazardous waste. A sampling connection is also provided at the discharge of the oil separator.

Waste Oil Storage Tank

Waste oil from the oil separator reservoir and other plant areas is stored in a waste oil storage tank. A sampling connection is provided on the tank to verify that the oil does not require handling and disposal as a hazardous material. A truck connection on the tank allows for removal of the waste oil from the tank for offsite disposal.

Waste Water Retention Basin

The waste water retention basin is a lined basin with two compartments constructed such that its contents, dissolved or suspended, do not penetrate the liner and leach into the ground. Either of these compartments can receive waste streams for holdup or, if required, for treatment to meet specific environmental discharge requirements.

The configuration and size of the waste water retention basin allows settling of solids larger than 10 microns which may be suspended in the waste water stream.

Waste water can be sampled prior to discharge from the waste water retention basin.

Basin Transfer Pumps

Two submersible type pumps, one per basin compartment, send the waste water from the retention basin to either the circulating water system or to a site-specific plant outfall. In the event of oily waste leakage into the retention basin, a recirculation line is provided to recycle the oil/water waste from the basin to the oil separator. Controls are provided for automatic or manual operation of the pumps based on the level of the retention basin.

Waste Water Sumps

Waste water collection sumps are provided for the auxiliary building, the diesel generator building, the annex building and the diesel fuel oil area. These collection sumps are drained by air operated pumps and the effluent from the sumps, except the effluent from the diesel fuel oil area, is directed to the turbine building sumps for processing and release. The effluent from the diesel fuel oil area is pumped directly to the oil separator.

Sump Pumps

The waste water sump pumps are pneumatic, double diaphragm pumps. The plant service air system provides the supply of air for operation of these pumps. Operation of the pumps is automatic based on sump level with controls provided for manual operation.

9.2.9.3 Safety Evaluation

The waste water system has no safety-related function and therefore requires no nuclear safety evaluation.

9.2.9.4 Tests and Inspections

System performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.9.5 Instrumentation Applications

Level instrumentation and associated pump controls on the turbine building sumps, the waste water retention basin, the auxiliary building sump, the diesel generator building sumps, and the diesel fuel oil sump are provided to prevent overflow of these waste water collection points. High alarms indicate basin or tank level where operator action is required.

A radiation monitor located on the common waste water retention basin pump discharge piping initiates an alarm and trips the turbine building sump and waste water retention basin pumps when radioactivity above a preset high level point is detected in the waste stream.

9.2.10 Hot Water Heating System

The hot water heating system (VYS) supplies heated water to selected nonsafety-related air handling units and unit heaters in the plant during cold weather operation and to the containment recirculating fans coil units during cold weather plant outages.

9.2.10.1 Design Basis

9.2.10.1.1 Safety Design Basis

The hot water heating system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.10.1.2 Power Generation Design Basis

- During normal plant operation, the hot water heating system maintains acceptable design ambient air temperatures in various areas throughout the AP1000.

- During plant outages in cold weather, the hot water heating system supplies hot water to the plant chilled water piping serving the containment building recirculation fan coil units to maintain acceptable ambient air temperatures inside containment.

9.2.10.2 System Description

9.2.10.2.1 General Description

Major components of the heating system include heat exchangers, pumps, a surge tank, and provisions for chemical feed. Component and equipment classification for the hot water heating system is given in Section 3.2. The hot water heating system consists of a heat transfer package for the production of hot water and a distribution system to the various HVAC systems and unit heaters. The hot water heating system is a nonsafety-related system.

During cold weather plant operation, the hot water heating system supplies hot water throughout the plant to protect equipment from freezing and for personnel comfort. During cold weather plant outages, the hot water heating system supplies hot water to the containment building recirculation fan coil units to maintain acceptable ambient air temperatures inside containment. During a loss of normal ac power, provisions are made to power the hot water heating system from the onsite diesel generators as an investment protection load. In this mode of operation, heating steam is supplied from the auxiliary steam supply system.

The hot water heating system, using a steam source from high-pressure turbine crossunder piping or the auxiliary boiler, extracts heat energy from the steam through a heat exchanger and transfers this energy to heat water. The heated water is pumped in a closed loop system to hot water coils in the air conditioning systems. Condensate from the heat exchanger is level controlled and drained to the main condenser or auxiliary boiler feedwater system.

Two 50-percent capacity system pumps take suction from the return main of the closed loop system, pump water through two 50-percent capacity system heat exchangers, and supply hot water to the heating system main header. To match system heat load and maintain fluid system temperature, part of the water passes through the heater while the remainder is diverted through the heater bypass. To prevent flashing of the heated water into steam, the pump in combination with the system surge tank keeps the system pressure above saturation conditions. The surge tank uses both elevation and nitrogen overpressure to keep the minimum system pressure above

saturation conditions at the pump suction. Demineralized water is supplied to the system for surge tank makeup.

During plant outages in cold weather, hot water flows to the containment building recirculation fan coil units to heat the containment atmosphere. The recirculation fan coil units, containment supply and return piping to these units, and the containment isolation valves are part of the central chilled water system as described in subsection 9.2.7. During normal plant operation the hot water heating system is isolated from the containment recirculation fan coils.

The hot water heating system is a manually actuated system and may operate when the site ambient temperature is 73°F or below.

9.2.10.2.2 Component Description

Major component design data of the hot water heating system are listed in Table 9.2.10-1.

Heat Exchanger

Each heat exchanger is a horizontal, shell-and-tube type, with an integral drain cooler, and uses the heat of vaporization of low-pressure steam for the heating of water. The heat exchanger is located in the closed loop hot water heating system downstream of the system pumps in the turbine building. This heat exchanger provides heated water for selected air handling unit and unit heater hot water coils.

Pumps

Two pumps distribute hot water to the various HVAC and unit heater systems. They are motor driven centrifugal pumps.

Surge Tank

The surge tank maintains system pressure by allowing the water to expand when the water temperature increases and provides a volume to accept makeup water to the hot water heating system.

The tank is a carbon steel, welded, pressure vessel with nitrogen supply, tank recirculation, and instrument connections.

Chemical Feed Tank

The chemical feed tank provides a means of chemical mixing in the system. Addition of chemicals provides control of corrosion.

The tank is a vertical cylinder of carbon steel construction with a capacity of less than 150 gallons and a top hinged opening for introducing the chemicals and side connections for transporting water through the chemical mixing tank from the pump discharge or the demineralized water transfer and storage system supply.

9.2.10.2.3 System Operation

As the system is filled with demineralized water, samples are taken and the closed loop water chemistry adjusted with chemicals recirculated through the chemical mixing tank with the use of a single pump. A pump is started and steam is admitted to a hot water system heat exchanger and the system is gradually heated.

The three-way diverting valve modulates hot water heating flow through each hot water heating system heat exchanger maintaining a constant heat exchanger outlet temperature, measured at the heat exchanger outlet.

A condensate level is maintained in each system heat exchanger by throttling the heat exchanger discharge flow to the condenser. During a plant outage when extraction steam is shutdown and auxiliary steam is used from the auxiliary boiler, a manual block valve is opened to establish flow of condensate from each heat exchanger to the auxiliary steam supply system deaerator.

Hot water flowing to individual heating coils is controlled either by flow balancing fixed orifices or by temperature controlled solenoid valves, according to the requirements of the heating system. Area temperatures are controlled by cycling the fans in unit heaters, by use of integral face/bypass dampers in air handling units, or by thermostats controlling hot water solenoids in heating coils of HVAC ducts. Further detail of hot water heating of the individual unit heaters, air handling units, and duct heating coils is provided in Section 9.4. In the radwaste building, normally isolated hot water supply and return connections are provided for a mobile radwaste system.

9.2.10.3 Safety Evaluation

The hot water heating system has no safety-related function and therefore requires no nuclear safety evaluation.

The hot water heating system interfaces with only nonsafety-related systems. Hot water heating is used in the containment to keep piping and components from freezing during cold weather when the plant is not operating. A hot water heating system interface with the central chilled water system is outside containment and in nonsafety-related piping of the chilled water system. Piping is shared inside the containment between hot water heating and central chilled water. During normal plant operation, the hot water system is isolated from the central chilled water system and containment. Containment isolation by the central chilled water system is described in subsection 6.2.3.

The hot water heating system is a high energy system. Hot water heating piping is generally excluded from safety-related plant areas outside the containment. Piping of this system routed in safety-related areas is 1 inch and smaller and is not evaluated for pipe ruptures. Design bases for routing high energy pipe in safety-related areas and protection against the dynamic effects associated with the postulated rupture of piping are given in Section 3.6. The effects of flooding on the safe shutdown capability of the plant are described in Section 3.4.

The temperature control range for areas serviced by the hot water heating system is described in Section 9.4 with the ventilation systems.

9.2.10.4 Tests and Inspections

The hot water heating piping circuits are hydrostatically tested and balanced to provide designed flowrates and temperatures. Active component performance is monitored by instrumentation on the system. System performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.10.5 Instrument Applications

Instruments are provided for monitoring system parameters. Essential system parameters are monitored in the main control room.

Total system flow is monitored and displayed in the main control room. The system heat exchangers are level controlled with the instrument signals controlling the level control valve as well as sending level indication and low- and high-level alarms to the data system. Temperature measured downstream of the heat exchangers controls fluid flow to, and around, the heat exchangers and indicates the temperature of heated water being sent to the hot water heating coils. Also temperature is monitored in the system return main.

Pressure is measured in the pump suction and at the pump discharge.

Level instrumentation on the surge tank provides both high- and low-level alarms. At tank low-level, makeup is provided from the demineralized transfer and storage system. At a low-low-level point in the tank, a signal is sent to stop the hot water heating system pumps.

9.2.11 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

9.2.12 References

1. ASME Code, Section IV, Pt. HWL, 1998.

2. Uniform Plumbing Code, Section 318, 2000.

Table 9.2.1-1

NOMINAL SERVICE WATER FLOWS AND HEAT LOADS AT DIFFERENT OPERATING MODES

	CCS Pumps and Heat Exchangers	SWS Pumps and Cooling Tower Cells (Number Normally is Service)	Flow (gpm)	Heat Transferred (Btu/hr)
Normal Operation (Full Load)	1	1	9,000	$83x10^6$
Cooldown	2	2	18,000	$296x10^6$ ($148x10^6$ per cell)
Refueling (Full Core Offload)	2	2	18,000	$74x10^6$
Plant Startup	2	2	18,000	$96x10^6$
Minimum to Support Shutdown Cooling and Spent Fuel Cooling	2	2	14,400	$240x10^6$ ($120x10^6$ per cell)

Table 9.2.2-1

NOMINAL COMPONENT DATA - COMPONENT COOLING WATER SYSTEM

CCS Pumps (all data is per pump)	
Quantity	2
Type	Horizontal centrifugal
Minimum capacity (gpm, each) to support shutdown cooling and spent fuel pool cooling	4950
Design capacity (gpm, each)	8960
Design total differential head (ft)	320
CCS Heat Exchangers (all data is per exchanger)	
Quantity	2
Type	Plate
Design duty end of cooldown (MBtu/hr)	39.5
Minimum UA (MBtu/hr/°F) to support shutdown cooling and spent fuel pool cooling	12.1
Design UA (MBtu/hr/°F)	14.0
CCS side Design flow rate (gpm)	 8960
Service water side Design flow rate (gpm)	 9000
Plate material	Austenitic stainless steel
Seismic design	Non-seismic

Table 9.2.2-2

PLANT COMPONENTS COOLED BY COMPONENT COOLING WATER SYSTEM

Component	System
RCP 1A	RCS
RCP 1B	RCS
RCP 2A	RCS
RCP 2B	RCS
RCP 1A Variable Frequency Drive	RCS
RCP 1B Variable Frequency Drive	RCS
RCP 2A Variable Frequency Drive	RCS
RCP 2B Variable Frequency Drive	RCS
Letdown HX	CVCS
RCDT HX	WLS
RHR HX	RNS
RHR HX	RNS
RHR Pump A	RNS
RHR Pump B	RNS
SFP HX A	SFS
SFP HX B	SFS
Chiller A	VWS
Chiller B	VWS
Sample HX	PSS
Miniflow HX	CVS
Miniflow HX	CVS
Air Compressor A	CAS
Air Compressor B	CAS
Air Compressor C	CAS
Air Compressor D	CAS
Cond Pump A Oil Cooler	CDS
Cond Pump B Oil Cooler	CDS
Cond Pump C Oil Cooler	CDS

Table 9.2.3-1

GUIDELINES FOR DEMINERALIZED WATER (MEASURED AT THE OUTLET OF THE DEMINERALIZED WATER TREATMENT SYSTEM)

Parameters	Normal Value	Initiate Action
Specific conductivity, μS/cm at 77°F	≤ 0.1	≤ 0.2
Active silica, ppb	≤ 10	≤ 20
Total silica, ppb	≤ 50	
Suspended solids, ppb	≤ 50	
Aluminum, ppb	≤ 20	
Calcium, ppb	≤ 5	
Magnesium, ppb	≤ 5	
Chloride, ppb	≤ 1	
Sulfate, ppb	≤ 1	
Total organic carbon, ppb	≤ 100	

Table 9.2.7-1

COMPONENT DATA - CENTRAL CHILLED WATER SYSTEM (NOMINAL VALUES)

High Capacity Subsystem	
Water Cooled Chillers	
Capacity (ton)	1770 (max)
Compressor type	Centrifugal
Maximum power input (kW)	1500
Entering chilled water temperature (°F)	56
Leaving chilled water temperature (°F)	40
Cooling water flowrate (gpm)	3500 (max)
Low Capacity Subsystem	
Air Cooled Chillers	
Capacity (ton)	230 (max)
Compressor type	Reciprocating, Rotary or Screw
Maximum power input (kW)	375
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Coil	**Flow (gpm)**
VBS MY C01 A/B	138
VBS MY C02 A/C	108
VBS MY C02 B/D	84
VAS MY C07 A/B	24
VAS MY C12 A/B	15
VAS MY C06 A/B	15

Table 9.2.8-1

TURBINE BUILDING CLOSED COOLING WATER SYSTEM
NORMAL POWER OPERATION
NOMINAL VALUES

Component	Approximate Total Flow (gpm)
Main turbine lube oil coolers	4400
Main feedwater pump lube oil coolers	300
Air side seal oil cooler	185
Hydrogen side seal oil cooler	65
Exciter air coolers	350
Generator hydrogen coolers	3975
Generator stator cooling water cooler	2115
Isolated phase bus coolers	220
CT case and neutral enclosure	25
Low pressure feedwater heater drain pump	45
MSR drain pump	10
Condenser vacuum pump	800
EH control coolers	20
Secondary sampling system coolers	130
Total	12,640

Table 9.2.10-1

HOT WATER HEATING SYSTEM DESIGN DATA (NOMINAL VALUES)

Available Steam Supply	
High pressure turbine extraction	
Pressure (psia)	170
Enthalpy (Btu/lbm)	1087
Temperature (°F)	368
Auxiliary steam	
Pressure (psia)	210
Enthalpy (Btu/lbm)	1199
Temperature (°F)	386
Heat Exchanger	
Quantity	2
Type	Shell and Tube – subcooled
Capacity (Btu/hr)	12,000,000

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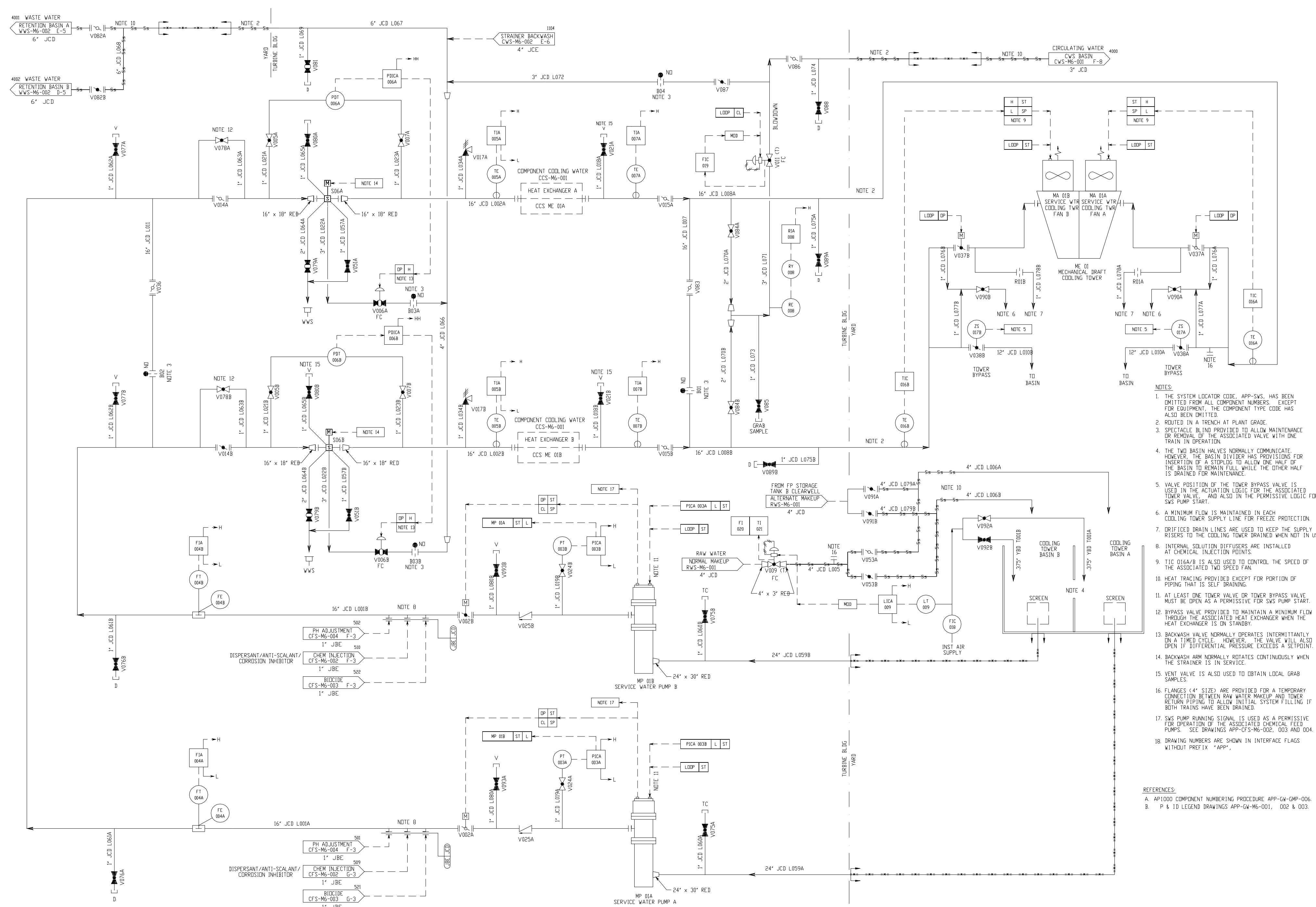


Figure 9.2.1-1

**Service Water System
Piping and Instrumentation Diagram
(REF) SWS001**

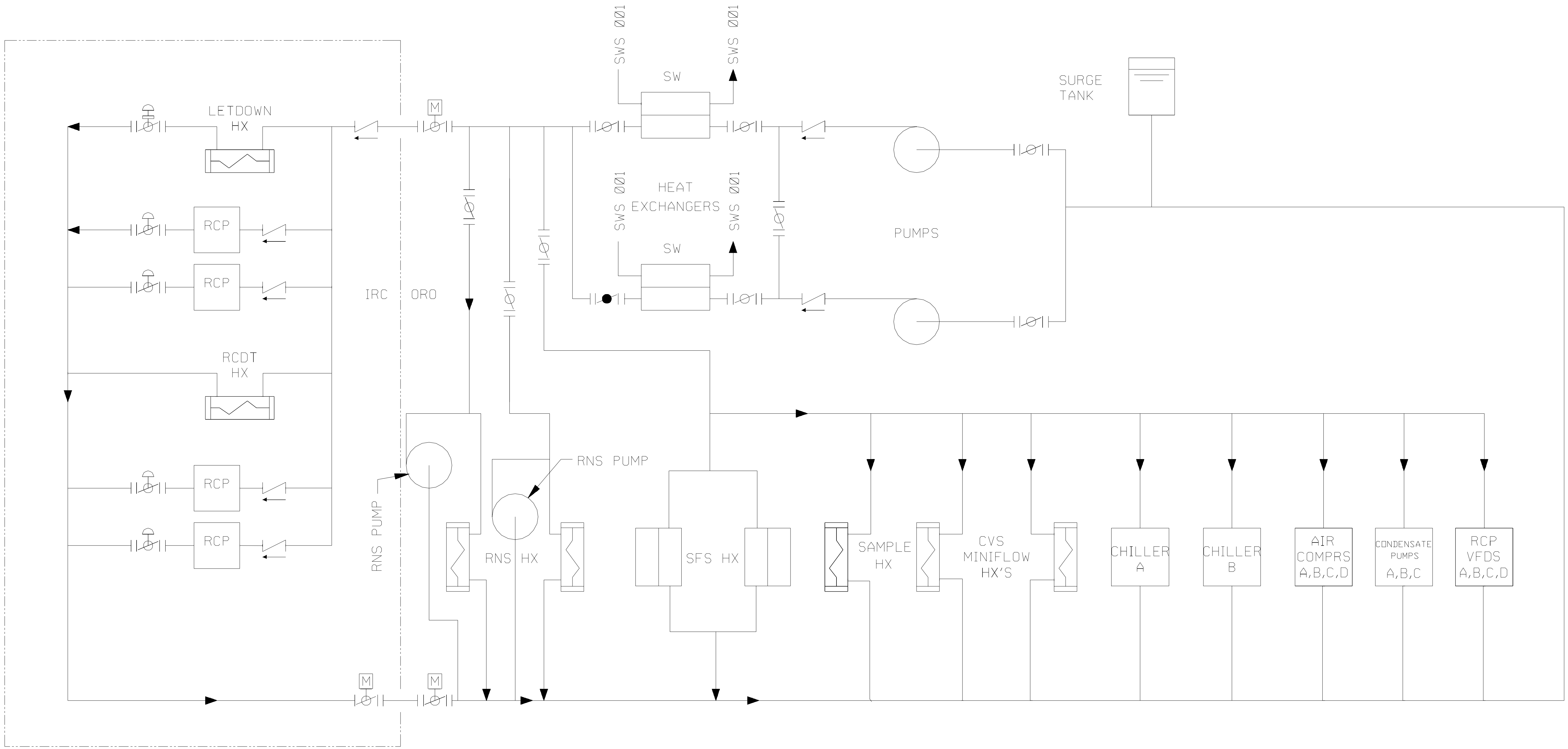
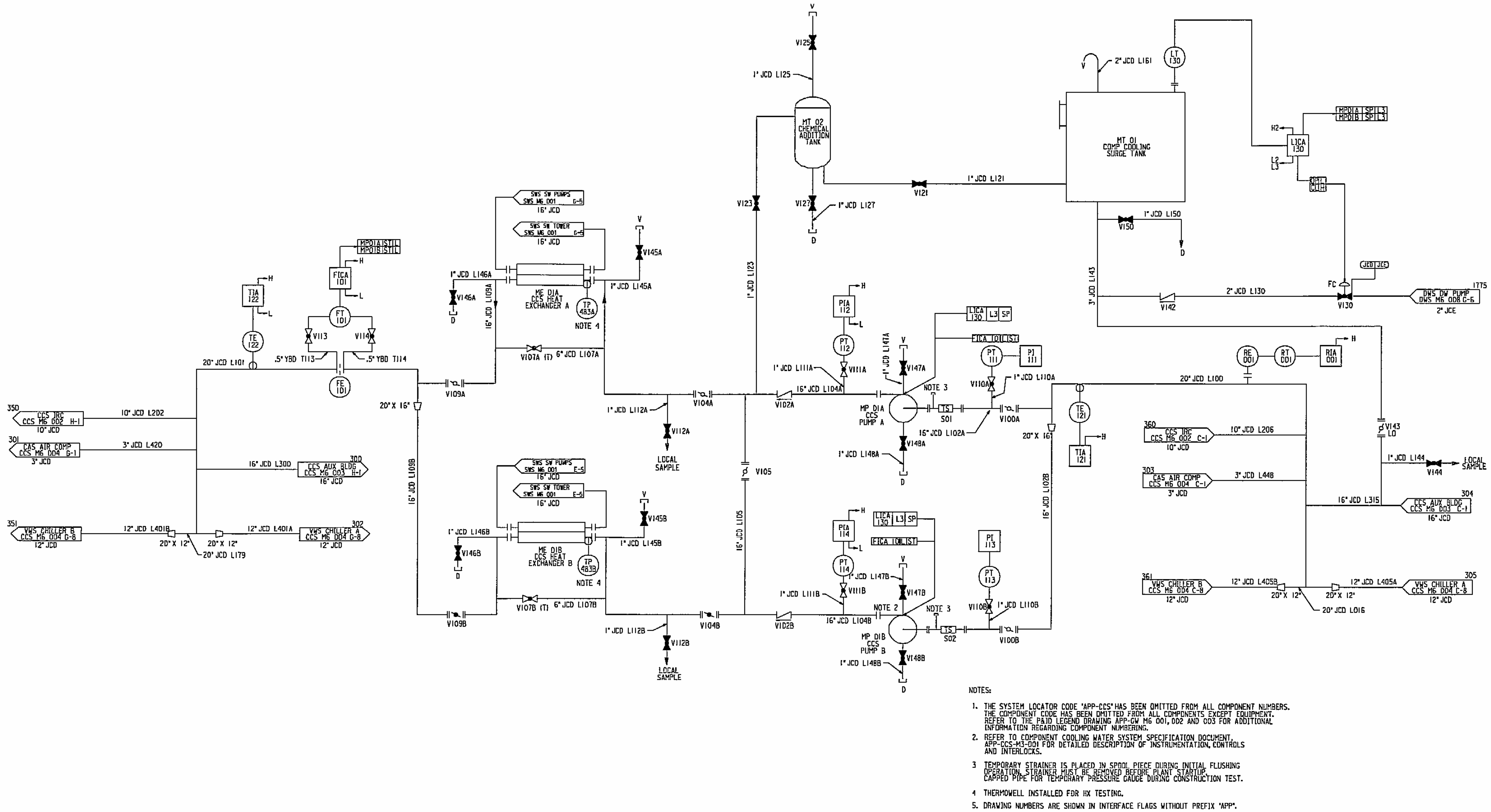


Figure 9.2.2-1

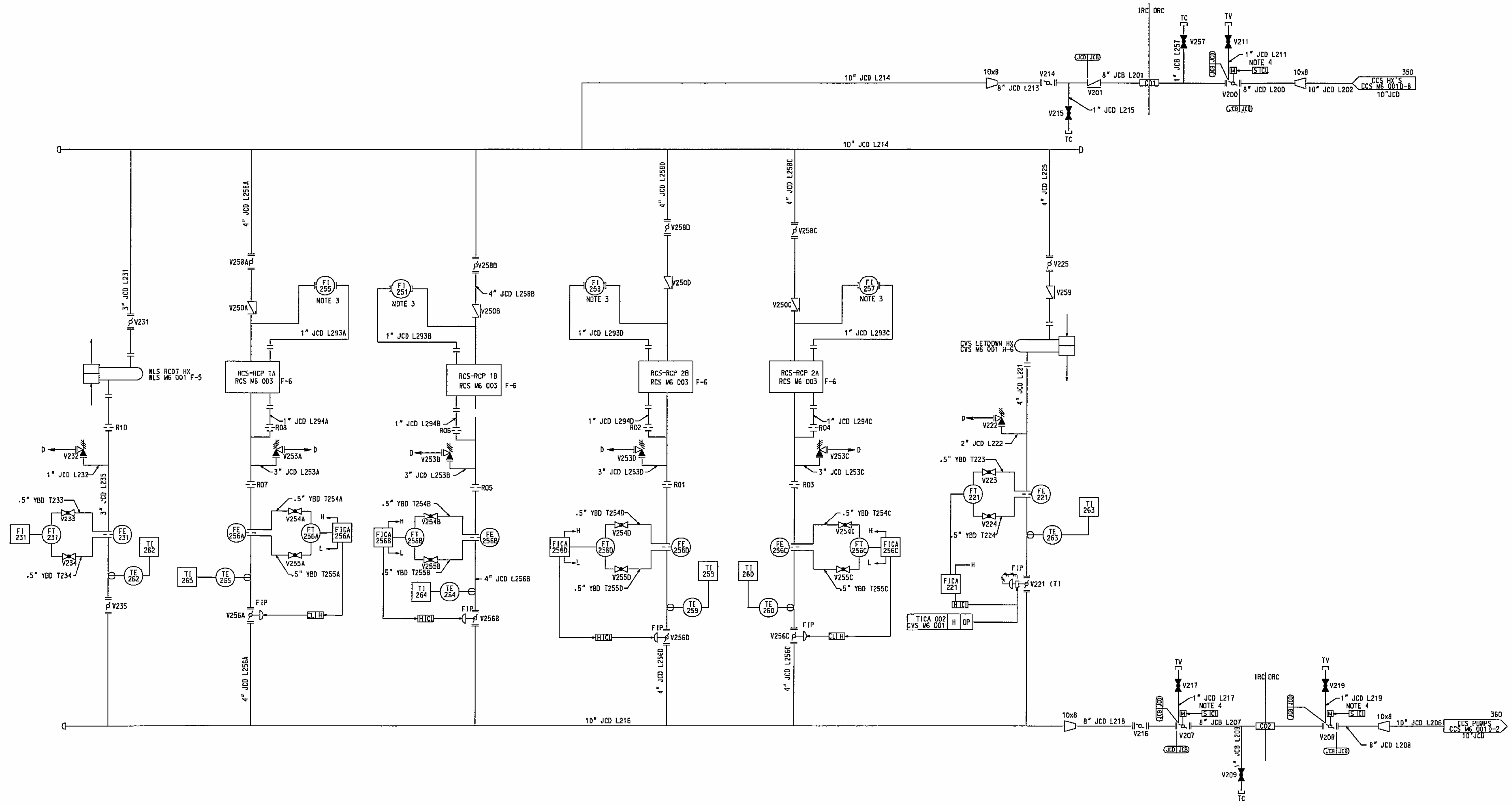
Component Cooling Water System
Simplified Flow Diagram
(REF) CCS



Inside Turbine Building

Figure 9.2.2-2 (Sheet 1 of 5)

Component Cooling Water System
Piping and Instrumentation Diagram
(REF CCS 001)



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-CCS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING
2. REFER TO COMPONENT COOLING WATER SYSTEM SPECIFICATION DOCUMENT, APP-CCS-M3-001, FOR DETAILED DESCRIPTION OF INSTRUMENTATION, CONTROLS AND INTERLOCKS.
3. TEMPORARY ROTAMETER USED TO SET BEARING COOLING WATER FLOW. IT WILL BE REPLACED BY SPOOL PIECE AFTER SETTING.
4. SAFETY INJECTION SIGNAL.
5. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP".

Figure 9.2.2-2 (Sheet 2 of 5)

Component Cooling Water System Piping and Instrumentation Diagram (REF) CCS 002

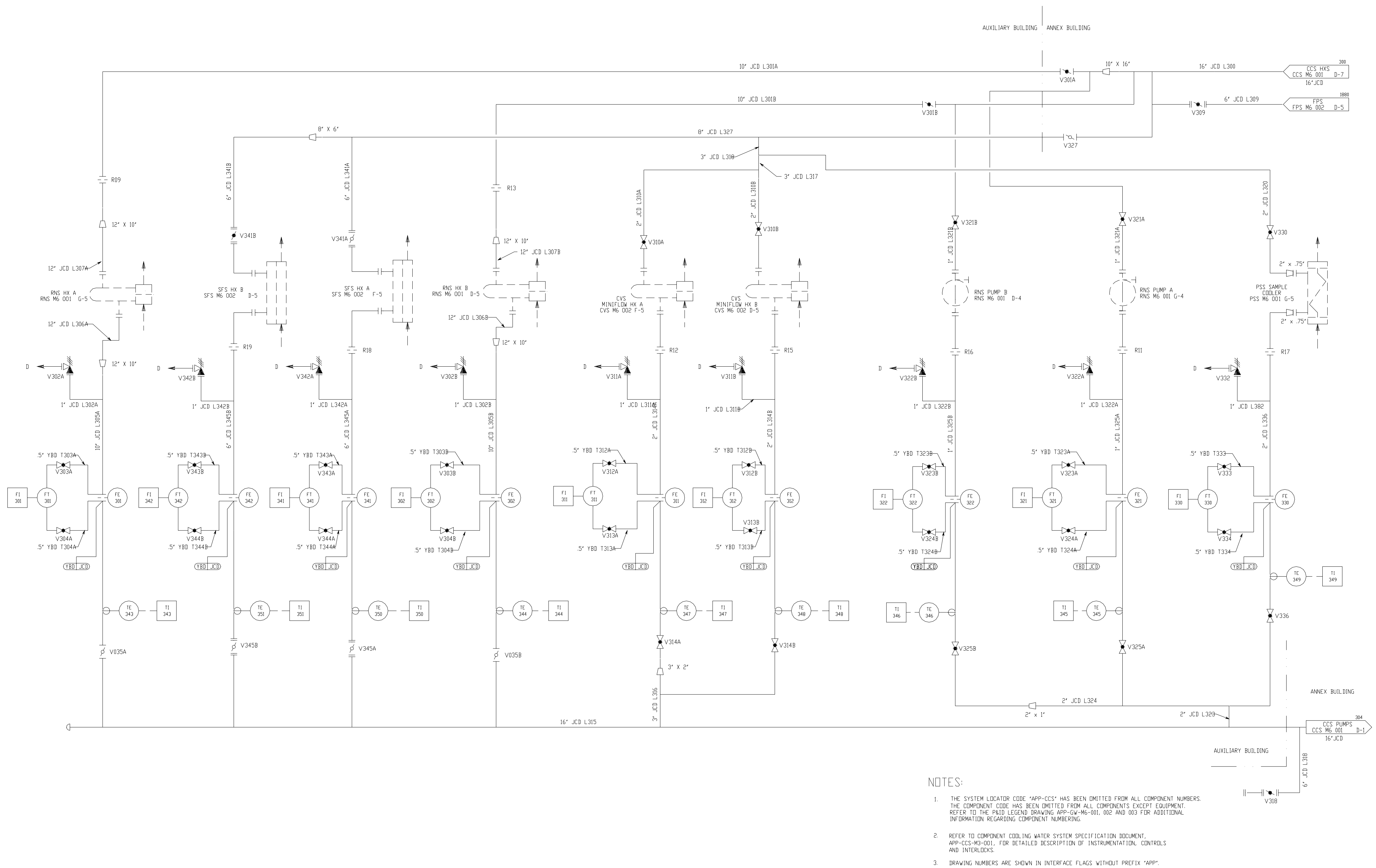
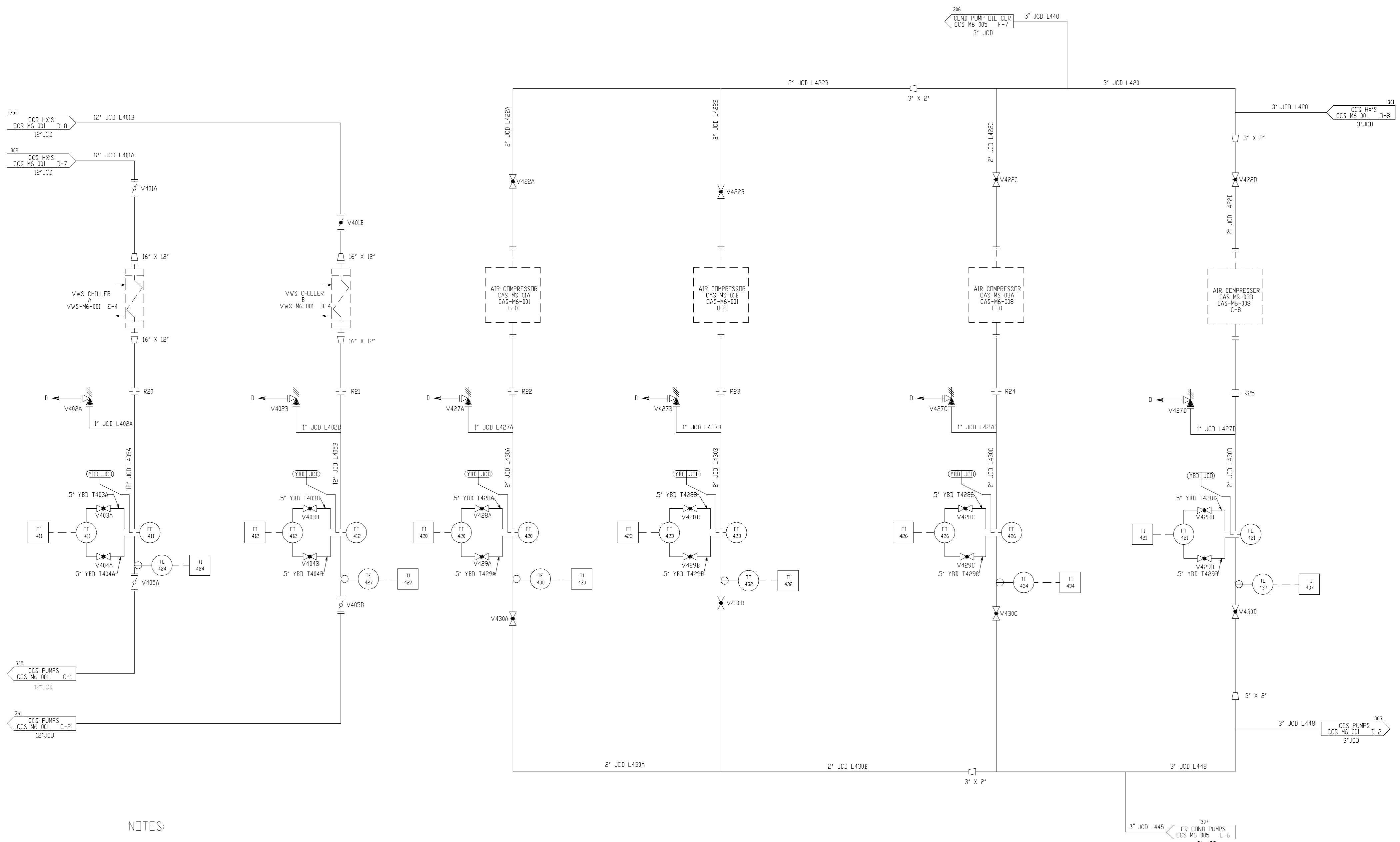


Figure 9.2.2-2 (Sheet 3 of 5)

Component Cooling Water System Piping and Instrumentation Diagram (REF) CCS 003



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-CCS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002, AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.

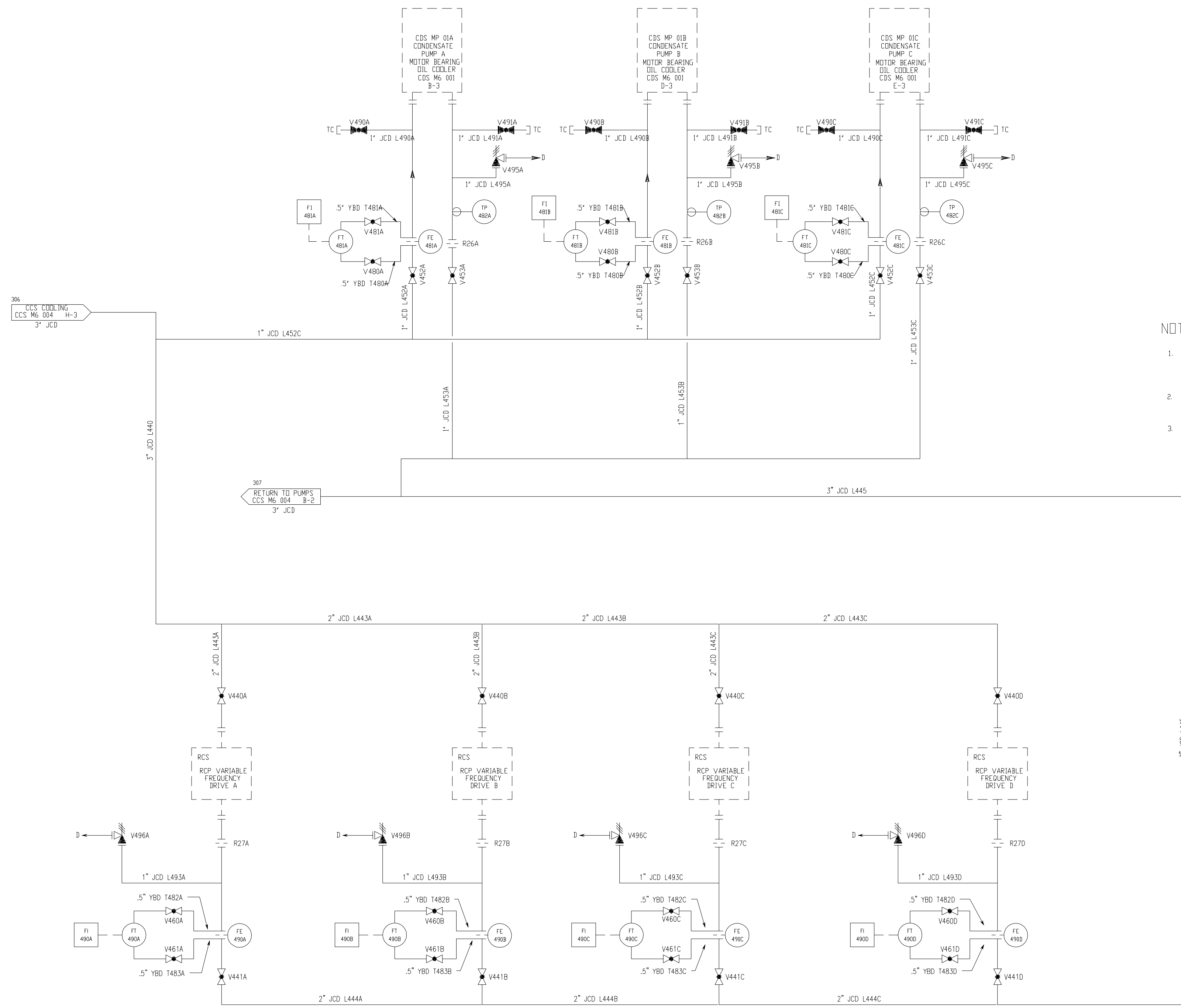
2. REFER TO COMPONENT COOLING WATER SYSTEM SPECIFICATION DOCUMENT, APP-CCS-M3-001, FOR DETAILED DESCRIPTION OF INSTRUMENTATION, CONTROLS AND INTERLOCKS.

3. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP".

Inside Turbine Building

Figure 9.2.2-2 (Sheet 4 of 5)

Component Cooling Water System
Piping and Instrumentation Diagram
(REF) CCS 004



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-CCS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002, AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.

2. REFER TO COMPONENT COOLING WATER SYSTEM SPECIFICATION DOCUMENT, APP-CCS-M3-001, FOR DETAILED DESCRIPTION OF INSTRUMENTATION, CONTROLS AND INTERLOCKS.

3. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP".

Inside Turbine Building

Figure 9.2.2-2 (Sheet 5 of 5)

Component Cooling Water System Piping and Instrumentation Diagram (REF) CCS 005

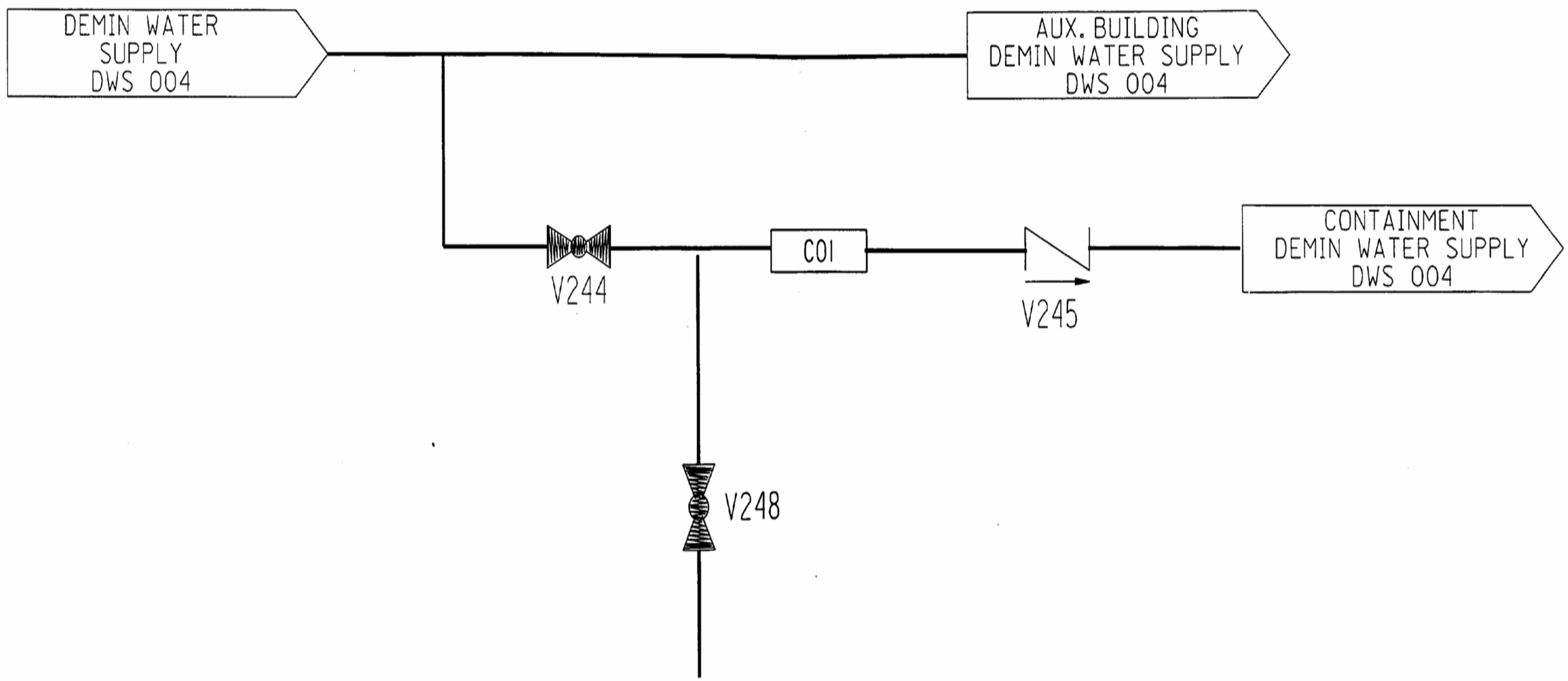
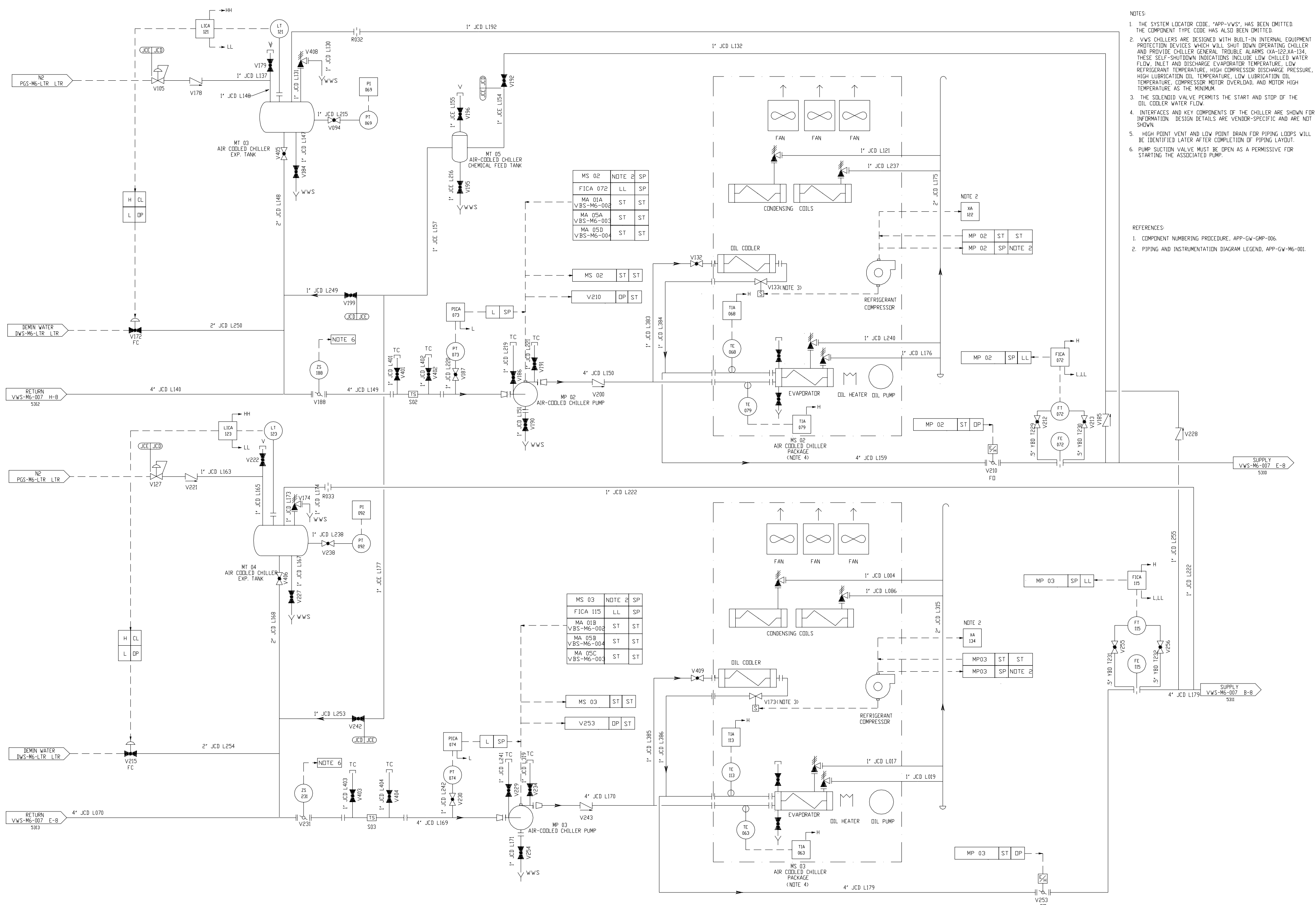


Figure 9.2.4-1

Demineralized Water Transfer and Storage System
Containment Isolation Provision
(REF) DWS 007



Inside Auxiliary Building

Figure 9.2.7-1 (Sheet 1 of 3)

Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 006

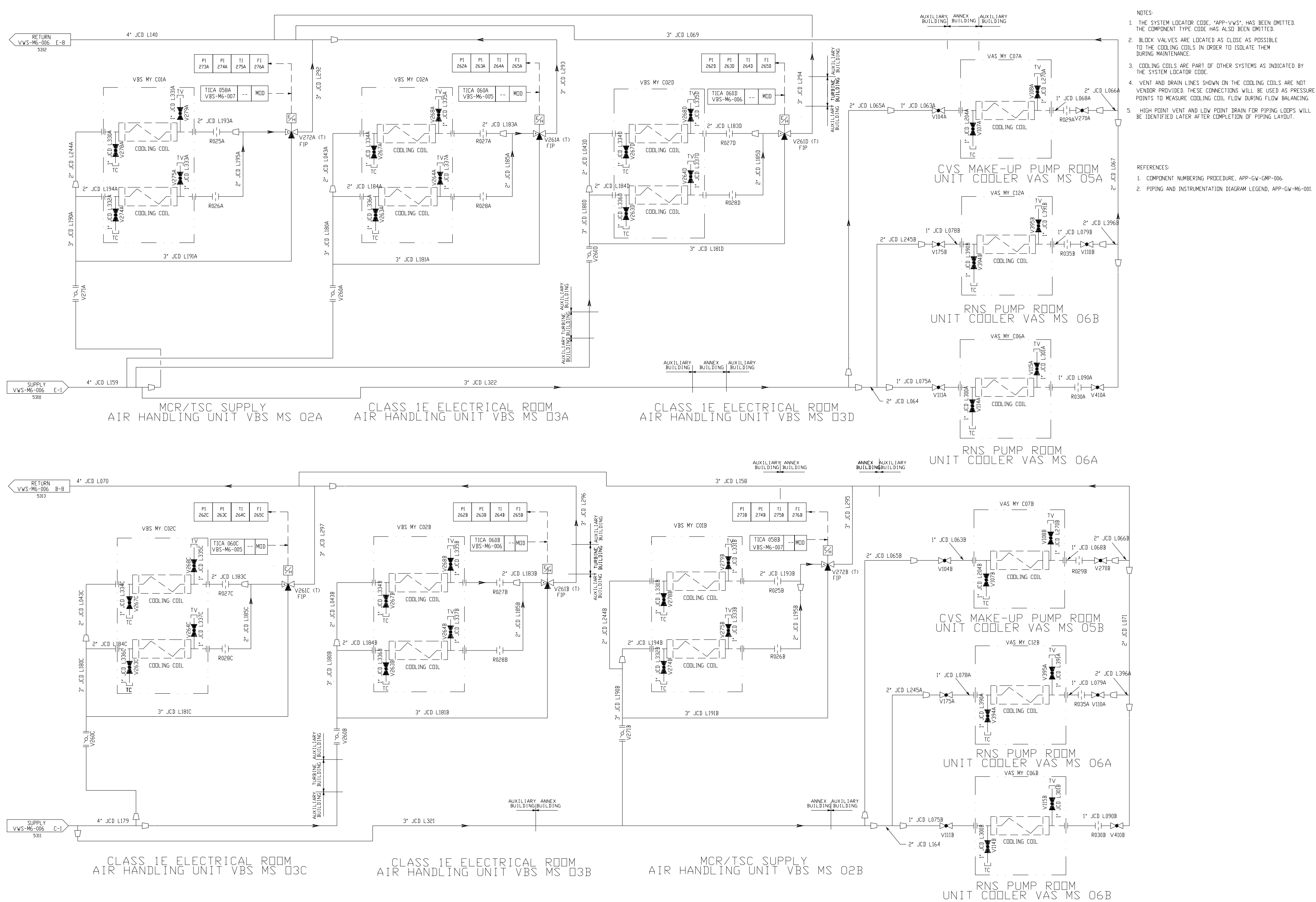


Figure 9.2.7-1 (Sheet 2 of 3)

Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 007

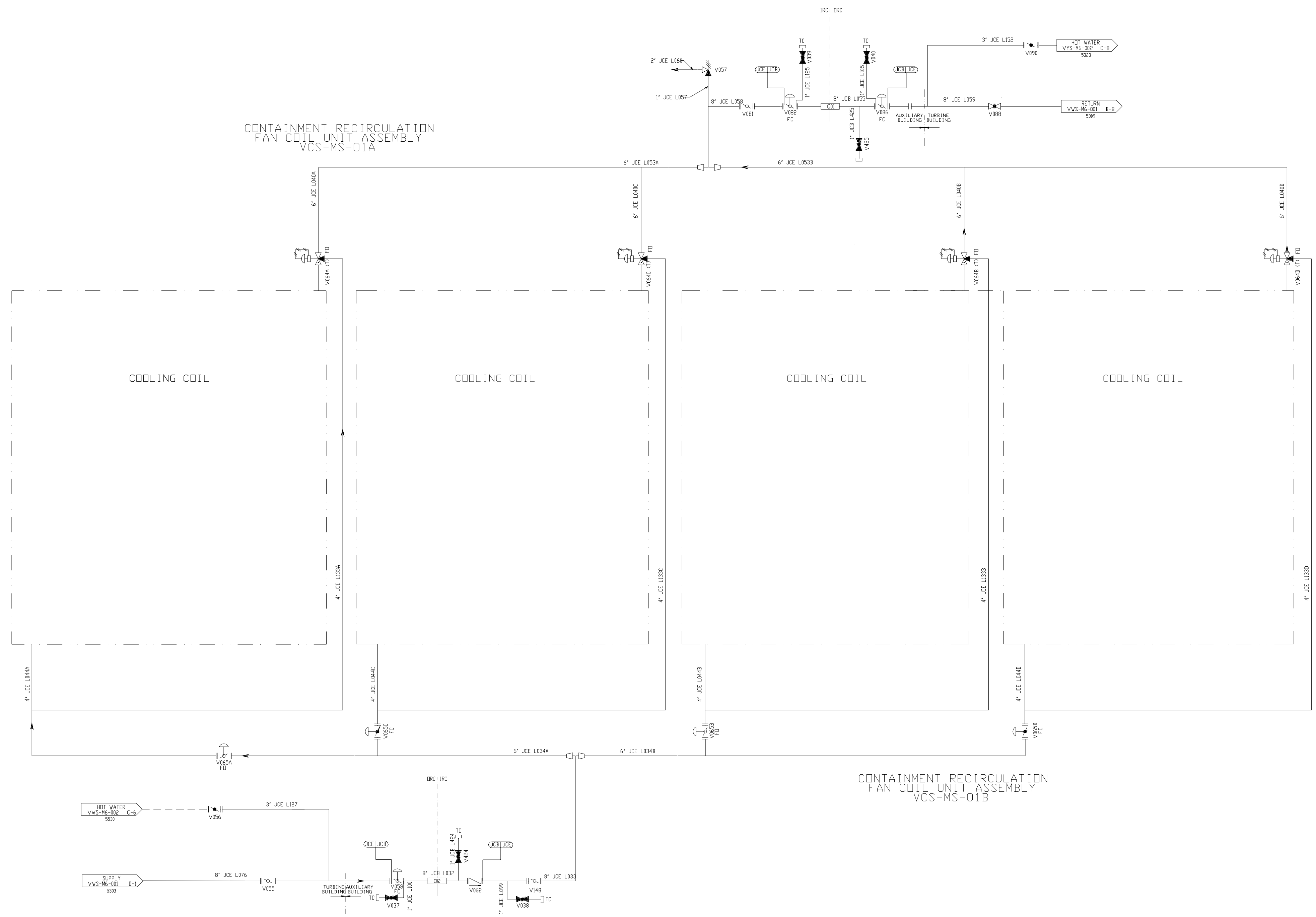


Figure 9.2.7-1 (Sheet 3 of 3)

Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 003

9.3 Process Auxiliaries

9.3.1 Compressed and Instrument Air System

The compressed and instrument air system (CAS) consists of three subsystems; instrument air, service air, and high-pressure air. Instrument air supplies compressed air for air-operated valves and dampers. Service air is supplied at outlets throughout the plant to power air-operated tools and is used as a motive force for air-powered pumps. The service air subsystem is also utilized as a supply source for breathing air. Individually packaged air purification equipment is used to produce breathing quality air for protection against airborne contamination. The high-pressure air subsystem supplies air to the main control room emergency habitability system (VES), the generator breaker package, and fire fighting apparatus recharge station. The high-pressure air subsystem also provides a connection for refilling the VES storage tanks from an offsite source. Major components of the compressed and instrument air system are located in the turbine building.

9.3.1.1 Design Basis

9.3.1.1.1 Safety Design Basis

The compressed and instrument air system serves no safety-related function other than containment isolation and therefore has no nuclear safety design basis except for containment isolation. See subsection 6.2.3 for the containment isolation system.

9.3.1.1.2 Power Generation Design Basis

The instrument air subsystem provides filtered, dried, and oil-free air for air-operated valves and dampers. The instrument air subsystem consists of two compressors and associated support equipment and controls that are powered from switchgear backed by the nonsafety-related onsite standby diesel generators as an investment protection category load. The subsystem provides high quality instrument air as specified in the ANSI/ISA S7.3 standard (Reference 9.3.8.1).

The service air subsystem provides filtered, dried, and oil-free compressed air for service outlets located throughout the plant. The service air subsystem consists of two compressors and their associated support equipment and controls. Plant breathing air requirements are satisfied by using the service air subsystem as a supply source. Individually packaged air purification equipment is used to improve the service air to Quality Verification Level D breathing air as defined in ANSI/CGA G-7.1.

The high-pressure air subsystem consists of one compressor, its associated air purification system and controls, and a high-pressure receiver. It provides clean, oil-free, high-pressure air to recharge the main control room emergency habitability system cylinders, refill the individual fire fighting breathing air bottles, and recharge the generator breaker reservoir. Quality Verification Level E air as defined in ANSI/CGA G-7.1 is produced by this subsystem. See Section 6.4 for a description of the main control room habitability system.

9.3.1.2 System Description

9.3.1.2.1 General Description

Classifications of components and equipment in the compressed and instrument air system are given in Section 3.2. In accordance with NUREG-1275, instrument air quality meets the manufacturer's standards for pneumatic equipment supplied as a part of the plant. Intake filters for instrument air, service air, and high-pressure air compressors remove particulates 10 microns and larger.

Instrument Air Subsystem

The instrument air subsystem consists of two 100 percent capacity parallel air supply trains discharging to a common air distribution system. An air compressor, dryer, controls, and receiver comprise one air supply train. The two compressor trains join to a single instrument air header downstream of the receivers.

Provisions are made to temporarily cross connect the instrument and service air subsystems at the distribution header.

The instrument air line to the containment is normally open; however, air flow to the containment is monitored and a high flow alarm is provided to indicate a possible instrument air line rupture inside containment. Safety-related air-operated valves supplied by the system are identified in Table 9.3.1-1. None of these valves require instrument air to perform their safety-related function. The valves with an active safety-related function fail in the safe position on loss of instrument air pressure.

One instrument air compressor train, including its air dryer and associated equipment and controls, can be connected to each of the nonsafety-related onsite standby diesel generators. The compressors are cooled by water supplied from the component cooling water system (CCS). Refer to subsection 9.2.2 for details. The instrument air subsystem is shown schematically in Figure 9.3.1-1. Major system components are described in Table 9.3.1-2.

Service Air Subsystem

Two 100 percent capacity compressor trains are provided for the service air subsystem. These compressor trains consist of identical equipment and share a common air receiver that feeds the service air distribution system. Cooling water to the service air compressors is supplied from the component cooling water system. Refer to subsection 9.2.2 for details.

The service air line to containment is normally closed and is opened on an as-needed basis. The service air subsystem is shown schematically in Figure 9.3.1-1 and major system components are described in Table 9.3.1-3.

High-Pressure Air Subsystem

The high-pressure air subsystem consists of a high-pressure air compressor with an integral air purification system, controls, and a receiver.

The high-pressure air subsystem is manually operated and may be loaded on an onsite standby diesel generator. This subsystem supplies air to the main control room emergency habitability system, the generator breaker, and the fire fighting apparatus recharge station. The isolation valves to these locations are normally closed and are opened on an as-needed basis to refill the specified equipment air storage reservoirs. The high-pressure air subsystem is shown schematically in Figure 9.3.1-1 and major system components are described in Table 9.3.1-4.

9.3.1.2.2 Component Description

Instrument Air Subsystem

The instrument air subsystem consists of two air compressor trains. Each compressor train consists of a multistage, low-pressure, rotary screw, air compressor package, a desiccant dryer with a prefilter and afterfilter, and an air receiver. Each compressor package includes an intake filter, rotary screw compressor elements, silencer, intercooler, aftercooler, moisture separators, bleed-off cooler, oil cooler, oil reservoir, automatic load controls, relief valves, and a discharge air check valve. Each compressor train produces oil-free air.

Two instrument air receivers function as storage devices for compressed air. The receivers continue to supply the instrument air subsystem following a loss of the instrument air compressors until the receiver pressure drops below system requirements. Each air receiver is equipped with an automatic condensate drain valve and a pressure relief valve.

Two air dryer assemblies are provided for the instrument air subsystem. Each dryer assembly consists of a desiccant-filled, twin tower design. One tower may be used to dry air while the other tower goes through regeneration. When instrumentation senses a high dew point, the towers switch. The former operating tower then undergoes regeneration while the regenerated tower drys the instrument air.

Each dryer assembly includes a coalescing prefilter that removes oil aerosols and moisture droplets, as well as an afterfilter to remove desiccant dust.

The instrument air subsystem supplies ANSI/ISA S-7.3 high quality instrument air. Table 9.3.1-2 provides design information for the main components associated with the instrument air subsystem.

Service Air Subsystem

The service air subsystem consists of two air compressor trains. Each compressor train consists of a multistage, low-pressure, rotary screw, air compressor package, and a desiccant dryer with a prefilter and afterfilter. A common air receiver is provided for the two trains. Each compressor package includes an intake filter, rotary screw compressor elements, silencer, intercooler, aftercooler, moisture separators, bleed-off cooler, oil cooler, oil reservoir, automatic load controls, relief valves, and a discharge air check valve. Each compressor train produces oil-free air.

The common service air receiver functions as a storage device for compressed air. This air receiver is equipped with an automatic condensate drain valve and a pressure relief valve.

Two air dryer assemblies are provided for the service air subsystem. Each dryer assembly consists of a desiccant-filled, twin tower design. One tower may be used to dry air while the other tower goes through regeneration. When instrumentation senses a high dew point, the towers switch. The former operating tower then undergoes regeneration while the regenerated tower drys the service air.

Each dryer assembly includes a coalescing prefilter that removes oil aerosols and moisture droplets, as well as an afterfilter to remove desiccant dust.

Table 9.3.1-3 provides design information for the main components associated with the service air subsystem.

High-Pressure Air Subsystem

The high-pressure air subsystem utilizes an air-cooled, oil-lubricated, four-stage, reciprocating-air compressor with an integral air purification system to produce oil-free air for high-pressure applications. The compressor train includes an intake filter, air-cooled intercoolers, interstage oil/water separators, an air-cooled aftercooler, a final oil/water separator, relief valves, an air purification system, discharge check valves, and a high-pressure receiver.

The high-pressure air subsystem supplies ANSI/CGA G-7.1 Quality Verification Level E air. See Table 9.3.1-4 for the design parameters for this system.

9.3.1.2.3 System Operation

Instrument Air Subsystem

The instrument air compressors are operated by a local pressure controller located in the instrument air distribution header, which can be programmed for various sequences of operation. Normally one compressor runs continuously loading and unloading as required to supply compressed air demand. The second compressor serves as a backup and starts automatically if the first unit fails or if demand exceeds the capacity of the operating compressor.

Air from the instrument air subsystem compressor packages discharges to the air dryers and then to the receivers where it is distributed to air-operated valves and dampers throughout the plant. Instrument air pressure is reduced by pressure regulators at the pneumatic component as required.

The onsite standby power system (diesel generators) provides an alternate source of electrical power for the instrument air compressor trains. One compressor train is supplied from each electrical load group.

Service Air Subsystem

The service air subsystem compressors are operated by a local controller that can be programmed for various sequences of operation. Normally one compressor runs continuously and loads and unloads as required to supply service air demand. The second compressor serves as a backup and starts automatically if the first compressor fails or demand exceeds the capacity of the operating compressor. Air from each service air subsystem compressor package discharges to an air dryer

and then to the common receiver. Service air flows from the receiver to the various service air outlets throughout the plant.

Breathing air can be obtained from any service air subsystem outlet by attaching a portable individually packaged air purification system. The breathing air purification package consists of replaceable cartridge-type filters, a pressure regulator, carbon monoxide monitoring equipment, air supply hoses, and air supply devices. Carbon monoxide is controlled by a catalytic conversion to carbon dioxide within the package. Breathing air of a Quality Verification Level D or better is supplied to personnel from the packaged purification system in accordance with the requirements of ANSI/CGA G-7.1.

High-Pressure Air Subsystem

The high-pressure air subsystem is operated when a specific high-pressure source requires refilling to replace air lost to leakage or expended during plant operations. System isolation valves to the specified equipment are manually opened and the equipment storage reservoir is replenished from the high-pressure receiver. The compressor is then started to replenish the air stored in the high-pressure receiver.

Breathing air of a Quality Verification Level E is supplied from the integral high-pressure air purification system in accordance with the requirements of ANSI/CGA G-7.1. This integral air purification system utilizes a series of replaceable cartridge-type filters to produce breathing quality air. Breathing air connections of the high pressure air subsystem are incompatible with the breathing air connections of the service air subsystem. Carbon monoxide is controlled by a catalytic conversion to carbon dioxide within the package.

The onsite standby power system (diesel generators) provides an alternate source of electrical power for the high-pressure air compressor.

9.3.1.3 Safety Evaluation

The compressed and instrument air system has no safety-related function other than containment isolation and therefore requires no nuclear safety evaluation. Containment isolation functions are described in subsection 6.2.3.

The compressed and instrument air system is required for normal operation and startup of the plant. Air-operated valves that are essential for safe shutdown and accident mitigation are designed to actuate to the fail-safe position upon loss of air pressure. These air-operated valves utilize safety-related solenoid valves to control the air supply.

The instrument and service air subsystems are classified as moderate-energy systems. There are no adverse effects on safety-related components associated with a postulated failure of the instrument and service air piping.

The high-pressure air subsystem is classified as a high-energy system. The high-pressure compressor and receiver are located in the turbine building, which contains no safety-related, equipment or structures. Air piping routed in safety-related areas is 1 inch or less in diameter and the dynamic consequences of a rupture are not required to be analyzed. The high-pressure air

subsystem is not required to operate following a design basis accident nor is it used for safe shutdown of the plant.

9.3.1.4 Tests and Inspections

System components, such as the air compressors and air dryers, are inspected or tested prior to installation. The installed compressed air system is inspected, tested, and operated to verify that it meets its performance requirements, including operational sequences and alarm functions.

Air compressors and associated components on standby are checked and operated periodically. Desiccant in the air dryers is changed when required.

Sample points are provided downstream of the air dryers in both the instrument and service air subsystems and downstream of the purifier in the high-pressure air subsystem. Periodic checks are made to ensure high quality instrument air as specified in the ANSI/ISA S-7.3 standard. Periodic checks on the high-pressure air compressor are made on a regular basis to verify that the breathing air meets the Quality Verification Level E as indicated in the ANSI/CGA G-7.1 standard.

During the initial plant testing prior to reactor startup, safety systems utilizing instrument air are tested as part of the safety system test to verify fail-safe operation of air-operated valves upon sudden loss of instrument air or gradual reduction of air pressure as described in Regulatory Guide 1.68.3. Section 1.9 summarizes conformance with Regulatory Guide 1.68.

9.3.1.5 Instrumentation Applications

An instrumentation package is included with each of the instrument and service air compressors. Each package consists of temperature and pressure transducers, indicators, and automatic protection devices. The temperature and pressure transducers support the automatic control modes of compressor operation. A manual mode of operation is also provided for each control system. Compressed air system indication and control are available in the main control room.

The high-pressure air subsystem includes pressure and carbon monoxide instrumentation, automatic protection devices, and temperature indication.

9.3.2 Plant Gas System

The plant gas system (PGS) provides hydrogen, carbon dioxide, and nitrogen gases to the plant systems as required.

Other gases, such as oxygen, methane, acetylene, and argon, are supplied in smaller individual containers and are not supplied by the plant gas system.

9.3.2.1 Design Basis

9.3.2.1.1 Safety Design Basis

The plant gas system serves no safety-related function and therefore has no nuclear safety design basis.

9.3.2.1.2 Power Generation Design Basis

The nitrogen portion of the plant gas system supplies nitrogen for pressurizing, blanketing, and purging of various plant components.

The hydrogen gas portion of the plant gas system supplies hydrogen to the main plant electrical generator for cooling as well as to other plant auxiliary systems.

The carbon dioxide portion of the plant gas system supplies carbon dioxide to the generator for purging of hydrogen and air during layup or plant outages.

9.3.2.2 System Description

Classification of equipment and components is given in Section 3.2.

9.3.2.2.1 General Description

The nitrogen portion of the plant gas system is a packaged system consisting of a liquid nitrogen storage tank and vaporizers. Nitrogen gas is supplied in both a high-pressure and a low-pressure subsystem. The high-pressure subsystem uses a pump to pressurize the gas supplying the accumulators in the passive core cooling system. The high-pressure supply is then reduced to supply makeup to the reactor coolant drain tank for purging and blanketing. Low-pressure nitrogen is provided for component purging, layup/blanketing, and pressurization.

The main steam isolation valves (MSIVs) and main feedwater isolation valves (MFIVs) use compressed nitrogen stored within the valve operators as the motive force to close the valves. The main steam isolation valves are described in subsection 10.3.2.2.4 and the main feedwater isolation valves are described in subsection 10.4.7.2.2. Nitrogen makeup for these valves (if needed) is provided from portable high-pressure nitrogen bottles using temporary connections on the valves.

The packaged nitrogen system is located inside the turbine building.

The hydrogen gas portion of the plant gas system is a packaged system consisting of a liquid hydrogen storage tank and vaporizers to supply hydrogen gas to the main generator for generator cooling and to the demineralized water transfer and storage system to support removal of dissolved oxygen and to other miscellaneous services. The hydrogen supply package system is located outdoors at the hydrogen storage tank area.

The carbon dioxide portion of the plant gas system, which is a packaged system consisting of one liquid storage tank and a vaporizer, produces gaseous carbon dioxide to purge the main generator. This packaged system is located in the turbine building.

Liquid gas storage tanks are built in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, 1998 Edition, 2000 Addenda.

9.3.2.2.2 Component Description

Liquid Nitrogen Storage Tank

Liquid nitrogen is stored under its own vapor pressure as a saturated liquid in a dual wall tank. This tank supplies nitrogen for the high- and low-pressure nitrogen gas systems. The annular space between the inner and outer tank walls is filled with insulation and evacuated when the tank is cold.

Liquid Nitrogen Pump

A cryogenic liquid nitrogen pump is utilized to provide a supply of high-pressure nitrogen. It is a single-cylinder, positive displacement pump with the entire "cold" pumping assembly enclosed in a vacuum-jacket, which permits the pump to remain cold in the standby condition.

Nitrogen High-Pressure Ambient Air Vaporizer

Liquid nitrogen is vaporized by a high-pressure natural convection vaporizer, which vaporizes and superheats cryogenic nitrogen using heat from the ambient air.

Nitrogen Low-Pressure Ambient Air Vaporizer

The low-pressure vaporizer unit has two parallel banks. In the event of frost buildup on the active bank, flow is redirected to the opposite bank while the other bank defrosts.

Gaseous Nitrogen Storage Tubes

Gaseous nitrogen storage tubes are provided. These storage tubes provide short-term storage for high-pressure nitrogen.

Liquid Hydrogen Storage Tank

Cryogenic liquid hydrogen is stored in a dual wall tank. The annular space between the walls is insulated using a vacuum and wrapped reflective insulation to minimize heat leakage.

Hydrogen Ambient Air Vaporizers

Two parallel banks of vaporizers are provided. In the event of frost buildup on the active bank, flow is redirected to the opposite bank while the other bank defrosts.

Liquid Carbon Dioxide Storage Tank

Cryogenic liquid carbon dioxide is stored in an insulated dual wall tank to minimize heat transfer.

Carbon Dioxide Electric Vaporizer

The liquid carbon dioxide is vaporized using electric resistance heating.

9.3.2.2.3 System Operation

Liquid nitrogen is stored under its own vapor pressure as a saturated liquid. An economizer circuit minimizes product loss due to vessel boiloff under low-flow conditions. A pressure build circuit maintains pressure at a suitable level above line delivery pressures. For the low-pressure system, liquid is withdrawn, vaporized, and pressure regulated prior to delivery to the low-pressure nitrogen manifold. For high-pressure nitrogen, liquid is withdrawn by the pump, vaporized, and discharged into the high-pressure storage tubes. The gas is then pressure regulated and routed to the high-pressure nitrogen manifold.

Liquid hydrogen is stored in a cryogenic storage vessel complete with an economizer circuit and a pressure build circuit. Ambient air vaporizers turn the liquid to a gas, which is pressure regulated. See subsection 9.3.6 for further discussion of hydrogen use in the chemical and volume control system.

Liquid carbon dioxide is distributed from a cryogenic storage vessel, complete with an economizer circuit and a pressure build circuit. An electric vaporizer turns the liquid to a gas, which is pressure regulated for the generator purge.

9.3.2.3 Safety Evaluation

The plant gas system is required for normal plant operation and startup of the plant. The plant gas system is not required for safe shutdown of the plant. Therefore, it is not designed to meet seismic Category I requirements or single failure criterion. The plant gas system serves no safety-related function and has no safety design basis.

The nitrogen and carbon dioxide portions of the plant gas system are located inside the turbine building and the hydrogen system storage is located outside of the main buildings. The storage tanks are analyzed as a potential missile source. Refer to Section 3.5.

The effects of the plant gas system on main control room habitability are addressed in Section 6.4 including explosive gases and burn conditions for those gases. For explosions, the plant gas system is designed for conformance with Regulatory Guide 1.91.

9.3.2.4 Tests and Inspections

9.3.2.4.1 Storage Vessel Testing

- Each storage vessel is hydrostatically tested in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, 1998.

- Each vessel is examined using the magnetic particle method.

9.3.2.5 Instrumentation Requirements

Low-level indication alarms are provided in the main control room for the liquid nitrogen and the hydrogen storage tank levels.

Temperature and pressure indications are provided at various points within the plant gas system.

9.3.3 Primary Sampling System

The AP1000 primary sampling system (PSS) performs the following functions:

- Collects in normal operation mode both liquid and gaseous samples
- Provides for local grab samples during normal operation mode

This system includes equipment to collect representative samples of the various process fluids, including reactor coolant system and containment air, in a manner that adheres to as-low-as-reasonably-achievable (ALARA) principles during normal and post-accident conditions.

The primary sampling system also includes provisions to route sample flow to a laboratory for continuous or intermittent sample analysis, as desired.

The primary sampling system provides a way to monitor the plant and various system conditions using the collected and analyzed samples.

A safety-related containment hydrogen analyzer provided to monitor the containment atmosphere following a postulated loss-of-coolant accident (LOCA) is described in subsection 6.2.4. A discussion of process radiation monitoring is provided in Section 11.5.

9.3.3.1 Design Bases

9.3.3.1.1 Safety Design Basis

The primary sampling system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation, which is described in subsection 6.2.3.

The equipment and seismic classification are discussed in Section 3.2.

9.3.3.1.2 Power Generation Design Basis

9.3.3.1.2.1 Sampling During Normal Plant Operations

During normal operation, the primary sampling system collects representative samples of fluids in the reactor coolant system (RCS) and auxiliary primary systems process streams and the containment atmosphere for analysis, as listed in Table 9.3.3-1. Local sample points, as listed in Table 9.3.3-2, are provided at various process points of the systems.

The results of the sample analyses are used to perform the following functions:

- Monitor core reactivity
- Monitor fuel rod integrity
- Evaluate ion exchanger (demineralizer) and filter performance
- Specify chemical additions to the various systems;
- Maintain acceptable hydrogen levels in the reactor coolant system
- Detect radioactive material leakage

The measurements are used to evaluate water chemistry and to recommend corrective action by the laboratory staff.

The primary sampling system component classification is provided in Section 3.2.

9.3.3.1.2.2 Post-Accident Sampling

The primary sampling system does not include specific post-accident sampling capability. However, in accordance with Reference 5 there are contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere. These plans include the procedures to analyze, during the later stages of accident response, reactor coolant for boron, containment atmosphere for hydrogen and fission products, and containment sump water for pH.

The primary means of containment atmosphere hydrogen analysis is the hydrogen analyzer described in subsection 6.2.4, which is not part of the post-accident sampling capabilities.

9.3.3.2 System Description

The primary sampling system is a manually operated system. It collects representative samples of fluids from the reactor coolant system and various primary auxiliary system process streams for analysis by the plant operating staff. This sampling process is performed during normal plant operations.

The primary sampling system consists of two separate portions: the liquid sampling portion and the gas sampling portion.

9.3.3.2.1 Nuclear Sampling System - Liquids

The liquid sampling portion of the primary sampling system collects samples from the reactor coolant system and the auxiliary systems and transports them to a common location in a sample room in the auxiliary building. Control and instrumentation is provided for safe, reliable operation. This portion of the system uses 1/4 inch stainless steel tubing. The small tubing flow area limits flow to less than chemical and volume control system makeup capacity in the event of a leak in the sampling lines. Dissolved gases in the reactor coolant system are collected in this system also.

Sample flow is routed to a grab sampling unit. This unit is in an enclosure, which controls the spread of contamination and provides shielding. The grab sampling unit is further shielded by a concrete wall to minimize radiation exposure.

Valves inside the grab sampling unit have long handles extending outside the enclosure and are manually operated. This arrangement allows the operator to obtain a sample quickly with minimum radiation exposure. A schematic diagram is provided on the front of the grab sampling unit to illustrate the tube routing inside.

Since the motive force during normal operations is the system pressure, the sampling system is designed to reactor coolant system pressure. If system pressure is not available, an eductor supplies the motive force for sample collection.

A direct line from the grab sampling unit to the laboratory provides the capability for continuous liquid sampling and analysis with online monitors.

Prior to the collection of liquid samples either in the laboratory or in the grab sampling unit, the lines are purged with source liquid to provide representative samples. The purging flow returns to the effluent holdup tank of the liquid radwaste system.

Figure 9.3.3-1 is a simplified sketch of the primary sampling system.

9.3.3.2.2 Nuclear Sampling System - Gaseous

This portion of the primary sampling system collects gaseous samples from the containment atmosphere. Gaseous sampling is conducted in the sample room in the auxiliary building, and it shares with the liquid sampling portion the grab sampling unit and the control panel. However, it uses 3/8 inch stainless steel tubing. Similar to the liquid sampling system, the gas sample subsystem is also manually operated with extension stems on the valves. Only grab samples are collected for the gas sampling process. The lines are purged prior to sample collection to provide representative samples. The purged gas returns to the effluent holdup tank of the liquid radwaste system.

Provisions are also made to dilute the gas sample. The dilution process uses nitrogen from a local gas bottle.

The gas sampling system uses an ejector as the motive force for sample collection. The ejector uses nitrogen from a local gas bottle as the motive force.

9.3.3.3 Containment Isolation Valves

Containment isolation valves are classified as Safety Class B. The lines penetrating the reactor containment meet the containment isolation criteria. See subsection 6.2.3.

Three lines penetrate the containment. One line carries the liquid samples from their sources to the grab sampling unit or the laboratory. The second line carries the containment air samples from their source to the sampling unit. The third line returns the liquid or containment air sampling flows to the containment sump. The valves fail closed.

These valves close on a containment isolation signal. In addition, the outside containment isolation valve in the liquid sampling path closes on a high sampling flow temperature or high radiation downstream of the sample cooler. This prevents the operator from working with high temperature fluid and minimizes the possibility of operator injury.

9.3.3.4 System Operation and Performance

The primary sampling system is manually operated. The tubing size and sampling flow rate are selected throughout the system to reduce the amount of purge flow and to provide turbulent sampling flow (to collect representative samples). A delay coil of tubing is installed inside containment to provide at least 60 seconds of transit time for the sampling fluid to exit the containment from the hot leg. This 60-second delay is needed for N-16 decay.

9.3.3.5 Design Evaluation

The primary sampling system has no safety function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation.

Subsection 6.2.3 provides the safety evaluation for the containment isolation system. Primary sampling system lines penetrating the containment are isolated at the containment boundary by valves that close upon receipt of a containment isolation signal and by manual actuation. (See subsection 6.2.3 for a discussion of containment isolation.)

The primary sampling system connects to the reactor coolant system and the passive core cooling system (PXS) and therefore provides features consistent with ANSI standards and ASME codes to protect these system pressure boundaries.

The primary sampling system is not required for accident mitigation or post-accident sampling; but there are plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere in accordance with Reference 5.

The acceptability of the design of the primary sampling system is based on specific general design criteria and regulatory guides. The design of the primary sampling system is consistent with the criteria set forth in subsection 9.3.2, "Process and Post-Accident Sampling Systems," of the NRC's Standard Review Plan (Reference 6) as modified by Reference 5. The specific general design criteria identified in the Standard Review Plan are General Design Criteria 1, 2, 13, 14, 26, 41, 60, 63, and 64. See Section 1.9 for a discussion of regulatory compliance.

9.3.3.6 Inspection and Testing Requirements

9.3.3.6.1 Preoperational Testing

Preoperational testing is performed after installation and prior to plant startup. Proper operation of the primary sampling system is demonstrated during preoperational testing. A sample is drawn from the reactor coolant system, containment atmosphere and other sample points via the sampling system in order to verify proper system operation.

9.3.3.6.2 Operational Testing

The proper operation and availability of the liquid and gaseous sampling subsystems are proven by continued proper sampling operations.

9.3.3.7 Instrumentation Requirements

The primary sampling system uses indicators as required to facilitate manual operation and to verify sample conditions before samples are drawn. Radiation monitoring instruments are used to monitor the incoming fluid (liquid or gas) radioactivity level.

The temperature indicator inside the grab sampling unit provides a signal to close the outside containment isolation valve when the sampling flow temperature exceeds pre-set limits. Likewise, the radiation monitors also provide a signal to close the outside containment isolation valves when excessive radiation levels are detected, for operator protection.

9.3.4 Secondary Sampling System

The secondary sampling system (SSS) delivers representative samples of fluids from secondary systems to sample analyzer packages. Continuous online secondary chemistry monitoring detects impurity ingress and provides early diagnosis of system chemistry excursions in the plant. Secondary sampling monitors send control signals to the turbine island chemical feed system that automatically injects corrosion control chemicals into the condensate and feedwater systems.

9.3.4.1 Design Basis

9.3.4.1.1 Safety Design Basis

The secondary sampling system serves no safety-related function and therefore has no nuclear safety design basis.

9.3.4.1.2 Power Generation Design Basis

The secondary sampling system monitors water samples from the condensate, feedwater, main steam, heater drain, steam generator blowdown, auxiliary steam supply, and condensate polishing systems, as listed in Table 9.3.4-1 and Table 9.3.4-2. Water quality analyses are performed on these samples to determine the following:

- pH
- Conductivity levels (specific and cation)
- Dissolved oxygen level
- Residual oxygen scavenger
- Sodium content
- Sulfate content.

The sample analyses are used to control water chemistry and to permit appropriate corrective action.

9.3.4.2 System Description

Classification of equipment and components for the secondary sampling system is given in Section 3.2. The sample points listed in Table 9.3.4-1 are continuously monitored. The sample points listed in Table 9.3.4-2 are selectively monitored (where a single analyzer package can be used to selectively monitor multiple sample points).

Sample analysis data from the continuous analyzers is recorded using computer systems that also provide trending capability of the measured process parameters. Measurements are used to automatically control condensate and feedwater system pH and dissolved oxygen levels by chemical addition. Refer to subsection 10.4.11 for further discussion of the turbine island chemical feed system.

Samples are analyzed and the results are used for automatic or manual control of the plant secondary water chemistry. After being analyzed, pure samples are returned to the condensate system. Sample lines containing reagents and those from sink drains are collected in the waste water system and processed for disposal. Each sample line has a grab sampling capability for laboratory analysis.

Roughing coolers are provided for the samples whose temperatures exceed 125°F. Samples are cooled to approximately 77°F by chilled water supplied to trim coolers.

9.3.4.3 Safety Evaluation

The secondary sampling system has no safety-related function and therefore requires no nuclear safety evaluation.

9.3.4.4 Tests and Inspections

Proper operation of the secondary sampling system is initially demonstrated during preoperational testing.

The system draws continuous and selective samples from the condensate, feedwater, main steam, and steam generator blowdown systems for automatic or manual water quality analysis. Calibration of the analyzers is checked periodically through laboratory analysis of a grab sample from the same process flow. The output of the continuous analyzers is recorded, and abnormal values are evaluated.

9.3.4.5 Instrumentation Applications

The secondary sampling system uses pressure, temperature, and flow indicators to facilitate operation and to verify sample conditions.

9.3.5 Equipment and Floor Drainage Systems

The equipment and floor drainage systems collect liquid wastes from equipment and floor drains during normal operation, startup, shutdown, and refueling. The liquid wastes are then transferred to appropriate processing and disposal systems.

Equipment and floor drainage is segregated according to the type of waste. Liquid wastes are classified and segregated for collection as follows:

- Radioactive liquid waste
- Nonradioactive liquid waste
- Chemical and detergent liquid waste
- Oily liquid waste

9.3.5.1 Design Basis

9.3.5.1.1 Safety Design Basis

The equipment and floor drainage systems are nonsafety-related and serve no safety-related function except for the backflow preventers in drain lines from containment cavities to the containment sump. No nuclear safety design basis is required except for the backflow preventers described in Section 11.2. Single active failures do not prevent the proper function of the safety-related backflow preventers.

The floor drainage systems and equipment are designed to prevent damage to safety-related systems, structures, and equipment. Safety-related components are not damaged as a result of equipment and floor drain components failure from a seismic event. Floor drainage systems and equipment single failures will not prevent the proper function of any safety-related equipment.

9.3.5.1.2 Power Generation Design Basis

Nonradioactive liquid waste sumps and drain tanks that can be potentially radioactive during normal plant operation are provided with sampling capabilities. There are no permanent connections between the radioactive drain system and nonradioactive piping. Provisions for temporary diversion of contaminated water from normally nonradioactive drains to the liquid radwaste system are included.

Equipment drains are adequately sized to meet the flow requirements.

Radioactive sump vents are directed to the ventilation system exhaust ducts, serving the areas where the sump is located. The containment sump vents directly to the containment.

Drainage systems are drained by gravity. The slope of the drain lines is 1/8 inch per foot as a minimum. The drainage systems are designed not to compromise the integrity of the areas maintained under a slight negative pressure during normal plant operation. This is achieved by avoiding cross connection with adjacent areas that are not maintained under a slight negative pressure.

Radioactive drain systems are designed to avoid crud traps and to minimize drain traps.

Sump and drain tank pumps discharge at a flowrate adequate to prevent sump overflow for drain rates anticipated during normal plant operation, maintenance, decontamination, fire suppression system testing, and fire fighting activities. Sump and drain tank capacities provide a live storage capacity consistent with an operating period of approximately 10 minutes with one pump

operating as a minimum. The containment sump pumping time between high and low level is approximately 3 minutes.

Plugging of the drain headers is minimized by designing them large enough to accommodate more than the design flow and by making the flow path as straight as possible. Drain headers are at least 4 inches in diameter.

9.3.5.2 System Description

9.3.5.2.1 General Description

The drainage systems include collection piping, equipment drains, floor drains, vents, traps, cleanouts, sampling connections, valves, collection sumps, drain tanks, pumps, and discharge piping. The general arrangement of the drainage systems is shown on Figure 9.3.5-1.

Radioactive Wastes

The radioactive waste drain system is arranged to receive inputs from the radiologically controlled areas of the auxiliary, annex, and radwaste buildings based on segregation of the liquid wastes into chemical and nonchemical drains. The radioactive waste drain system collects radioactive liquid wastes at atmospheric pressure from equipment and floor drainage of the radioactive portions of the auxiliary building, annex building, and radwaste building and directs these wastes to a centrally located sump located in the auxiliary building. The contents of the sump are pumped to the liquid radwaste system tanks. Drainage lines from the negative pressure boundary areas of the auxiliary, radwaste, and annex buildings do not terminate outside the negative pressure boundary without a normally closed valve or plugged drain to maintain the integrity of the negative pressure boundary.

The liquid radwaste system collects radioactive and borated liquid wastes from equipment and floor drains in containment. Waste from the equipment drains inside containment is drained to the reactor coolant drain tank. The liquid waste from floor drains, fan coolers, and the containment wall gutter inside containment is drained to the containment sump. The contents of the drain tank and sump are pumped out of containment for processing by the liquid radwaste system. Refer to Section 11.2 for further details.

The sumps, pumps, and associated valves for the drain systems are located outside of high-radiation areas to the extent practical.

Nonradioactive and Potentially Radioactive Waste Drains

The waste water system collects nonradioactive waste from floor and equipment drains in auxiliary, annex, turbine, and diesel generator building sumps or tanks. Selected normally nonradioactive liquid waste sumps and tanks are monitored for radioactivity to determine whether the liquid wastes have been inadvertently contaminated. If contaminated, the wastes are diverted to the liquid radwaste system for processing and ultimate disposal. Refer to subsection 9.2.9 for further details. Drainage lines from the positive pressure boundary areas of the auxiliary building do not terminate outside the positive pressure boundary without a closed valve, plugged drain, or water seal to maintain the integrity of the positive pressure boundary.

Chemical Waste Drains

The radioactive waste drain system collects chemical wastes from the auxiliary building chemical laboratory and decontamination solution drains from the annex building and directs these wastes to the chemical waste tank of the liquid radwaste system.

Detergent Waste Drains

The laundry and respirator cleaning functions that generate detergent wastes are performed offsite. Detergent wastes from hot sinks and showers are routed to the chemical waste tank.

Oily Waste Drains

The waste water system collects nonradioactive, oily, liquid waste in drain tanks and sumps. Drain tank and sump liquid wastes are pumped through an oil separator prior to further processing. The oil is collected in a tank for disposal.

Sampling for oil in the waste holdup tank of the liquid radwaste system is provided to detect oil contamination before the ion exchanger resins are damaged. Oily water is pumped from the tank through an oil adsorbing bag filter before further processing. The spent bag filters are transferred to drums and stored in the radwaste building as described in Section 11.4.

9.3.5.2.2 Component Description

General description and summaries of the design requirements for these components are provided below. Key equipment parameters are contained in Tables 9.3.5-1 and 11.2-2. Principal construction codes and standards and the classification applicable to the floor and equipment drainage systems are listed in Section 3.2.

Sumps and Drain Tanks

In general, the inlet drain lines to the sump or drain tank are kept submerged a minimum of 6 inches below pump shutoff level to prevent backgassing. The containment sump inlet is not submerged.

Sumps are covered to keep out debris. Covers are removable, or manholes are provided for access. The total capacity of each sump includes a 10 percent freeboard allowance to permit operation of high-high level alarms and associated controls before the overflow point is reached.

Each sump is fitted with a vent connection to exhaust potential sump gases into the room. Nonradioactive drain tanks are vented to the atmosphere. The reactor coolant drain tank is vented to the gaseous radwaste system (Section 11.3). Where necessary for the control of airborne radioactivity, the sump vents are routed to the ventilation system exhaust duct for the room.

Radioactive sumps are stainless steel construction. Nonradioactive collection sumps are constructed of concrete with corrosion resistant coating or liner.

Sump and Drain Tank Pumps

Sumps outside containment are provided with air diaphragm pumps mounted on the sump cover plate. Pumps are equipped with reliable, mechanical diaphragms of demonstrated acceptable design that are easy to maintain. Pumps and associated piping connections and accessories are designed for easy replacement of pump diaphragms. The containment sump pumps are described in Section 11.2. The turbine building drain tank pumps are described in subsection 9.2.9.

Valves

Air-operated valves are provided for on/off functions of air supply to the sump pump diaphragms. Swing check valves, where provided, are installed in horizontal pipe runs. Pressure control valves are provided to control air supply pressure to the sump pump diaphragms. Manual ball valves are provided for maintenance purposes.

9.3.5.2.3 System Operation

The equipment and floor drainage systems operate during all modes of normal plant operation. Liquid wastes drain by gravity to collection tanks or sumps. Drainage flowrates vary based on the status of the plant. Sump pumps disposing of collected radioactive wastes discharge to the liquid radwaste system for further processing. Nonradioactive liquid wastes are discharged to the waste water system.

Pump operation is automatic with manual override. The pumps are automatically started and stopped by preset high, high-high, and low level instrumentation.

Where sumps are provided with two pumps, the capability is provided to allow equalizing the operational period of each pump. For the radioactive waste drain system, when the first pump is started on high level, a portion of the flow is recycled to allow recirculation of the flow through a mixing eductor.

The sump and drain tank pumps are not required to operate during design basis accidents. Sump pumps in the containment are interlocked with the associated containment isolation valves. The pumps trip and the isolation valves close on receipt of containment isolation signals (see subsection 6.2.3).

The equipment and floor drainage systems can be operated either automatically or manually for cleanup following an accident, including fire, provided that the compressed and instrument air system and ac power are available, and the drainage systems and support systems are not disabled by the event.

9.3.5.2.4 Instrumentation Applications

Level indication is provided in the main control room for the sump in-containment to provide indication of the presence of reactor coolant from unidentified leaks (refer to subsection 5.2.5). The sump and the drain tank outside containment are monitored for water level. On high sump or tank level, the solenoid-operated three-way valve for the selected pump is energized to admit air to the pump diaphragm. On high-high sump or tank level, the solenoid-operated three-way valve for the remaining pump is also energized to admit air to that pump diaphragm. On low level, both pumps are stopped by deenergizing their respective solenoid valves. Operating status of the pumps is provided to the plant control system.

9.3.5.3 Safety Evaluation

The equipment and floor drainage systems are nonsafety-related except for backflow preventers in drain lines from containment cavities to the containment sump. No nuclear safety evaluation is required other than that described for the backflow preventers in Section 11.2.

9.3.5.4 Tests and Inspections

The operability of equipment and floor drainage systems dependent upon gravity flow can be checked by normal usage. Portions of these systems dependent upon pumps to discharge to interfacing systems may be checked through instrumentation and alarms via the plant control system and trouble alarms in the main control room during operation or test.

9.3.6 Chemical and Volume Control System

The chemical and volume control system is designed to perform the following major functions:

- **Purification -** maintain reactor coolant system fluid purity and activity level within acceptable limits.

- **Reactor coolant system inventory control and makeup -** maintain the required coolant inventory in the reactor coolant system; maintain the programmed pressurizer water level during normal plant operations.

- **Chemical shim and chemical control -** maintain the reactor coolant chemistry conditions by controlling the concentration of boron in the coolant for plant startups, normal dilution to compensate for fuel depletion and shutdown boration, and provide the means for controlling the reactor coolant system pH by maintaining the proper level of lithium hydroxide.

- **Oxygen control -** provide the means for maintaining the proper level of dissolved hydrogen in the reactor coolant during power operation and for achieving the proper oxygen level prior to startup after each shutdown.

- **Filling and pressure testing the reactor coolant system -** provide the means for filling and pressure testing the reactor coolant system. The chemical and volume control system does not perform hydrostatic testing of the reactor coolant system, which is only required prior to

initial startup and after major, nonroutine maintenance, but provides connections for a temporary hydrostatic test pump.

- **Borated makeup to auxiliary equipment -** provide makeup water to the primary side systems that require borated reactor grade water.

- **Pressurizer Auxiliary Spray -** provide pressurizer auxiliary spray water for depressurization.

9.3.6.1 Design Bases

9.3.6.1.1 Safety Design Basis

The safety functions provided by the chemical and volume control system are limited to containment isolation of chemical and volume control system lines penetrating containment, termination of inadvertent reactor coolant system boron dilution, isolation of makeup on a steam generator or pressurizer high level signal, and preservation of the reactor coolant system pressure boundary, including isolation of normal chemical and volume control system letdown from the reactor coolant system.

9.3.6.1.2 Power Generation Design Basis

The principal functions of the chemical and volume control system are outlined above and include controlling reactor coolant system chemistry, purity, and inventory. The system provides some functions necessary for the continued normal operation of the plant. Reliability is achieved by the use of redundant equipment (pumps, filters, and demineralizers). The equipment classification for the chemical and volume control system is contained in Section 3.2.

9.3.6.1.2.1 Purification

The chemical and volume control system removes radioactive corrosion products, ionic fission products, and fission gases from the reactor coolant system to maintain low reactor coolant system activity levels. The chemical and volume control system purification capability considers occupational radiation exposure (ORE) to support ALARA goals.

The chemical and volume control system is designed to maintain the reactor coolant system activity level at less than the technical specification limit for normal operations, with design basis fuel defects. The technical specifications allow these limits to be exceeded for a specified duration. See Chapter 16.

The purification rate is based on minimizing occupational radiation exposure and providing access to the reactor coolant system equipment. The chemical and volume control system provides a reactor coolant system purification rate of at least one reactor coolant system mass per 16 hours.

The chemical and volume control system has sufficient reactor coolant system purification and degasification capability (in conjunction with the liquid radwaste system) to allow the reactor vessel head to be removed in a timely manner during a refueling shutdown. In addition, purification during shutdowns has positive impact on the occupational radiation exposure to

workers during the outage. The chemical and volume control system supports the plant ALARA goals with the shutdown purification function.

9.3.6.1.2.2 Reactor Coolant System Inventory Control and Makeup

The chemical and volume control system provides a means to add and remove mass from the reactor coolant system, as required, to maintain the programmed inventory during normal plant operations. Operations that are accommodated include startup, shutdown, step load changes, and ramp load changes.

The chemical and volume control system is capable of maintaining a constant volume in the reactor coolant system, while the plant is being heated up or cooled down. During a heatup it is necessary to remove reactor coolant system mass due to expansion. The maximum rate of net expansion occurs at the end of the heatup, so the limiting case is based on controlling the pressurizer level during this phase of operation. This expansion is accommodated by the normal letdown path. During cooldown, it is necessary to add mass due to reactor coolant system shrinkage. The chemical and volume control system is capable of maintaining the minimum pressurizer level with makeup during cooldown from hot zero power to cold shutdown while maintaining normal purification flow. Ramp and step load changes, as well as load rejections, are accommodated by the reactor coolant system pressurizer level control system. The chemical and volume control system can function to accommodate normal pressurizer level control system makeup and letdown requirements.

The chemical and volume control system is designed to make up for leaks, including leaks up to 3/8-inch inside diameter and for anticipated steam generator tube leaks, allowing the plant to be taken to cold shutdown conditions without the use of safety-related makeup systems.

9.3.6.1.2.3 Chemical Shim and Chemical Control

The chemical and volume control system provides the means to vary the boron concentration in the reactor coolant system. The system also controls the reactor coolant system chemistry for the purpose of limiting corrosion and enhancing core heat transfer.

Chemical Shim

The concentration of boron in the reactor coolant system is changed, as required, to maintain the desired control rod position with core depletion. The chemical and volume control system has the capacity to accommodate a cold shutdown followed by a return to power at the end of core life and also (as an independent case) to borate the plant to cold shutdown immediately following return to power from refueling. The system has boration and dilution capacity to meet these requirements, as well as the capability to transfer effluents to other systems.

The chemical and volume control system boric acid solutions are stored at concentrations that do not require heat tracing or room temperatures above normal values. The 2.5 weight percent boric acid solution requires freeze protection but does not impose special ambient temperature requirements.

pH Control

Lithium hydroxide (Li7OH) is used to control the pH of the reactor coolant system. The required concentration of Li7OH is varied to minimize the formation of tritium.

9.3.6.1.2.4 Oxygen Control

The chemical and volume control system maintains the proper conditions in the reactor coolant system to minimize corrosion of the fuel and primary surfaces. During power operations, dissolved hydrogen is added to the reactor coolant system to eliminate free oxygen and to prevent ammonia formation. The chemical and volume control system is capable of maintaining the concentration of dissolved hydrogen in the reactor coolant system at a minimum of 25 cubic centimeters hydrogen, at standard temperature and pressure, per kilogram of coolant, assuming anticipated operating losses.

This concentration can be reduced to 15 cc/kg within 24 hours prior to shutdown. Prior to opening the reactor coolant system during a cold or refueling shutdown, the hydrogen concentration is reduced to approximately 5 cubic centimeters per kilogram. To prevent delays, the chemical and volume control system (in conjunction with the liquid radwaste system) is capable of making this 15 to 5 cubic centimeters per kilogram reduction within the time to achieve normal plant cooldown.

During plant startup from cold shutdown, the chemical and volume control system introduces an oxygen scavenger into the reactor coolant system. The solution is only used for oxygen control at low reactor coolant system temperatures during startup from cold shutdown conditions. At other times during plant operation, hydrogen is used for oxygen control.

9.3.6.1.2.5 Filling and Pressure Testing the Reactor Coolant System

The chemical and volume control system provides a means for filling and pressure testing the reactor coolant system. The chemical and volume control system also provides connections for a temporary hydrotest pump.

9.3.6.1.2.6 Borated Makeup

The chemical and volume control system provides makeup to the passive core cooling system accumulators, core makeup tanks, in-containment refueling water storage tank, and to the spent fuel pool at various boron concentrations.

9.3.6.2 System Description

The chemical and volume control system consists of regenerative and letdown heat exchangers, demineralizers and filters, makeup pumps, tanks, and associated valves, piping, and instrumentation. The system parameters are given in Table 9.3.6-1. The piping and instrumentation diagram for the chemical and volume control system is included as Figure 9.3.6-1.

9.3.6.2.1 Purification

9.3.6.2.1.1 Ionic Purification

The normal chemical and volume control system purification loop is inside containment and operates at reactor coolant system pressure, utilizing the developed head of the reactor coolant pumps as the motive force for the purification flow. During power operations, fluid is continuously circulated through the chemical and volume control system from the discharge of one of the reactor coolant pumps. It passes through the regenerative heat exchanger where it is cooled by the returning chemical and volume control system flow, and is further cooled by component cooling water in the letdown heat exchanger to a temperature compatible with the demineralizer resins. The letdown fluid flows through a mixed bed demineralizer, optionally through a cation bed demineralizer, and through a filter. It returns to the suction of a reactor coolant pump after being heated in the regenerative heat exchanger. The purification loop is at reactor coolant system pressure.

Since the motive force for the purification loop is the reactor coolant pump head in a closed loop with the reactor coolant system, continuous purification is provided without operating the chemical and volume control system makeup pumps.

The mixed bed demineralizers are provided in the purification loop to remove ionic corrosion products and certain ionic fission products. The demineralizers also act as filters. One mixed bed is normally in service, with a second demineralizer acting as backup in case the normal unit should become exhausted during operation. Each demineralizer and filter is sized to provide a minimum of one fuel cycle of service without changeout.

The mixed bed demineralizer in service can be supplemented by intermittent use of the cation bed demineralizer for additional purification in the event of fuel defects. In this case, the cation resin removes mostly lithium and cesium isotopes. The cation bed demineralizer has sufficient capacity to maintain the cesium-136 concentration in the reactor coolant below 1.0 microcurie per cubic centimeter with design basis fuel defects. Each mixed bed and the cation bed demineralizer is sized to accept the maximum purification flow. Filters are provided downstream of the demineralizers to collect particulates and resin fines.

During plant shutdowns when the reactor coolant pumps are stopped, the normal residual heat removal system provides the motive force for the chemical and volume control system purification. Purification flow from the normal residual heat removal system heat exchanger is routed directly through the normal chemical and volume control system purification loop. Boron changes and dissolved gas control are still possible by operating the chemical and volume control system in a semiclosed loop arrangement.

9.3.6.2.1.2 Gaseous Purification

Removal of radiogases from the reactor coolant system are not normally necessary because the gases do not build up to unacceptable levels when fuel defects are within normally anticipated ranges. If radiogas removal is required because of high fuel defects, the chemical and volume control system can be operated by routing flow to the liquid radwaste system degassifier. In this configuration, the letdown fluid is depressurized by flowing through the letdown orifice. The

letdown flow is routed outside of containment through the liquid radwaste system degassifier to one of the liquid radwaste system effluent holdup tanks, returned to the reactor coolant system with the chemical and volume control system makeup pumps. This provides efficient gas removal.

Removal of radioactive gas and hydrogen during shutdown operations is necessary to avoid extending the maintenance and refueling outages. The reactor coolant system pressure boundary cannot be opened to the containment atmosphere until the gas concentrations are reduced to low levels. The shutdown degassing process is accomplished by operating the chemical and volume control system in the open loop configuration. In addition, a line is provided to allow the letdown orifice to be manually bypassed, so gas removal can continue after the reactor coolant system has been depressurized.

9.3.6.2.2 Reactor Coolant System Inventory Control and Makeup

Changes in reactor coolant volume are accommodated by the pressurizer level program for normal power changes, including transition from hot standby to full-power operation and returning to hot standby. In addition, the pressurizer has sufficient volume, within the deadband of the level control program, to accommodate minor reactor coolant system leakage for some time. The chemical and volume control system provides inventory control to accommodate minor leakage from the reactor coolant system, expansion during heatup from cold shutdown, and contraction during cooldown. This inventory control is provided by letdown and makeup connections to the chemical and volume control system purification loop.

9.3.6.2.3 Chemical Shim and Chemical Control

The chemical and volume control system provides the following functions to support the water chemistry and chemical shim requirements of the reactor coolant system:

- Means of addition and removal of pH control chemicals for startup and normal operation.

- Means of addition and removal of soluble chemical neutron absorber (boron) and makeup water, at concentrations and rates compatible with normal plant operation.

Reactor coolant system chemistry changes are accomplished with a feed and bleed operation. The letdown and makeup paths are operated simultaneously and appropriate chemicals are provided at the suction of the reactor makeup pumps. In this situation chemistry changes are made as feed and bleed operations.

9.3.6.2.3.1 Chemical Shim

Reactor coolant system boron changes are required to compensate for fuel depletion, startups, shutdowns, and refueling.

To borate the reactor coolant system, the operator sets the makeup control system to automatically add a preset amount of boric acid by fully diverting the three-way valve in the pump suction to the boric acid tank, with delivered flow measured at the discharge of the makeup pumps. Dilution operates in a similar fashion. In either case, if the pressurizer level exceeds its control point, the letdown path to the liquid radwaste system holdup tanks is automatically opened.

Boric acid is provided to the boric acid tank by mixing 2.5 weight percent boric acid solution in the boric acid batching tank. Boric acid crystals are mixed with a mixer, while the mixture is heated to an appropriate temperature to provide efficient mixing by the batching tank immersion heater. After the boric acid crystals are dissolved, the solution is drained by gravity into the boric acid tank. No provisions are incorporated for boric acid recycle from the liquid radwaste system.

9.3.6.2.3.2 pH Control

The chemical agent used for pH control is lithium hydroxide (Li7OH). This chemical is chosen for its compatibility with the material and water chemistry of borated water, stainless steel, zirconium systems. In addition, lithium-7 is produced in the core region because of irradiation of the dissolved boron in the coolant. A chemical mixing tank is provided to introduce the solution to the suction of the makeup pumps, as required to maintain the proper concentration of Li7OH in the reactor coolant system.

The solution is poured into the chemical mixing tank and is then flushed to the suction manifold of the makeup pumps with demineralized water. A flow orifice is provided on the demineralized water inlet pipe to allow chemicals to be flushed into the reactor coolant system at acceptable concentrations.

The concentration of lithium-7 in the reactor coolant system varies according to a pH control curve as a function of the boric acid concentration of the reactor coolant system. If the concentration exceeds the proper value, as it may during the early stages of core life when lithium-7 is produced in the core at a relatively high rate, the cation bed demineralizer is used in the letdown path in series with the mixed bed demineralizer to lower the lithium-7 concentration. Since the buildup of lithium is slow, the cation bed demineralizer is used only intermittently. When letdown is being diverted to the liquid radwaste system, the letdown flow is routed through the cation bed demineralizer for removal of as much lithium-7 and cesium as possible.

9.3.6.2.4 Oxygen Control

The chemical and volume control system provides control of the reactor coolant system oxygen concentration, both during startup by introducing an oxygen scavenger and during power operations by driving toward zero the equilibrium concentration of oxygen produced by radiolysis in the core by injecting hydrogen.

9.3.6.2.4.1 Startups

During plant startup from cold conditions, an oxygen scavenging agent is used. The oxygen scavenger solution is introduced into the reactor coolant system via the makeup flow and chemical mixing tank, in the same manner as described for lithium-7 addition. The oxygen scavenger is used for oxygen control only at startup from cold shutdown conditions.

9.3.6.2.4.2 Power Operation

Dissolved hydrogen is employed during normal power operation to control and scavenge oxygen produced due to radiolysis of water in the core region. Hydrogen makeup is supplied to the reactor coolant system by direct injection of high-pressure gaseous hydrogen. The hydrogen comes from a

bottle outside containment, through a containment penetration and is mixed in the chemical and volume control system purification loop. Hydrogen removal from the reactor coolant system is not necessary because hydrogen is consumed in the core.

9.3.6.2.5 Reactor Coolant System Filling and Pressure Testing

Reactor coolant system filling is accomplished by using the chemical and volume control system makeup pumps to provide fluid at the proper boron concentration (refueling), taking suction from both the boric acid tank and the demineralized water tank. The makeup pumps can also take suction from a clean liquid radwaste system holdup tank, by opening the line to the makeup pumps from that holdup tank.

The chemical and volume control system makeup pumps produce sufficient head to pressure test the reactor coolant system after maintenance and refueling.

A temporary hydrotest pump is required for initial hydrotesting, which requires higher pressures than can be achieved with the makeup pumps.

9.3.6.2.6 Borated Makeup

The makeup pumps are used to provide makeup at the proper boron concentration to the passive core cooling system accumulators, core makeup tanks, in-containment refueling water storage tank, and to the spent fuel pool. Makeup to these locations is at boric acid concentration as required, which can be varied from 0 to 4375 parts per million (2.5 weight percent). A mixture of 2.5 weight percent boric acid and demineralized water is provided by taking suction from both the boric acid tank and the demineralized water tank.

9.3.6.3 Component Descriptions

The general descriptions and summaries of the chemical and volume control system components are provided below. The key equipment parameters for the chemical and volume control system components are contained in Table 9.3.6-2. Information regarding component classifications is available in Section 3.2. See Section 5.2 for additional information on analysis requirements.

9.3.6.3.1 Chemical and Volume Control System Makeup Pumps

Two centrifugal makeup pumps are provided. These pumps are driven by ac motors, and flow is controlled by positioning a control valve in the common discharge line from the pumps. A cavitating venturi in the common discharge line limits the makeup flow and provides protection from excessive pump runout. Each pump has a recirculation loop with a heat exchanger and flow control orifice to provide adequate minimum flow for pump protection. The mini-flow heat exchanger is cooled by component cooling water.

The makeup pumps are arranged in parallel with common suction and discharge headers. Each provides full capability for normal makeup; thus, there is redundancy for normal operations. The normal makeup pump suction fluid comes from the boric acid tank and the demineralized water connection. A three-way valve in the suction header is positioned to provide a full range of concentrations.

One makeup pump is capable of maintaining normal reactor coolant system inventory with leaks up to a 3/8-inch inside diameter, without an actuation of the safety injection systems. The second pump can be manually started to provide additional reactor coolant makeup.

These pumps are used to pressure test the reactor coolant system.

Parts of the pump in contact with reactor coolant are constructed of austenitic stainless steel. The pump motor and lube oil are air-cooled.

9.3.6.3.2 Chemical and Volume Control System Heat Exchangers

Letdown Heat Exchanger

One single-shell pass U-tube letdown heat exchanger is provided. The heat exchanger is designed to cool the purification loop flow from the regenerative heat exchanger outlet temperature to the desired letdown temperature allowing the letdown to be processed by the demineralizers while maximizing the thermal efficiency of the chemical and volume control system.

The letdown heat exchanger outlet temperature is controlled by the operator by remotely positioning a component cooling system flow control valve.

The reactor coolant in the purification loop flows through the tubes, which are stainless steel, and component cooling water flows through the shell, which is carbon steel.

Miniflow Heat Exchangers

Two miniflow heat exchangers are provided, one in each makeup pump miniflow recirculation line. Each heat exchanger is designed to cool the flow through the chemical and volume control system makeup pump minimum flow recirculation lines to the desired temperature for pump protection. The makeup water flows through the tubes, which are stainless steel, and component cooling water flows through the shell, which is carbon steel.

Regenerative Heat Exchanger

One regenerative heat exchanger is provided. This heat exchanger is used to recover heat from the purification loop flow leaving the reactor coolant system by reheating the fluid entering the reactor coolant system. This provides increased thermal efficiency and also reduces thermal stresses on the reactor coolant system.

The design basis for this heat exchanger is the last hour of plant heatup, when expansion of the reactor coolant system requires a net removal of inventory. For this case the regenerative heat exchanger outlet temperature must be low enough to allow the letdown heat exchanger to cool the letdown to the desired temperature with anticipated cooling water temperatures.

The reactor coolant leaving the reactor coolant system flows through the tube side of this heat exchanger, and the returning fluid flows through the shell. This arrangement places the cleaner fluid on the shell side and the lower quality fluid on the tube side, where there are fewer crevices available for crud deposition.

9.3.6.3.3 Chemical and Volume Control System Tanks

Boric Acid Tank

One boric acid tank is provided. The tank is sized to allow for one shutdown to cold shutdown followed by a shutdown for refueling at the end of the fuel cycle.

The tank is vented to the atmosphere. Relatively little boric acid is used during power operation, since load follow is accomplished with gray rods and without changes in the reactor coolant system boron concentration. Therefore, the boric acid which is injected has a negligible effect on the free oxygen level in the reactor coolant system.

The tank is a free-standing stainless steel cylindrical design, located outside of the buildings, with only normal freeze protection required to maintain solubility of the 2.5 weight percent boric acid.

Boric Acid Batching Tank

The boric acid batching tank is a cylindrical tank with an immersion heater used in the preparation of 2.5 weight percent boric acid. A mixer is included with the tank. The tank is constructed of austenitic stainless steel and is provided with fill, vent and drain connections.

Chemical Mixing Tank

The chemical mixing tank is a small vertical, cylindrical tank sized to provide sufficient capacity for injecting an oxygen scavenger solution necessary to provide a concentration of ten parts per million in the cold reactor coolant system for oxygen scavenging.

A variety of chemicals to be added to the primary system are mixed in the tank. The solution to be injected is placed into the mixing tank and then flushed to the suction of the makeup pumps with demineralized water.

The tank is constructed of austenitic stainless steel and is provided with fill, vent, and drain connections.

9.3.6.3.4 Chemical and Volume Control System Demineralizers

Cation Bed Demineralizer

One cation resin bed demineralizer is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of lithium-7 (pH control) in the reactor coolant system. The demineralizer is sized to accommodate maximum purification flow when in service, which is adequate to control the lithium-7 and/or cesium concentration in the reactor coolant.

The demineralizer vessel is designed for reactor coolant system pressure and is constructed of austenitic stainless steel, with connections for resin addition, replacement, flushing, and draining. The vessel incorporates a retention screen, an inflow screen, and mesh screens on the drain connections. The screens are designed to retain the resin with minimum pressure drop. The inflow

screen prevents inadvertent flushing of the resin into the purification loop through the demineralizer inlet and also deflects the incoming flow to preserve a smooth resin bed.

Mixed Bed Demineralizers

Two mixed bed demineralizers are provided in the purification loop to maintain reactor coolant purity. A mixture of lithiated cation and anion resin is used in the demineralizer. Both forms of resin remove fission and corrosion products. Each demineralizer is sized to accept the full purification flow during normal plant operation and to have a minimum design life of one core cycle.

The construction of the mixed bed demineralizers is identical to that of the cation bed demineralizer.

9.3.6.3.5 Chemical and Volume Control System Filters

Makeup Filter

One makeup filter is provided to collect particulates in the makeup stream, such as boric acid tank sediment. The filter is designed to accept maximum makeup flow. The unit is constructed of austenitic stainless steel with a disposable synthetic cartridge and is designed for reactor coolant system hydrostatic test pressure.

Reactor Coolant Filters

Two reactor coolant filters are provided. The filters are designed to collect resin fines and particulate matter from the purification stream. Each filter is designed to accept maximum purification flow.

The units are constructed of austenitic stainless steel with disposable synthetic cartridges and are designed for reactor coolant system pressure.

9.3.6.3.6 Chemical and Volume Control System Letdown Orifice

One letdown orifice is provided in the letdown line, where fluid leaves the high-pressure purification loop before it exits containment. The orifice limits the letdown flow to a rate compatible with the chemical and volume control system equipment and also plant heatup and dilution requirements.

The orifice consists of an assembly that provides for permanent pressure loss without recovery and is made of austenitic stainless steel.

A manual bypass line is provided around the orifice to allow shutdown purification and degassing when the reactor coolant system pressure is low.

9.3.6.3.7 Chemical and Volume Control System Valves

The chemical and volume control system valves are stainless steel for compatibility with the borated reactor coolant. Isolation valves are provided at connections to the reactor coolant system. Lines penetrating the reactor containment meet the containment isolation criteria described in subsection 6.2.3.

Purification Stop Valves

These normally open, motor-operated valves are located inside containment and close automatically on a low pressurizer level signal from the protection and safety monitoring system to preserve reactor coolant pressure boundary and to prevent uncovering of the heater elements in the pressurizer. The valves fail "as is" on loss of power and manual control (open/auto/close) is provided in the main control room and at the remote shutdown workstation.

Letdown Flow Inside Containment Isolation Valve

This normally closed, fail closed, air-operated globe valve is located inside containment and isolates letdown to the liquid radwaste system. This valve automatically opens and closes on a plant control system signal from the pressurizer level control or a containment isolation signal from the protection and safety monitoring system. It automatically opens on high pressurizer level and closes when the pressurizer level returns to normal. It also closes on a high-high liquid radwaste system degassifier level or a containment isolation signal. This valve operator has a flow restricting orifice in the vent line so it closes more slowly than the letdown flow outside containment isolation valve. Manual control is also provided in the main control room and at the remote shutdown workstation.

Letdown Flow Outside Containment Isolation Valve

This normally closed, fail closed, air-operated globe valve is located outside containment and isolates letdown to the liquid radwaste system. This valve automatically opens and closes on a plant control system signal from the pressurizer level control system or a containment isolation signal from the protection and safety monitoring system. This valve operates in the same fashion as the letdown flow inside containment isolation valve. The letdown flow outside containment isolation valve closes more quickly than inside containment letdown flow isolation valve to limit seat wear of inside containment isolation valve. This valve operator has a flow restricting orifice in the air line, so it opens more slowly than inside containment letdown flow isolation valve. In addition, during brief periods of shutdown, when the reactor coolant system is water solid, this valve throttles to maintain the reactor coolant system pressure. Manual control is also provided in the main control room and at the remote shutdown workstation.

Makeup Stop Valve

This normally open, air-operated stop check valve is located inside containment and functions to isolate the flow in the charging line to the reactor coolant system. This valve can be closed from the main control room or the remote shutdown workstation to isolate charging downstream of the regenerative heat exchanger. This valve is closed to support the auxiliary spray function. The

valve fails open on loss of power or loss of instrument air so the charging line to the reactor coolant system remains available.

Auxiliary Spray Line Isolation Valve

This normally closed, air-operated globe valve is located inside containment, downstream of the regenerative heat exchanger, and functions to isolate the auxiliary spray line to the reactor coolant system pressurizer. This valve is opened to provide flow to the auxiliary spray line during heatups and cooldowns to add chemicals or to collapse the steam bubble in the pressurizer. This valve fails closed on a loss of power or loss of instrument air to accomplish the function of preserving the reactor coolant pressure boundary. This valve closes automatically on a low-1 pressurizer level signal from the protection and safety monitoring system to preserve reactor coolant pressure boundary. This valve is operated from the main control room and the remote shutdown workstation.

Makeup Line Containment Isolation Valves

These normally open, motor-operated globe valves provide containment isolation of the chemical and volume control system makeup line and automatically close on a high-2 pressurizer level, high steam generator level, or high-2 containment radiation signal from the protection and safety monitoring system. The valves also close on a safeguards actuation signal coincident with high-1 pressurizer level. This allows the chemical and volume control system to continue providing reactor coolant system makeup flow, if the makeup pumps are operating following a safeguards actuation signal. These valves are also controlled by the reactor makeup control system and close when makeup to other systems is provided. Manual control is provided in the main control room and at the remote shutdown workstation.

Hydrogen Addition Containment Isolation Valve

This normally closed, fail closed, air-operated globe valve is located outside containment in the hydrogen addition line. The valve automatically closes on a containment isolation signal from the protection and safety monitoring system. Manual control is provided in the main control room and at the remote shutdown workstation.

Demineralized Water System Isolation Valves

These normally open, air-operated butterfly valves are located outside containment in the line from the demineralized water storage and transfer system. These valves close on a signal from the protection and safety monitoring system derived by either a reactor trip signal, a source range flux doubling signal, low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers, or a safety injection signal, isolating the demineralized water source to prevent inadvertent boron dilution events. Manual control for these valves is provided from the main control room and at the remote shutdown workstation.

Makeup Pump Suction Header Valve

This air-operated, three-way valve is automatically controlled by the makeup control system to provide the desired boric acid concentration of makeup to the reactor coolant system (boric acid,

demineralized water, or blend based on the desired reactor coolant system boron concentration). The valve fails with the pump suction aligned to the boric acid tank on a loss of instrument air. This valve will also align to the boric acid tank on either a reactor trip, source range flux doubling signal, low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers, or a safety injection signal from the protection and safety monitoring system. This valve also aligns the makeup pump suction to the boric acid tank when low pressure is detected in the demineralized water supply line to protect the pump from a loss of suction supply. Manual control for this valve is provided in the main control room and at the remote shutdown workstation.

Makeup Pump Suction Relief Valves

A relief valve is provided in the suction of each makeup pump to prevent overpressurization of the pump suction. These relief valves prevent overpressurization that might be caused by backleakage through the makeup pump discharge check valves when the pump suction valves are closed. The set pressure of these relief valves is equal to the pump suction design pressure. The relief capacity is sufficient to accommodate expected check valve back leakage rates.

Letdown Line Relief Valve

A relief valve is provided to prevent overpressurization of the letdown line connected to the waste processing system. This relief valve prevents overpressurization that might be caused by opening the letdown line with a closed valve in the waste processing system. The set pressure of this relief valve is equal to the design pressure of the line connecting to the waste processing system. The relief capacity is sufficient to accommodate a conservatively high letdown rate assuming minimum flow resistances in the piping, valves, orifices and equipment in the letdown line.

Resin Sluice Line Relief Valve

A relief valve is provided to prevent overpressurization of the line that is used to sluice resin from the mixed bed and cation bed demineralizers to the waste processing system. This relief valve prevents overpressurization that might be caused by opening the letdown line with a closed valve in the waste processing system. The set pressure of this relief valve is equal to the design pressure of the line it is connected to which is equal to the design pressure of the CVS purification equipment inside containment. The relief capacity is sufficient to accommodate thermal expansion of the water that is trapped between the two containment isolation valves that might occur following an accident that results in heatup of the containment.

9.3.6.3.8 Piping Requirements

The chemical and volume control system piping that handles radioactive liquid is made of austenitic stainless steel. The piping joints and connections are welded, except where flanged connections are required for equipment removal for maintenance and hydrostatic testing.

9.3.6.4 System Operation and Performance

The operation of the chemical and volume control system for the various modes of reactor plant operation is described in the following subsections.

9.3.6.4.1 Plant Startup

Plant startup is the operation that brings the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

The makeup pumps initially fill the reactor coolant system via the purification flow return line. During filling, makeup water is drawn from the demineralized water connection and blended with boric acid from the boric acid tank to provide makeup at the desired reactor coolant system boron concentration. The reactor coolant system is vented via the reactor vessel head and the pressurizer. A vacuum fill subsystem may be used to enhance the reactor coolant fill operation.

The auxiliary spray line may be used to fill the pressurizer and establish proper water chemistry in the pressurizer. If water solid operation is desired, reactor coolant system pressure is controlled by operation of the letdown control valve and the makeup control valve. To accomplish this, a letdown flow path is established to the liquid radwaste system with the letdown orifice bypassed. The makeup flow rate is maintained by the makeup control valve at a constant value selected by the operators. At the same time, the letdown control valve controls letdown flow to maintain reactor coolant system pressure at a constant value, also selected by the operators. These water solid operations are not required if vacuum fill is used.

After the reactor coolant pumps are started, chemical treatment, using an oxygen scavenger, is performed. The oxygen scavenger is added to the reactor coolant during the initial stages of heatup to scavenge oxygen in the system. Subsequently, hydrogen makeup to the reactor coolant system is started, and the reactor coolant system hydrogen level is brought up to the normal operating point of approximately 30 cubic centimeters per kilogram.

The pressurizer heaters are used to heat up the water in the pressurizer and draw a steam bubble. As the steam bubble grows, effluent continues to be diverted to the liquid radwaste system through the chemical and volume control system letdown line. The makeup pumps are operated to supply demineralized water, so the reactor coolant system boron concentration is reduced to the level required for criticality. Following attainment of pressurizer normal water level, the letdown flow control valve and the makeup pumps are set to operate only as necessary to maintain pressurizer level or on demand from the operator.

Criticality is achieved as follows:

- The reactor coolant system boron concentration is reduced to the calculated level by dilution, routing effluent from the chemical and volume control system purification loop to the liquid radwaste system, and by providing unborated makeup with the makeup pumps taking suction from the demineralized water storage tank.

- Chemical analysis is used to measure water quality, boron concentration, and hydrogen concentration.

- Appropriate control rods are withdrawn.

- Further adjustments in boron concentration are made to establish preferred control group rod positions.

9.3.6.4.2 Normal Operation

Normal operation consists of operation at steady power (base load) level, load follow operation, and hot standby.

9.3.6.4.2.1 Base Load Operation

At a constant power level, the chemical and volume control system purification loop operates continuously as a closed loop around a reactor coolant pump. The purification flow is approximately 100 gallons per minute with one mixed bed demineralizer and one reactor coolant filter in service. The chemical and volume control system makeup pumps and the letdown line to the liquid radwaste system are not normally operating. The makeup pumps are normally available and are set to start automatically on low pressurizer level. The boric acid blending valve in the pump suction permits the operator to preset the blend of boric acid and demineralized water to achieve the desired makeup concentration. The letdown control valve opens automatically, if the pressurizer level reaches its high (relative to programmed level) setpoint. Reactor coolant samples are taken to check boron and H_2 concentration, water quality, pH, and activity level.

Variations in power demand are accommodated automatically by control rod and gray rod movement. The only adjustments in boron concentration necessary are those to compensate for core burnup. These adjustments are made to maintain the rod control groups within their allowable limits by setting the makeup pumps to provide the required amount of demineralized water as makeup. If necessary, effluent is automatically routed to the liquid radwaste system to maintain the required pressurizer level.

9.3.6.4.2.2 Load Follow Operation

Load follow power changes and the resulting xenon changes are accommodated by the control rods and gray rods, with no changes required to the reactor coolant system boron concentration. The chemical and volume control system does not have load follow functions.

9.3.6.4.3 Plant Shutdown

9.3.6.4.3.1 Hot Shutdown

If required for periods of maintenance or following spurious reactor trips, the reactor is maintained subcritical, with the capability to return to full power within the period of time required to withdraw the control rods. During hot standby operation, the average temperature is maintained at no-load T_{avg} by initially dumping steam to the condenser to provide residual heat removal, or at later stages by running the reactor coolant pumps to maintain system temperature.

Initially the control rods are inserted and the core is maintained at or slightly above the minimum required shutdown margin. Following shutdown, xenon buildup occurs and increases the shutdown margin. The effect of xenon buildup increases the shutdown margin to a minimum of about 3 percent $\Delta k/k$ at about 9 hours following shutdown.

If rapid recovery is required, dilution of the system may be performed to counteract this xenon buildup. A shutdown group of rods is withdrawn during dilution to provide the capability for rapid shutdown if needed, and frequent checks are made on critical rod position.

9.3.6.4.3.2 Cold Shutdown

Cold shutdown is the operation that brings the reactor plant from normal operating temperature and pressure to a cold shutdown temperature and pressure for maintenance or refueling.

The chemical and volume control system purification loop continues to operate normally in advance of a planned shutdown. In addition, in the beginning of a shutdown, the chemical and volume control system is designed so the letdown flow is routed out of containment to the liquid radwaste system, where it is stripped of gases and returned to the makeup pump suction. This gas stripping is required for approximately 48 hours to reduce reactor coolant activity level and hydrogen level sufficiently, permitting personnel access for refueling or maintenance operations.

Before cooldown and depressurization of the reactor coolant system is initiated, the reactor coolant boron concentration is increased to the cold shutdown value. The operator sets the reactor makeup control to "borate" and selects the volume of boric acid solution necessary to perform the boration. Correct concentration is verified by reactor coolant samples. The operator sets the reactor makeup control for makeup at the shutdown reactor coolant boron concentration.

Contraction of the coolant during cooldown of the reactor coolant system results in actuation of the pressurizer level control system to maintain normal pressurizer water level. Makeup continues to be automatic, with the makeup pumps starting and stopping as required.

During shutdowns, after the reactor coolant pumps are stopped, the normal residual heat removal system provides the motive force for chemical and volume control system purification loop. Whenever the reactor coolant system is pressurized, the chemical and volume control system can be operated to provide purification. After the normal residual heat removal system is placed in service and the reactor coolant pumps are stopped, further cooling and depressurization of the pressurizer fluids are accomplished by charging through the auxiliary spray connection.

9.3.6.4.3.2.1 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media is spent and ready to be transferred to the solid radwaste system (WSS), the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidizes in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system. Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

9.3.6.4.3.2.2 Filter Cartridge Replacement

Replacement of spent filter cartridges is performed as described in subsection 11.4.2.3.2.

9.3.6.4.4 Abnormal Operation

9.3.6.4.4.1 Reactor Coolant System Leak

The chemical and volume control system is capable of making up for a small reactor coolant system leak with either makeup pump at reactor coolant system pressures above the low pressure setpoint.

9.3.6.4.5 Accident Operation

The chemical and volume control system can provide borated makeup to the reactor coolant system following accidents such as small loss-of-coolant accidents, steam generator tube rupture events, and small steam line breaks. In addition, pressurizer auxiliary spray can reduce reactor coolant system pressure during certain events such as a steam generator tube rupture.

To protect against steam generator overfill, the makeup function is isolated by closing the makeup line containment isolation valves, if a high steam generator level signal is generated. These valves also close and isolate the system on a high pressurizer level signal.

Some of the valves in the chemical and volume control system are required to operate under accident conditions to effect reactor coolant system pressure boundary and containment isolation, as discussed in subsection 9.3.6.3.7.

9.3.6.4.5.1 Boron Dilution Events

The chemical and volume control system is designed to address a boron dilution accident by closing either one of two redundant safety-related, air-operated valves from the demineralized water system to the makeup pump suction.

For dilution events occurring at power (assuming the operator takes no action), a reactor trip is initiated on either an overpower trip or an overtemperature ΔT trip. Following a reactor trip signal, the line from the demineralized water system is isolated by closing two safety-related, remotely operated valves. The three-way pump suction control valve aligns so the makeup pumps take suction from the boric acid tank. When the trip occurs while the makeup pumps are operating, the realignment of these valves causes the makeup pumps, if they continue to operate, to borate the plant.

For dilution events during shutdown, the source range flux doubling signal is used to isolate the line from the demineralized water system by closing the two safety-related, remotely operated valves. The three-way pump suction control valve aligns the makeup pumps to take suction from the boric acid tank and therefore stops the dilution. For refueling operations, administrative controls are used to prevent boron dilutions by verifying the valves in the line from the demineralized water system are closed and secured.

9.3.6.5 Design Evaluation

The chemical and volume control system has redundant, safety-related isolation valves and piping to protect the reactor coolant system pressure boundary, and is designed in accordance with ANSI/ANS-51.1 (Reference 4).

The chemical and volume control system lines that penetrate containment incorporate valve and piping arrangements, meeting the containment isolation criteria described in subsection 6.2.3.

Since the chemical and volume control system supplies unborated water to the reactor coolant system, the potential for inadvertent boron dilution events exists. A safety-related method of stopping an inadvertent boron dilution, which operates as described in subsection 9.3.6.4.5.1, is incorporated into the chemical and volume control system.

The chemical and volume control system also incorporates a safety-related method of isolating the makeup to the reactor coolant system upon receipt of a high steam generator level signal or a high pressurizer level signal, as described in subsection 9.3.6.4.5. Other chemical and volume control system components are not safety-related.

Chemical and volume control system components and piping are compatible with the radioactive fluids they contain or functions they perform.

The design of the chemical and volume control system is based on specific General Design Criteria and regulatory guides. The design of the chemical and volume control system is compared to the criteria set forth in subsection 9.3.4, "Chemical and Volume Control System (PWR) (Including Boron Recovery System)," Revision 2, of the Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan section are General Design Criteria 1, 2, 3, 4, 14, 29, 30, 31, 32, 33, 53, 54, 56, 60, and 61 as discussed in Section 3.1. Additionally, subsection 1.9.1 discusses compliance with Regulatory Guides 1.26 and 1.29.

9.3.6.6 Inspection and Testing Requirements

The only required surveillance are for containment and reactor coolant pressure boundary isolation valves and boron dilution mitigation valves. These valves are identified as active and are tested in accordance with the in-service test provisions provided in Table 3.9-16.

Other chemical and volume control system components are monitored for acceptable performance as follows:

- Mixed and cation bed demineralizer -- monitor for bed exhaustion by comparing reactor coolant system samples to samples taken at the outlet of the reactor coolant filter.
- Reactor coolant and makeup filters -- remotely monitor differential pressure with the installed gages and change the filter cartridges, or switch to the backup filter when high differential pressure is detected with the installed pressure gage.

Inspection of the various components is required in accordance with their safety class. The safety classification assignments can be found in Section 3.2.

9.3.6.6.1 Preoperational Inspection and Testing

Preoperational tests are conducted to verify proper operation of the chemical and volume control system. The preoperational tests include valve inspection and testing and flow testing.

9.3.6.6.1.1 Valve Inspection and Testing

The inspection requirements of the chemical and volume control system valves that constitute the reactor coolant pressure boundary are consistent with those identified in subsection 5.2.4. The inspection requirements of the chemical and volume control system valves that isolate the lines penetrating containment are consistent with those identified in Section 6.6.

9.3.6.6.1.2 Flow Testing

Each chemical and volume control system pump is tested to measure the flow rate from each makeup pump to the reactor coolant system. Testing will be performed with the pump suction aligned to the boric acid tank and the discharge aligned to the reactor coolant system. Testing will also be performed with the pump suction aligned to the boric acid tank and the discharge aligned to the pressurizer auxiliary spray. Flow will be measured using instrumentation in the pump discharge line. Testing will confirm that each pump provides at least 100 gallons per minute of makeup flow at normal reactor coolant system operating pressure. This is the minimum flow rate necessary to meet the chemical and volume control system functional requirement of providing makeup and pressurizer spray to support the functions described in subsection 9.3.6.4.4.1. Testing is performed to verify that the maximum makeup flow with both pumps operating is less than 200 gpm, as assumed in the boron dilution analyses presented in subsection 15.4.6. Testing is performed with both pumps operating and taking suction from the demineralized water system. The chemical and volume control system is aligned to the reactor coolant system at a pressure at or near atmospheric pressure.

9.3.6.6.1.3 Boric Acid Tank Inspection

Inspection of the boric acid tank will be performed to verify that the volume in the boric acid tank is sufficient to provide 70,000 gallons of borated makeup to the reactor coolant system. This volume of boric acid is required to meet the functional requirement of providing makeup to the reactor coolant system to support the functions described in subsection 9.3.6.4.4.

9.3.6.7 Instrumentation Requirements

Process control instrumentation is provided to acquire data concerning key parameters about the chemical and volume control system. The location of the instrumentation is shown on the chemical and volume control system piping and instrumentation diagram.

The instrumentation furnishes input signals for monitoring and/or alarming. Indications and/or alarms are provided in the main control room for the following parameters:

- Pressure and differential pressure
- Flow

- Temperature
- Water level

The instrumentation also supplies input signals for control purposes to maintain proper system operation and to prevent equipment damage. Some specific control functions are listed below:

- **Purification isolation** – To preserve the reactor coolant pressure boundary in the event of a break in the chemical and volume control system loop piping. The purification stop valves close automatically on a signal from the protection and safety monitoring system generated by a low-1 pressurizer level signal. This isolation also serves as an equipment protection function to prevent uncovering of the heater elements in the pressurizer. One of these valves also closes on high temperature downstream of the letdown heat exchanger, to protect the resin in the mixed bed and cation demineralizers from being exposed to temperatures that could damage the resins.

- **Containment isolation** – To preserve the containment boundary, containment isolation valves are provided in the letdown line to the liquid radwaste system, the chemical and volume control system makeup line, and the hydrogen addition line. These valves are opened or closed manually from the main control room and the remote shutdown workstation. Interlocks are provided to close these valves automatically upon receipt of a containment isolation signal from the protection and safety monitoring system and require operator action to reopen.

- **Letdown isolation valves** – The letdown isolation valves are used to isolate letdown flow to the liquid radwaste system in addition to the containment isolation function described above. The plant control system provides a signal to automatically open these valves on a high-pressurizer level signal derived from the pressurizer level control system. On a containment isolation signal from the protection and safety monitoring system, a high-high liquid radwaste system degassifier level signal (plant control system), or a low-pressurizer level signal (plant control system), these valves automatically close to provide isolation of the letdown line. The letdown isolation valves also receive a signal from the protection and safety monitoring system to automatically close and isolate letdown during midloop operations based on a low hot leg level. Manual control is provided from the main control room and at the remote shutdown workstation. The letdown flow control valve controls reactor coolant system pressure during startup, as described in subsection 9.3.6.4.1.

- **Demineralized water system isolation valves** – To prevent inadvertent boron dilution, the demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers, or a safety injection signal providing a safety-related method of stopping an inadvertent dilution. The main control room and remote shutdown workstation provide manual control for these valves.

- **Makeup isolation valves** – To isolate the makeup flow to the reactor coolant system, two valves are provided in the chemical and volume control system makeup line. These valves automatically close on a signal from the protection and safety monitoring system derived from either a high-2 pressurizer level, high steam generator level signal, or a safeguards signal coincident with high-1 pressurizer level to protect against pressurizer or steam generator overfill. Manual control for these valves is provided in the main control room and at the remote shutdown workstation. In addition, the valves close on a high-2 containment radiation signal to protect containment integrity.

- **Makeup flow control** – To control makeup flow to the reactor coolant system, a flow controller, which operates in the makeup line, in conjunction with the makeup control system is provided in the chemical and volume control system makeup pump discharge line. This flow controller controls makeup flow by modulating a flow control valve.

- **Makeup pump control** – The makeup pumps can be controlled from the main control room and at the remote shutdown workstation. On a signal from the plant control system generated by a low pressurizer level signal (relative to the programmed level), one of the chemical and volume control system makeup pumps starts automatically to provide makeup. The operating pump automatically stops when the pressurizer level increases to the correct value. During reactor coolant system boron changes (fuel depletion, startups, shutdowns, and refueling), the operator starts one of the makeup pumps after selecting the desired amount of boric acid.

  The makeup pumps can be used to provide reactor coolant system makeup following an accident such as a small loss-of-coolant accident, a steam generator tube rupture, or a small steam line break. Following a safeguards actuation signal, if necessary, the operator remotely opens the makeup line isolation valves. One makeup pump automatically starts to control the pressurizer level between 10 and 20 percent. In addition, a makeup pump may be used to provide pressurizer auxiliary spray in reducing the reactor coolant system pressure for certain accident scenarios.

9.3.7 Combined License Information

The Combined License applicant will address DCD1.9.4.2.3, Issue 43 as part of training and procedures identified in section 13.5.

9.3.8 References

1. Instrument Society of America Standards, "Quality Standard for Instrument Air," S7.3; 1981.

2. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Pressure Vessels," 1998 Edition, 2000 Addenda.

3. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Pressure Vessels," Subsection A, Part UG-99, Standard Hydrostatic Test, 1998.

4. ANSI/ANS-51.1-1983, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

5. Safety Evaluation by the Office of Nuclear Regulation Related to WCAP-14986, “Westinghouse Owners Group Post Accident Sampling System Requirements,” Westinghouse Owners Group Project No. 694, June 14, 2000.

6. NUREG 0800, Standard Review Plan Section 9.3.2 "Process and Post-Accident Sampling Systems."

Table 9.3.1-1 (Sheet 1 of 2)

SAFETY-RELATED AIR-OPERATED VALVES

Valve Number	Normal/Failure Position	Function
Compressed and Instrument Air System (CAS)		
CAS-PL-V014	NO/FC	Instrument Air Supply Outside Containment Isolation
Chemical and Volume Control System (CVS)		
CVS-PL-V045	NC/FC	Letdown Containment Isolation IRC
CVS-PL-V047	NC/FC	Letdown Containment Isolation ORC
CVS-PL-V084	NC/FC	Auxiliary Pressurizer Spray Line Isolation
CVS-PL-V092	NC/FC	Hydrogen Addition Containment Isolation
CVS-PL-V136A	NO/FC	Demineralized Water System Isolation
CVS-PL-V136B	NO/FC	Demineralized Water System Isolation
Passive Containment Cooling System (PCS)		
PCS-PL-V001A	NC/FO	Passive Containment Cooling Water Storage Tank Isolation
PCS-PL-V001B	NC/FO	Passive Containment Cooling Water Storage Tank Isolation
Primary Sampling System (PSS)		
PSS-PL-V011	NC/FC	Containment Isolation – Liquid Sample Line
PSS-PL-V023	NO/FC	Containment Isolation – Sample Return Line
PSS-PL-V046	NO/FC	Containment Isolation – Air Sample Line
Passive Core Cooling System (PXS)		
PXS-PL-V014A	NC/FO	Core Makeup Tank A Discharge Isolation
PXS-PL-V014B	NC/FO	Core Makeup Tank B Discharge Isolation
PXS-PL-V015A	NC/FO	Core Makeup Tank A Discharge Isolation
PXS-PL-V015B	NC/FO	Core Makeup Tank B Discharge Isolation
PXS-PL-V042	NO/FC	Nitrogen Supply Containment Isolation ORC
PXS-PL-V108A	NC/FO	Passive Residual Heat Removal Heat Exchanger Control
PXS-PL-V108B	NC/FO	Passive Residual Heat Removal Heat Exchanger Control
PXS-PL-V130A	NO/FC	In-Containment Refueling Water Storage Tank Gutter Isolation
PXS-PL-V130B	NO/FC	In-Containment Refueling Water Storage Tank Gutter Isolation

Table 9.3.1-1 (Sheet 2 of 2)

SAFETY-RELATED AIR-OPERATED VALVES

Valve Number	Normal/Failure Position	Function
Normal Residual Heat Removal System (RNS)		
RNS-PL-V061	NC/FC	Shutdown Purification Flow Isolation
RNS-PL-V057A	NO/FO	RNS Pump Miniflow Isolation
RNS-PL-V057B	NO/FO	RNS Pump Miniflow Isolation
Steam Generator System (SGS)		
SGS-PL-V036A	NO/FC	Steam Line Condensate Drain Isolation
SGS-PL-V036B	NO/FC	Steam Line Condensate Drain Isolation
SGS-PL-V074A	NO/FC	Steam Generator Blowdown Isolation
SGS-PL-V074B	NO/FC	Steam Generator Blowdown Isolation
SGS-PL-V075A	NO/FC	Steam Generator Series Blowdown Isolation
SGS-PL-V075B	NO/FC	Steam Generator Series Blowdown Isolation
SGS-PL-V086A	NC/FC	Steam Line Condensate Drain Control
SGS-PL-V086B	NC/FC	Steam Line Condensate Drain Control
SGS-PL-V233A	NC/FC	Power Operated Relief Valve
SGS-PL-V233B	NC/FC	Power Operated Relief Valve
SGS-PL-V240A	NO/FC	Main Steam Isolation Valve Bypass Isolation
SGS-PL-V240B	NO/FC	Main Steam Isolation Valve Bypass Isolation
SGS-PL-V250A	NO/FC	Main Feedwater Control
SGS-PL-V250B	NO/FC	Main Feedwater Control
SGS-PL-V255A	NC/FC	Startup Feedwater Control
SGS-PL-V255B	NC/FC	Startup Feedwater Control
Main Control Room Emergency Habitability System (VES)		
VES-PL-V022A	NC/FO	Relief Isolation Valve A
VES-PL-V022B	NC/FO	Relief Isolation Valve B
Containment Air Filtration System (VFS)		
VFS-PL-V003	NC/FC	Containment Purge Inlet Containment Isolation Valve
VFS-PL-V004	NC/FC	Containment Purge Inlet Containment Isolation Valve
VFS-PL-V009	NC/FC	Containment Purge Discharge Containment Isolation Valve
VFS-PL-V010	NC/FC	Containment Purge Discharge Containment Isolation Valve
Liquid Radwaste System (WLS)		
WLS-PL-V055	NC/FC	Sump Discharge Containment Isolation IRC
WLS-PL-V057	NC/FC	Sump Discharge Containment Isolation ORC
WLS-PL-V067	NC/FC	Reactor Coolant Drain Tank Gas Outlet Containment Isolation IRC
WLS-PL-V068	NC/FC	Reactor Coolant Drain Tank Gas Outlet Containment Isolation ORC

Table 9.3.1-2

NOMINAL COMPONENT DESIGN DATA - INSTRUMENT AIR SUBSYSTEM

Air Compressors

Quantity	2
Type	Rotary
Capacity, each (scfm)	800
Design pressure (psig)	150

Air Receivers

Quantity	2
Capacity, each (ft^3)	672
Design pressure (psig)	150

Prefilters

Quantity	2
Type	Coalescing

Air Dryers

Quantity	2
Type	Desiccant/Purge Air Regenerative
Capacity, each (scfm)	800
Operating pressure dew point, maximum (°F)	-28

Afterfilters

Quantity	2
Type	Particulate

Table 9.3.1-3

NOMINAL COMPONENT DESIGN DATA - SERVICE AIR SUBSYSTEM

Air Compressor

Quantity 2
Type .... Rotary
Capacity, each (scfm) 800
Design pressure (psig) 150

Air Receiver

Quantity 1
Capacity (ft^3) 672
Design pressure (psig) 150

Prefilters

Quantity 2
Type .... Coalescing

Air Dryer

Quantity 2
Type .... Desiccant/Purge Air Regenerative
Capacity, each (scfm) 800
Design pressure dew point, maximum (°F) .... -28

Afterfilters

Quantity 2
Type .... Particulate

Table 9.3.1-4

NOMINAL COMPONENT DESIGN DATA - HIGH-PRESSURE AIR SUBSYSTEM

Air Compressor

Quantity 1
Type .... Reciprocating
Capacity (scfm) 60
Design pressure (psig) 5000

Breathing Air Purifier

Quantity 1
Type .... Molecular Sieve/Activated Carbon
CO to CO_2 conversion .... Catalysis
Air supply quality level .... E

Air Receiver

Quantity 1
Capacity, water volume (ft^3) 46
Design pressure (psig) 4000

Table 9.3.3-1

PRIMARY SAMPLING SYSTEM SAMPLE POINTS - NORMAL PLANT OPERATIONS (LIQUID AND GASEOUS)

Sample Point Name	Type of Sample[(a)]
Liquid Sample	
1. RCS Hot Leg (before CVS demineralizer)	Grab
2. Pressurizer Liquid Space	Grab
3. CVS Demineralizer Downstream	Grab
4. PXS Accumulators	Grab
5. PXS Core Makeup Tanks (at top)	Grab
6. PXS Core Makeup Tanks (at bottom)	Grab
7. Containment Sump (pump discharge)	Grab
Gaseous Sample	Grab
8. Containment Air	Grab

Note:

a. This column shows methods to obtain a sample for chemical analysis. It does not specify the frequency of sampling nor does it specify actual location of sample collection. "Grab" means that a grab sample is required for the intended chemical analysis. Depending on the sampling condition, this grab sample can be obtained in the laboratory or in the grab sampling unit.

Table 9.3.3-2 (Sheet 1 of 4)

LOCAL SAMPLE POINT NOT IN THE PRIMARY SAMPLING SYSTEM (NORMAL PLANT OPERATIONS)

Sample Point Name	Available Number of Points	Type of Sample[a]	Process Measurement
Liquid Sample			
1. CVS boric acid tank	1	Grab	pH, chlorine, fluorine, boron, silica, suspended solids, radioisotopic liquid, oxygen
2. CVS boric acid batching tank	1	Grab	Boron, chlorine, fluorine
3. Residual heat removal heat exchanger	2	Grab	Radioisotopic liquid, suspended solids, radioisotopic gas, gross specific activity, strontium, iron, tritium, hydrogen, I-131, conductivity, pH, oxygen, chlorine, fluorine, boron, aluminum, silica, lithium radio-isotopic liquid, lithium radioisotopic particulate, magnesium, sulfate, calcium, lithium
4. PXS IRWST	1	Grab	pH, Oxygen, fluorine, boron, conductivity, gross specific activity, sodium, sulfate, silica
5. Main Steam Line (Outlet SG 1)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
6. Main Steam Line (Outlet SG 2)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
7. BDS steam generator blowdown	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
8. SFS purification (Upstream & downstream of SFS ion exchangers) (spent fuel pool treatment)	2	Grab	Conductivity, pH, chloride, silica, corrosion product metals, gross activity, corrosion product activity, fission product activity, I-131, tritium, turbidity, boron, corrosion product metals, organic impurities
9. PCS water storage tank	1	Grab	Hydrogen peroxide
10. Reactor Coolant drain tank	1	Grab	Gross radioactivity and identification and concentration of principal radionuclide and alpha emitters. Dissolved gases.

Table 9.3.3-2 (Sheet 2 of 4)

LOCAL SAMPLE POINT NOT IN THE PRIMARY SAMPLING SYSTEM (NORMAL PLANT OPERATIONS)

Sample Point Name	Available Number of Points	Type of Sample[(a)]	Process Measurement
11. WLS degasifier (downstream of degasifier discharge pump)	1	Grab	Dissolved gases
12. CCS component cooling surge tank	1	Grab	pH, sodium, chloride, silica, corrosion product metals, corrosion inhibitors
13. CCS loops (downstream of CCS pumps)	2	Grab	pH, sodium, chloride, silica, corrosion product metals, tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
14. CCS hot leg (upstream of CCS pumps)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
15. WLS discharge (liquid radwaste effluent)	2	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
16. WLS effluent holdup tanks MT05A, B	2	Grab	Gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
17. WLS waste holdup tanks MT06A, B	2	Grab	Gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
18. WLS monitor tanks MT07A, B, C	3	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters. State and federal environmental discharge requirements such as pH, suspended solids, oil and grease, iron, copper, sodium nitrite
19. WLS ion exchanger pre-filter (downstream)	1	Grab	Suspended solids
20. WLS ion exchanger after-filter (downstream)	1	Grab	Suspended solids

Table 9.3.3-2 (Sheet 3 of 4)

LOCAL SAMPLE POINT NOT IN THE PRIMARY SAMPLING SYSTEM (NORMAL PLANT OPERATIONS)

Sample Point Name	Available Number of Points	Type of Sample[(a)]	Process Measurement
21. WLS chemical waste tank	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
22. WSS spent resin tank (liquid)	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
23. SWS blowdown (service water)	1 1	Continuous Grab	Radiation monitor (See Section 11.5, Table 11.5-1) Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
24. WWS turbine building drain tank	2	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
25. CPS (secondary coolant) spent resin sluice line (liquid)	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
Gaseous Sample			
26. VES MCR emergency air supply headers	2	Grab	Air quality, oxygen, carbon monoxide, carbon dioxide, contaminants
27. WGS effluent discharge to environment	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
28. WGS inlet	1	Continuous	Oxygen, hydrogen, moisture
29. WGS carbon bed vault	1	Continuous	Hydrogen
30. WGS delay bed outlets MV02A, B (waste gas holdup)	2	Grab	Moisture, noble gases, iodine, particulates, tritium
31. Condenser air removal system[(b)] (including hogging)	1	Grab	Iodine, noble gases, tritium

Table 9.3.3-2 (Sheet 4 of 4)

LOCAL SAMPLE POINT NOT IN THE PRIMARY SAMPLING SYSTEM (NORMAL PLANT OPERATIONS)

Sample Point Name	Available Number of Points	Type of Sample[(a)]	Process Measurement
32. Gland seal system[(b)]	1	Grab	Iodine, noble gases, tritium
33. Plant vent (including containment purge, auxiliary building ventilation, fuel storage and radwaste area ventilation discharge)	1	Continuous & Grab[(c)]	Iodine, noble gases, particulates

Notes:

a. This column shows methods to obtain a sample for analysis. "Grab" means that a grab sample is required for the intended analysis. Depending on the sampling condition, this grab sample can be obtained in the laboratory or in the grab sampling unit. "Continuous" means that the required analysis is performed via a probe that monitors the sampling steam continuously.

b. Continuous monitoring of discharge for radiation provided in turbine island vent (See Section 11.5, Table 11.5-1).

c. Includes analysis for tritium.

Table 9.3.4-1 (Sheet 1 of 2)

SECONDARY SAMPLING SYSTEM
(CONTINUOUS MEASUREMENTS)

Continuous Sample Points	Process Measurements
Hotwell (Tube Bundle Condenser Shell A)	Specific Conductivity Sodium
Hotwell (Tube Bundle Condenser Shell B)	Specific Conductivity Sodium
Hotwell (Tube Bundle Condenser Shell C)	Specific Conductivity Sodium
Condensate Pump Discharge	Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen
Deaerator Inlet (Condensate)	Specific Conductivity Cation Conductivity Sodium pH Oxygen Scavenger Residual Dissolved Oxygen
Feedwater	Specific Conductivity Cation Conductivity Sodium Dissolved Oxygen pH Oxygen Scavenger Residual
Steam Generator Blowdown (SG 1)	Specific Conductivity Cation Conductivity Sodium pH Sulfate Dissolved Oxygen
Steam Generator Blowdown (SG 2)	Specific Conductivity Cation Conductivity Sodium pH Sulfate Dissolved Oxygen

Table 9.3.4-1 (Sheet 2 of 2)

SECONDARY SAMPLING SYSTEM
(CONTINUOUS MEASUREMENTS)

Main Steam System (SG 1)	Cation Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen
Main Steam System (SG 2)	Cation Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen

Table 9.3.4-2

SECONDARY SAMPLING SYSTEM
(SELECTIVE MEASUREMENTS)

Condenser Tube Bundle B (North Side)
Condenser Tube Bundle B (South Side)
Heater Drain (LP Heater 1A)
Heater Drain (LP Heater 1B)
Heater Drain (MSR-A Tube Drain)
Heater Drain (MSR-A Shell Drain)
Auxiliary Steam
Auxiliary Boiler Feedwater
Auxiliary Boiler Drum
Auxiliary Boiler Condensate
Condensate Polisher Outlet
Heater Drain (Heater 6)
Deaerator Outlet (Feedwater)
Startup Feedwater

Table 9.3.5-1

COMPONENT DATA - RADIOACTIVE WASTE DRAINS SYSTEM (NOMINAL VALUES)

Drain Sump	
Capacity (gal)	1400
Design pressure	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Drain Sump Pumps	
Quantity per sump	2
Design flow rate (gpm)	125
Pump type	Pneumatic double diaphragm
Material	Stainless steel

Table 9.3.6-1

NOMINAL CHEMICAL AND VOLUME CONTROL SYSTEM PARAMETERS

Purification flow rate (gpm)	100[a]
Normal boration flow rate (gpm)	100
Normal dilution flow rate (gpm)	100
Temperature of reactor coolant entering chemical and volume control system (assumed) (°F)	537
Expected life of demineralizer resin	1 fuel cycle
Normal temperature of effluent to liquid radwaste system (°F)	130
Flow rate to liquid radwaste system (gpm)	100

Note:
a. Volumetric flow rates are based on 130°F and 2300 psia.

Table 9.3.6-2 (Sheet 1 of 3)

CHEMICAL AND VOLUME CONTROL SYSTEM
NOMINAL EQUIPMENT DESIGN PARAMETERS

Pumps

Makeup Pumps

Number	2
Type	Multistage horizontal centrifugal
Design pressure (psig)	3,100
Design flow (gpm)	140
Material	Stainless Steel (SS)

Heat Exchangers

Regenerative Heat Exchanger

Number	1
Type	Counterflow

	Shell Side	Tube Side
Design pressure (psig)	3,100	3,100
Design temperature (°F)	600	650
Design flow (lb/hr)	41,580	49,710
Material	SS	SS

Letdown Heat Exchanger

Number	1
Type	U-Tube

	Shell Side	Tube Side
Design pressure (psig)	150	3,100
Design temperature (°F)	200	650
Design flow (lb/hr)	224,034	49,710
Material	Carbon Steel	SS

Table 9.3.6-2 (Sheet 2 of 3)

CHEMICAL AND VOLUME CONTROL SYSTEM
NOMINAL EQUIPMENT DESIGN PARAMETERS

Demineralizers

Mixed Bed Demineralizer

Number	2
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	100
Resin volume (ft^3)	50
Material	SS
Resin type	Mixed Bed Li7OH Form

Cation Bed Demineralizer

Number	1
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	100
Resin volume (ft^3)	50
Material	SS
Resin type	Cation H+ Form

Table 9.3.6-2 (Sheet 3 of 3)

CHEMICAL AND VOLUME CONTROL SYSTEM
NOMINAL EQUIPMENT DESIGN PARAMETERS

Filter

Reactor Coolant Filter

Number	2
Type	Disposable Cartridge
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	100
Dp at design flow (psi)	10

Tank

Boric Acid Tank

Number	1
Volume (gal)	70,000
Type	Cylindrical
Design pressure (psig)	Atmospheric
Design temperature (°F)	200
Material	SS

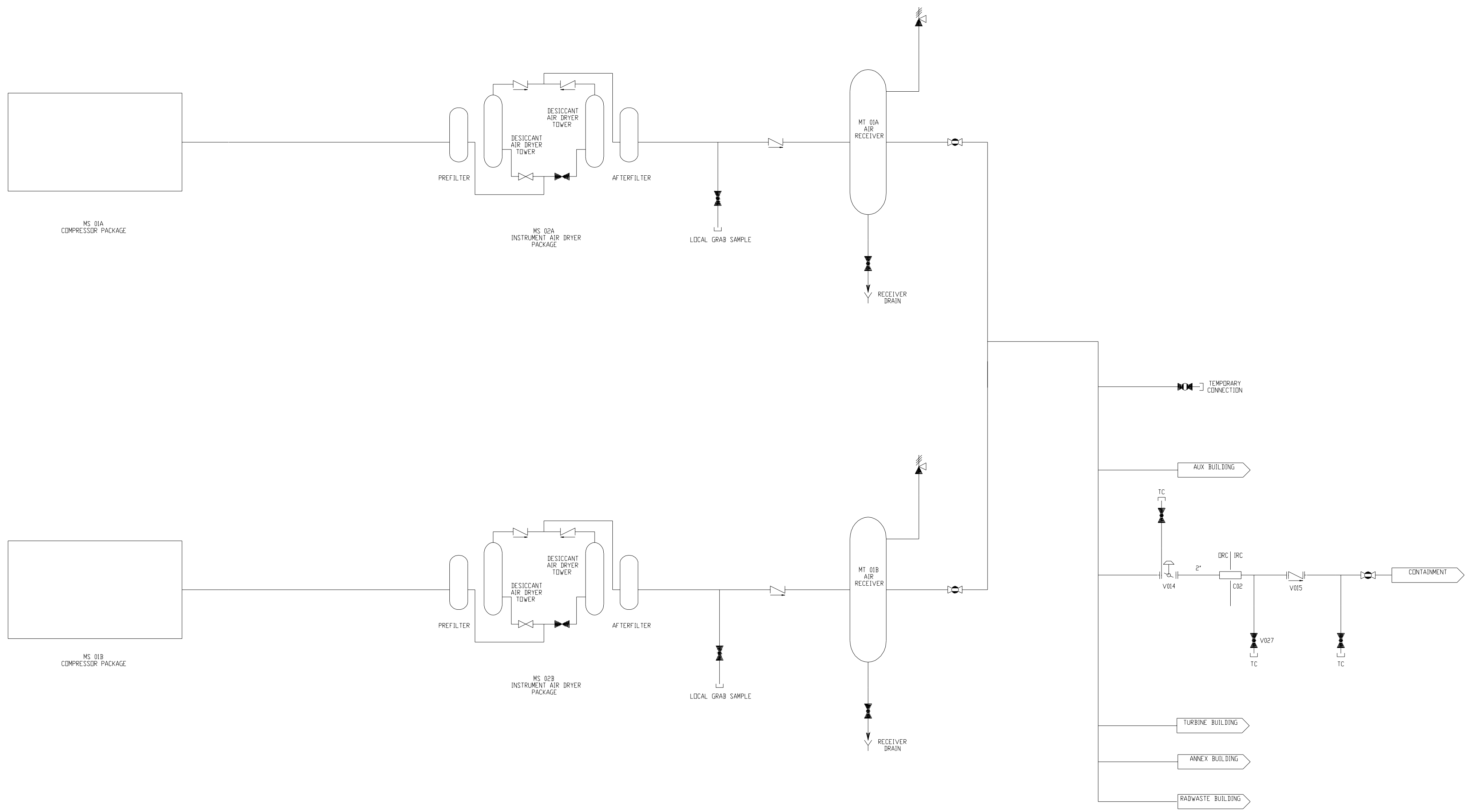


Figure 9.3.1-1 (Sheet 1 of 3)

Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 001 & 005)

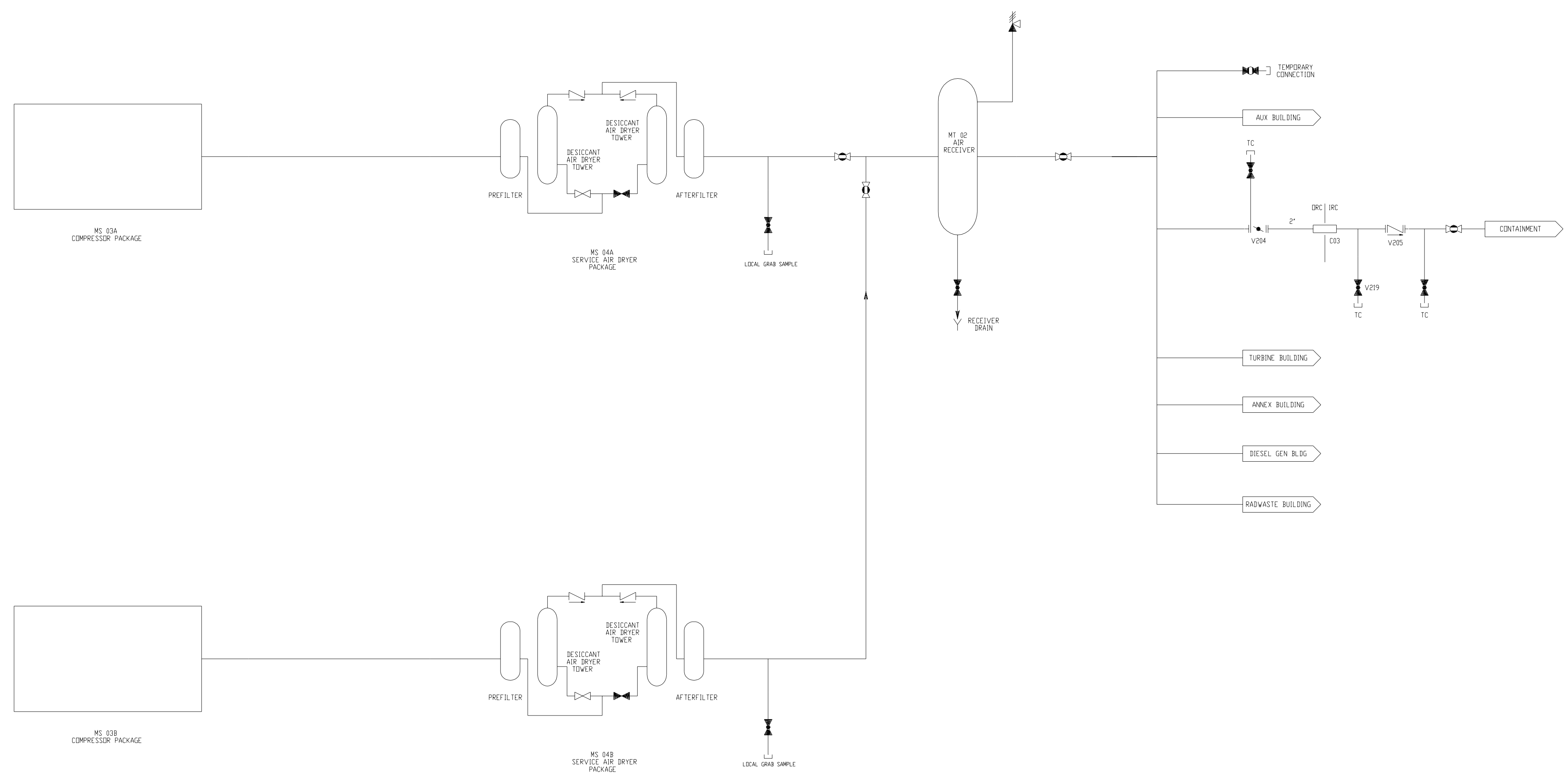


Figure 9.3.1-1 (Sheet 2 of 3)

Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 008 & 012)

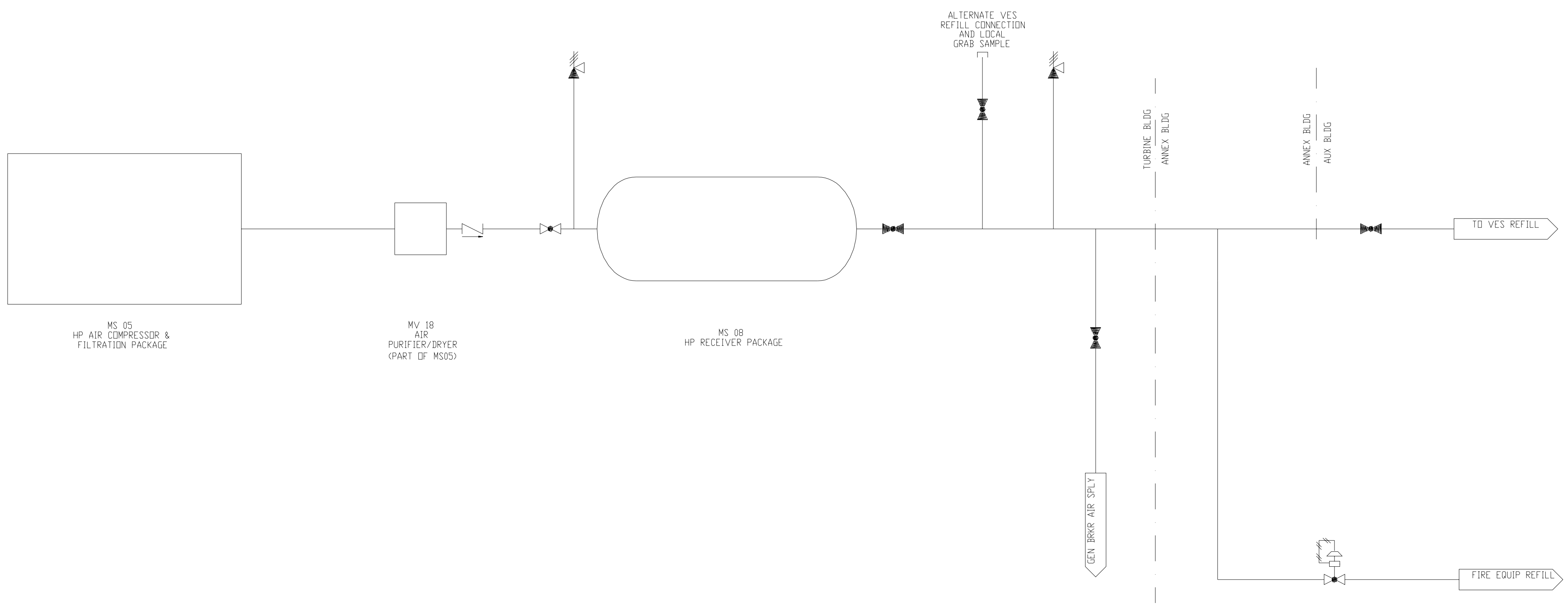


Figure 9.3.1-1 (Sheet 3 of 3)

Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 015)

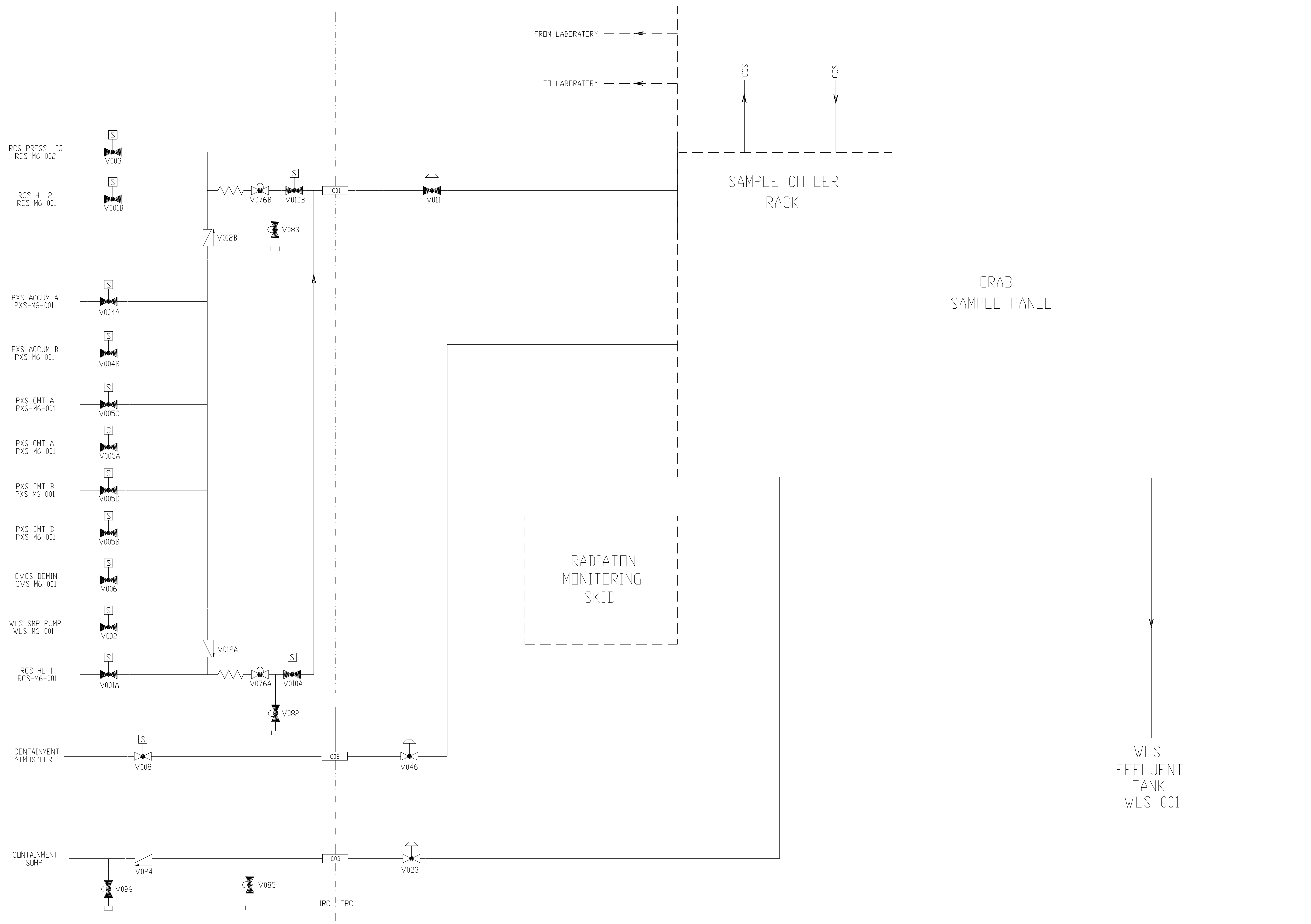


Figure 9.3.3-1

Simplified Sketch of the Primary Sampling System
(REF PSS 001)

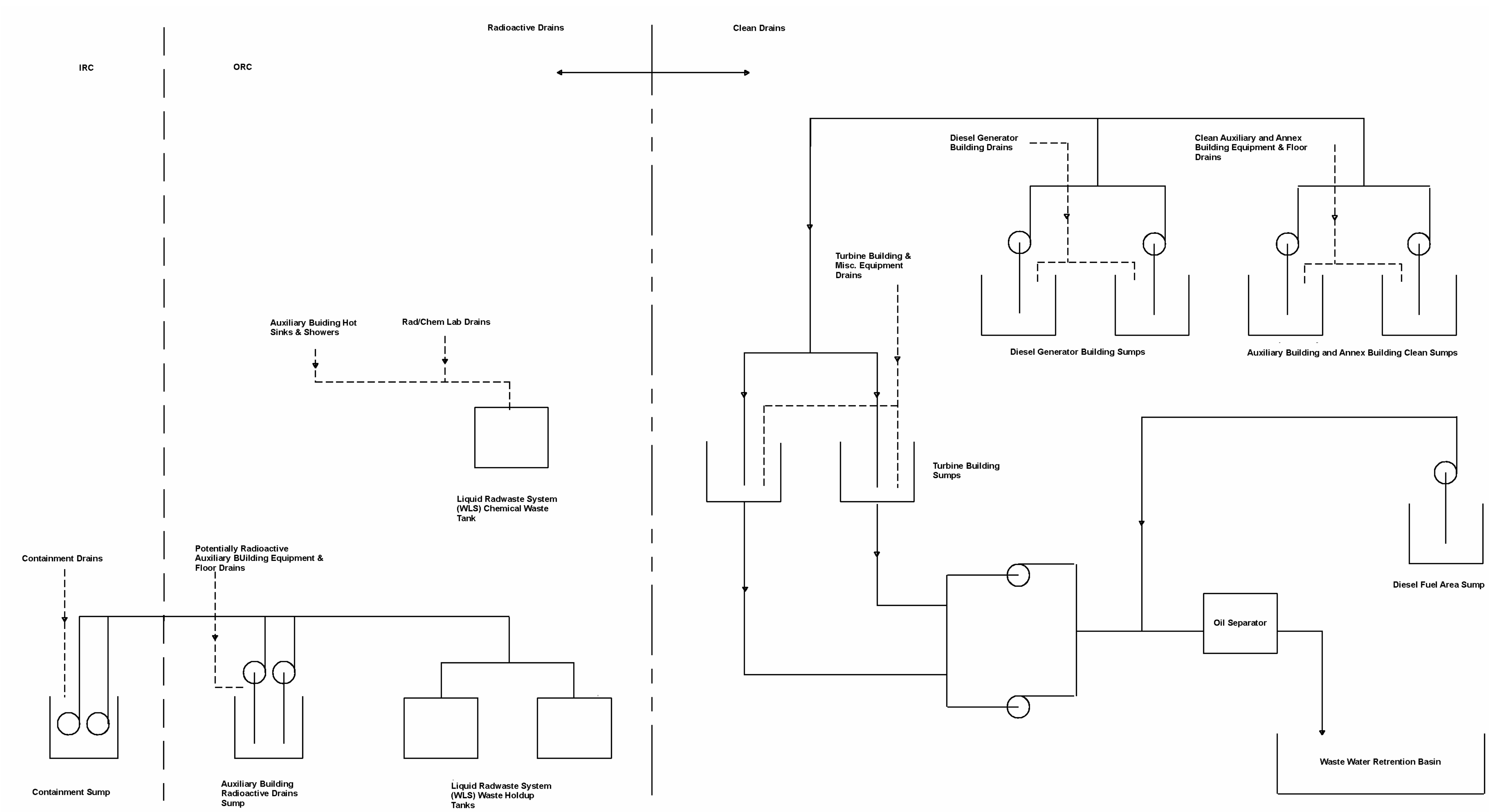


Figure 9.3.5-1

General Arrangement of Drainage Systems

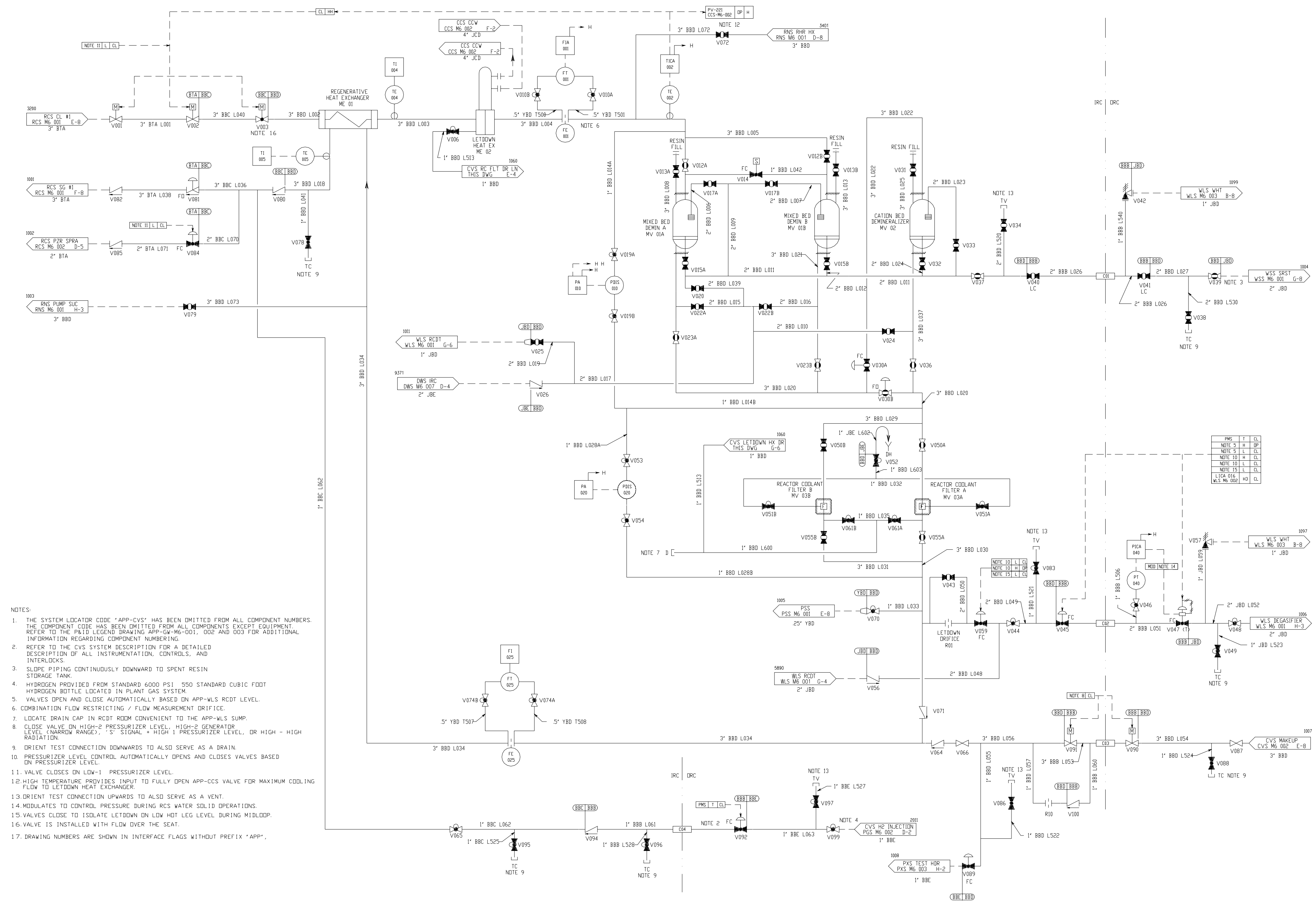


Figure 9.3.6-1 (Sheet 1 of 2)

Chemical and Volume Control System Piping and Instrumentation Diagram

(REF) CVS 001

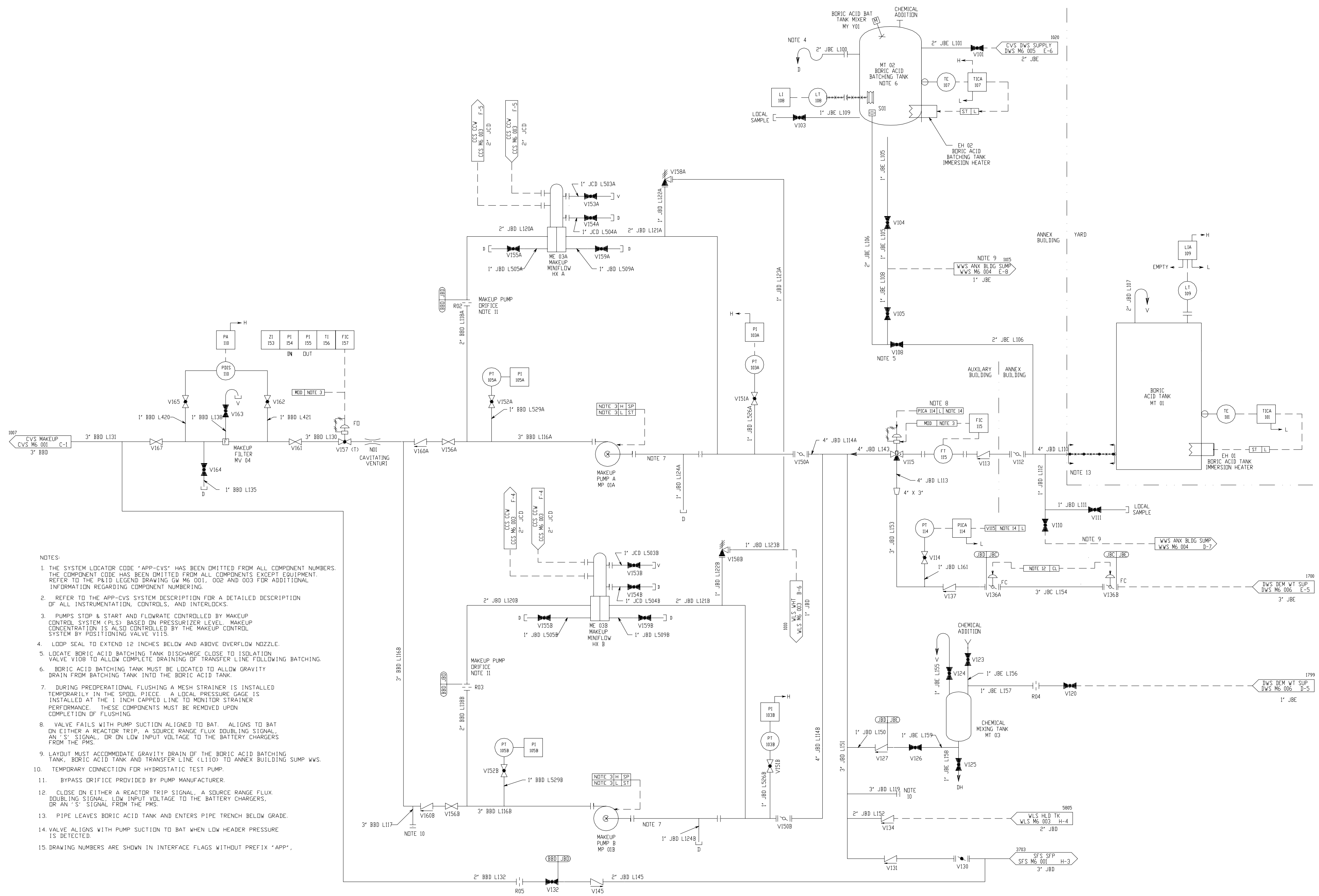


Figure 9.3.6-1 (Sheet 2 of 2)

Chemical and Volume Control System Piping and Instrumentation Diagram (REF) CVS 002

9.4 Air-Conditioning, Heating, Cooling, and Ventilation System

The air-conditioning, heating, cooling, and ventilation system is comprised of the following systems that serve the various buildings and structures of the plant:

- Nuclear island nonradioactive ventilation system (subsection 9.4.1)
- Annex/auxiliary buildings nonradioactive HVAC system (subsection 9.4.2)
- Radiologically controlled area ventilation system (subsection 9.4.3)
- Containment recirculation cooling system (subsection 9.4.6)
- Containment air filtration system (subsection 9.4.7)
- Radwaste building HVAC system (subsection 9.4.8)
- Turbine building ventilation system (subsection 9.4.9)
- Diesel generator building heating and ventilation system (subsection 9.4.10)
- Health physics and hot machine shop HVAC system (subsection 9.4.11)

9.4.1 Nuclear Island Nonradioactive Ventilation System

The nuclear island nonradioactive ventilation system (VBS) serves the main control room (MCR), technical support center (TSC), Class 1E dc equipment rooms, Class 1E instrumentation and control (I&C) rooms, Class 1E electrical penetration rooms, Class 1E battery rooms, remote shutdown room, reactor coolant pump trip switchgear rooms, adjacent corridors, and the passive containment cooling system (PCS) valve room during normal plant operation.

The main control room emergency habitability system provides main control room habitability in the event of a design basis accident (DBA) and is described in Section 6.4.

9.4.1.1 Design Basis

9.4.1.1.1 Safety Design Basis

The nuclear island nonradioactive ventilation system provides the following nuclear safety-related design basis functions:

- Monitors the main control room supply air for radioactive particulate and iodine concentrations

- Isolates the HVAC penetrations in the main control room boundary on high-high particulate or iodine concentrations in the main control room supply air or on extended loss of ac power to support operation of the main control room emergency habitability system as described in Section 6.4

Those portions of the nuclear island nonradioactive ventilation system which penetrate the main control room envelope are safety-related and designed as seismic Category I to provide isolation of the main control room envelope from the surrounding areas and outside environment in the event of a design basis accident. Other functions of the system are nonsafety-related. HVAC equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is

nonsafety-related and nonseismic. The equipment is procured to meet the environmental qualifications used in standard building practice.

The nuclear island nonradioactive ventilation system is designed to control the radiological habitability in the main control room within the guidelines presented in Standard Review Plan (SRP) 6.4 and NUREG 0696 (Reference 1), if the system is operable and ac power is available.

Portions of the system that provide the defense-in-depth function of filtration of main control room/technical support center air during conditions of abnormal airborne radioactivity are designed, constructed, and tested to conform with Generic Issue B-36, as described in Section 1.9 and Regulatory Guide 1.140 (Reference 30), as described in Appendix 1A, and the applicable portions of ASME AG-1 (Reference 36), ASME N509 (Reference 2), and ASME N510 (Reference 3).

Power to the ancillary fans to provide post-72-hour ventilation of the control room and I&C rooms is supplied from divisions B and C regulating transformers through two series fuses for isolation. The fuses protect the regulating transformers from failures of the non-1E fan circuits. When normal ventilation is available the ancillary fan circuits are disconnected from the supply with manual normally-open switches.

The nuclear island nonradioactive ventilation system is designed to provide a reliable source of heating, ventilation, and cooling to the areas served when ac power is available. The system equipment and component functional capabilities are to minimize the potential for actuation of the main control room emergency habitability system or the potential reliance on passive equipment cooling. This is achieved through the use of redundant equipment and components that are connected to standby onsite ac power sources.

9.4.1.1.2 Power Generation Design Basis

Main Control Room/Technical Support Center Areas

The nuclear island nonradioactive ventilation system provides the following specific functions:

- Controls the main control room and technical support center relative humidity between 25 to 60 percent

- Maintains the main control room and technical support center areas at a slightly positive pressure with respect to the adjacent rooms and outside environment during normal operations to prevent infiltration of unmonitored air into the main control room and technical support center areas

- Isolates the main control room and/or technical support center area from the normal outdoor air intake and provides filtered outdoor air to pressurize the main control room and technical support center areas to a positive pressure of at least 1/8 inch wg when a high gaseous radioactivity concentration is detected in the main control room supply air duct

- Isolates the main control room and/or technical support center area from the normal outdoor air intake and provides 100 percent recirculation air to the main control room and technical support center areas when a high concentration of smoke is detected in the outside air intake

- Provides smoke removal capability for the main control room and technical support center areas

- Maintains the main control room emergency habitability system passive cooling heat sink below its initial design ambient air temperature limit of 75°F

- Maintains the main control room/technical support center carbon dioxide levels below 0.5 percent concentration and the air quality within the guidelines of Table 1 and Appendix C, Table C-1 of Reference 32.

The background noise level in the main control room does not exceed 65 dB(A) when the VBS is operating.

The system maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2-1:

Area	**Temperature (°F)**
Main control room	67 - 75
Technical support center	67 - 78

Class 1E Electrical Rooms/Remote Shutdown Room

The nuclear island nonradioactive ventilation system provides the following specific functions:

- Exhausts air from the Class 1E battery rooms to limit the concentration of hydrogen gas to less than 2 percent by volume in accordance with Regulatory Guide 1.128 (Reference 31).

- Maintains the Class 1E electrical room emergency passive cooling heat sink below its initial design ambient air temperature limit of 75°F

- Provides smoke removal capability for the Class 1E electrical equipment rooms and battery rooms

The background noise level in the remote shutdown room does not exceed 65 dB(A) when the VBS is operating.

The system maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2-1:

Area	Temperature (°F)
Class 1E battery rooms	67 - 73
Class 1E dc equipment rooms	67 - 73
Class 1E electrical penetration rooms	67 - 73
Class 1E instrumentation and control rooms	67 - 73
Corridors	67 - 73
Remote shutdown room	67 - 73
Reactor coolant pump trip switchgear rooms	67 - 73
HVAC equipment rooms	50 - 85

Passive Containment Cooling System Valve Room

The subsystem maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2-1:

Area	Temperature (°F)
Passive containment cooling system valve room	50 - 120

Post-72-Hour Design Basis

Main Control Room

The specific function of the nuclear island nonradioactive ventilation system is to maintain the control room below a temperature approximately 4.5°F above the average outdoor air temperature.

Divisions B and C Instrumentation and Control Rooms Design Basis

The specific function of the nuclear island nonradioactive ventilation system is to maintain the I&C rooms below the qualification temperature of the I&C equipment.

9.4.1.2 System Description

The nuclear island nonradioactive ventilation system is shown in Figure 9.4.1-1. The system consists of the following independent subsystems:

- Main control room/technical support center HVAC subsystem
- Class 1E electrical room HVAC subsystem
- Passive containment cooling system valve room heating and ventilation subsystem

9.4.1.2.1 General Description

9.4.1.2.1.1 Main Control Room/Technical Support Center HVAC Subsystem

The main control room/technical support center HVAC subsystem serves the main control room and technical support center areas with two 100 percent capacity supply air handling units, return/exhaust air fans, supplemental air filtration units, associated dampers, instrumentation and controls, and common ductwork. The supply air handling units and return/exhaust air fans are connected to common ductwork which distributes air to the main control room and technical support center areas. The main control room envelope consists of the main control room, shift supervisor office, tagging room, toilet, clerk room, and kitchen/operator area. The technical support center areas consist of the main technical support center operations area, conference rooms, NRC room, computer rooms, shift turnover room, kitchen/rest area, and restrooms. The main control room and technical support center toilets have separate exhaust fans.

Outside supply air is provided to the plant areas served by the main control room/technical support center HVAC subsystem through an outside air intake duct that is protected by an intake enclosure located on the roof of the auxiliary building at elevation 153′-0″. The outside air intake duct is located more than 50 feet below and more than 100 feet laterally away from the plant vent discharge. The supply, return, and toilet exhaust are the only HVAC penetrations in the main control room envelope and include redundant safety-related seismic Category I isolation valves that are physically located within the main control room envelope. Redundant safety-related radiation monitors are located inside the main control room upstream of the supply air isolation valves. These monitors initiate operation of the nonsafety-related supplemental air filtration units on high gaseous radioactivity concentrations and isolate the main control room from the nuclear island nonradioactive ventilation system on high-high particulate or iodine radioactivity concentrations. See Section 11.5 for a description of the main control room supply air radiation monitors.

Both redundant trains of supplemental air filtration units and one train of the supply air handling unit are located in the main control room mechanical equipment room at elevation 135′-3″ in the auxiliary building. The other supply air handling unit subsystem is located in the main control room mechanical equipment room at elevation 135′-3″ in the annex building. The main control room toilet exhaust fan is located at elevation 135′-3″ in the auxiliary building. A humidifier is provided for each supply air handling unit. The supply air handling unit cooling coils are provided with chilled water from air-cooled chillers in the central chilled water system. See subsection 9.2.7 for the chilled water system description.

The main control room/technical support center HVAC subsystem is designed so that smoke, hot gases, and fire suppressant will not migrate from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Fire or combination fire and smoke dampers are provided to isolate each fire area from adjacent fire areas during and following a fire in accordance with NFPA 90A (Reference 27) requirements. These combination smoke/fire dampers close in response to smoke detector signals or in response to the heat from a fire. See Appendix 9A for identification of fire areas.

No silicone sealant or other patching material is used on the main control room/technical support center HVAC subsystem filters, housing, mounting frame, ducts or penetrations.

9.4.1.2.1.2 Class 1E Electrical Room HVAC Subsystem

The Class 1E electrical room HVAC subsystem serves the Class 1E electrical rooms, Class 1E instrumentation and control (I&C) rooms, Class 1E electrical penetration rooms, Class 1E battery rooms, spare Class 1E battery room, remote shutdown room, and reactor coolant pump trip switchgear rooms. The A and C electrical divisions, spare battery room, and reactor coolant pump trip switchgear rooms are served by one ventilation subsystem; the B and D electrical divisions and remote shutdown room are served by a second ventilation subsystem.

Each subsystem consists of two 100 percent capacity supply air handling units, return/exhaust air fans, associated dampers, controls and instrumentation, and common ductwork. The supply air handling units and return/exhaust air fans are connected to a common ductwork which distributes air to the Class 1E electrical rooms. The outside supply air intake enclosure for the A and C subsystem is common to the main control room/technical support center intake located on the roof of the auxiliary building at elevation 153′-0″. The outside supply air intake for the B and D subsystem is located separate from the main control room/technical support center air intake enclosure on the auxiliary building roof at elevation 153′-0″. The exhaust ducts from the battery rooms are connected to the turbine building vent to remove hydrogen gas generated by the batteries.

The HVAC equipment which serves the A and C electrical divisions is located in the nuclear island nonradioactive ventilation system main control room/A and C equipment room at elevation 135′-3″ in the auxiliary building. The HVAC equipment which serves the B and D division of Class 1E electrical equipment is located in the upper and lower nuclear island nonradioactive ventilation system B and D equipment rooms at elevation 117′-0″ and at elevation 135′-3″.

The supply air handling unit cooling coils are provided with chilled water from the air-cooled chillers in the central chilled water system. The two air handling units for each set of electrical divisions are provided with chilled water from redundant air-cooled chillers. Refer to subsection 9.2.7 for the chilled water system description.

Each subsystem for the Class 1E battery rooms is provided with two 100 percent capacity exhaust fans.

The Class 1E electrical room HVAC subsystem is designed so that smoke, hot gases, and fire suppressant does not migrate from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Separate ventilation subsystems are provided to serve the electrical division A and C equipment rooms and the electrical division B and D equipment rooms. The use of separate HVAC distribution subsystems for the redundant trains of electrical equipment prevents smoke and hot gases from migrating from one distribution division to the other through the ventilation system ducts. In addition, combination fire-smoke dampers are provided for Class 1E equipment rooms, including the remote shutdown room, to isolate each fire area and block the migration of smoke and hot gases to or from adjacent fire areas

in accordance with NFPA 90A requirements. These combination fire/smoke dampers close in response to smoke detector signals or in response to the heat from a fire. During a fire, the pressure difference across the doors in the stairwells S01 and S02 is maintained in accordance with the guidance of NFPA 92A (Reference 33) by dedicated stairwell pressurization fans. See Appendix 9A for identification of fire areas.

9.4.1.2.1.3 Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem

The passive containment cooling system valve room heating and ventilation subsystem serves the passive containment cooling system valve room.

The subsystem consists of one 100 percent ventilating fan, two 100 percent capacity electric unit heaters, associated dampers, controls and instrumentation. The passive containment cooling system valve room heating and ventilation subsystem equipment is located in the passive containment cooling system valve room in the containment dome area at elevation 286′-6″.

The exhaust fan draws outside air through an intake louver damper and directly exhausts to the environment.

9.4.1.2.2 Component Description

The nuclear island nonradioactive ventilation system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.1-1, 9.4.1-2 and 9.4.1-3 provide design parameters for major components in each subsystem.

Supply Air Handling Units

Each air handling unit consists of a mixing box section, a low efficiency filter bank, high efficiency filter bank, an electric heating coil, a chilled water cooling coil bank, and supply and return/exhaust air fans.

Supply and Return/Exhaust Air Fans

The supply and return/exhaust air fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5) and ANSI/AMCA 300 (Reference 6).

Ancillary Fans

The ancillary fans are centrifugal type with non-overloading horsepower characteristics. Each can provide a minimum of 1,530 cfm. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Supplemental Air Filtration Units

Each supplemental air filtration unit includes a high efficiency filter bank, an electric heating coil, a charcoal adsorber with upstream HEPA filter bank, a downstream postfilter bank and a fan. The filtration unit configurations, including housing, internal components, ductwork, dampers, fans and controls, and the location of the fans on the filtered side of units are designed, constructed, and tested to meet the applicable performance requirements of ASME AG-1, ASME N509, and ASME N510 (References 36, 2, and 3) to satisfy the guidelines of Regulatory Guide 1.140 (Reference 30).

Low Efficiency Filters, High Efficiency Filters, and Postfilters

The low efficiency filters and high efficiency filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). Filter minimum average dust spot efficiency is shown in Table 9.4.1-1 and 9.4.1-2. High efficiency filter performance upstream of HEPA filter banks meet the design requirements of ASME AG-1 (Reference 36), Section FB. Postfilters downstream of the charcoal filters have a minimum DOP efficiency of 95 percent. The filters meet UL 900 (Reference 8) Class I construction criteria.

HEPA Filters

HEPA filters are constructed, qualified, and tested in accordance with UL-586 (Reference 9) and ASME AG-1 (Reference 36), Section FC. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-μm aerosol in accordance with ASME AG-1 (Reference 36), Section TA.

Charcoal Adsorbers

Each charcoal adsorber is designed, constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FE; and Regulatory Guide 1.40. Each charcoal adsorber is a single assembly with welded construction and 4-inch deep Type III rechargeable adsorber cell, conforming with IE Bulletin 80-03 (Reference 29).

Electric Heating Coils

The electric heating coils are multi-stage fin tubular type. The electric heating coils meet the requirements of UL-1995 (Reference 10). The coils for the supplemental air filtration subsystem are constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section CA.

Electric Unit Heaters

The electric unit heaters are single-stage or two-stage fin tubular type. The electric unit heaters are UL-listed and meet the requirements of UL-1996 (Reference 26) and the National Electrical Code NFPA 70 (Reference 28).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifiers

The humidifiers are packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifiers are designed and rated in accordance with ARI 620 (Reference 13).

Isolation Dampers and Valves

Nonsafety-related isolation dampers are bubble tight, single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power. The isolation dampers are constructed, qualified, and tested in accordance with ANSI/AMCA 500 (Reference 14) or ASME AG-1 (Reference 36), Section DA.

The main control room pressure boundary penetrations include isolation valves, interconnecting piping, and vent and test connection with manual test valves. The isolation valves are classified as Safety Class C (see subsection 3.2.2.5 and Table 3.2-3) and seismic Category I. Their boundary isolation function will be tested in accordance with ASME N510 (Reference 3).

The main control room pressure boundary isolation valves have electro-hydraulic operators. The valves are designed to fail closed in the event of loss of electrical power. The valves are qualified to shut tight against control room pressure.

Tornado Protection Dampers

The tornado protection dampers are split-wing type and designed to close automatically. The tornado protection dampers are designed against the effect of 300 mph wind.

Shutoff, Balancing and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Backdraft dampers are of the counterbalanced type and are provided to delay smoke migration through ductwork in case of fire. The backdraft dampers meet the Leakage Class II requirements of ASME N509 (Reference 2). Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow and meet the performance requirements in accordance with ANSI/AMCA 500 (Reference 14). The supplemental air filtration subsystem dampers are constructed, qualified, and tested in accordance with ANSI/AMCA 500 or ASME AG-1 (Reference 36), Section DA.

Combination Fire/Smoke Dampers

Combination fire/smoke dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The combination fire/smoke dampers meet the design, leakage testing, and installation requirements of UL-555S (Reference 25).

Ductwork and Accessories

Ductwork, duct supports, and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures. Ductwork, supports, and accessories meet the design and construction requirements of SMACNA Industrial Rectangular and Round Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards – Metal and Flexible (Reference 17). The supplemental air filtration and main control room/technical support center HVAC subsystem's ductwork, including the air filtration units and the portion of the ductwork located outside of the main control room envelope, that maintains integrity of the main control room/technical support center pressure boundary during conditions of abnormal airborne radioactivity are designed in accordance with ASME AG-1 (Reference 36), Article SA-4500, to provide low leakage components necessary to maintain main control room/technical support center habitability.

9.4.1.2.3 System Operation

9.4.1.2.3.1 Main Control Room/Technical Support Center HVAC Subsystem

Normal Plant Operation

During normal plant operation, one of the two 100 percent capacity supply air handling units and return/exhaust air fans operates continuously. Outside makeup air supply to the supply air handling units is provided through an outside air intake duct. The outside airflow rate is automatically controlled to maintain the main control room and technical support center areas at a slightly positive pressure with respect to the surrounding areas and the outside environment.

The main control room/technical support center supply air handling units are sized to provide cooling air for personnel comfort, equipment cooling, and to maintain the main control room emergency habitability passive heat sink below its initial ambient air design temperature. The temperature of the air supplied by each air handling unit is controlled by temperature sensors located in the main control room return air duct to maintain the ambient air design temperature within its normal design temperature range by modulating the electric heat or chilled water cooling.

The outside air is continuously monitored by smoke monitors located at the outside air intake plenum and the return air is monitored for smoke upstream of the supply air handling units. The supply air to the main control room is continuously monitored for airborne radioactivity while the supplemental air filtration units remain in a standby operating mode.

The standby supply air handling unit and corresponding return/exhaust fans are started automatically if one of the following conditions shuts down the operating unit:

- Airflow rate of the operating fan is above or below predetermined setpoints.
- Return air temperature is above or below predetermined setpoints.
- Differential pressure between the main control room and the surrounding areas and outside environment is above or below predetermined setpoints.
- Loss of electrical and/or control power to the operating unit.

Abnormal Plant Operation

Control actions are taken at two levels of radioactivity as detected in the main control room supply air duct. The first is "high" radioactivity based upon gaseous radioactivity instrumentation. The second is "high-high" radioactivity based upon either particulate or iodine radioactivity instruments.

If "high" gaseous radioactivity is detected in the main control room supply air duct and the main control room/technical support center HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the main control room and technical support center areas to at least 1/8 inch wg with respect to the surrounding areas and the outside environment using filtered makeup air. After the room is pressurized, one of the supplemental air filtration units is manually shut down. The normal outside air makeup duct and the main control room and technical support center toilet exhaust duct isolation dampers close. The smoke/purge exhaust isolation dampers close, if open. The main control room/technical support center supply air handling unit continues to provide cooling with recirculation air to maintain the main control room passive heat sink below its initial ambient air design temperature and maintains the main control room and technical support center areas within their design temperatures. The supplemental air filtration subsystem pressurizes the combined volume of the main control room and technical support center concurrently with filtered outside air. A portion of the recirculation air from the main control room and technical support center is also filtered for cleanup of airborne radioactivity. The main control room/technical support center HVAC equipment and ductwork that form an extension of the main control room/technical support center pressure boundary limit the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure) rates to those values shown in Table 9.4.1-1. Based on these values, the system is designed to maintain personnel doses within allowable General Design Criteria (GDC) 19 limits during design basis accidents in both the main control room and the technical support center.

If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding GDC 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room from the normal main control room/technical support center HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. Main control room habitability is maintained by the main control room emergency habitability system, which is discussed in Section 6.4.

The main control room and technical support center areas ventilation supply and return/exhaust ducts can be remotely or manually isolated from the main control room.

If a high concentration of smoke is detected in the outside air intake, an alarm is initiated in the main control room and the main control room/technical support center HVAC subsystem is manually realigned to the recirculation mode by closing the outside air and toilet exhaust duct isolation valves. The main control room and technical support center toilet exhaust fans are tripped upon closure of the isolation valves. The main control room/technical support center areas are not pressurized when operating in the recirculation mode. The main control room/technical support center HVAC supply air subsystem continues to provide cooling, ventilation, and temperature control to maintain the emergency habitability passive heat sink below its initial ambient air design temperature and maintains the main control room and technical support center areas within their design temperatures.

In the event of a fire in the main control room or technical support center, in response to heat from the fire or upon receipt of a smoke signal from an area smoke detector, the combination fire/smoke dampers close automatically to isolate the fire area. The subsystem continues to provide ventilation/cooling to the unaffected area and maintains the unaffected areas at a slightly positive pressure. The main control room/technical support center HVAC subsystem can be manually realigned to the once-through ventilation mode to supply 100 percent outside air to the unaffected area. Realignment to the once-through ventilation mode minimizes the potential for migration of smoke or hot gas from the fire area to the unaffected area. Smoke and hot gases can be removed from the affected area by reopening the closed combination fire/smoke damper(s) from outside of the affected fire area during the once-through ventilation mode. In the once-through ventilation mode, the outside air intake damper to the air handling unit mixing plenum opens and the return air damper to the air handling unit closes to provide 100 percent outside air to the supply air handling unit. In this mode, the subsystem exhaust air isolation damper opens to exhaust the return air directly to the turbine building vent.

Power is supplied to the main control room/technical support center HVAC subsystem by the plant ac electrical system. In the event of a loss of the plant ac electrical system, the main control room/technical support center ventilation subsystem can be transferred to the onsite standby diesel generators.

When complete ac power is lost and the outside air is acceptable radiologically and chemically, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR. It is expected that outside air will be acceptable within 72 hours following a radiological release. See subsection 6.4.2.2 for details. The outside air pathway to the ancillary fans is provided through the nonradioactive ventilation system air intake opening located on the roof, the mechanical room at floor elevation 135′-3″, and nonradioactive ventilation system supply duct. Warm air from the MCR is vented to the annex building through stairway S05, into the remote shutdown room and the clean access corridor at elevation 100′-0″. The ancillary fan capacity and air flow rate maintain the MCR environment near the daily average outdoor air temperature. The ancillary fans and flow path are located within the auxiliary building which is a Seismic Category I structure.

Power supply to the ancillary fans is from the respective division B or C regulating transformers which receive power from the ancillary diesel generators. For post-72-hour power supply discussion see subsection 8.3.1.1.1.

9.4.1.2.3.2 Class 1E Electrical Room HVAC Subsystem

The Class 1E electrical room HVAC equipment that serves electrical division A and C equipment is described in this section. The operation of the Class 1E electrical room HVAC equipment that serves electrical division B and D is similar.

Normal Plant Operation

During normal plant operation, one of the redundant supply air handling units, return fans, and battery room exhaust fans operate continuously to provide room temperature control, to maintain the Class 1E electrical room emergency passive heat sink below its initial ambient air temperature, and to purge and prevent build-up of hydrogen gas concentration in the Class 1E Battery Rooms. The temperature of the air supplied by each air handling unit is controlled by temperature sensors located in the return air duct to maintain the room air temperature within the normal design range by modulating electric heating or chilled water cooling.

During normal plant operation, the exhaust airflow from the Class 1E battery rooms is vented directly to the turbine building vent to limit the concentration of hydrogen gas in the rooms to less than 2 percent by volume in accordance with the guidelines of Regulatory Guide 1.128.

The outside makeup air to the supply air handling units is provided through an outside air intake duct. The outside airflow rate is manually balanced during system startup to provide adequate makeup air for the battery room exhaust fans.

The standby supply air handling unit and the corresponding return/exhaust fans are started automatically if one of the following conditions occurs:

- Airflow rate of the operating fan is above or below predetermined set points
- Return air temperature is above or below predetermined setpoints.
- Loss of electrical and/or control power to the operating unit.

Abnormal Plant Operation

The operation of the Class 1E electrical room HVAC subsystem is not affected by the detection of airborne radioactivity in the main control room supply air duct of the main control room/technical support center HVAC subsystem. During a design basis accident (DBA), if the plant ac electrical system is unavailable, the Class 1E electrical room passive heat sink provides area temperature control. Refer to Section 6.4 for further details.

If a high concentration of smoke is detected in the outside air intake and an alarm is initiated in the main control room, the Class 1E electrical HVAC subsystem(s) can be manually aligned to the recirculation mode by closing the outside air intake damper to the air handling unit mixing plenum. This allows 100 percent room air to return to the supply air subsystem air handling unit.

The subsystem continues to provide cooling, ventilation, and temperature control to maintain the areas served by the subsystem(s) within their design temperatures and pressures.

In the event of a fire in a Class 1E electrical room, in response to heat from the fire or upon receipt of a smoke signal from an area smoke detector, the combination fire/smoke dampers close automatically to isolate the fire area. The affected subsystem continues to provide ventilation/cooling to the remaining areas and maintains the remaining areas at a slightly positive pressure. Either or both subsystems can be manually realigned to the once-through ventilation mode to supply 100 percent outside air to the unaffected areas. Realignment to the once-through ventilation mode minimizes the potential for migration of smoke and hot gases from a non-Class 1E electrical room or a Class 1E electrical room of one division into the Class 1E electrical room of another division. Smoke and hot gases can be removed from the affected areas by reopening the closed combination fire/smoke dampers from outside of the affected fire area during the once-through ventilation mode. In the once-through ventilation mode, the outside air intake damper to the air handling unit mixing plenum opens and the return air damper to the air handling unit closes to allow 100 percent outside air to the supply air handling unit. The subsystem exhaust air isolation damper also opens to exhaust room air directly to the turbine building vent. During a fire, the pressure difference across the doors in stairwells S01 and S02 is maintained in accordance with the guidance of NFPA 92A (Reference 33) by dedicated stairwell pressurization fans.

The power supplies to the Class 1E electrical room HVAC subsystem are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the plant ac electrical system, the Class 1E electrical room HVAC subsystem is automatically transferred to the onsite standby diesel generators.

When complete ac power is lost, division B and C instrumentation and control room temperature is maintained by operating their respective ancillary fans (VBS-MA-11 and VBS-MA-12) to supply outside air to the I&C rooms. It is expected that outside air will be supplied within 72 hours following a radiological release. The outside air pathway to the ancillary fans is through the nonradioactive ventilation system outside air intake opening located on the roof, the mechanical room at floor elevation 135′-3″, stairway No. 1 doors at elevation 135′-3″ and 82′-6″, the access corridor at floor elevation 82′-6″, and the divisional battery rooms. The warm air is vented to the annex building through the clean access corridor at elevation 100′-0″. The outside air supply provides cooling and maintains room temperature below the qualification temperature of the I&C equipment. The ancillary fans and flow path are located within the auxiliary building which is a Seismic Category I structure.

Power supply to the ancillary fans is from the respective division B or C regulating transformers which receive power from the ancillary diesel generators. For post-72-hours power supply discussion see subsection 8.3.1.1.1.

9.4.1.2.3.3 Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem

Normal Plant Operation

The passive containment cooling system valve room ventilation fan exhausts room air to the outside environment to maintain room temperature within its normal design temperature range.

When heating is required, one of the two redundant electric unit heaters provides heating to maintain the passive containment cooling system valve room temperature above its minimum design temperature. The lead electric unit heater starts or stops when the room air temperature is above or below predetermined setpoints. The standby electric unit heater starts automatically if the room air temperature drops below a predetermined setpoint.

Abnormal Plant Operation

The power supplies to the passive containment cooling system valve room unit heaters are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the plant ac electrical system, the passive containment cooling system valve room unit heaters can be transferred to the onsite standby diesel generators by the operator.

The power supply to the passive containment cooling system valve room ventilation fan is provided by the plant ac electrical system. The room temperature is not expected to exceed 120°F, based on maximum ambient conditions and internal heat sources.

Following a fire in the passive containment cooling system valve room, smoke and hot gases can be removed from the area using portable exhaust fans and flexible ductwork.

9.4.1.3 Safety Evaluation

The nuclear island nonradioactive ventilation system has no safety-related function other than main control room envelope isolation and main control room supply air radioactivity monitoring, and therefore requires no nuclear safety evaluation. Redundant safety-related isolation valves are provided in the supply, return, and exhaust ducts penetrating the main control room. Therefore, there are no single active failures which would prevent isolation of the main control room envelope. The safety-related redundant main control room supply air radiation monitors are provided. The nuclear island nonradioactive ventilation system is designed so that safety-related systems, structures, or components are not damaged as a result of a seismic event.

9.4.1.4 Tests and Inspection

The nuclear island nonradioactive ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Airflow rates are measured and balanced within a tolerance of ±10 percent of design flow rate in accordance with the guidelines of SMACNA HVAC systems, Testing, Adjusting and Balancing (Reference 19) except the supplemental air filtration units which are balanced in accordance with the guidelines of ASME N510 (Reference 3). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability. Air quality within the MCR/TSC environment is confirmed to be within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 32 by analyzing air samples taken during preoperational testing.

The supplemental air filtration unit, HEPA filters, and charcoal adsorbers are tested in place in accordance with ASME N510 to verify that these components do not exceed a maximum

allowable bypass leakage rate. Samples of charcoal adsorbent, used or new, are periodically tested to verify a minimum charcoal efficiency of 90 percent in accordance with Regulatory Guide 1.140 (Reference 30), except that test procedures and test frequency are conducted in accordance with ASME N510.

The ductwork for the supplemental air filtration subsystem and portions of the main control room/technical support center HVAC subsystem that maintain the integrity of the main control room/technical support center pressure boundary during conditions of abnormal airborne radioactivity are tested for leak tightness in accordance with ASME N510, Section 6. Testing for main control room/technical support center inleakage during Main Control Room/Technical Support Center HVAC Subsystem operation will be conducted in accordance with ASTM E741 (Reference 38). The remaining supply and return/exhaust ductwork is tested in place for leakage in accordance with SMACNA HVAC Duct Leakage Test Manual (Reference 18).

9.4.1.5 Instrumentation Applications

The nuclear island nonradioactive ventilation system is controlled by the plant control system except for the main control room isolation valves, which are controlled by the protection and safety monitoring system. Refer to subsection 7.1.1 for a description of the plant control and plant safety and monitoring systems. The instruments discussed below satisfy Table 4.2 of ASME N509 (Reference 2).

Temperature controllers are provided in the return air ducts to control the room air temperatures within the predetermined ranges. Temperature indication and alarms for the main control room return air, Class 1E electrical room return air, air handling unit supply air, supplemental filtration unit prefilter inlet air and charcoal adsorbers are provided to inform plant operators of abnormal temperature conditions.

Pressure differential indication and alarms are provided across each filter bank (except charcoal filters) to inform plant operators when filter changeout is necessary. Pressure differential indication and alarms are provided to control the main control room and monitor the technical support center ambient room pressure differentials with respect to surrounding areas.

Radioactivity indication and alarms are provided to inform the main control room operators of gaseous, particulate, and iodine radioactivity concentrations in the main control room supply air duct. See Section 11.5 for a description of the main control room supply air duct radiation monitors and their actuation functions.

Smoke monitors are provided to detect smoke in the outside air intake duct to the main control room and the main control room and Class 1E electrical room return air ducts.

Airflow indication and alarms are provided to monitor operation of the supply and exhaust fans.

Relative humidity indication and alarms are provided to monitor the average relative humidity in the return air from the main control room/technical support center areas and the inlet air to the supplemental air filtration unit charcoal filters.

Status indication is provided to monitor fans, heaters and controlled dampers.

9.4.2 Annex/Auxiliary Buildings Nonradioactive HVAC System

The annex/auxiliary buildings nonradioactive HVAC system serves the nonradioactive personnel and equipment areas, electrical equipment rooms, clean corridors, the ancillary diesel generator room and demineralized water deoxygenating room in the annex building, and the main steam isolation valve compartments, reactor trip switchgear rooms, and piping and electrical penetration areas in the auxiliary building.

9.4.2.1 Design Basis

9.4.2.1.1 Safety Design Basis

The annex/auxiliary buildings nonradioactive HVAC system serves no safety-related function and therefore has no nuclear safety design basis. System equipment and ductwork located in the nuclear island whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.2.1.2 Power Generation Design Basis

The annex/auxiliary buildings nonradioactive HVAC system provides the following specific functions:

- Provides conditioned air to maintain acceptable temperatures for equipment and personnel working in the area

- Provides suitable environmental conditions for equipment in the main steam isolation valve (MSIV) compartments

- Prevents the buildup of hydrogen in non-Class 1E battery rooms to less than 2 percent hydrogen by volume

- Removes vitiated air from locker, toilet, and shower facilities

The system maintains the following room temperatures based on maximum and minimum normal outdoor air temperature conditions shown in Chapter 2, Table 2-1:

Room or Area	Temperatures (°F)
Normal Operation	
Offices, corridors (annex building)	73-78
Locker rooms, toilet rooms (annex building)	73-78
Central alarm station, security access area (annex building)	73-78
Non-Class 1E battery rooms (annex building)	60-90
Switchgear and battery charger rooms (annex building)	50-105
HVAC and mechanical equipment rooms (annex building)	50-105
MSIV compartments (auxiliary building)	50-105
Non-safety electrical penetration rooms (auxiliary building)	50-105
Reactor trip SWGR rooms (auxiliary building)	50-105
Valve/piping penetration room (auxiliary building)	50-105
Ancillary diesel generator room (annex building)	50-105
Demineralized water deoxygenating room	50-105
Elevator machine room	50-105
Boric acid batching room	50-105
Upset Conditions (Loss of Plant ac Electrical System)	
Switchgear rooms (annex building)	122 (maximum)
Battery charger rooms (annex building)	122 (maximum)
Ancillary diesel generator room (annex building - DG sets operating)	122 (maximum)

9.4.2.2 System Description

The annex/auxiliary buildings nonradioactive HVAC system consists of the following independent subsystems:

- General area HVAC subsystem
- Switchgear room HVAC subsystem
- Equipment room HVAC subsystem
- MSIV compartment HVAC subsystem
- Mechanical equipment areas HVAC subsystem
- Valve/Piping penetration room HVAC subsystem

The defense in depth portion of the system and selected subsystems are shown in Figure 9.4.2-1.

9.4.2.2.1 General Description

9.4.2.2.1.1 General Area HVAC Subsystem

The general area HVAC subsystem serves personnel areas in the annex building outside the security area. These areas include the men's and women's change and toilet rooms, the ALARA briefing room, and operational support center, offices, and corridors. The general area HVAC subsystem consists of two 50 percent capacity supply air handling units of about 5,100 scfm each, a humidifier, a ducted supply and return air system, diffusers and registers, exhaust fan, automatic controls, and accessories. The air handling units are located on the low roof of the annex building at elevation 117′-6″. The units discharge into a ducted supply distribution system which is routed through the building to provide air into the various rooms and areas served via registers. An electric heating coil is provided in the branch supply duct to the men's and women's change rooms for tempering the supply air.

A humidifier is provided in the system to provide a minimum space relative humidity of 35 percent.

Air from the men's and women's locker, toilet, and shower facilities in the annex building is exhausted directly to atmosphere by an exhaust fan. Room air from the remaining areas served is recirculated back to the air handling unit via a ceiling return plenum and a return duct system. Outside make-up air is added to the return air stream at the air handling units to replace air exhausted from toilets and showers in the area served.

9.4.2.2.1.2 Switchgear Room HVAC Subsystem

The switchgear room HVAC subsystem serves electrical switchgear Rooms 1 and 2 in the annex building. The switchgear room HVAC system consists of two 100 percent capacity air handling units, a ducted supply and return air system, and automatic controls and accessories.

The air handling units are located in the north air handling equipment room in the annex building at elevation 135′-3″. They are connected to a common intake plenum located along the east wall adjacent to their air handling equipment room. This plenum also supplies air for the equipment room HVAC subsystem. The air handling units discharge into a common duct distribution system that is routed through the building to the rooms served. Air is returned to the air handling units from the rooms served by a return duct system.

The switchgear room HVAC subsystem is designed so that smoke can be removed after a fire by placing the system in a once-through smoke exhaust ventilation mode. See Appendix 9A for identification of fire areas.

The alternate switchgear room HVAC subsystem provides ventilation cooling to electrical switchgear Rooms 1 and 2 in the annex building in the event that the primary system air handling units are unavailable due to a fire. The alternate switchgear room HVAC subsystem consists of a 100 percent capacity supply fan, a 100% capacity exhaust fan, and controls. The fans are mounted in the annex building wall.

9.4.2.2.1.3 Equipment Room HVAC Subsystem

The equipment room HVAC subsystem serves electrical and mechanical equipment rooms in the annex and auxiliary buildings. These rooms include the non-Class 1E battery charger Rooms 1 and 2, the non-Class 1E battery Rooms 1 and 2, the reactor trip switchgear Rooms I and II, the non-Class 1E penetration room on elevation 100′-0″ and the non-Class 1E penetration room on elevation 117′-6″. This subsystem also serves the security area offices and the central alarm station in the annex building. These include two rest rooms, access areas, and corridors. The equipment room HVAC system consists of two 100 percent capacity air handling units, two battery room exhaust fans, a toilet exhaust fan, a ducted supply and return air system, and automatic controls and accessories.

The air handling units are located in the north air handling equipment room in the annex building at elevation 135′-3″. They are connected to a common intake plenum located along the east wall adjacent to their air handling equipment room. This plenum also supplies air for the switchgear room HVAC subsystem. The air handling units discharge into a common duct distribution system that is routed through the buildings to the various areas served. Air is returned to the air handling units from the rooms served (except the battery rooms and rest rooms) by a return duct system. Electric reheat coils are provided in the ductwork to areas requiring close temperature control such as the security rooms, restrooms and the central alarm station. Hot water unit heaters (VXS-MY-W01A, B, and C) are provided in the north air handling equipment room to maintain the area above 50°F.

A humidifier is provided in the branch duct to the security areas to provide a minimum space relative humidity of 35 percent.

Each non-Class 1E battery room is provided with an individual exhaust system to prevent the buildup of hydrogen gas in the room. Each exhaust system consists of an exhaust fan, an exhaust air duct and gravity back draft damper located in the fan discharge. Air supplied to the battery rooms by the air handling units is exhausted to atmosphere. Air from the rest rooms is exhausted to atmosphere by a separate exhaust fan.

The portion of the equipment room HVAC subsystem servicing the auxiliary building is designed so that smoke, hot gases, and fire suppressant will not migrate from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Fire or combination fire and smoke dampers are provided to isolate each fire area from adjacent fire areas during and following a fire in accordance with NFPA 90A (Reference 27) requirements. These combination smoke/fire dampers close in response to smoke detector signals or in response to the heat from a fire. See Appendix 9A for identification of fire areas.

9.4.2.2.1.4 MSIV Compartment HVAC Subsystem

The main steam isolation valve compartment HVAC subsystem serves the two main steam isolation valve compartments in the auxiliary building that contain the main steam and feedwater lines routed between the containment and the turbine building. Each compartment is provided with separate heating and cooling equipment.

The main steam isolation valve compartment HVAC subsystem consists of two 100-percent-capacity supply air handling units per compartment (VXS-MS-04A, B, C, and D) of about 3,300 scfm each with only low efficiency filters, ducted supply air distribution directly to the space served, automatic controls, and accessories for each main steam isolation valve compartment.

The supply air handling units are located directly within the space served. One unit in each compartment normally operates to maintain the temperature of the compartment. The air handling units can be connected to the standby power system, for investment protection, in the event of loss of the plant ac electrical system.

9.4.2.2.1.5 Mechanical Equipment Areas HVAC Subsystem

The mechanical equipment areas HVAC subsystem serves the ancillary diesel generator room, demineralized water deoxygenating room, boric acid batching room, upper south air handling equipment room, and lower south air handling equipment room in the annex building.

The mechanical equipment areas HVAC subsystem consists of two 50-percent capacity air handling units (VXS-MS-07A and B) with supply fans and return/exhaust fans of about 2,200 scfm each, a ducted supply and return air system, automatic controls, and accessories.

The air handling units are located in the lower south air handling unit equipment room on elevation 135′-3″ of the annex building. They are supplied from the air intake plenum #2 located at the extreme south end of the annex building between elevation 135′-3″ and 158′. This plenum also supplies air for the radiologically controlled area ventilation system, the health physics and hot machine shop HVAC system and the containment air filtration system. The intake is not protected from tornado missiles.

The ancillary diesel generator room is supplied air from the air handling units to maintain normal design temperatures. Air supplied to the room is exhausted direct to outdoors by means of a separate exhaust fan. Ventilation and cooling for the room when the ancillary diesel generators operate is provided by means of manually operated dampers and opening doors to allow radiator discharge air to be exhausted direct to outdoors.

9.4.2.2.1.6 Valve/Piping Penetration Room HVAC System

The valve/piping penetration room HVAC subsystem serves the valve/piping penetration room on elevation 100′-0″ of the auxiliary building. The valve/piping penetration room HVAC subsystem consists of two 100-percent-capacity air handling units (VXS-MS-08A and B) with supply fans of about 1,800 scfm each, a return air duct system, automatic controls, and accessories.

The air handling units are located directly within the space served.

9.4.2.2.2 Component Description

The annex/auxiliary buildings HVAC system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island or in the annex building. The seismic design classification, safety classification and principal construction

code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.2-1 and 9.4.2-2 provide the design parameters for major defense-in-depth components of the system.

Air Handling Units

Air handling units with integral supply and return/exhaust fans are utilized in the equipment room HVAC subsystem, switchgear room HVAC subsystem, and the mechanical equipment areas HVAC subsystem. Each air handling unit consists of a return/exhaust fan, a return/exhaust air plenum, a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil with integral face/bypass damper, a chilled water cooling coil, and a supply air fan.

Supply Air Handling Units

Supply air handling units are utilized in the general area HVAC subsystem, main steam isolation valve compartment HVAC subsystem, and the valve/piping penetration room HVAC subsystem. Each air handling unit consists of a low efficiency filter bank, a hot water heating coil, a chilled water cooling coil, and a supply fan. The general area HVAC subsystem air handling unit also includes a high efficiency filter bank and has face and bypass dampers on the heating coil.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. Air handling unit fans that have little or no ductwork may utilize forward curved blades. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

The supply and exhaust fans for the alternate switchgear room HVAC subsystem are propeller fans. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). The filters meet UL 900 (Reference 8) Class I construction criteria.

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Electric Heating Coils

The electric heating coils are multi-stage fin tubular type. The electric heating coils meet the requirements of UL 1995 (Reference 10).

Electric Unit Heaters

The electric unit heaters are single-stage or two-stage fin tubular type. The electric unit heaters are UL-listed and meet the requirements of UL 1996 (Reference 26) and the National Electric Code NFPA 70 (Reference 28).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the supply duct system. The humidifier is performance rated in accordance with ARI 620 (Reference 13).

Hot Water Unit Heaters

The hot water unit heaters consist of a fan section and hot water heating coil section factory assembled as a complete and integral unit. The unit heaters are either horizontal discharge or vertical downblast type. The coil ratings are in accordance with ANSI/ARI 410 (Reference 12).

Isolation Dampers

Isolation dampers are bubble tight, single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss-of-electrical power or loss-of-air pressure. The isolation dampers are constructed, qualified and tested in accordance with ANSI/AMCA 500 (Reference 14).

Shutoff, Control, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through ventilators, exhaust fans and the valve/piping penetration room air handling units. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. Dampers meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15). Fire dampers are not provided in locations where combination fire/smoke dampers are provided.

Combination Fire/Smoke Dampers

Combination fire/smoke dampers are provided at the duct penetrations through fire barriers between the annex building and the auxiliary building, and to the ICC/non-1E penetration room, to maintain the fire resistance ratings of the barriers. The combination fire/smoke dampers meet the design leakage testing, and installation requirements of UL-555S (Reference 25).

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17).

9.4.2.2.3 System Operation

9.4.2.2.3.1 General Area HVAC Subsystem

Normal Plant Operation

During normal plant operation, both supply air handling units and the toilet/shower exhaust fan operate continuously to maintain suitable temperatures in the areas served. The temperature of the air supplied by each handling units is controlled by individual temperature controls with their sensors located in the annex building main entrance. The temperature sensor sends a signal to a temperature controller which modulates the chilled water control valve and the face and bypass dampers across the supply air heating coil to maintain the area within the design range. The switchover between cooling and heating modes is automatically controlled by the temperature controllers.

Supplemental heating is provided for the men's/women's change room areas by an electric reheat coil located in the supply air duct to the areas served. The reheat coil operates intermittently under the control of its temperature controller with sensor located in the women's change room, which modulates the electric heating elements to maintain the space temperature in the change room areas within the design range.

The supply air is humidified by a common humidifier located in the ductwork downstream of the supply air handling units. A humidistat located in the main entrance of the annex building intermittently operates the humidifier to maintain a minimum space relative humidity of 35 percent in the area served.

The differential pressure drop across each supply unit filter bank is monitored, and individual alarms are actuated when any pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on a supply unit, the affected supply fan is stopped and isolated from the duct system by means of isolation dampers. The toilet/shower exhaust fan is also stopped. During filter replacement, the system operates at approximately 50 percent capacity. This mode of operation will maintain a slight positive pressure in the building.

Abnormal Plant Operation

The general area HVAC subsystem is not required to operate during any abnormal plant condition.

9.4.2.2.3.2 Switchgear Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit operates continuously to maintain the indoor temperatures in the two switchgear rooms. The temperature of the air supplied by the air handling unit is maintained at 62°F by a temperature controller based on outside ambient temperature conditions. When the outdoor air temperature is below 62°F, the temperature controller modulates the outside air, return air and exhaust air dampers of the air handling unit to mix return air and outside air in the proper proportion, and modulates the face and bypass dampers of the hot water heating coils to maintain a mixed air temperature of 62°F. A minimum amount of outside air is always provided for ventilation requirements. When the outdoor temperature is above 62°F, the outside air, return air and exhaust air dampers automatically reposition for minimum outside air and the temperature controller modulates the chilled water control valves to maintain the supply air at 62°F. The switchover between cooling and heating modes is automatically controlled by the supply air temperature controllers.

The differential pressure drop across each air handling unit filter bank is monitored and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers. During filter replacement, the second air handling unit operates at full system capacity.

Abnormal Plant Operation

In the event of a loss of the plant ac electrical system, the air handling unit supply and return/exhaust fans are connected to the standby power system to provide ventilation cooling to the diesel bus switchgear. This cooling permits the switchgear to perform its defense in depth functions in support of standby power system operation. In this mode of operation, the switchgear rooms are cooled utilizing once-through ventilation using outdoor air. When in the once-through ventilation mode, the switchgear rooms will be maintained at or below 122°F. Equipment in these rooms that operate following a loss of the plant ac electrical system are designed for continuous operation at this temperature. To maintain the areas above freezing, the mixing dampers will modulate to maintain a supply air temperature of 62°F for outdoor temperatures below 62°F. For outdoor temperature above 62°F, the outside air, return air, and exhaust air dampers are positioned for a once-through flow.

The alternate switchgear room HVAC subsystem provides ventilation cooling to electrical switchgear Rooms 1 and 2 in the annex building in the event that the primary system air handling units are unavailable due to a fire. The switchgear rooms will be maintained at or below 122°F. Equipment in these rooms that operate following a loss of the plant ac electrical system are

designed for continuous operation at this temperature. The fans will be controlled to maintain the areas above freezing.

9.4.2.2.3.3 Equipment Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit and both battery room exhaust fans operate continuously to maintain the indoor temperatures in the equipment and security access areas served by the system.

The temperature of the air supplied by the air handling unit is maintained at 62°F by a temperature controller based on outside ambient temperature conditions. When the outdoor air temperature is below 62°F, the temperature controller modulates the outside air, return air and exhaust air dampers of the air handling unit to mix return air and outside air in the proper proportion, and modulates the face and bypass dampers of the hot water heating coils to maintain a mixed air temperature of 62°F. A minimum amount of outside air is always provided for ventilation requirements. When the outdoor air temperature is above 62°F, the outside air, return air and exhaust air dampers automatically reposition for minimum outside air and the temperature controller modulates the chilled water control valves to maintain the supply air at 62°F. The switchover between cooling and heating modes is automatically controlled by the supply air temperature controllers.

Electric reheat coils serving the security room #2 and the central alarm station are controlled by temperature controllers with sensors located in the areas served. The temperature sensor sends a signal to a temperature controller which modulates the electric heating elements to maintain the security access areas at their design temperatures. Hot water unit heaters operate intermittently to provide supplemental heating for the north air handling equipment room to maintain the area temperature above 50°F.

A humidistat located in the security access area intermittently operates the humidifier to maintain the security office area at a minimum space relative humidity of 35 percent.

The differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters of an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers. During filter replacement, the second air handling unit operates at full system capacity.

A temperature controller opens the outside air intake and starts and stops the elevator machine room exhaust fan as required to maintain room design temperature conditions. A local thermostat controls the electric unit heater.

Abnormal Plant Operation

In the event of a loss of the plant ac electrical system, the air handling unit supply and return/exhaust fans are connected to the standby power system to provide ventilation cooling to

the dc switchgear and inverters. This cooling permits that equipment to perform its defense in depth functions. In this mode of operation, the rooms are cooled utilizing once-through ventilation using outdoor air. When in the once-through ventilation mode, the dc switchgear and inverter areas will be maintained at or below 122°F. Equipment in those areas that operate following a loss of the plant ac electrical system are designed for continuous operation at this temperature. To maintain the areas above freezing, the mixing dampers will modulate to maintain a supply air temperature of 62°F for outdoor temperatures below 62°F. For outdoor temperature above 62°F, the outside air, return air, and exhaust air dampers are positioned for a once-through flow.

9.4.2.2.3.4 MSIV Compartment HVAC Subsystem

Normal Plant Operation

During normal plant operation, one of the main steam isolation valve compartment air handling units in each compartment operates continuously in a recirculation mode to maintain the indoor temperature in the equipment area served by the system. A temperature controller modulates the chilled water and hot water control valves serving the operating unit to maintain the compartment temperature at or less than 105°F and above a minimum of 50°F. The switchover between cooling and heating modes is automatically controlled by the area temperature controller.

The differential pressure drop across each air handling unit filter bank is monitored and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. An air handling unit may be shutdown for filter replacement or other maintenance as required, with the other air handling unit in the same compartment operating to maintain the area temperature.

Abnormal Plant Operation

The main steam isolation valve compartment HVAC subsystem is not required to operate during abnormal plant conditions.

9.4.2.2.3.5 Mechanical Equipment Areas HVAC Subsystem

During normal plant operation, the air handling units operate continuously to maintain the indoor temperatures in the areas served. The temperature of the air supplied by each air handling unit is controlled by individual temperature controls with their sensors located in the upper south air handling equipment room. The temperature sensor sends a signal to a temperature controller which modulates the face and bypass dampers across the supply air heating coil and the chilled water control valve to maintain the mechanical equipment areas within the design temperature range. A constant volume of outside air is used to provide ventilation and to maintain the area at a slight positive pressure with respect to the surroundings. The switchover between cooling and heating modes is automatically controlled by the area temperature controller.

Differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when pressure drop rises to a predetermined level indicative of the need for filter replacement. During filter replacement, the system operates at approximately 50 percent capacity. To replace the filters of an air handling unit, the unit is stopped and isolated from the

duct system by means of isolation dampers. To replace the filters of an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers.

The exhaust fan for the ancillary diesel generator room operates continuously for room ventilation.

Abnormal Plant Operation

The mechanical equipment areas HVAC subsystem is not required to operate during abnormal plant conditions.

When the ancillary diesel generator sets are operated, a manual damper is opened as required and the outside door is opened to maintain acceptable temperatures.

9.4.2.2.3.6 Valve/Piping Penetration Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit operates continuously in a recirculation mode to maintain the indoor temperature in the room. A temperature controller modulates the chilled water control valve and opens and closes the hot water control valve serving the operating unit to maintain the area temperature at or less than 105°F and above a minimum of 50°F. The switchover between cooling and heating modes is automatically controlled by the area temperature controller.

The differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement.

Abnormal Plant Operation

The valve/piping penetration room HVAC subsystem is not required to operate during abnormal plant conditions.

9.4.2.3 Safety Evaluation

The annex/auxiliary buildings nonradioactive HVAC system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.2.4 Tests and Inspections

The annex/auxiliary buildings nonradioactive HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustments to design conditions are made during the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting, and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.2.5 Instrumentation Applications

The annex/auxiliary buildings nonradioactive HVAC system operation is controlled by the plant control system (PLS). Refer to subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Supply air temperature is controlled by either sensing local room temperature or by sensing the supply air temperature in the air handling unit discharge duct, depending on the subsystem. Unit heaters are controlled by local thermostats. Temperature indication and alarms are accessible locally via the plant control system.

Temperature is indicated for each air handling unit supply air discharge duct, except for local recirculation units such as those in the main steam isolation valve compartment and valve/piping penetration room.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room or locally.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for low air flow rates in the fan discharge ducts.

An alarm is provided for smoke in discharge ducts from the air handling units.

Position indicating lights are provided for automatic dampers.

9.4.3 Radiologically Controlled Area Ventilation System

The radiologically controlled area ventilation system (VAS) serves the fuel handling area of the auxiliary building, and the radiologically controlled portions of the auxiliary and annex buildings, except for the health physics and hot machine shop areas which are provided with a separate ventilation system (VHS).

9.4.3.1 Design Basis

9.4.3.1.1 Safety Design Basis

The radiologically controlled area ventilation system serves no safety-related function and therefore has no nuclear safety design basis. System equipment and ductwork located in the nuclear island whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.3.1.2 Power Generation Design Basis

The radiologically controlled area ventilation system provides the following functions:

- Provides ventilation to maintain the equipment rooms within their design temperature range
- Provides ventilation to maintain airborne radioactivity in the access areas at safe levels for plant personnel
- Maintains the overall airflow direction within the areas it serves from areas of lower potential airborne contamination to areas of higher potential contamination
- Maintains each building area at a slightly negative pressure to prevent the uncontrolled release of airborne radioactivity to the atmosphere or adjacent clean plant areas
- Automatically isolates selected building areas from the outside environment by closing the supply and exhaust duct isolation dampers and starting the containment air filtration system when high airborne radioactivity in the exhaust air duct or high ambient pressure differential is detected. See subsection 9.4.7 for a description of the containment air filtration system.

The system maintains the following room temperatures based on the maximum and minimum normal outside air temperature conditions shown in Chapter 2, Table 2-1:

Access and Equipment Areas	**Temperatures (°F)**
Auxiliary/Annex Building Subsystem	
Degasifier column	50-130
RNS and CVS pump rooms (pumps not operating)	50-104
RNS and CVS pump rooms (pumps operating)	50-130
Containment purge exhaust filter rooms (fans not operating)	50-104
Containment purge exhaust filter rooms (fans operating)	50-130
Liquid radwaste tank rooms	50-130
Liquid radwaste pump rooms	50-104
HVAC equipment room	50-104
Gaseous radwaste equipment rooms	50-104
Spent fuel pool pump and heat exchanger rooms	50-104
Annex building staging and storage area	50-104
Other corridors and staging areas	50-104
Fuel Handling Area Ventilation Subsystem	
Rail car bay/filter storage area	50-104
Spent resin equipment rooms	50-130
Corridors and access areas	50-104

Occupied Areas	**Temperatures (°F)**
Fuel Handling Area Ventilation Subsystem	
Fuel handling area	50-96
Auxiliary/Annex Building Ventilation Subsystem	
Radiation chemistry laboratory	73-78
Primary sample room	50-104
Security rooms	73-78

9.4.3.2 System Description

The radiologically controlled area ventilation system consists of the following subsystems:

- Auxiliary/annex building ventilation subsystem
- Fuel handling area ventilation subsystem

The defense in depth portion of the system is shown in Figure 9.4.3-1.

9.4.3.2.1 General Description

9.4.3.2.1.1 Auxiliary/Annex Building Ventilation Subsystem

The auxiliary/annex building ventilation subsystem serves radiologically controlled equipment, piping and valve rooms and adjacent access and staging areas. See Figure 9.4.3-1, sheet 2 of 3, for a complete listing of rooms and corridors serviced by this subsystem. The auxiliary/annex building ventilation subsystem consists of two 50 percent capacity supply air handling units of about 18,000 scfm each, a ducted supply and exhaust air system, isolation dampers, diffusers and registers, exhaust fans, automatic controls and accessories. The supply air handling units are located in the south air handling equipment room of the annex building at elevation 158′-0″. They are connected to the air intake plenum #3 located in the extreme south end of the annex building. This common intake plenum is described in subsection 9.4.7. The units discharge into a ducted supply distribution system which is routed through the radiologically controlled areas of the auxiliary and annex buildings. The supply and exhaust ducts have isolation dampers that close to isolate the auxiliary and annex buildings from the outside environment when high airborne radioactivity is detected in the exhaust air duct. The supply and exhaust ducts are configured so that two building zones may be independently isolated. The annex building staging and storage area, containment air filtration exhaust rooms, containment access corridor, and adjacent auxiliary building staging, equipment areas, middle annulus, middle annulus access room, and security rooms are aligned to one zone. The other zone includes the remaining rooms and corridors shown in Figure 9.4.3-1 sheet 2 of 3, including but not limited to the radiation chemistry laboratory, primary sample room, spent fuel pool cooling water pump and heat exchanger rooms, normal residual heat removal pump and heat exchanger rooms, CVS makeup pump room, lower annulus, and various radwaste equipment rooms, pipe chases, and access corridors. A radiation monitor is located in the exhaust air duct from each zone.

The two 50 percent capacity exhaust air fans sized to allow the system to maintain a negative pressure are located in the upper radiologically controlled area ventilation system equipment room at elevation 145′-9″ of the auxiliary building. The exhaust air ductwork is routed to minimize the spread of airborne contamination by directing the supply airflow from the low radiation access areas into the radioactive equipment and piping rooms with a greater potential for airborne radioactivity. Additionally, the exhaust air ductwork is connected to the radioactive waste drain system (WRS) sump to maintain the sump atmosphere at a negative air pressure to prevent the exfiltration of potentially contaminated air into the surrounding area. The exhaust air ductwork is connected to the radwaste effluent holdup tanks to prevent the potential buildup of airborne radioactivity or hydrogen gas within these tanks. The exhaust fans discharge the exhaust air into the plant vent for monitoring of offsite airborne radiological releases.

The ventilation airflow dilutes potential airborne contamination to maintain the concentration at the site boundary within 10 CFR 20 (Reference 21) allowable effluent concentration limits and the internal room airborne concentrations within 10 CFR 20 occupational derived air concentration (DAC) limits during normal plant operation.

Unit coolers are located in the normal residual heat removal system (RNS) and chemical and volume control system (CVS) pump rooms because they have significant cooling loads on an intermittent basis when large equipment is operating. Each unit cooler is sized to accommodate 100 percent of its corresponding pump cooling load. The unit coolers are provided with chilled water from redundant trains of the central chilled water system (VWS) low capacity subsystem. The normal residual heat removal pump room unit coolers have two cooling coils per unit cooler so that chilled water supplied by either train A or train B alone can support concurrent operation of both normal residual heat removal system pumps. The two chemical and volume control makeup pump room unit coolers are connected to redundant trains of the chilled water system; however, operation of either the train A or train B unit cooler alone maintains the common makeup pump room temperature conditions and supports operation of either makeup pump.

Heating coils are located in the supply air ducts serving plant areas that require supplemental heating during periods of cold outside air temperature conditions. The heating coils are supplied with hot water from the hot water heating system (VYS). The radiation chemistry laboratory and security room supply air ducts are provided with local electric coils and humidifiers to maintain the environmental conditions within the areas suitable for personnel comfort. Electric unit heaters provide supplemental heating in the middle annulus.

The upper annulus is separated from the middle annulus area of the auxiliary building by a concrete floor section and flexible seals that connects the containment steel shell to the shield building. The annulus seal provides a passive barrier during normal plant operation or when the auxiliary building is isolated, preventing the exfiltration of unmonitored releases from the middle annulus to the environment.

9.4.3.2.1.2 Fuel Handling Area Ventilation Subsystem

The fuel handling area ventilation subsystem serves the fuel handling area, rail car bay/filter storage area, resin transfer pump/valve room, spent resin tank room, waste disposal container area, WSS (spent resin) valve/piping area and elevator machine room. The fuel handling area

ventilation subsystem consists of two 50 percent capacity supply air handing units of about 9,500 scfm each, a ducted supply and exhaust air system, isolation dampers, diffusers, registers, exhaust fans, automatic controls and accessories. Hot water heating coils supplied with water from the hot water heating system (VYS) and cooling coils supplied with water from the central chilled water system (VWS) are used to maintain ambient room temperatures within the normal range. The ventilation airflow capacity is designed to maintain environmental conditions that support worker efficiency during fuel handling operations based on a maximum wetbulb globe temperature of 80°F (96°F drybulb) as defined by EPRI NP-4453 (Reference 22). The supply air handling units are located in the south air handling equipment room of the annex building at elevation 135′-3″. They are connected to the air intake plenum #2 located at the south end of the annex building. This common intake plenum is described in subsection 9.4.2. The units discharge into a ducted supply distribution system which is routed to the fuel handling and rail car bay/filter storage areas of the auxiliary building. The supply and exhaust ducts are provided with isolation dampers that close when high airborne radioactivity in the exhaust air or high pressure differential with respect to the outside atmosphere is detected.

The two 50 percent capacity exhaust air fans sized to allow the system to maintain a negative pressure are located in the upper radiologically controlled area ventilation system equipment room at elevation 145′-9″ of the auxiliary building. The supply and exhaust ductwork is arranged to exhaust the spent fuel pool plume and to provide directional airflow from the rail car bay/filter storage area into the spent resin equipment rooms. The exhaust fans discharge the normally unfiltered exhaust air into the plant vent for monitoring of offsite airborne gaseous and other radiological releases.

The ventilation airflow dilutes potential airborne contamination to maintain the concentration at the site boundary within 10 CFR 20 (Reference 21) allowable effluent concentration limits and the internal room airborne concentrations within 10 CFR 20 occupational derived air concentration (DAC) limits during normal plant operation.

9.4.3.2.2 Component Description

The radiologically controlled area ventilation system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Table 9.4.3-1 provides design parameters for major defense in depth components in the system.

Supply Air Handling Units

Each supply air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil bank, a chilled water cooling coil bank, and a supply fan.

Supply and Exhaust Air Fans

The supply and exhaust air fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with

ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Unit Coolers

Each unit cooler consist of a low efficiency filter bank, a chilled water cooling coil bank and a supply fan. The normal residual heat removal system pump room unit coolers have redundant cooling coil banks. The principal construction code is the manufacturer's standard.

Low and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). The filters minimum average dust spot efficiencies for the defense in depth filters are shown in Table 9.4.3-1. The filters meet UL 900 (Reference 8) Class I construction criteria.

Electric Unit Heaters

The electric unit heaters are single-stage or two-stage fin tubular type. The electric unit heater are UL-listed and meet the requirements of UL-1996 (Reference 26) and National Electric Code (Reference 28).

Hot Water Heating Coils

The hot water heating coils are finned tubular type. The outside supply air heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. Coils are performance rated in accordance with ANSI/ARI 410 (Reference 12).

Electric Heating Coils

The electric heating coils are multistage fin tubular type. The electric heating coils meet the requirements of UL 1995 (Reference 10).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the supply duct system. The humidifier is performance rated in accordance with ARI 620 (Reference 13).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance rating of the barriers. The fire dampers meet the design, testing and installation requirements of UL-555 (Reference 15).

Shutoff and Balancing Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow and meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Isolation Dampers

Isolation dampers are bubble tight, single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power or loss of air pressure. The isolation dampers are constructed, qualified and tested in accordance with ANSI/AMCA 500 (Reference 14).

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standard - Metal and Flexible (Reference 17).

9.4.3.2.3 System Operation

9.4.3.2.3.1 Auxiliary/Annex Building Ventilation Subsystem

Normal Plant Operation

During normal plant operation, both supply air handling units and both exhaust fans operate continuously to ventilate the areas served on a once-through basis. The supply airflow rate is modulated to maintain the areas served at a slightly negative pressure differential with respect to the outside environment. The exhaust air is unfiltered and directed to the plant vent for discharge and monitoring of offsite gaseous releases.

The temperature of the supply air is controlled by temperature sensors located in the supply air ducts. When the supply air temperature is low, the face and bypass dampers across the supply air hot water heating coil are modulated to heat the supply air. Local thermostats operate supply duct heating coils and unit heaters to provide supplemental heating for building areas that have conductive heat loss to the outside environment during periods of cold outside temperature conditions. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. The ventilation air is continuously monitored by smoke monitors located in the common ductwork downstream of the supply air handling units and upstream of the exhaust fans.

A supply air handling unit is automatically shut down if one of the following conditions is detected:

- Airflow rate of the fan is below a predetermined setpoint
- Supply air temperature is below a predetermined setpoint

Each chemical and volume control system makeup pump and normal residual heat removal system pump unit cooler automatically starts whenever the associated pump receives a start signal or a high room temperature signal.

The gaseous radwaste equipment areas have sufficient ventilation to remove hydrogen gas that may leak from the radwaste equipment into the equipment rooms to maintain the concentration of hydrogen below a safe level of about 1 percent. Instrumentation available to monitor hydrogen concentration is listed in Table 11.3-2.

Abnormal Plant Operation

If high airborne radioactivity is detected in the exhaust air from the auxiliary or annex buildings, the supply and exhaust duct isolation dampers automatically close to isolate the affected area from the outside environment. The containment air filtration system mitigates the exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at a slightly negative pressure with respect to the outside environment and adjacent unaffected plant areas. The auxiliary/annex building ventilation subsystem remains in operation at a reduced capacity if either the auxiliary or annex building is not isolated. A disruption in the normal ventilation airflow rate that causes a high pressure differential with respect to the outside environment causes the same automatic actuations. The containment air filtration system maintains a slightly negative pressure differential with respect to the outside environment until operation of the auxiliary/annex building ventilation subsystem is restored. Refer to subsection 9.4.7 for a description of the containment air filtration system.

If smoke is detected in the supply or exhaust air ducts, an alarm is initiated in the main control room. The auxiliary/annex building ventilation subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. In the event of a fire occurring within the auxiliary or annex buildings, local fire dampers automatically isolate the HVAC ductwork penetrating the fire area when the local air temperature exceeds predetermined setpoints.

In the event of a loss of the plant ac electrical system, the unit coolers serving the normal residual heat removal, and chemical and volume control pump rooms can be powered by the onsite standby diesel generators.

9.4.3.2.3.2 Fuel Handling Area Ventilation Subsystem

Normal Plant Operation

During normal plant operation, both supply air handling units and both exhaust fans operate continuously to ventilate the areas served on a once-through basis. The supply airflow rate is modulated to maintain the areas served at a slightly negative pressure differential with respect to

the outside environment. The exhaust air is unfiltered and directed to the plant vent for discharge and monitoring of offsite gaseous releases.

The temperature of the supply air is controlled by temperature sensors located in the supply air ducts. When the supply air temperature is low, the face and bypass dampers across the supply air hot water heating coil are modulated to heat the supply air. A local thermostat provides supplemental heating in the rail car bay/filter storage area by controlling a supply duct heating coil. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. The ventilation air is continuously monitored by a smoke monitor located in the common ductwork downstream of the supply air handling units and by a monitor upstream of the exhaust fans.

A supply air handling unit is automatically shut down if one of the following conditions is detected:

- Airflow rate of the operating fan is below a predetermined setpoint
- Supply air temperature is below a predetermined setpoint

Abnormal Plant Operation

If high airborne radioactivity is detected in the exhaust air from the fuel handling area, the supply and exhaust duct isolation dampers automatically close to isolate the fuel handling area from the outside environment. The containment air filtration system mitigates exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at a slightly negative pressure differential with respect to the outside environment and adjacent unaffected plant areas. A disruption in the normal ventilation airflow rate that causes a high pressure differential with respect to the outside environment causes the same automatic actuations. The containment air filtration system maintains a slightly negative pressure differential with respect to the outside environment until operation of the fuel handling area ventilation subsystem is restored. Refer to subsection 9.4.7 for a description of the containment air filtration system.

If smoke is detected in the supply or exhaust air ducts, an alarm is initiated in the main control room. The fuel handling area subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. In the event of a fire occurring within the fuel handling area, fire dampers automatically isolate the HVAC ductwork penetrating this fire area when the local air temperature exceeds predetermined setpoints.

9.4.3.3 Safety Evaluation

The radiologically controlled area ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

The isolation dampers for the fuel handling area, auxiliary and annex buildings are provided to help keep normal plant releases below 10 CFR 20 (Reference 21) limits and 10 CFR 50 Appendix I (Reference 20) guidelines in the event of an abnormal release of airborne radioactivity.

9.4.3.4 Tests and Inspections

The radiologically controlled area ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Airflow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.3.5 Instrumentation Applications

The radiologically controlled area ventilation system is controlled by the plant control system (PLS). Refer to subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers maintain the proper air temperatures and provide indication and alarms. Main control room temperature indication is provided for the normal residual heat removal system pump rooms, and the chemical and volume control makeup pump room to allow room temperatures to be verified during pump operation without requiring personnel access to these rooms.

Operational status of fans and dampers is indicated in the main control room. Fans and air handling units can be placed into operation or shut down from the main control room.

Differential pressure indication and high differential pressure alarms are provided for the filters in the air handling units and room coolers. Pressure differential indication and alarms are provided via instruments (VAS-030, VAS-032, and VAS-033) to control the negative pressure in the radiologically controlled areas of the auxiliary and annex buildings.

Radioactivity indication and alarms are provided to inform the main control room operators of gaseous radioactivity concentrations in the exhaust ducts from the fuel handling area and radiologically controlled areas of the auxiliary and annex buildings.

Flow indication and alarms are provided to alert plant operators to equipment malfunctions. Smoke alarms are provided.

9.4.4 Balance-of-Plant-Interface

Not applicable to AP1000.

9.4.5 Engineered Safety Features Ventilation System

Not applicable to AP1000.

9.4.6 Containment Recirculation Cooling System

The containment recirculation cooling system controls building air temperature and humidity to provide a suitable environment for equipment operability during normal operation and shutdown.

9.4.6.1 Design Basis

9.4.6.1.1 Safety Design Basis

The containment recirculation cooling system serves no safety-related function and therefore has no nuclear safety design basis. The containment recirculation system is not required to mitigate the consequences of a design basis accident or loss of coolant accident. System equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.6.1.2 Power Generation Design Basis

The containment recirculation cooling system provides the following functions:

- Controls the containment thermal environment to maintain an average bulk air temperature below 120°F during normal operation

- Controls the containment thermal environment to maintain an average bulk air temperature below 70°F and above 50°F for personnel accessibility and equipment operability during refueling and plant shutdown

- Maintains a homogeneous containment temperature and pressure during containment integrated leak rate testing (ILRT)

- Maintains a homogeneous containment temperature and pressure during a loss of the plant ac electrical system

- Controls the reactor cavity area average concrete temperature to less than 150°F with a maximum local area temperature of 200°F

9.4.6.2 System Description

The containment recirculation cooling system is shown in Figure 9.4.6-1.

9.4.6.2.1 General Description

The containment recirculation cooling system is comprised of two 100 percent capacity skid-mounted fan coil unit assemblies with a total of four 50 percent capacity fan coil units which connect to a common duct ring header and distribution system. Each fan coil unit contains a fan and associated cooling coil banks. The two fan coil unit assemblies are located on a platform at elevation 153′-0″, approximately 180 degrees apart to provide a proper return air and mixing pattern through the ring header. The top of the ring header is approximately at elevation 176′-6″. The ring header and the fan assemblies are designed to provide uniform air and temperature

distribution inside the containment, considering the possibility that one fan coil assembly may be out of service.

The cross-connections between the central chilled water system piping for containment cooling and hot water heating system piping for containment heating are located outside the containment. The water piping inside containment is common to both the central chilled water system and hot water heating system.

9.4.6.2.2 Component Description

The containment recirculation cooling system is comprised of the following components. These components are located in buildings on the Seismic Category I Nuclear Island. Table 9.4.6-1 provides design parameters for the major components of the system.

Containment Recirculation Fan Coil Units

Each fan coil unit assembly consists of two separate but physically connected 50 percent capacity fan coil units. Each fan coil unit assembly is comprised of a return air mixing plenum section with a physical barrier in the middle and three cooling coils attached to the sides of each plenum section. The cooling coils are counterflow finned tubular type. The cooling coils are rated and meet the performance requirements in accordance with ANSI/ARI 410 (Reference 12) and ASHRAE 33 (Reference 11).

The recirculation fans are vane axial upblast type, direct driven with a high efficiency wheel, adjustable blades and an inlet bell. The fans are mounted vertically on top of the mixing air plenum section. The fans are designed with a non-overloading two-speed motor. The high speed is used during normal operation and the low speed is used during high ambient air density operating conditions such as the integrated leak rate testing. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6). Fans are factory tested and rated for performance in accordance with ANSI/AMCA 210, ANSI/AMCA 211 and ANSI/AMCA 300.

Pressure Relief Damper

Pressure relief dampers relieve high pressure differential across the ductwork to protect the equipment or components from possible damage resulting from abnormal containment pressure transients. The pressure relief dampers are the weight loaded type. The damper(s) will be placed in their standard design positions during final duct layout. They will be located so that the entire containment ring duct can be relieved without damage. They meet the performance and testing requirements of ANSI/AMCA-211 (Reference 5) and ANSI/AMCA-500 (Reference 14).

Ductwork and Accessories

Ductwork, accessories, and duct supports are constructed of galvanized steel and structurally designed to accommodate fan shutoff pressures. The ductwork meets the design, testing and construction requirements according to SMACNA HVAC Duct Construction Standards – Metal and Flexible (Reference 17).

Balancing and Backdraft Dampers

Multiblade, balancing dampers are opposite-blade type. Backdraft dampers are provided to prevent reverse flow through the standby fan while the redundant fan is operating. The backdraft dampers also allow start up of the standby fan while the redundant fan remains in operation. The balancing and backdraft dampers are designed for the same differential pressure as the duct section in which they are located and meet the performance requirements in according with ANSI/AMCA 211 (Reference 5) and ANSI/AMCA500 (Reference 14).

9.4.6.2.3 System Operation

Normal Plant Operation

During normal plant operation, one of the two 50 percent capacity fans in each fan coil unit assembly draws air from the upper levels of the operating floor and delivers cooling air through the ring duct and the secondary ductwork distribution system to the cubicles, compartments, and access areas above and below the operating floor. In addition, cooling air is delivered to the reactor cavity and reactor support areas to maintain appropriate local area and concrete temperatures. The normal supply temperature is 60°F in order to meet the environmental design requirements during various modes of operation.

As the supply air absorbs the heat released from various components inside containment, return air rises through vertical passages and openings due to its lower density to the upper containment level where it is again drawn into the fan coil units, cooled, dehumidified, and recirculated.

The standby fan coil units will be started automatically if one of the following events occurs:

- Air discharge flow rate from the operating fans decreases to a predetermined setpoint
- Air discharge temperature from the operating fan coil unit is above or below a predetermined setpoint
- Electrical and/or control power is lost

Fan coil unit supply fans are connected to 480V buses with backup power supply from the onsite standby diesel generators. Following a reactor shutdown when the outside air temperature is below a predetermined temperature, the fan coil units cooling water supply will be manually realigned by the operators from the central chilled water system to the hot water heating system. Refer to subsection 9.2.7 for further details.

Shutdown and Refueling Operation

During reactor shutdown, the system maintains the average bulk air temperature within appropriate limits for personnel access and maintenance. In addition, a steam generator maintenance space ventilation subsystem with a portable exhaust air filtration unit is available. The maintenance ventilation subsystem is designed to protect maintenance personnel and to control the spread of airborne contamination from the steam generator compartments to the other containment areas. The steam generator maintenance space ventilation subsystem consists of

permanently installed exhaust ductwork with flexible hose connections in the vicinity of the steam generator channel heads. The other end of ductwork can be connected to a portable exhaust air filtration unit. During maintenance ventilation subsystem operation, flexible hoses can be connected to the exhaust ductwork to allow the portable exhaust air filtration unit to clean up and exhaust the compartment air to containment atmosphere, the supply air distribution system to each steam generator compartment is isolated by closing dampers. Local exhaust connections with flexible hoses can be connected to the maintenance ventilation subsystem ductwork or piping to be used for clean up of localized airborne contamination.

Integrated Leak Rate Testing Operation

During integrated leak rate testing, fan coil unit operation is controlled by the main control room operator. The fan coil unit vaneaxial fans are operated at low speed to prevent the fan motors from exceeding their rated horsepower while equalizing the containment air temperature and pressure which could affect the containment integrated leak rate testing results. The recirculation fan coil units draw air from the upper levels of the operating floor and deliver airflow through the ring header and its distribution ductwork that is connected to equipment compartments, cubicles, and access areas above and below the operating floor.

Abnormal Plant Operation

The containment recirculation system is not required to mitigate the consequences of a design basis fuel handling accident or a loss of coolant accident. If the system is available following abnormal operational transients, it can be operated at reduced speed for post-event recovery operations to lower the containment temperature and pressure.

The power supplies to the containment recirculation cooling system are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the plant ac electrical system, the containment recirculation components can be connected to the onsite standby diesel generators in accordance with the optional electrical load sequencing.

9.4.6.3 Safety Evaluation

The containment recirculation cooling system has no safety function and therefore requires no nuclear safety evaluation. The containment recirculation cooling system is designed to preclude damage to safety-related systems, structures, or components as a result of a seismic event.

9.4.6.4 Tests and Inspections

The containment recirculation cooling system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of the system are accessible for periodic inspection. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

The system airflows are balanced in accordance with SMACNA HVAC Systems - Testing, Adjusting and Balancing (Reference 19).

9.4.6.5 Instrumentation Application

The containment recirculation cooling system is controlled by the plant control system. Process indication and alarm signals are locally accessible through the plant control system. Refer to subsection 7.1.1 for a description of the plant control system.

Temperature controllers are provided in the ring headers of the corresponding containment recirculation fan coil unit which provide an input signal to modulate the central chilled water system supply valves to the cooling coils. The containment volumetric average high and low temperature are monitored and alarmed when the temperature is out of the normal operating range. The ambient temperature in a specific equipment compartment or areas of the containment are monitored and alarmed.

The discharge flowrate from each containment recirculation fan unit is monitored and low flow condition is alarmed to alert the operator for a manual start of the spare fan unit. Flow to the reactor cavity is also monitored and low flow condition is alarmed.

9.4.7 Containment Air Filtration System

The containment air filtration system (VFS) serves the containment, the fuel handling area and the other radiologically controlled areas of the auxiliary and annex buildings, except for the hot machine shop and health physics areas which are served by a separate ventilation system.

9.4.7.1 Design Basis

9.4.7.1.1 Safety Design Basis

The containment air filtration system serves no safety-related function, other than containment isolation, and therefore has no nuclear safety design basis except for containment isolation. See subsection 6.2.3 for a description of the containment isolation system. System equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.7.1.2 Power Generation Design Basis

Containment Area

The containment air filtration system provides the following functions:

- Provides intermittent flow of outdoor air to purge the containment atmosphere of airborne radioactivity during normal plant operation, and continuous flow during hot or cold plant shutdown conditions to provide an acceptable airborne radioactivity level prior to personnel access

- Provides intermittent venting of air into and out of the containment to maintain the containment pressure within its design pressure range during normal plant operation

- Directs the exhaust air from the containment atmosphere to the plant vent for monitoring, and provides filtration to limit the release of airborne radioactivity at the site boundary within acceptable levels

- Monitors gaseous, particulate and iodine concentration levels discharged to the environment through the plant vent

The system conditions and filters outside air supplied to the containment for compatibility with personnel access during maintenance and refueling operations. Based on the maximum and minimum outside air normal temperature conditions shown in Chapter 2, Table 2-1, the system supplies air between 50 and 70°F. The air is distributed and conditioned within the containment by the containment recirculation system (subsection 9.4.6).

Radiologically Controlled Areas Outside Containment

The containment air filtration system provides filtration of exhaust air from the fuel handling area, auxiliary, or annex buildings to maintain these areas at a slightly negative pressure with respect to the adjacent areas when the radiologically controlled area ventilation system detects high airborne radioactivity or high pressure differential. Refer to subsection 9.4.3 for a description of the radiologically controlled area ventilation system.

9.4.7.2 System Description

The containment air filtration system is shown in Figure 9.4.7-1.

9.4.7.2.1 General Description

The containment air filtration system consists of two 100 percent capacity supply air handling units, a ducted supply and exhaust air system with containment isolation valves and piping, registers, exhaust fans, filtration units, automatic controls and accessories. The supply air handling units are located in the south air handling equipment room of the annex building at elevation 158′-0″. The supply air handling units are connected to a common air intake plenum, located at the south end of the fan room. The common air intake plenum #3 is located at the extreme south end of the annex building between elevation 158′-0″ and about 180′-0″. This plenum supplies air for the radiologically control area ventilation system, and the containment air filtration system. The intake is not protected from tornado missiles. The containment air filtration system supply air handling units discharge the supply air towards the east containment recirculation cooling system (VCS) recirculation unit to distribute the purge air within the containment. Refer to subsection 9.4.6 for a description of the containment recirculation cooling system.

The exhaust air filtration units are located within the radiologically controlled area of the annex building at elevation 135′-3″ and 146′-3″. The filtration units are connected to a ducted system with isolation dampers to provide HEPA filtration and charcoal adsorption of exhaust air from the containment, fuel handling area, auxiliary and annex buildings. A gaseous radiation monitor is located downstream of the exhaust air filtration units in the common ductwork to provide an alarm if abnormal gaseous releases are detected. The plant vent exhaust flow is monitored for gaseous, particulate and iodine releases to the environment. During containment purge, the exhaust air

filtration units satisfy 10 CFR 50 Appendix I guidelines (Reference 20) for offsite releases and meets 10 CFR 20 (Reference 21) allowable effluent concentration limits when combined with gaseous releases from other sources. During conditions of abnormal airborne radioactivity in the fuel handling area, auxiliary and/or annex buildings, the filtration units provide filtered exhaust to minimize unfiltered offsite releases.

The size of the containment air filtration system supply and exhaust air lines that penetrate the containment pressure boundary is 36 inches in diameter. Each penetration includes an inboard and outboard branch connection with 16 inch diameter containment isolation valves that are opened when the containment air filtration system is connected to the containment. The ends of the 36 inch containment penetrations are capped for possible future addition of a high volume purge system. In the event of a loss-of-coolant accident (LOCA) while the containment air filtration system is aligned to containment, there will not be a significant release of radioactivity during closure of the 16 inch diameter supply and exhaust valves. The maximum time for valve closure (see Table 6.2.3-1) is consistent with the analysis assumptions for radiological consequences (see Table 15.6.5-2). The closure time is also consistent with the basis (compliance with 10 CFR Part 100) for Branch Technical Position CSB 6-4 to Standard Review Plan 6.2.4 (Reference 23) or described in Subsection 6.2.1.5.

The exhaust air containment penetrations also serve as a connection for the containment integrated leak rate test system to pressurize and depressurize the containment during integrated leak rate testing. Otherwise, the containment air filtration exhaust subsystem is not involved with the containment integrated leak rate test and is isolated from the containment during this time period.

9.4.7.2.2 Component Description

The containment air filtration system is comprised of the following components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Table 9.4.7-1 provides design parameters for the major components of the system.

Supply Air Handling Units

Each supply air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil bank, a chilled water cooling coil bank and a supply fan.

Exhaust Air Filtration Units

Each exhaust air filtration unit consists of an electric heater, an upstream high efficiency filter bank, a HEPA filter bank, a charcoal adsorber with a downstream postfilter bank, and an exhaust fan. The filtration unit configurations, including housing, internal components, ductwork, dampers, fans, and controls, are designed, constructed, and tested to meet the applicable performance requirements of ASME AG-1, N509, and N510 (References 36, 2, and 3) to satisfy the guidelines of Regulatory Guide 1.140 (Reference 30) except as noted in Appendix 1A. The filtration unit housings maximum leakage rates do not exceed one percent of the design flow in accordance with ASME AG-1. Refer to Table 9.4-1 for a summary of the containment air

filtration system filtration efficiencies and Appendix 1A for a comparison of the containment air filtration system exhaust air filtration units with Regulatory Guide 1.140 (Reference 30).

Isolation Dampers

Isolation dampers are bubble tight, single-blade or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power or instrument air. The design and construction of the isolation dampers is in accordance with ANSI/AMCA 500 or ASME AG-1 (References 14 and 36).

Pressure Differential Control Dampers

Pressure differential control dampers utilize opposed-blade type construction and meet the performance requirements of ANSI/AMCA 500 (Reference 14) or ASME AG-1 (Reference 36), Section DA. The dampers maintain a slight negative pressure within the fuel handling building area, with respect to the environment and adjacent non-radiologically controlled plant areas.

Supply and Exhaust Fans

The supply and exhaust air fans are centrifugal type, single width single inlet (SWSI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. Fan performance is rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5) and ANSI/AMCA 300 (Reference 6).

Containment Penetrations

The containment penetrations include containment isolation valves, interconnecting piping, and vent and test connections with manual test valves. The containment isolation components that maintain the integrity of the containment pressure boundary after a LOCA are classified as Safety Class B and seismic Category I. Seismic Category I debris screens are mounted on Safety Class C, seismic Category I pipe to prevent entrainment of debris through the supply and exhaust openings that may prevent tight valve shutoff. The screens are designed to withstand post-LOCA pressures.

The containment isolation valves inside and outside the containment have air operators. The valves are designed to fail closed in the event of loss of electrical power or air pressure. The valves are controlled by the protection and plant safety monitoring system as discussed in subsection 7.1.1. The valves shut tight against the containment pressure following a design basis accident.

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures. The system air ductwork inside containment meets seismic Category II criteria so that it will not fall and damage any safety-related equipment following a safe shutdown earthquake. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standard - Metal and Flexible (Reference 17). The exhaust air ductwork and

supports meet the design and construction requirements of ASME AG-1 (Reference 36), Article SA-4500.

Shutoff and Balancing Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow and meet the performance requirements of ANSI/AMCA 500 (Reference 14). The containment exhaust air dampers meet the design and construction criteria of ASME AG-1 (Reference 36), Section DA.

Fire Dampers

Fire dampers are provided where the ductwork penetrates a fire barrier to maintain the fire resistance rating of the fire barriers. The fire dampers meet the design and installation requirements of UL-555 (Reference 15).

Low Efficiency Filters, High Efficiency Filters, and Postfilters

Low and high efficiency filters are rated in accordance with ASHRAE Standard 52 and 126 (References 7 and 35). The minimum average dust spot efficiencies of the filters are shown in Table 9.4.7-1. High efficiency filter performance upstream of HEPA filter banks meet the design requirements of ASME AG-1 (Reference 36), Section FB. Postfilters located downstream of the charcoal adsorbers have a minimum DOP efficiency of 95 percent. The filters meet UL 900 Class I construction criteria (Reference 8).

HEPA Filters

HEPA filters are constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FC. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-μm aerosol in accordance with ASME AG-1, Section TA.

Charcoal Adsorbers

Each charcoal adsorber is designed constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FE; and Regulatory Guide 1.40. Each charcoal adsorber is a single assembly with welded construction and 4-inch deep Type III rechargeable adsorber cell, conforming with 1E Bulletin 80-03 (Reference 29).

Electric Heating Coils

The electric heating coils are fin tubular type. The electric heating coils meet the requirements of UL-1995 (Reference 10). The coils are constructed, qualified and tested in accordance with ASME AG-1 (Reference 36), Section CA.

Heating Coils

The heating coils are hot water, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. Coils are performance rated in accordance with ANSI/ARI 410 (Reference 12).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

9.4.7.2.3 System Operation

Normal Plant Operation

During normal plant operation, the containment air filtration system operates on a periodic basis to purge the containment atmosphere as determined by the main control room operator to reduce airborne radioactivity or to maintain the containment pressure within its normal operating range. One supply air handling unit provides outdoor air that is filtered, cooled, or heated to the containment areas above the operating floor. The airflow rate is controlled to a constant value by modulating the supply fan inlet vanes to compensate for filter loading or changes in containment pressure. The cooling coils are supplied with chilled water from the central chilled water system (VWS) to cool and/or dehumidify the outside supply air. The heating coils are supplied with hot water by the hot water heating system (VYS). Refer to subsections 9.2.7 and 9.2.10 for descriptions of the central chilled water and hot water heating systems.

The temperature of the air supplied by each air handling unit is controlled by temperature sensors located in the supply air duct. When the supply air temperature is low, the face and bypass dampers across the supply air heating coil are modulated to heat the supply air. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. The supply air is continuously monitored by a smoke monitor located in the common ductwork downstream of the supply air handling units.

The airflow rate through the exhaust filters is controlled to a constant value when the exhaust filters are connected to the containment by modulating the exhaust fan inlet vanes to compensate for filter loading or changes in system resistance caused by single or parallel fan operation, or changes in containment pressure. The exhaust lines from the containment include a pair of isolation dampers arranged in parallel to restrict the airflow to maintain the exhaust filter plenums at a negative air pressure when the containment is positively pressurized. Based on predetermined setpoints, the operators select the appropriate damper to open. This prevents exfiltration of unfiltered air from bypassing the filters.

The filtered exhaust air from the containment is discharged to the atmosphere through the plant vent by the exhaust fan. The gaseous effluents in the plant vent are monitored for radioactivity levels before the air is discharged to the environment. Refer to Section 11.5 for a description of the plant vent radiation monitor.

During single subsystem operation, the standby supply and exhaust air units can be started manually by the operator if the operating train fails.

Prior to and during plant shutdown, one or both trains of the containment air filtration system can be operated to remove airborne radioactivity prior to personnel access. During cold ambient conditions, the supply air is heated by the hot water heating system. The exhaust filter unit electric heater controls the relative humidity of the exhaust air entering the charcoal adsorber below 70 percent.

When both trains are operated concurrently, the containment air filtration system provides a maximum airflow rate equivalent to approximately 0.21 air changes per hour.

Abnormal Plant Operation

The containment isolation valves in the supply and exhaust air lines automatically close when containment isolation signals are initiated by the protection and safety monitoring system or diverse actuation system. Refer to subsections 6.2.3, 7.7.1.11 and 7.3 for discussions of the containment isolation system, diverse actuation system and protection and safety monitoring system.

Main control room operators can connect the containment air filtration system to the containment for cleanup of potential airborne radioactivity while the containment remains isolated if a containment high radiation signal is not present.

If high airborne radioactivity or high pressure differential is detected in the fuel handling area, the auxiliary and/or annex buildings, the radiologically controlled area ventilation system isolates the affected area from the outside environment and starts the containment air filtration exhaust subsystem to maintain a slight negative pressure differential in the isolated zone(s). The airflow rate through the exhaust fan is maintained at a constant value by modulating the fan inlet vanes. An outside air makeup damper modulates to control the exhaust airflow rate through the HEPA and charcoal filters to maintain the isolated area(s) at a slightly negative pressure relative to the clean areas. The containment air filtration system is automatically isolated from the containment, if purging is in progress and the standby exhaust filter train does not start. If both exhaust trains are connected to the containment, one exhaust train is automatically isolated from the containment and realigned to the isolated area(s). The exhaust subsystem can be manually connected to the onsite diesel generators if there is a loss of ac power.

The containment air filtration system is not required to mitigate the consequences of a design basis fuel handling accident or a loss of coolant accident. If the exhaust air filtration units are operational and ac power is available, they may be used to support post-event recovery operations. The plant vent high range radiation detectors monitor effluents discharged into the plant vent.

If smoke is detected in the common supply air duct, an alarm is initiated. The system remains in operation unless plant operators determine that there is a need to manually shut down the supply air handling units. Fire dampers are provided for HVAC ductwork that passes through a fire barrier in order to isolate each fire zone in the event of a fire.

9.4.7.3 Safety Evaluation

The containment air filtration system has no safety-related function, other than containment isolation, and therefore requires no nuclear safety evaluation. The containment isolation function is evaluated in subsection 6.2.3.

The failure of equipment and ductwork will not reduce the functioning of safety-related systems, structures or components that are required to close to maintain containment isolation integrity after a design basis accident. Ductwork that is located inside containment whose failure may affect any safety-related equipment is designed to seismic Category II requirements.

9.4.7.4 Tests and Inspections

The containment air filtration system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. The exhaust subsystem is balanced to provide airflow in accordance with the guidelines of ASME N510 (Reference 3). The supply air subsystem airflow rate is measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

The tests and inspections of the containment isolation valves associated with the containment air filtration system are discussed in subsections 6.2.3 and 6.2.5.

HEPA filters and charcoal adsorbers are tested in place in accordance with ASME N510 to verify that these components do not exceed a maximum allowable bypass leakage. Samples of charcoal adsorbent are periodically tested to verify a minimum charcoal efficiency of 90 percent in accordance with Regulatory Guide 1.140 (Reference 30) except that test procedures and test frequency are conducted in accordance with ASME N510.

The exhaust ductwork and filter plenums are tested in place for leak tightness in accordance with ASME N510, Section 6.

9.4.7.5 Instrumentation Application

The containment air filtration system operation is controlled by the plant control system (PLS) except for the containment isolation valves which are controlled by the protection and safety monitoring system (PMS) and diverse actuation system (DAS). Refer to subsection 7.1.1 for a discussion of the plant control system, protection and safety monitoring system, and diverse actuation system. Automatic protection and safety monitoring system actuations of these valves are discussed in Section 7.3; the diverse actuation system signals are discussed in subsection 7.7.1.11. Display and monitoring of system instrumentation is consistent with the requirements of Table 4-2 of ASME N509 (Reference 2).

Temperature controllers maintain the proper supply air temperature. Temperature indication and alarms are provided to inform operators of abnormal temperature conditions for supply air and charcoal adsorbers.

Pressure differential indication and alarms are provided to inform plant operators when air filter changeout is necessary.

Status indication and alarms are provided to monitor operation of fans, controlled dampers and controlled valves. Fans can be placed into operation or shut down from the main control room.

Relative humidity indication and an alarm are provided to monitor the relative humidity of the air upstream of the containment air filtration exhaust air charcoal adsorbers.

Radioactivity indication and alarms are provided to inform the main control room operators of the concentration of gaseous radioactivity in the containment air filtration system exhaust duct and gaseous, particulate and iodine concentrations in the plant vent. See Section 11.5 for a description of these radiation monitors.

Flow indication and alarms are provided to alert plant operators to equipment malfunctions.

9.4.8 Radwaste Building HVAC System

The radwaste building HVAC system serves the radwaste building which includes the clean electrical/mechanical equipment room and the potentially contaminated HVAC equipment room, the packaged waste storage room, the waste accumulation room, and the mobile systems facility.

9.4.8.1 Design Basis

9.4.8.1.1 Safety Design Basis

The radwaste building HVAC system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.8.1.2 Power Generation Design Basis

The radwaste building HVAC system provides the following functions:

- Provide conditioned air to work areas to maintain acceptable temperatures for equipment and personnel working in the areas
- Provide confidence that air movement is from clean to potentially contaminated areas to minimize the spread of airborne contaminants
- Collect the vented discharges from potentially contaminated equipment
- Provide for radiation monitoring of exhaust air prior to release to the environment
- Maintain the radwaste building at a negative pressure with respect to ambient to prevent unmonitored releases from the radwaste building

The system maintains the following temperature based on maximum and minimum normal outdoor air temperature conditions shown below in Chapter 2, Table 2-1:

Room or Area	Temperatures (°F)
Processing areas and storage areas	50-105
Mechanical and electrical equipment rooms	50-105

9.4.8.2 System Description

The radwaste building HVAC system is shown in Figure 9.4.8-1.

9.4.8.2.1 General Description

The radwaste building HVAC system is a once-through ventilation system that consists of two integrated subsystems: the radwaste building supply air system and the radwaste building exhaust air system. The systems operate in conjunction with each other to maintain temperatures in the areas served while controlling air flow paths and building negative pressure.

The supply air system consists of two 50 percent capacity air handling units of about 9,000 scfm each with a ducted air distribution system, automatic controls, and accessories. The air handling units are located in an electrical/mechanical equipment room on elevation 100′-0″ on the southwest side of the building. Each unit draws 100 percent outdoor air through individual louvered outdoor air intakes. The two units discharge into a common duct distribution system which is routed through the building. Branch connections from the main duct supply air through registers into the various areas served.

The exhaust air system consists of two 50 percent capacity exhaust centrifugal fans sized to allow the system to maintain a negative pressure, an exhaust air duct collection system, and automatic controls and accessories. The airflow rates are balanced to maintain a constant exhaust design air flow through the fans. The exhaust fans are located in an equipment room on Elevation 100′-0″ in the northwest corner of the radwaste building.

The exhaust fans discharge to a common duct which is routed to the plant vent. A radiation monitor records activity in the discharge duct and activates an alarm in the main control room when excess activity in the effluent discharge is detected. The radiation monitoring system is described in Section 11.5.

The exhaust air collection duct inside the radwaste building exhausts air from areas and rooms where low levels of airborne contamination may be present. Exhaust connection points are provided to allow the direct exhaust of equipment located on the mobile systems. Where potential for significant airborne release exists, mobile systems include HEPA filtration. Back draft dampers are provided at each mobile system connection to prevent blowback through the equipment in the event of exhaust system trip. Criteria for mobile processing systems are included in Sections 11.2 and 11.4.

9.4.8.2.2 Component Description

The radwaste building HVAC system is comprised of the following major components. These components are located in the non-seismic radwaste building.

Supply Air Handling Units

Each air handling unit consists of a plenum section, a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil, a chilled water cooling coil bank, and a supply fan with automatic inlet vanes.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). The filters meet UL 900 (Reference 8) Class I construction criteria.

Hot Water Unit Heaters

The hot water unit heaters consist of a fan section and hot water heating coil section factory assembled as a complete and integral unit. The unit heaters are either horizontal discharge or vertical downblast type. The coil ratings are in accordance with ANSI/ARI 410 (Reference 12).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Shutoff, Control, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through exhaust connections for mobile systems. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. Dampers meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17).

9.4.8.2.3 System Operation

Normal Plant Operation

During normal operation, both supply air handling units and both exhaust fans operate continuously to maintain suitable temperatures in the radwaste building. The radwaste building supply air flow through the inlet vanes of the supply fans is modulated automatically by the differential pressure controllers to maintain the building at a negative pressure relative to the outdoors. Sensors for the controllers are mounted in the general building area. Other sensors are mounted outdoors shielded from the effects of wind. Electric interlocks between the truck access doors and the supply fan flow controller permits the supply air to drop to 6000 cfm below the exhaust flow when any truck bay door is open. This creates a flow into the building through the open door.

The temperature of the air supplied by the air handling unit is controlled by separate heating and cooling controllers, with sensors in the general building area. The cooling controllers modulate the control valves in the chilled water supply lines to the air handling units. The heating controllers modulate the face and bypass dampers of the hot water heating coils in the air handling units.

Differential pressure drop across the supply units filter banks is monitored, and individual alarms are actuated when any pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on a supply unit, the affected supply fan and exhaust fan are stopped and isolated from the duct system by means of isolation dampers. During filter replacement, the supply and exhaust systems operate at 50 percent capacity. In this mode of operation, radwaste processing operations are adjusted to obtain acceptable temperature in the radwaste building.

The hot water unit heaters in the mobile systems facility are not normally required to operate to maintain the general building temperature. These heaters operate, in response to local thermostat control, to temper air entering the building when a truck access door is opened.

The hot water unit heater in the electrical/mechanical room operates in response to local thermostat control to maintain the required minimum temperature.

Abnormal Plant Operation

The radwaste building HVAC system is not required to operate during any abnormal plant condition.

9.4.8.3 Safety Evaluation

The radwaste building HVAC system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.8.4 Tests and Inspections

The radwaste building HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC systems - Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.8.5 Instrumentation Applications

The radwaste building HVAC system operation is controlled by the plant control system (PLS). Refer to subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Supply air temperature is controlled by sensing the temperature in the mobile systems facility and the electrical/mechanical equipment room. Unit heaters are controlled by local thermostats. Temperature indication and alarms are accessible locally via the plant control system.

Temperature is indicated for each air handling unit supply air discharge duct.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for low air flow rates in the fan discharge ducts.

An alarm is provided for high radiation in the main exhaust duct to the vent stack.

An alarm is provided for smoke in the common discharge duct from the supply air handling units.

Position indicating lights are provided for automatic dampers.

9.4.9 Turbine Building Ventilation System

The turbine building ventilation system (VTS) operates during startup, shutdown, and normal plant operations. The system maintains acceptable air temperatures in the turbine building for equipment operation and for personnel working in the building.

9.4.9.1 Design Basis

9.4.9.1.1 Safety Design Basis

The turbine building ventilation system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.9.1.2 Power Generation Design Basis

The turbine building ventilation system provides the following functions:

- Maintains acceptable temperatures for equipment operation
- Provides for removal of chemical fumes from the secondary sampling laboratory room, flammable vapors from the lube oil reservoir room and the clean and dirty lube oil storage room, and vitiated air from the toilets
- Provides conditioning air to maintain acceptable temperatures for electrical equipment rooms and personnel work areas
- Maintains the following temperatures based on the maximum and minimum normal outside air temperature conditions shown in Chapter 2 Table 2-1:
  - General area (operating deck, intermediate levels, and base slab) .... 50-105°F
  - Auxiliary boiler room .... 50-105°F
  - Fire pump room (motor driven) .... 50-105°F
  - Electrical equipment rooms (switchgear room 1, switchgear room 2, electrical equipment room, and variable frequency drive [VFD] power converter room) .... 50-105°F
  - Personnel work areas (Secondary sampling laboratory, office space at elevation 171′-0″) .... 73-78°F

9.4.9.2 System Description

The turbine building ventilation system consists of the following subsystems:

- General area heating and ventilation
- Electrical equipment and personnel work area HVAC
- Local area heating and ventilation
  - Lube oil reservoir room ventilation
  - Clean and dirty lube oil storage room ventilation
  - Auxiliary boiler room ventilation
  - Motor-driven fire pump room heating and ventilation
  - Toilet area ventilation

The turbine building HVAC system general area subsystem is shown in Figure 9.4.9-1.

9.4.9.2.1 General Description

9.4.9.2.1.1 General Area Heating and Ventilation

Most of the turbine building is supplied by the general area ventilation and heating subsystem. Air is exhausted from the turbine building to the atmosphere by roof exhaust ventilators. The roof exhaust ventilators pull in outside air through wall louvers located at elevations 100′-0″, 117′-6″, and 135′-3″. Wall louvers are located at the operating deck to provide additional air during plant outage operations. The general area heating subsystem uses hot water unit heaters to provide local heating throughout the turbine building. During heating operation, the general area ventilation system is not operated.

9.4.9.2.1.2 Electrical Equipment and Personnel Work Area HVAC

The electrical equipment and personnel work area air conditioning subsystem serves electrical equipment areas (switchgear rooms, the electrical equipment room and the reactor coolant pump variable frequency drive power converter room) and personnel work areas (secondary sampling laboratory, office space at elevation 171′-0″). This subsystem is subdivided into two independent HVAC systems, one serving the electrical equipment areas and one serving the personnel work areas.

The electrical equipment HVAC system consists of two 50 percent capacity air handling units with a supply fan and a return air fan of about 16,500 scfm each, a ducted supply and return air system, automatic controls, and accessories. The air handling units are located on elevation 149′-0″ of the turbine building. The temperature of the rooms is maintained by thermostats which control the chilled water control valves for cooling and the integral face/bypass dampers for heating. Outside air is mixed with recirculated air to maintain a positive pressure.

The personnel work area HVAC system consists of two 50 percent capacity air handling units of about 4,500 scfm each, a ducted supply and return air system, automatic controls, and accessories. The air handling units are located on elevation 100′-0″ of the turbine building. The temperature of the rooms is maintained by thermostats which control the chilled water control valves for cooling and the integral face/bypass dampers for heating. Electric reheat coils are provided in the

ductwork to each room to maintain close temperature control. Outside air is mixed with recirculated air to maintain a positive pressure.

9.4.9.2.1.3 Local Area Heating and Ventilation

The lube oil reservoir room, clean and dirty lube oil storage room, toilet areas (facilities), and secondary sampling laboratory fume hood have centrifugal exhaust fans to remove flammable vapors, odors, or chemical fumes as required.

The auxiliary boiler room and the motor driven fire pump room have exhaust ventilators to remove heat generated by the boiler equipment and fire pump. Air is pulled from the general area of the turbine building through wall fire damper openings in the rooms and is exhausted outside of the turbine building to the atmosphere. The motor-driven fire pump room is heated by a hot water unit heater to provide freeze protection for the fire pump. Hot water heating is not provided in the auxiliary boiler room, however, air is pulled from the general area of the turbine building to control space temperature in the boiler room.

9.4.9.2.2 Component Description

The turbine building ventilation system is comprised of the following major components. These components are located in the non-seismic turbine building.

HVAC Air Handling Units

Each air handling unit is a horizontal draw-through cabinet type consisting of a mixing box section, low efficiency (25 percent) filter, high efficiency (80 percent) filter, integral face/ bypass damper, hot water heating coil, chilled water cooling coil. The electrical equipment room air handling units include a return air fan and a supply fan. The personnel area air handling units include a supply air fan.

Low Efficiency Filters and High Efficiency Filters

The efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). The filters meet UL 900 (Reference 8) Class I construction criteria.

Exhaust Ventilators

The turbine building roof exhaust ventilators are hooded, direct driven, propeller type with pneumatic operated backdraft damper. Ventilators in the auxiliary boiler room and fire pump room are smaller, two-speed, propeller type with pneumatically actuated backdraft dampers. Ventilators in the lube oil rooms and restrooms are centrifugal type. The exhaust ventilators are built to the manufacturer's standards.

Shutoff, Control, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through shut down fans. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. Dampers meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Unit Heaters

Unit heaters are the down-blow type with propeller type fans directly connected to the fan motor. Each unit heater is equipped with a four-way discharge outlet. The coil ratings are in accordance with ANSI/ARI 410 (Reference 12).

Electric Duct Heaters

Electric duct heaters are open grid type. The duct heaters are UL-listed for zero clearance and meet requirements of NFPA 70 (Reference 28).

Humidifiers

A humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifier is designed and rated in accordance with ARI 620 (Reference 13).

Fire Dampers

Fire dampers are provided at HVAC duct penetrations through fire barriers to maintain fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL-555 (Reference 15) as applicable.

Ductwork and Accessories

Ductwork, duct supports, and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17).

9.4.9.3 System Operation

9.4.9.3.1 General Area Heating and Ventilation

The general area ventilation system is manually controlled. Roof exhaust ventilators are manually started and stopped as required to satisfy space temperature conditions. Wall louvers located at the ground floor and the two intermediate levels of the turbine building are normally open during ventilation operation. The wall louvers located at the operating floor are manually opened to

increase ventilation air to the area during outage operations. The operating floor louvers normally remain closed during power operation.

Hot water unit heaters are controlled automatically or manually. In the automatic mode, the heater fan motors are thermostatically controlled by their respective space thermostats. The plant hot water heating system (VYS) supplies hot water to the unit heaters.

9.4.9.3.2 Electrical Equipment and Personnel Work Area HVAC

During normal operation, the two air handling units of the electrical equipment HVAC system operate continuously and the two air handling units of the personnel work area HVAC system operate continuously. The chilled water coils are supplied from the plant central chilled water system (VWS) and the hot water coils are supplied from the plant central hot water heating system.

9.4.9.3.3 Local Area Heating and Ventilation

The ventilation operation for the lube oil reservoir room and the clean and dirty lube oil storage room is similar. Each centrifugal exhaust fan runs continuously to prevent the accumulation of chemical fumes or flammable vapors in its respective room.

The ventilation operation for the auxiliary boiler room and the motor driven fire pump room is similar. Each directly driven, two-speed wall exhaust ventilator is automatically or manually controlled. In the automatic mode, the exhaust ventilator motor is thermostatically controlled by a two-stage room thermostat. In the manual mode the exhaust ventilator runs continuously at high speed until it is manually stopped.

The heating operation for the auxiliary boiler room depends upon pulling air from the turbine building general area. A heating thermostat is provided in the boiler room to control the operation of the exhaust fan below 50°F. The boiler room exhaust fan starts at low speed and continues to run until the space temperature rises above 50°F.

To provide heating of the motor driven fire pump room, a hot water unit heater fan motor is controlled by a space thermostat in the automatic mode, or the heater fans run continuously in the manual mode. The plant hot water heating system supplies hot water to the unit heater.

The toilet area exhaust fans run continuously.

9.4.9.4 Safety Evaluation

The turbine building ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

There is no safety-related equipment in the turbine building.

9.4.9.5 Tests and Inspections

The turbine building ventilation system is designed to permit periodic inspection of system components during normal plant operation. System air balance testing and adjustments for the electrical equipment and personnel work areas are conducted in accordance with SMACNA (Reference 19).

Fans are factory tested and rated in accordance with ANSI/AMCA 210 (Reference 4). Water coils are factory tested and rated in accordance with ANSI/ARI 410 (Reference 12).

Ductwork is leak tested in accordance with SMACNA (Reference 18).

9.4.9.6 Instrumentation Applications

The turbine building ventilation system is controlled by the plant control system.

Temperature indication and controllers control the room air temperatures within a predetermined range.

Temperature indication is provided to allow surveillance of room and space temperatures in the turbine building.

Differential pressure indication is provided for the air filters in each air handling unit. Alarms are provided for high pressure drops across the air filters.

9.4.10 Diesel Generator Building Heating and Ventilation System

The diesel generator building heating and ventilation system serves the standby diesel generator rooms, electrical equipment service modules, and diesel fuel oil day tank vaults in the diesel generator building and the two diesel oil transfer modules located in the yard near the fuel oil storage tanks.

9.4.10.1 Design Basis

9.4.10.1.1 Safety Design Basis

The diesel generator building heating and ventilation system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.10.1.2 Power Generation Design Basis

The diesel generator building heating and ventilation system provides the following functions:

- Provides sufficient quantities of ventilation air to maintain acceptable temperatures within the generator rooms for equipment operation and reliability during periods of diesel generator operation in order for the onsite standby power system to perform its defense in depth functions

- Provides adequate heating and ventilation for suitable environmental conditions for maintenance personnel working in the diesel generator room when the generators are not in operation

- Provides suitable environmental conditions for equipment operation in each diesel generator electrical equipment service module under the various modes of diesel generator operation

- Prevents the accumulation of combustible vapors and dissipate their concentration in the fuel oil day tank vault

- Provides adequate heating and ventilation to maintain acceptable temperature within the diesel oil transfer module enclosures

The system maintains the following room temperatures based on ambient outside air temperature conditions of 95°F (summer) and -5°F (winter):

Area	Design Minimum (°F)	Temperature Maximum (°F)
Diesel Generator Area		
Diesel Generator On	None	130
Diesel Generator Off	50	105
Service Module		
Diesel Generator On	50	105
Diesel Generator Off	50	105
Diesel Oil Transfer Module Enclosure	50	105

9.4.10.2 System Description

The diesel generator building heating and ventilation system is shown in Figure 9.4.10-1.

The system consists of the following subsystems:

- Normal heating and ventilation subsystem
- Standby exhaust ventilation subsystem
- Fuel oil day tank vault exhaust subsystem
- Diesel oil transfer module enclosures ventilation and heating subsystem

9.4.10.2.1 General Description

9.4.10.2.1.1 Normal Heating and Ventilation System

The normal heating and ventilation subsystem serves the diesel generator building. Each diesel generator train is provided with independent ventilation and heating equipment for the building areas serving that diesel generator train.

Each normal heating and ventilation subsystem for a diesel generator train consists of one 100 percent capacity engine room air handling unit which ventilates the diesel generator room, one 100 percent capacity service module air handling unit which ventilates the electrical equipment service module, an exhaust system for the fuel oil storage vault and electric unit heaters in the diesel generator area. Air intake louvers for these units are located as high in the diesel generator building wall as possible.

The engine room air handling units are located above the electrical equipment service module with supply and return ducts in the diesel generator room.

The service module air handling units are located above the service module with supply and return ducts into the module.

Electric unit heaters are provided in the diesel generator room to maintain the space at a minimum temperature of 50°F when the diesel generators are off.

9.4.10.2.1.2 Standby Exhaust Ventilation Subsystem

The standby exhaust ventilation subsystem for each diesel generator room consists of two 50 percent capacity roof mounted exhaust fans and motor operated air intake dampers mounted in the exterior walls of the room.

9.4.10.2.1.3 Fuel Oil Day Tank Vault Exhaust Subsystem

Each fuel oil day tank vault is continuously ventilated by a centrifugal exhaust fan. The exhaust fans are mounted on the roof of the vault and ducted to draw air from one foot above the vault floor and from above the oil containment dike to remove any oil fumes generated in the space. Air is drawn into the vault from the diesel generator room through an opening protected with a fire damper.

9.4.10.2.1.4 Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem

Each diesel oil transfer module enclosure is ventilated by a roof mounted exhaust fan. Outside air is drawn into the enclosure through manually operated louvered air intakes. The louvers are closed for winter operation when heating is required. An electric unit heater is provided in each enclosure to maintain the space at a minimum temperature of 50°F.

9.4.10.2.2 Component Description

The diesel generator building heating and ventilation system is comprised of the following major components. These components are located in the non-seismic diesel-generator building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.10-1 through 9.4.10-4 provide design parameters for major components in the system.

Supply Air Handling Units

Each air handling unit consists of a mixing box section, a low efficiency filter bank, a high efficiency filter bank, and a supply fan. Electric heating coils are provided for the service module air handling units for module heating.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency filters and high efficiency filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). Filter minimum average dust spot efficiency is shown in Table 9.4.10-1. The filters meet UL 900 (Reference 8) Class I construction criteria.

Electric Heating Coils

The electric heating coils are multi-stage fin tabular type. The electric heating coils meet the requirements of UL 1995 (Reference 10).

Roof Exhaust Fans

The standby exhaust fans are roof mounted, direct drive upblast ventilators. The fans are equipped with gravity dampers that open when the fan operates and close when the fan is shut down. The diesel oil transfer module enclosure exhaust fans are direct driven centrifugal fan roof ventilators. The ventilators are equipped with gravity dampers that open when the fan operates and close when the fan is shut down.

Electric Unit Heaters

The electric unit heaters are single-stage or two-stage fin tubular type. The electric unit heaters are UL-listed and meet the requirements of UL 1996 (Reference 26) and the National Electric Code (Reference 28).

Shutoff, Control, Balancing, and Backdraft Dampers

Multiblade, two-position shutoff remotely operated dampers are parallel-blade type. Multiblade, control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through shut down exhaust fans and to relieve pressure from the service module and diesel generator building. Dampers meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17).

9.4.10.2.3 System Operation

9.4.10.2.3.1 Normal Heating and Ventilation Subsystem

Normal Plant Operation

During normal plant operation, each engine room air handling unit operates continuously when the diesel generator is not operating and outdoor air is required for room cooling. Each air handling unit has 100 percent cooling capacity for the engine room served by the unit. The engine room air handling unit is not required to operate when the diesel generator in the engine room served operates. The unit draws outdoor air through a louvered air intake and mixes it with return air from the engine room in required proportion to satisfy a thermostat located in the space served. Excess outside air supplied to the engine room is discharged to outdoors via a gravity relief damper.

Each service module air handling unit operates continuously, providing 100 percent cooling and heating capacity for the service module served by the unit. The unit draws outside air through a louvered air intake and mixes it with return air from the service module in required proportion to satisfy a space thermostat located in the service module. Excess outside air supplied to the service module flows into the diesel engine area via a wall mounted relief damper. The electric heating coil in the service module air handling unit is controlled by a separate space thermostat. The service module air handling unit operates continuously regardless of diesel generator status.

The engine room electric unit heaters operate as required to maintain the minimum room temperature when the diesel generators are not operating. No specific minimum room temperature is maintained when the diesel generators operate. Local space thermostats turn the unit heaters on and off as required for temperature control.

Abnormal Plant Operation

The engine room air handling units and unit heaters are not required to operate during any abnormal plant condition. This equipment is not required to operate when the diesel generators operate.

The service module air handling units operate continuously during normal plant operation or when the diesel generators operate during a loss of the plant ac electrical system.

9.4.10.2.3.2 Standby Exhaust Ventilation Subsystem

Normal Plant Operation

During normal plant operation, the standby exhaust fans operate in conjunction with the diesel generators. Each exhaust fan has 50 percent cooling capacity for the engine room served by the fan. The fans for an engine room start when the diesel generator in that room is started. The fans shut down when the diesel generator is stopped and the engine room temperature satisfies the standby exhaust fan temperature controllers. One or both standby exhaust fans are required to operate to maintain the engine room temperature depending on the outdoor ambient temperature.

The motor operated air intake dampers automatically open when the fans start and close when both fans shut down.

The standby exhaust ventilation system is not required to operate when the diesel generators are not operating.

Abnormal Plant Operation

The standby exhaust ventilation system is required to operate to support diesel generator operation during loss of offsite power. System operation is identical to that for normal plant operation.

9.4.10.2.3.3 Fuel Oil Day Tank Vault Exhaust Subsystem

Normal Plant Operation

During normal plant operation, each fuel oil day tank vault exhaust fan operates continuously. The fans are manually started and shut down. Each exhaust fan has 100 percent capacity for ventilation of the day tank vault served by the fan.

Abnormal Plant Operation

The fuel oil day tank vault exhaust subsystem is not required to operate during any abnormal plant condition.

9.4.10.2.3.4 Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem

Normal Plant Operation

During normal plant operation, each diesel oil transfer module enclosure exhaust fan operates during warm outdoor ambient conditions under control of a temperature controller to maintain the enclosure below the maximum indoor design temperature. The unit heaters operate as required during the winter to maintain the minimum design enclosure temperature. The operable outside air intake louvers are manually opened for the cooling season and manually set closed during the winter heating season.

Abnormal Plant Operation

The diesel oil transfer module enclosure ventilation and heating subsystem is required to operate to support diesel generator operation during loss of the plant ac electrical system. System operation is identical to that for normal plant operation.

9.4.10.3 Safety Evaluation

The diesel generator building heating and ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.10.4 Tests and Inspection

The diesel generator building heating and ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems - Testing, Adjusting, and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.10.5 Instrumentation Applications

The diesel generator building heating and ventilation system operation is controlled by the plant control system. Refer to subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Temperature indication and alarms are accessible locally via the plant control system.

Operational status of fans is indicated in the main control room. All fans and air handling units can be placed into operation or shutdown from the main control room or locally.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

9.4.11 Health Physics and Hot Machine Shop HVAC System

The health physics and hot machine shop HVAC system serves the annex building stairwell, S02; the personnel decontamination area, frisking and monitoring facilities, radiation monitor calibration area, and health physics facilities on the 100′-0″ elevation of the annex building and the hot machine shop on the 107′-2″ elevation of the annex building.

9.4.11.1 Design Basis

9.4.11.1.1 Safety Design Basis

The health physics and hot machine shop HVAC system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.11.1.2 Power Generation Design Basis

The health physics and hot machine shop HVAC system provides the following functions:

- Provides conditioned air to work areas to maintain acceptable temperatures for equipment and personnel working in the areas
- Provides air movement from clean to potentially contaminated areas to minimize the spread of airborne contaminants
- Collects the vented discharges from potentially contaminated equipment in the area
- Provides for exhaust from welding booths, grinders and other miscellaneous equipment located in the hot machine shop
- Provides for radiation monitoring of exhaust air prior to release to the environment
- Maintains the access control area and hot machine shop at a slight negative pressure with respect to outdoors and the clean areas of the annex building to prevent unmonitored releases of radioactive contaminants
- Provides humidification to maintain a minimum of 35 percent relative humidity

The system maintains the following temperatures based on maximum and minimum normal outside air temperature conditions shown in Chapter 2, Table 2-1:

Room or Area	Temperatures (°F)
Health physics area	73-78
Hot machine shop	65-85

9.4.11.2 System Description

The health physics and hot machine shop HVAC system is shown in Figure 9.4.11-1.

9.4.11.2.1 General Description

The health physics and hot machine shop HVAC system is a once-through ventilation system consisting of two integrated subsystems: a supply air system and an exhaust air system. The systems operate in conjunction with each other to satisfy the functional requirements of maintaining temperatures in the areas served while controlling air flow paths and area negative pressure.

The supply air system consists of two 100 percent capacity air handling units of about 14,000 scfm each with a ducted air distribution system and automatic controls. The air handling units are located in the lower south air handling equipment room on elevation 135′-3″ of the annex building. Heating coils are supplied with water from the hot water heating system and cooling coils are supplied from the central chilled water system. The units draw 100 percent outdoor air through the common, louvered outdoor air intake plenum #2 as described in subsection 9.4.2. They discharge into a duct distribution system which is routed to the health physics and machine shop areas. Humidification is controlled to maintain a minimum 35 percent relative humidity via a steam humidifier located in the main system supply duct and supplied with water from the demineralized water system.

The exhaust air system consists of two 100 percent capacity exhaust centrifugal fans sized to allow the system to maintain a negative pressure with ductwork and automatic controls, and a separate machine shop exhaust fan and high efficiency filter for exhausting from machine tools and other localized areas in the hot machine shop. The exhaust fans are located in the staging and storage area on elevation 135′-3″ of the annex building. The machine shop exhaust fan and filter are located locally in the machine shop. The air flow rates are balanced to maintain a constant exhaust design air flow through the fans.

The exhaust fans discharge to a common duct which is routed to the plant vent stack. A radiation monitor measures activity in the common discharge duct downstream of the exhaust fans and activates an alarm in the main control room when excess activity in the effluent discharge is detected. The radiation monitoring system is described in Section 11.5.

Individual flexible exhaust duct branches are provided to machine tools. The flexible ducts are connected to a hard duct manifold which is connected to a filter and exhaust fan. The exhaust fan discharges into the main system exhaust ductwork.

9.4.11.2.2 Component Description

The health physics and hot machine shop HVAC system is comprised of the following major components. These components are located in the Seismic Category II portion of the annex building.

Supply Air Handling Units

Each air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil, a chilled water cooling coil bank, and a supply fan with automatic inlet vanes.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5), and ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52 and 126 (References 7 and 35). The filters meet UL 900 (Reference 8) Class I construction criteria.

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating heat output. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifier is designed and rated in accordance with ARI 620 (Reference 13).

Shutoff, Control, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through ductwork when operating the machine tools exhaust fan. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. Dampers meet the performance requirements of ANSI/AMCA 500 (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Ductwork and Accessories

Ductwork, duct supports and accessories are constructed of galvanized steel. Ductwork subject to fan shutoff pressure is structurally designed for fan shutoff pressures. Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards – Metal and Flexible (Reference 17).

9.4.11.2.3 System Operation

Normal Plant Operation

During normal operation, one supply air handling unit and one exhaust fan operate continuously to maintain suitable temperatures in the health physics and hot machine shop areas of the annex building. The supply air flow is automatically modulated to maintain a negative pressure in the areas served with respect to the outdoors and to surrounding areas which do not have their exhausts monitored for radioactivity. Differential pressure controllers, with sensors in the general health physics area and sensors mounted outdoors (shielded from wind effects), modulate the automatic inlet vanes of the supply fan to maintain area negative pressure. In addition, a separate differential pressure controller with a sensor in the hot machine shop modulates a damper in the supply air duct to the hot machine shop to maintain a negative pressure in the shop with respect to outdoors and to surrounding areas which do not have their exhausts monitored for radioactivity.

The temperature in the health physics and the hot machine shop area is maintained within the design range by a temperature sensor located in the health physics area, with which a controller modulates the control valve on the chilled water supply lines to the cooling coil and the face and bypass damper of the heating coil.

Abnormal Plant Operation

The health physics and hot machine shop HVAC system is not required to operate during any abnormal plant condition.

9.4.11.3 Safety Evaluation

The health physics and hot machine shop HVAC system has no safety-related functions and therefore requires no nuclear safety evaluation.

9.4.11.4 Tests and Inspections

The health physics and hot machine shop HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted during the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems - Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.11.5 Instrumentation Application

The health physics and hot machine shop HVAC system operation is controlled by the plant control system. Refer to subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers maintain the proper space temperature. Supply air temperature is controlled by sensing the temperature in the general health physics area.

Temperature is indicated for each air handling unit supply air discharge duct.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for low air flow rates in the fan discharge ducts.

An alarm is provided for high radiation in the main exhaust duct to the vent stack.

An alarm is provided for smoke in the common discharge duct from the supply air handling units.

Position indicating lights are provided for automatic dampers.

9.4.12 Combined License Information

The Combined License applicants referencing the AP1000 certified design will implement a program to maintain compliance with ASME AG-1 (Reference 36), ASME N509 (Reference 2), ASME N510 (Reference 3) and Regulatory Guide 1.140 (Reference 30) for portions of the nuclear island nonradioactive ventilation system and the containment air filtration system identified in subsection 9.4.1 and 9.4.7. The Combined License applicant will also provide a description of the MCR/TSC HVAC subsystem's recirculation mode during toxic emergencies, and how the subsystem equipment isolates and operates, as applicable, consistent with the toxic issues, including conformance with Regulatory Guide 1.78 (Reference 37), to be addressed by the Combined License applicant as discussed in DCD subsection 6.4.7.

9.4.13 References

1. "Functional Criteria For Emergency Response Facilities," USNRC NUREG 0696.

2. "Nuclear Power Plant Air-Cleaning Units and Components," ASME N509-1989 (R1996).

3. "Testing of Nuclear Air-Cleaning Systems," ASME N510-1989.

4. "Laboratory Method of Testing Fans for Rating Purposes," ANSI/AMCA 210-85.

5. "Certified Ratings Program Air Performance," ANSI/AMCA 211-87.

6. "Reverberant Room Method of Testing Fans For Rating Purposes," ANSI/AMCA 300-85.

7. Gravimetric and Dust Spot Procedures for Testing Air-Cleaning Devices Used in General Ventilation for Removing Particulate Matter, ASHRAE 52.1, 1992.

8. "Test Performance of Air-Filter Units," UL-900, 1994.

9. "High-Efficiency, Particular, Air-Filter Units," UL-586, 1996.

10. "Heating and Cooling Equipment," UL 1995, 1995.

11. "Methods of Testing for Rating Forced Circulation Air Cooling and Air Heating Coils," ASHRAE 33-78.

12. "Forced-Circulation Air Cooling and Air Heating Coils," ANSI/ARI 410-91.

13. "Self-Contained Humidifiers," ARI 620-96.

14. "Testing Methods for Louvers, Dampers, and Shutters," ANSI/AMCA 500-89.

15. "Fire Dampers," UL-555, 1999.

16. "Rectangular Industrial Duct Construction Standards," SMACNA, 1980.

17. "HVAC Duct Construction Standards – Metal and Flexible," SMACNA, 1995.

18. "HVAC Duct Leakage Test Manual," SMACNA, 1985.

19. "HVAC Systems – Testing, Adjusting, and Balancing," SMACNA, 1993.

20. Code of Federal Regulations, Title 10, Part 50, Appendix I.

21. Code of Federal Regulations, Title 10, Part 20.

22. "Heat-Stress Management Program for Nuclear Power Plants," EPRI NP-4453 by Westinghouse Electric Corporation, dated February 1986.

23. Branch Technical Position CSB 6-4 to "Containment Isolation System," Standard Review Plan 6.2.4 of NUREG-0800 Rev. 2, July 1981.

24. "Military Specification Filter, Particulate, High-Efficiency, Fire Resistant," MIL-F-51068F.

25. "Leakage Rated Dampers for Use in Smoke Control System," UL-555S, 1999.

26. "Electric Duct Heaters," UL-1996, 1996.

27. "Standard for Installation of Air Conditioning and Ventilation Systems," NFPA 90A, 1999.

28. "National Electrical Code," NFPA 70, 1999.

29. "Loss of Charcoal from Adsorber Cells," IE Bulletin 80-03, 1980.

30. "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmospheric Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," Regulatory Guide (RG) 1.140-2001, Revision 2.

31. "Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants," Regulatory Guide 1.128, Revision 1, October 1978.

32. "Ventilation for Acceptable Indoor Air Quality," ASHRAE Standard 62-1999.

33. NFPA 92A-2000, "Recommended Practice for Smoke Control Systems."

34. "Round Industrial Duct Construction Standards," SMACNA, 1999.

35. "Method of Testing HVAC Air Ducts," ASHRAE 126, 2000.

36. "Code on Nuclear Air and Gas Treatment," ASME/ANSI AG-1-1997.

37. "Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," USNRC Regulatory Guide 1.78, Revision 1, December 2001.

38. "Standard Test Methods for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution," ASTM E741, 2000.

Table 9.4-1

DESIGN FILTRATION EFFICIENCIES AND NOMINAL AIRFLOW RATES FOR HVAC SYSTEMS (1)

Areas Served(1)	Design/Test Standard	Ventilation Airflow (cfm)	Recirculation Flow (cfm)	Humidity Control	HEPA Efficiency	Charcoal Efficiency(3)	Maximum Inleakage (cfm)
MCR/TSC (Supplemental Air)	RG 1.140	860	3,140	Yes	99%	90%	110
Containment	RG 1.140	4,000(2)	N/A	Yes	99%	90%	N/A

Notes:
1. Ventilation cfm is shown for each train unless otherwise noted.
2. Both trains of the containment purge may be operated at the same time prior to and during cold shutdown.
3. Charcoal filters are 4-inch deep Type III adsorber cell.

Table 9.4.1-1 (Sheet 1 of 2)

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

MCR/TSC HVAC Subsystem (Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	22,000
Fan static pressure (in. wg)	9.75
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	20,500
Fan static pressure (in. wg)	6
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	960,000
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Electric
Capacity (kw)	170
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.1-1 (Sheet 2 of 2)

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

MCR/TSC HVAC Subsystem (Nominal Values)

Supplemental Air Filtration Subsystem	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Fan static pressure (in. wg)	14
Heating Coil Requirements	
Type	Electric
Capacity (kw)	20
Filter Requirements	
High efficiency filter, minimum ASHRAE efficiency (%)	80
HEPA filter, DOP efficiency (%)	99.97
Post filter, DOP efficiency (%)	95
Charcoal Adsorber Requirements	
Bed depth (in.)	4.0
Decontamination efficiency (%)	90
Air residence time (sec.)	0.5

MCR Envelope Leakage Rates

Leakage	Inleakage Rate at 1/8 in. wg (scfm)	Outleakage Rate at 1/8 in. wg (scfm)
MCR access doors	10	--
TSC access doors	10	--
MCR structure	--	20
TSC structure	--	500
MCR/TSC HVAC equipment & ductwork (operating)	70	480

Table 9.4.1-2 (Sheet 1 of 3)

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

Class 1E Electrical Room HVAC Subsystem (Nominal Values)

Division "A & C" Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	18,500
Fan static pressure (in. wg)	6.5
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	16,000
Fan static pressure (in. wg)	6.0
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	960,000
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Electric
Capacity (kw)	290
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, ASHRAE efficiency (%)	80

Table 9.4.1-2 (Sheet 2 of 3)

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

Class 1E Electrical Room HVAC Subsystem (Nominal Values)

Division "A & C" Class 1E Battery Room Exhaust Fans	
Quantity per electrical division	2
System capacity per fan (%)	100
Type	Centrifugal
Design airflow (scfm)	1,600
Fan static pressure (in. wg)	3.5
Division "B & D" Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	14,500
Fan static pressure (in. wg)	6.5
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	12,600
Fan static pressure (in. wg)	6.0
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	550,000
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Electric
Capacity (kw)	140
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, ASHRAE efficiency (%)	80

Table 9.4.1-2 (Sheet 3 of 3)

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

Class 1E Electrical Room HVAC Subsystem (Nominal Values)

Division "B & D" Class 1E Battery Room Exhaust Fans	
Quantity per electrical division	2
System capacity per fan (%)	100
Type	Centrifugal
Design airflow (scfm)	1,200
Fan static pressure (in. wg)	3.5

Table 9.4.1-3

COMPONENT DATA – NUCLEAR ISLAND NONRADIOACTIVE VENTILATION SYSTEM

Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem (Nominal Values)

Exhaust Fan Data	
Quantity	1
System capacity per fan (%)	100
Type	Propeller
Design airflow (scfm)	1,300
Fan static pressure (in. wg)	0.75
Electric Unit Heater	
Quantity	2
System capacity per unit heater (%)	100
Type	Horizontal
Capacity (kw)	10

Table 9.4.2-1

COMPONENT DATA –
ANNEX/AUXILIARY BUILDINGS NONRADIOACTIVE HVAC SYSTEM

Switchgear Room HVAC Subsystem
(Nominal Values)

Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	31,000
Static pressure (in. wg)	6.5
Return/Exhaust Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	31,000
Static pressure (in. wg)	3.0

Table 9.4.2-2

COMPONENT DATA –
ANNEX/AUXILIARY BUILDINGS NONRADIOACTIVE HVAC SYSTEM

Equipment Room HVAC System
(Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	31,000
Static pressure (in. wg)	6.9
Return/Exhaust Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	28,700
Static pressure (in. wg)	3.0
Battery Room Exhaust Fans	
Quantity	2
System capacity per unit (%)	100
Type	Centrifugal
Design airflow (scfm)	750
Static pressure (in. wg)	1.5

Table 9.4.3-1

COMPONENT DATA – RADIOLOGICALLY CONTROLLED AREA VENTILATION SYSTEM

Auxiliary/Annex Building Ventilation Subsystem (Nominal Values)

Normal Residual Heat Removal Pump Room Unit Coolers	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	2,500
Fan static pressure (in. wg)	4.5
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	102,000
Water flow (gpm)	See Table 9.2.7-1
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
Chemical and Volume Control Makeup Pump Room Unit Coolers	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	2,500
Fan static pressure (in. wg)	3.0
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	164,000
Water flow (gpm)	See Table 9.2.7-1
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25

Table 9.4.6-1

COMPONENT DATA – CONTAINMENT RECIRCULATION COOLING SYSTEM

Containment Recirculation Fan Coil Unit Subsystem (Nominal Values)

Reactor Containment Recirculation Fan Coil Assemblies	
Quantity	2
Fan coil units per assembly	2
System capacity per assembly (%)	100
Fan Data	
Quantity (fans/unit)	1
Type	Vaneaxial
Normal design air flow (scfm)	62,800
Low speed design air flow (scfm)	37,200
Fan static pressure (in. wg)	11
Cooling Coil Data	
Quantity (coil bank/unit)	3
Total cooling load (Btu/hr)	3,804,500
Total chilled water flow rate (gpm)	475
Total heating load (Btu/hr)	2,247,857
Total hot water flow rate (gpm)	225

Table 9.4.7-1 (Sheet 1 of 2)

COMPONENT DATA – CONTAINMENT AIR FILTRATION SYSTEM

(Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per assembly (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Fan static pressure (in. wg)	14
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	380,000
Water flow (gpm)	41
Heating Coil Requirements	
Type	Hot Water
Capacity (Btu/hr)	290,000
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.7-1 (Sheet 2 of 2)

COMPONENT DATA – CONTAINMENT AIR FILTRATION SYSTEM

(Nominal Values)

Exhaust Air Filtration Units	
Quantity	2
System capacity per assembly (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Fan static pressure (in. wg)	27
Heating Coil Requirements	
Type	Electric
Capacity (kw)	20
Filter Requirements	
High efficiency filter, minimum ASHRAE efficiency (%)	80
HEPA filter, DOP efficiency (%)	99.97
Post filter, DOP efficiency (%)	95
Charcoal Adsorber Requirements	
Bed depth (in.)	4.0
Decontamination efficiency (%)	90
Air residence time (sec.)	0.5

Table 9.4.10-1 (Sheet 1 of 2)

COMPONENT DATA – DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM

Normal Heating and Ventilation Subsystem (Nominal Values)

Engine Room Air Handling Unit	
Quantity	2 (one per diesel generator room)
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	15,000
Static pressure (in. wg)	3.4
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80
Service Module Air Handling Unit	
Quantity	2 (one per diesel generator room)
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	2,300
Static pressure (in. wg)	3.6
Motor nameplate horsepower	3.0
Heating Coil Requirements	
Type	Electric
Capacity (kw)	20 (two stages)
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.10-1 (Sheet 2 of 2)

COMPONENT DATA – DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM

Normal Heating and Ventilation Subsystem (Nominal Values)

Electric Unit Heaters	
Quantity	4 (two per diesel generator room)
System capacity per unit (%)	50
Type	Horizontal
Capacity (kw)	30

Table 9.4.10-2

COMPONENT DATA – DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM

Standby Exhaust Ventilation Subsystem (Nominal Values)

Standby Exhaust Fan	
Quantity	4 (two per diesel generator room)
System capacity per unit (%)	50
Type	Upblast Roof Ventilator
Design airflow (scfm)	25,000
Static pressure (in. wg)	0.25

Table 9.4.10-3

COMPONENT DATA – DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM

Fuel Oil Day Tank Vault Exhaust Subsystem (Nominal Values)

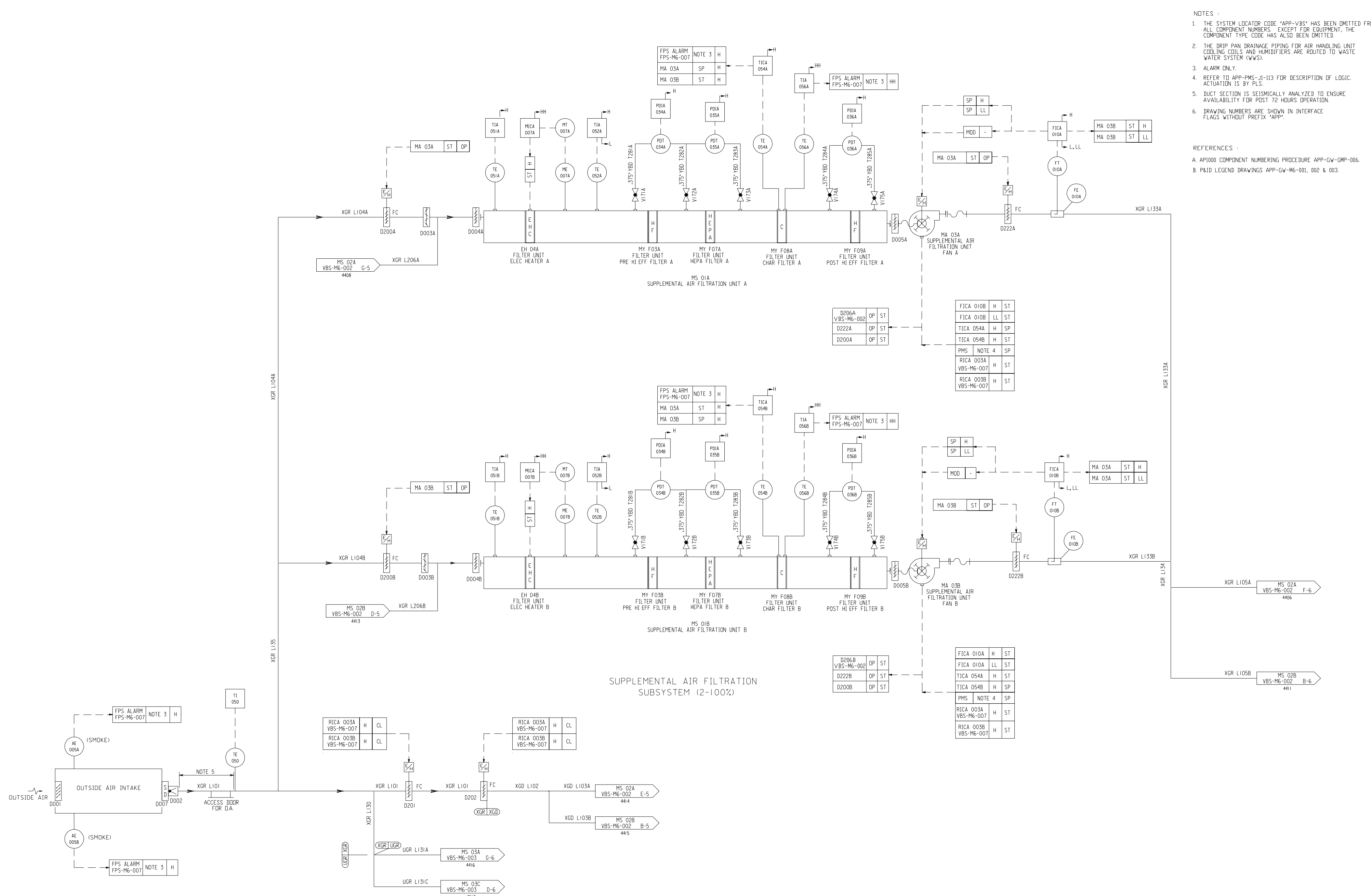
Fuel Oil Day Tank Vault Exhaust Fan	
Quantity	2 (one per tank vault)
System capacity per unit (%)	100
Type	Centrifugal
Design airflow (scfm)	500
Static pressure (in. wg)	0.5

Table 9.4.10-4

COMPONENT DATA – DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM

Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem (Nominal Values)

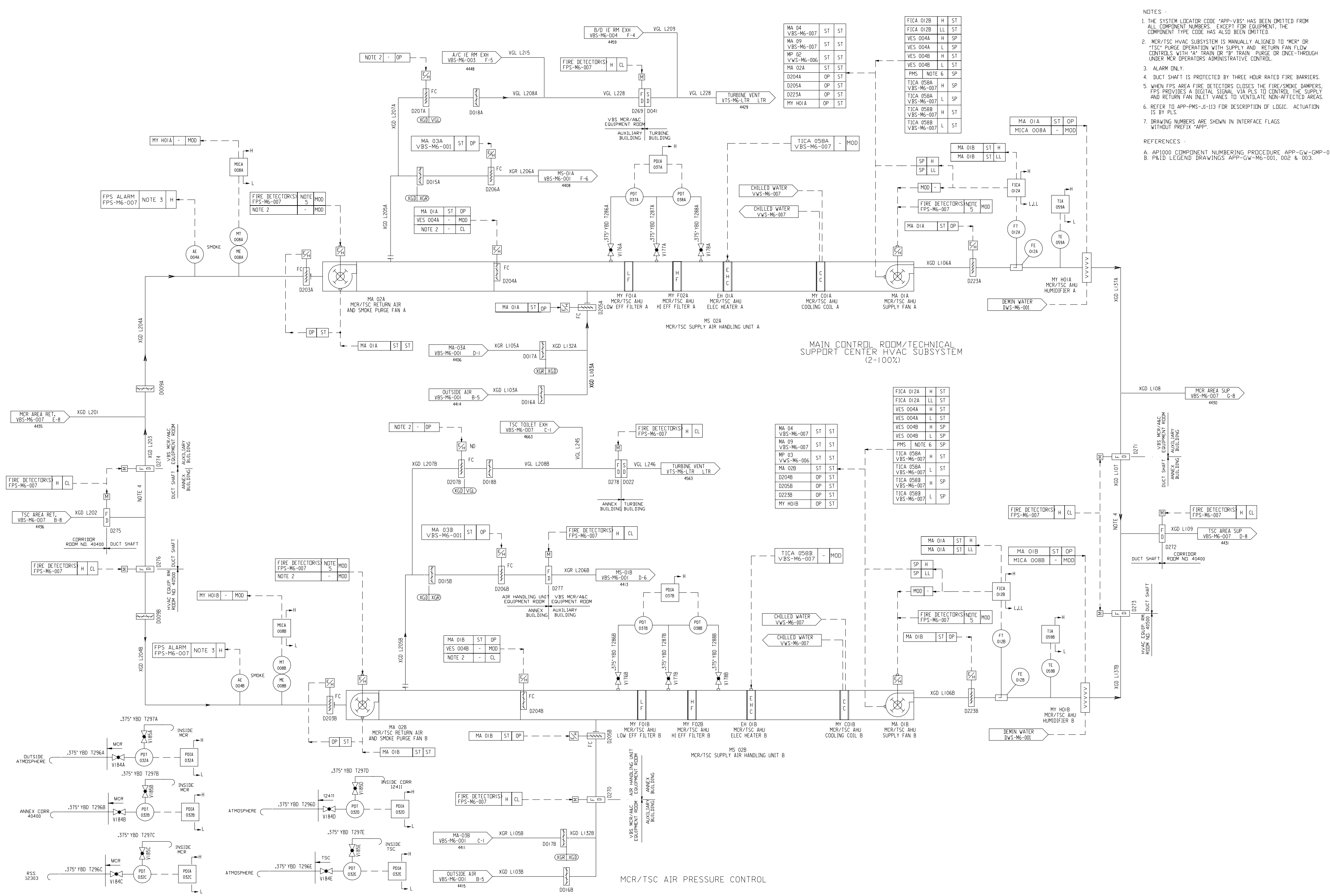
Diesel Oil Transfer Module Enclosure Exhaust Fan	
Quantity	2 (one per enclosure)
System capacity per unit (%)	100
Type	Centrifugal Roof Exhauster
Design airflow (scfm)	1,000
Static pressure (in. wg)	0.25
Electric Unit Heater	
Quantity	2 (one per enclosure)
System capacity per unit (%)	100
Type	Horizontal
Capacity (kw)	15



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 1 of 7)

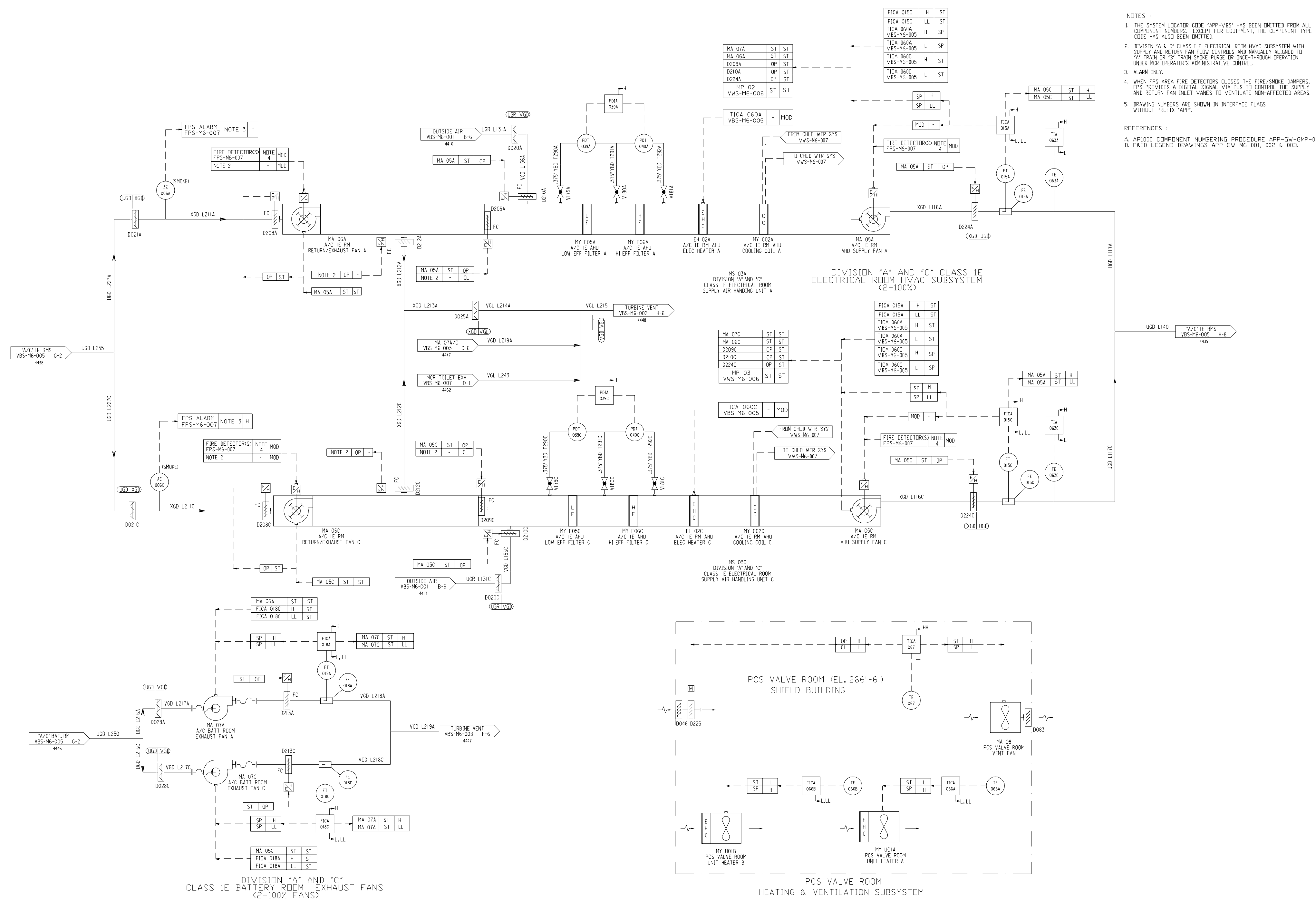
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 001



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 2 of 7)

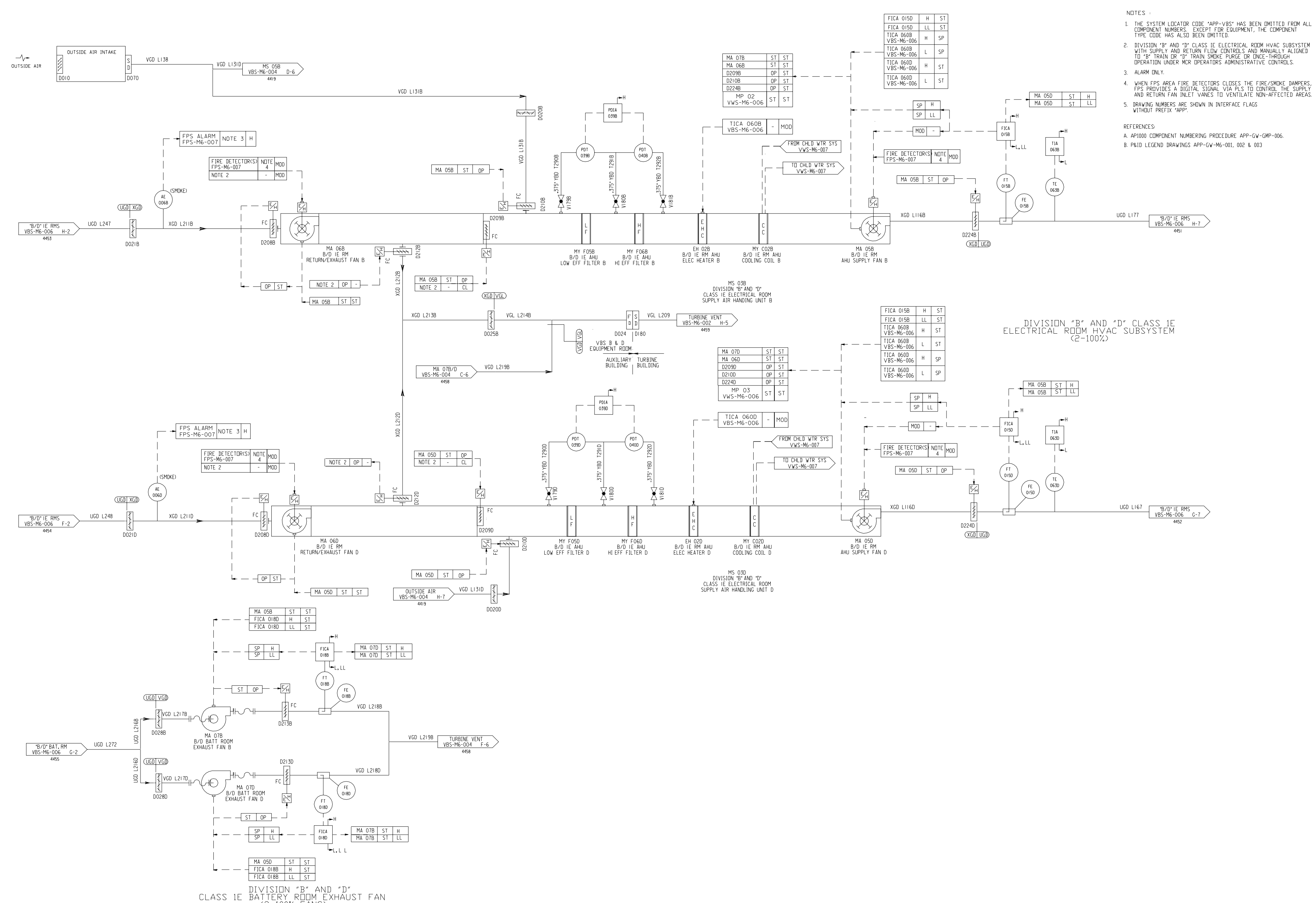
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 002



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 3 of 7)

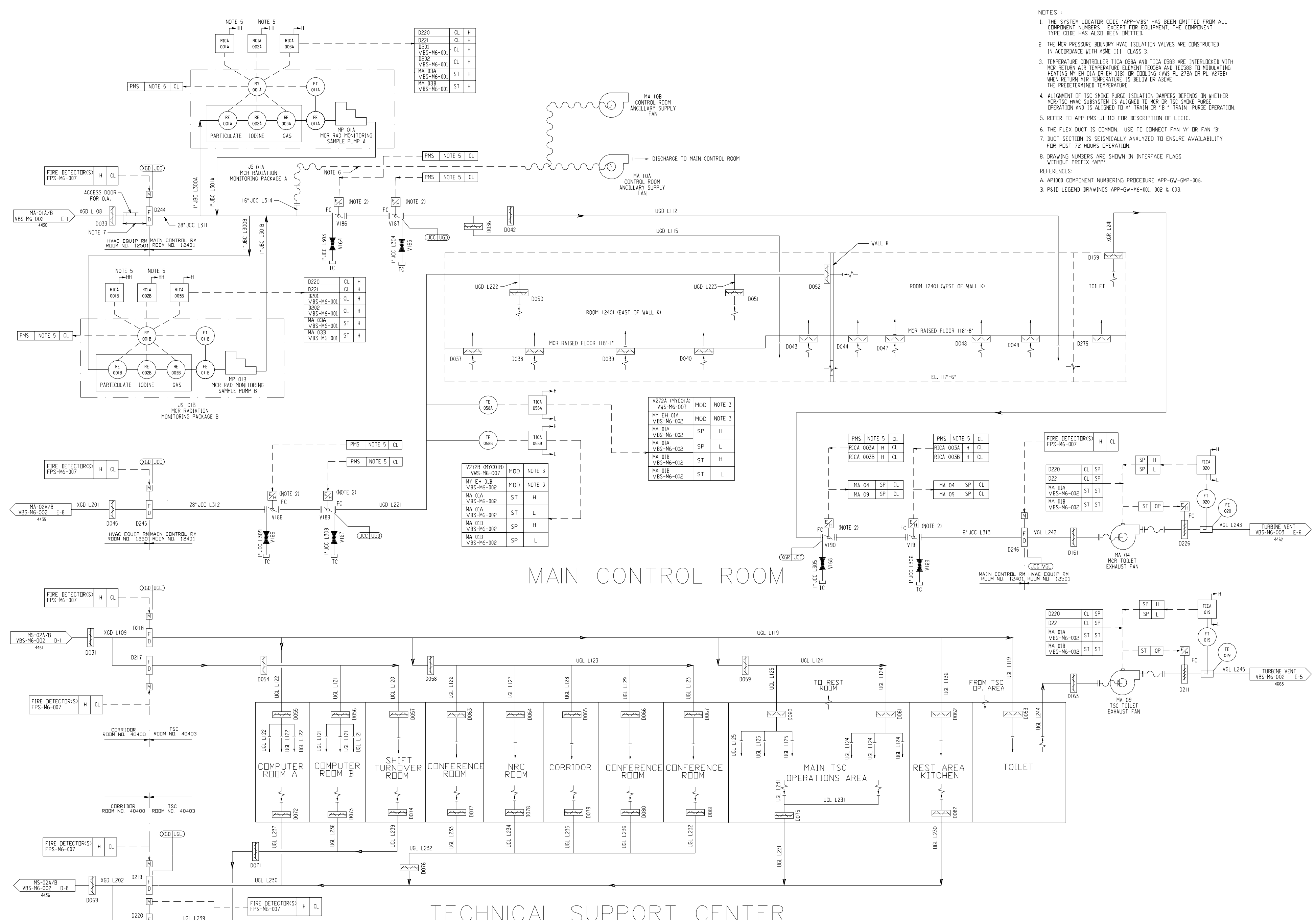
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 003



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 4 of 7)

Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 004



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 5 of 7)

Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 007

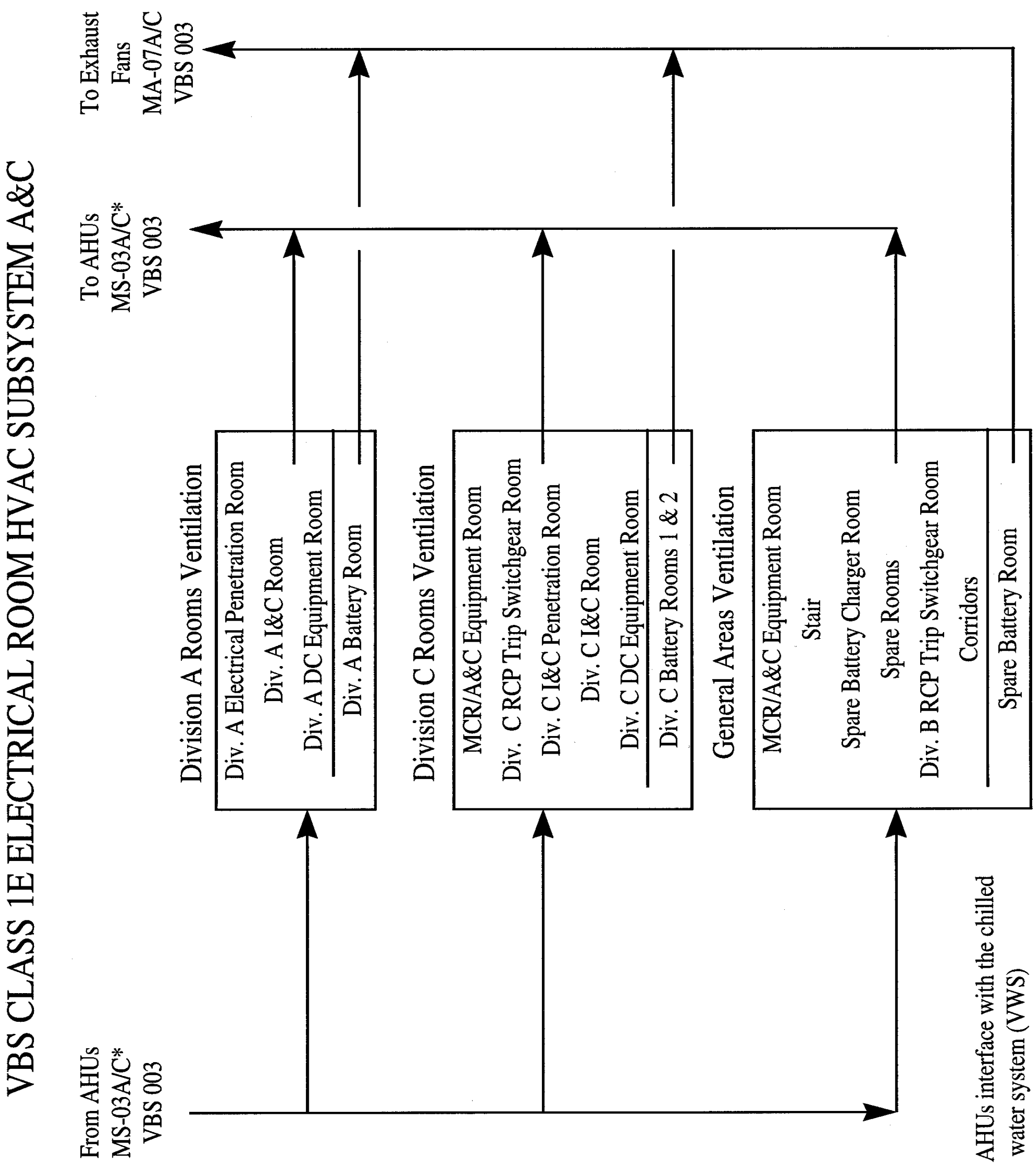


Figure 9.4.1-1 (Sheet 6 of 7)

Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation System
(REF) VBS 005

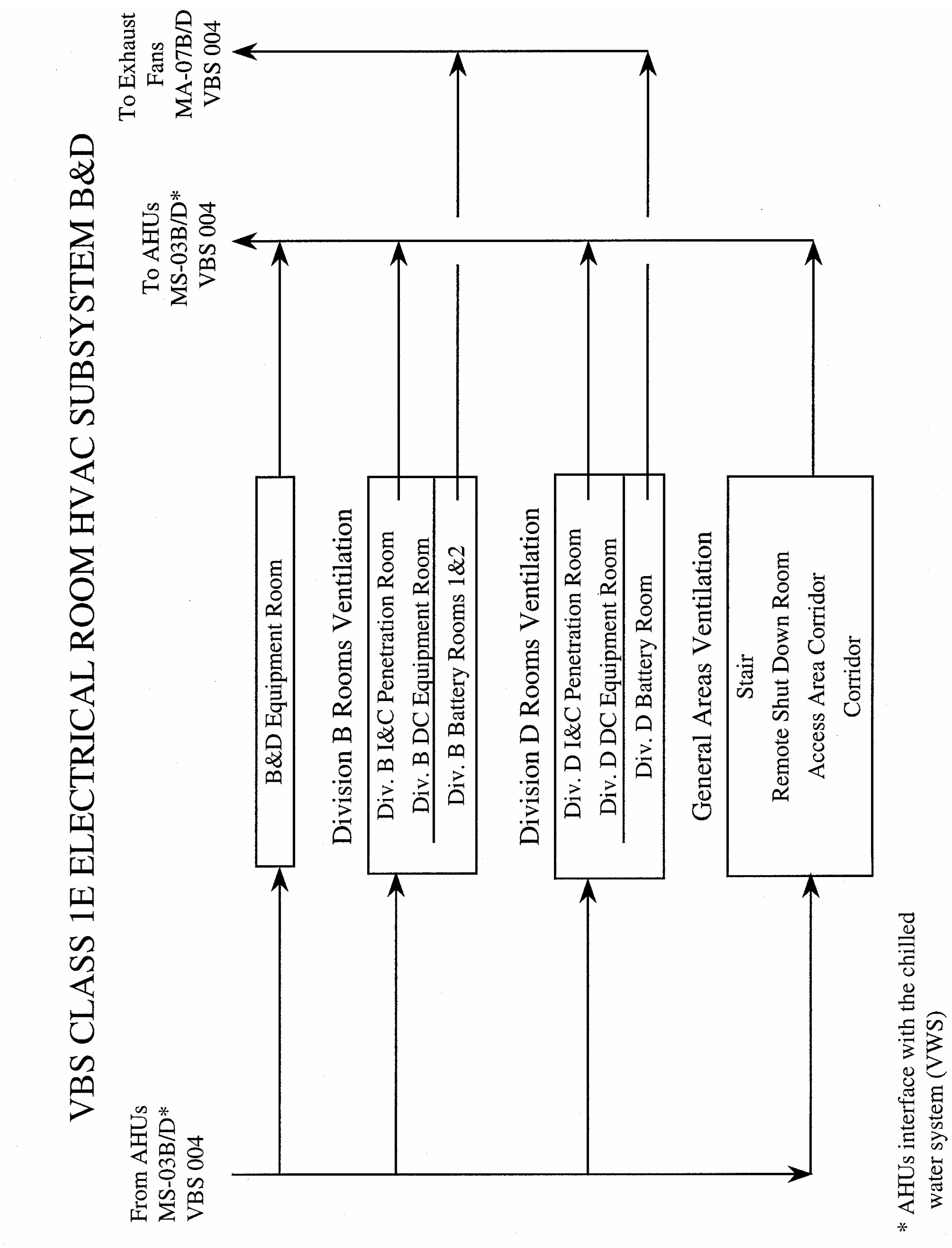
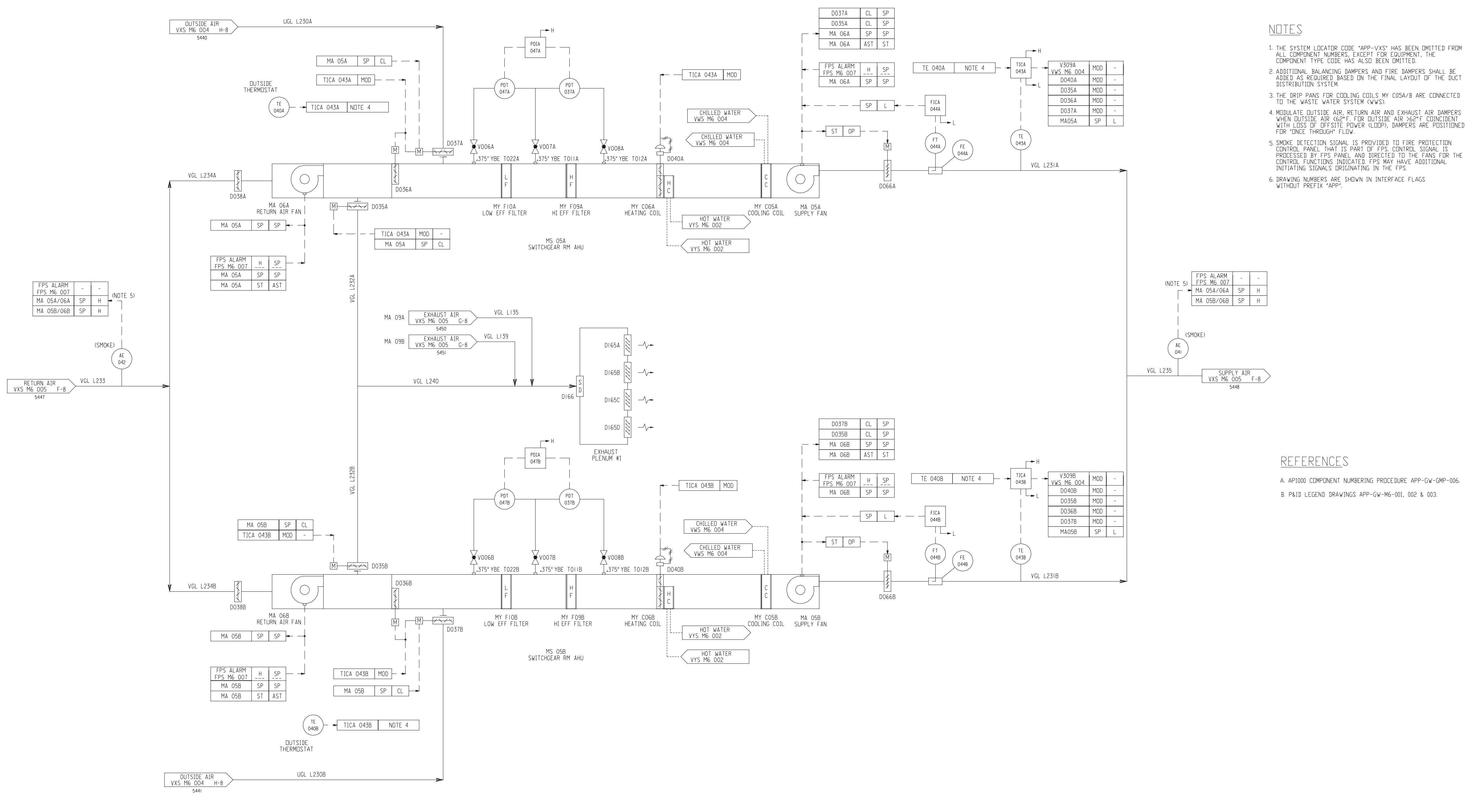


Figure 9.4.1-1 (Sheet 7 of 7)

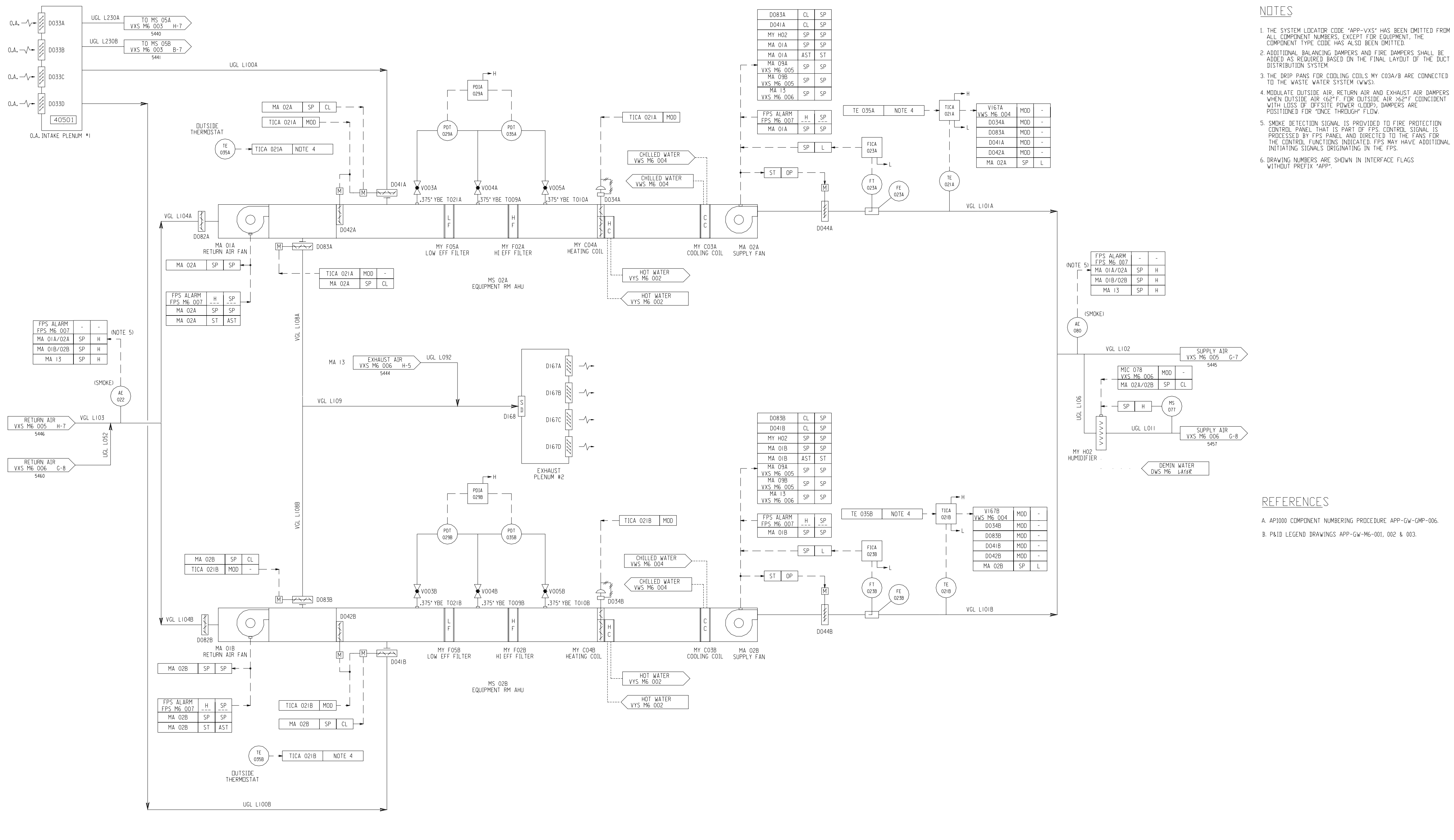
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 006



Inside Annex Building

Figure 9.4.2-1 (Sheet 1 of 6)

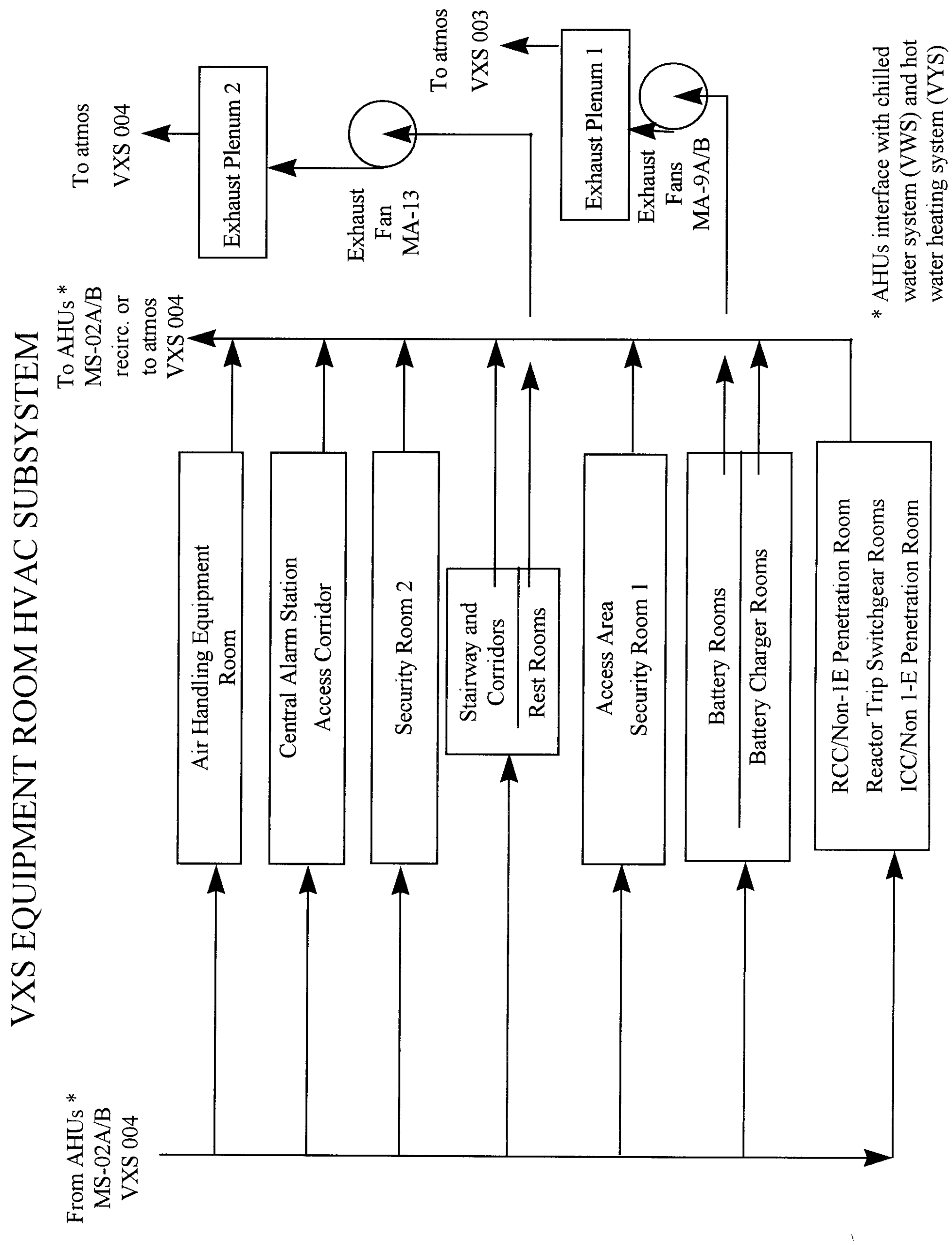
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 003



Inside Annex Building

Figure 9.4.2-1 (Sheet 2 of 6)

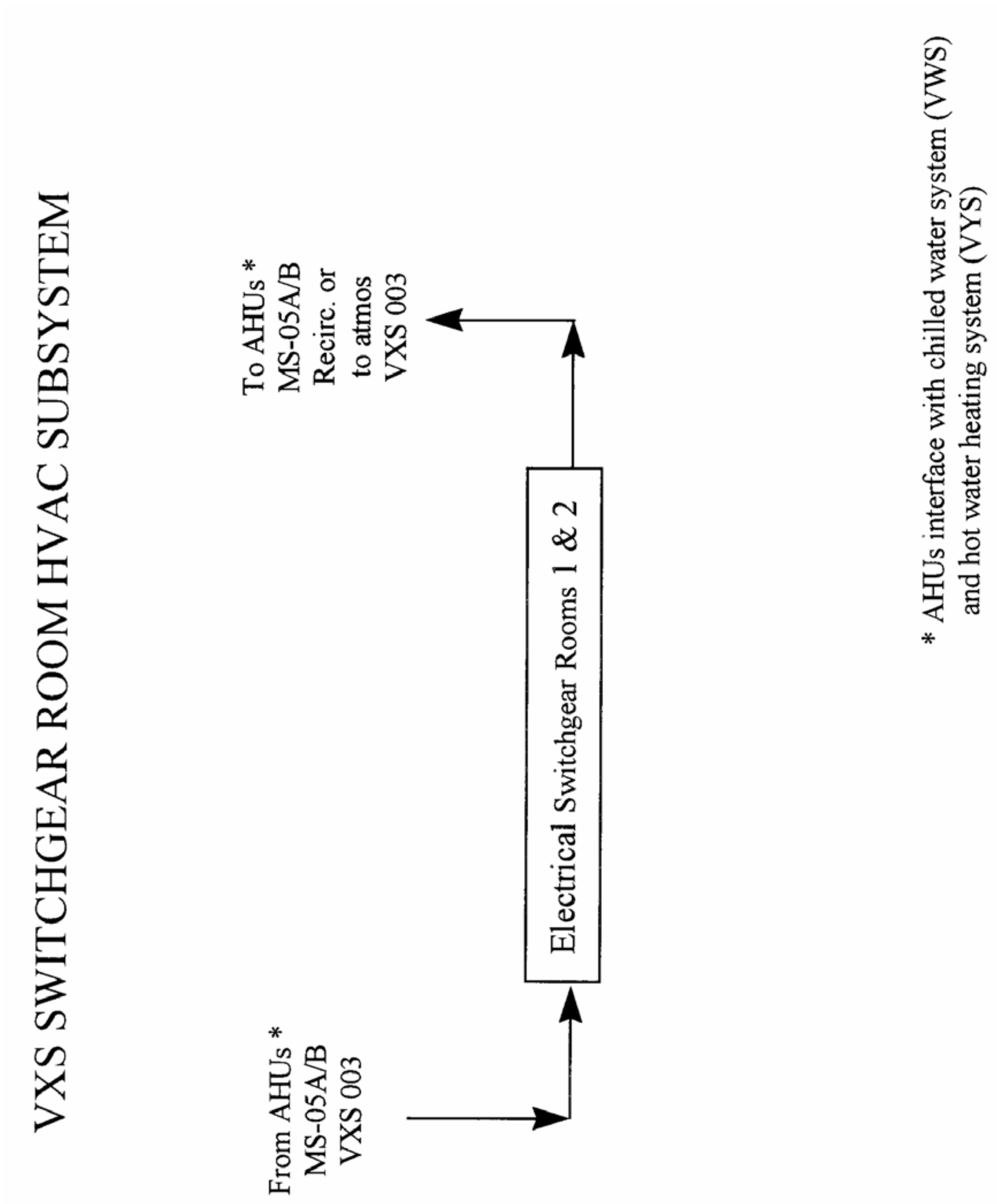
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 004



Inside Annex Building

Figure 9.4.2-1 (Sheet 3 of 6)

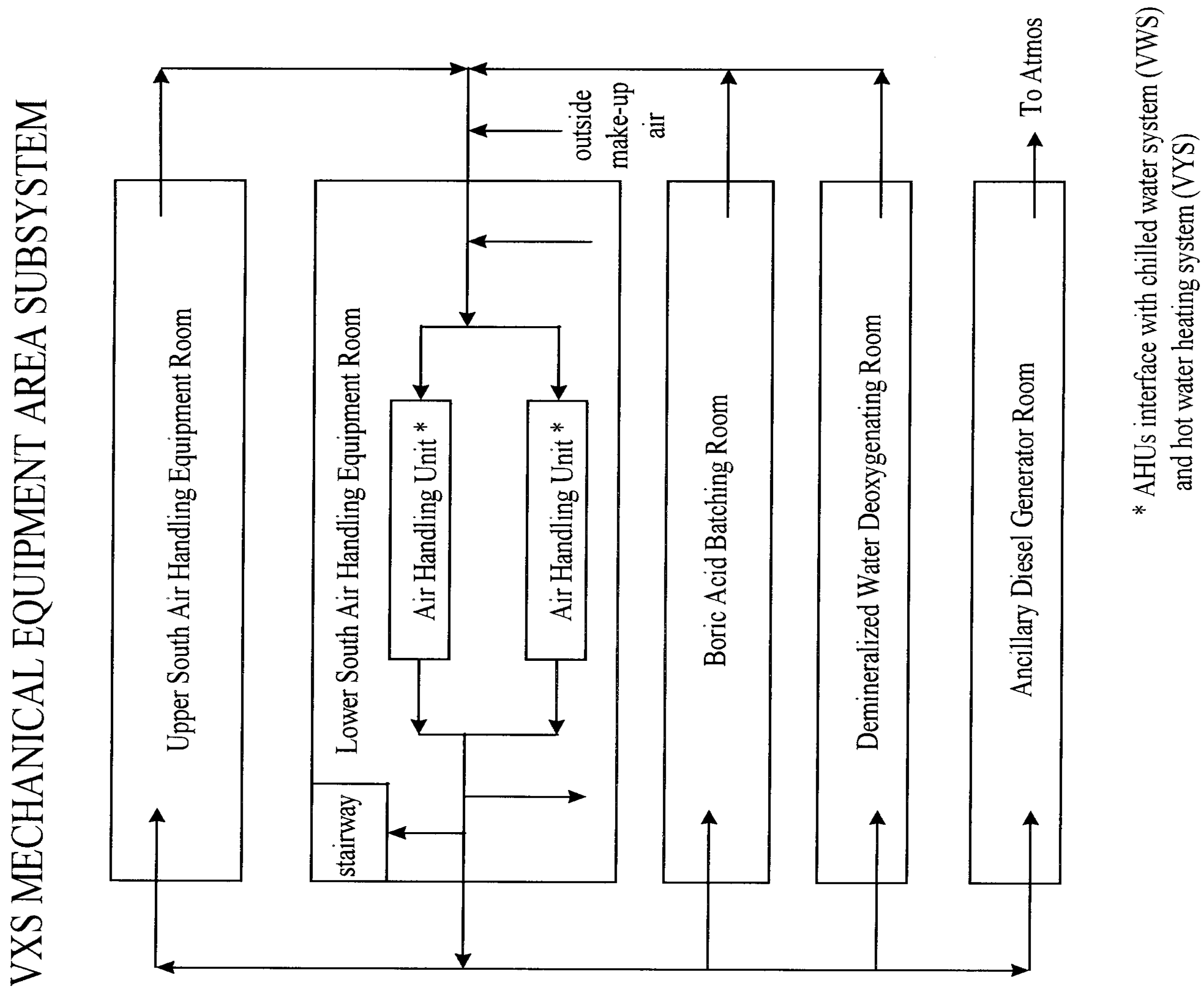
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 005 & 006



Inside Annex Building

Figure 9.4.2-1 (Sheet 4 of 6)

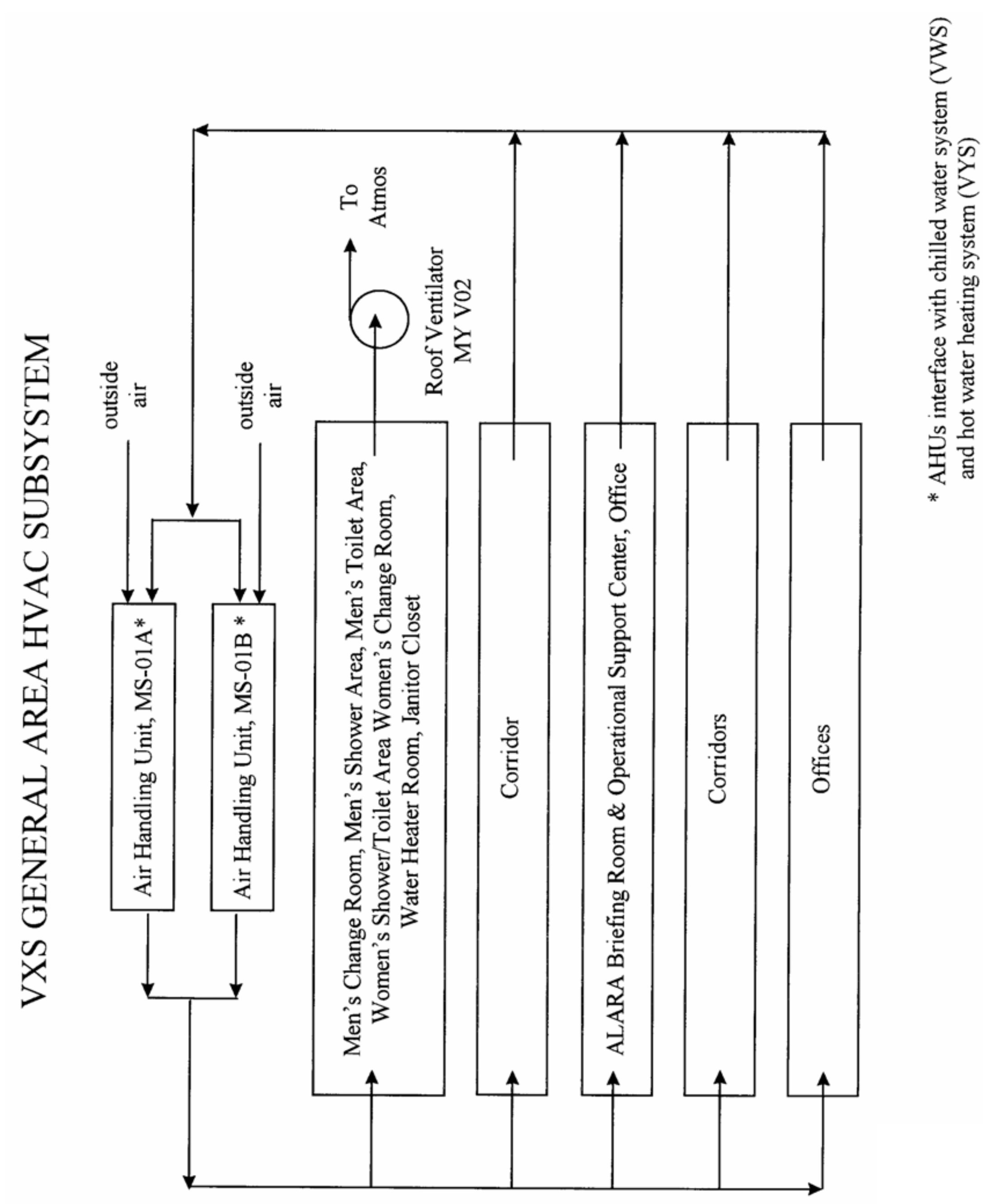
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 005



Inside Annex Building

Figure 9.4.2-1 (Sheet 5 of 6)

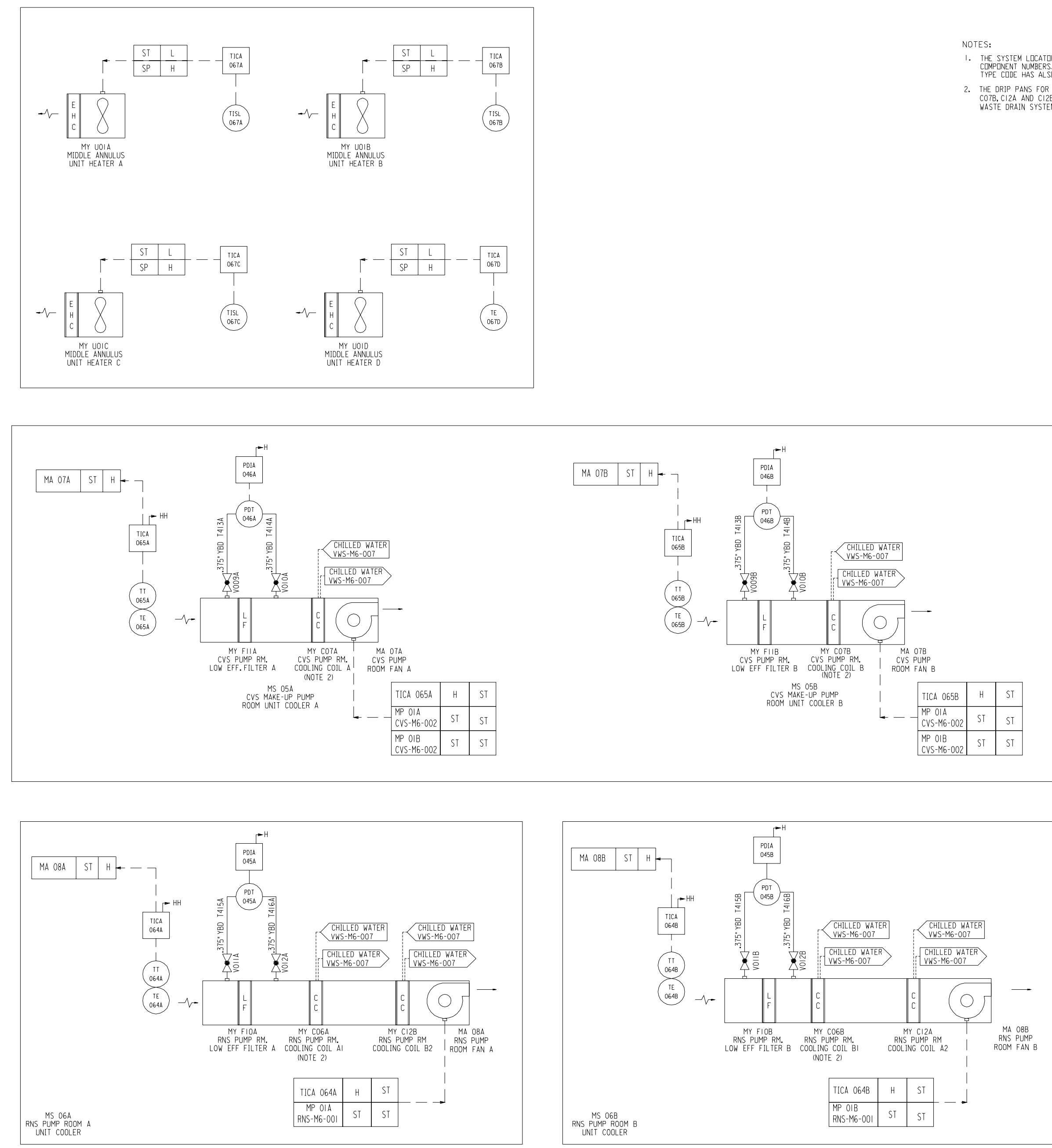
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 010



Inside Annex Building

Figure 9.4.2-1 (Sheet 6 of 6)

Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 002



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-VAS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. EXCEPT FOR EQUIPMENT, THE COMPONENT TYPE CODE HAS ALSO BEEN OMITTED.
2. THE DRIP PANS FOR COOLING COILS MY C06A, C06B, C07A C07B, C12A AND C12B ARE CONNECTED TO THE RADIOACTIVE WASTE DRAIN SYSTEM (WRS).

Inside Auxiliary Building

Figure 9.4.3-1 (Sheet 1 of 3)

Radiologically Controlled Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 008

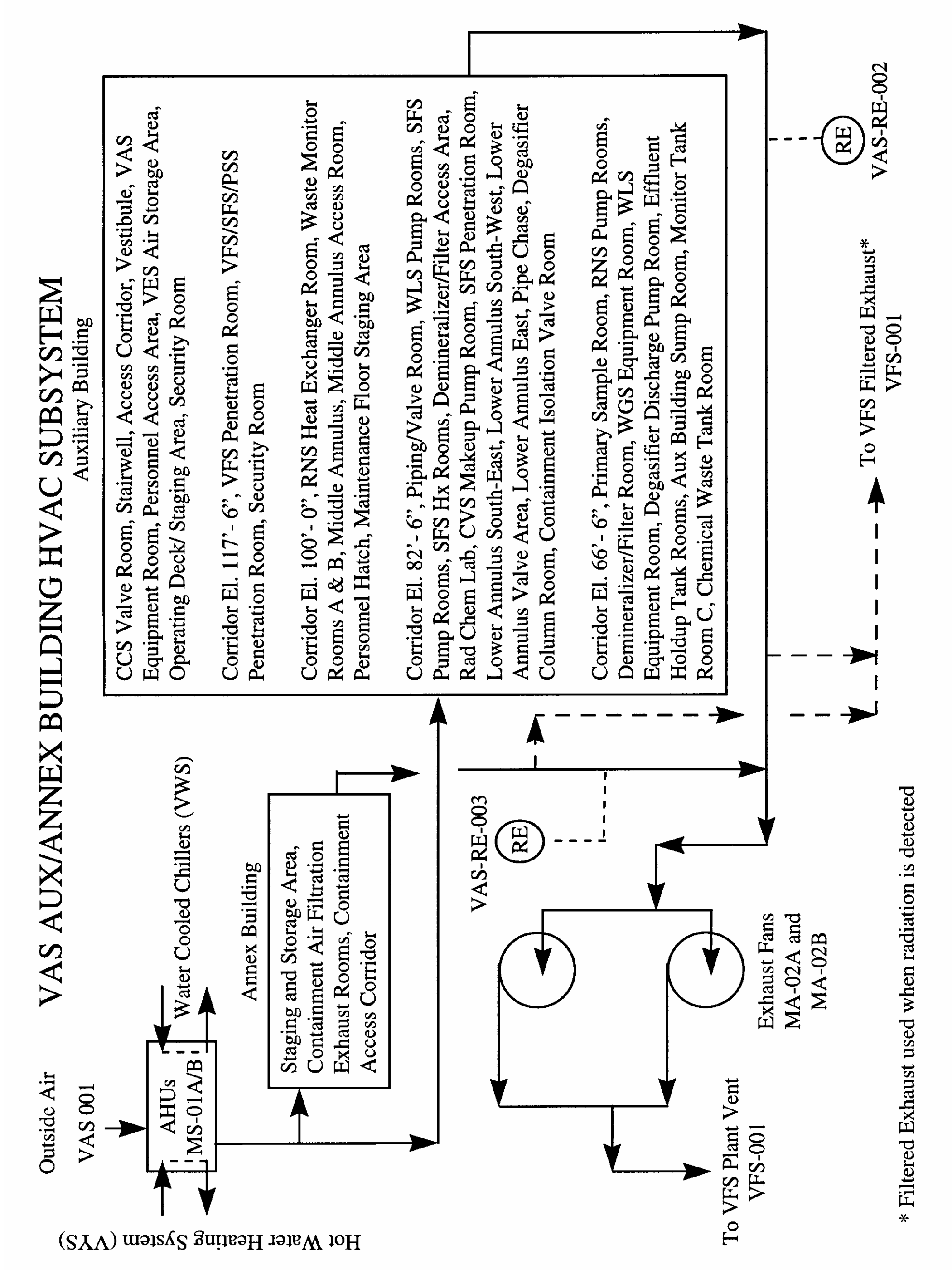


Figure 9.4.3-1 (Sheet 2 of 3)

Radiologically Controlled Area Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 003 & 010

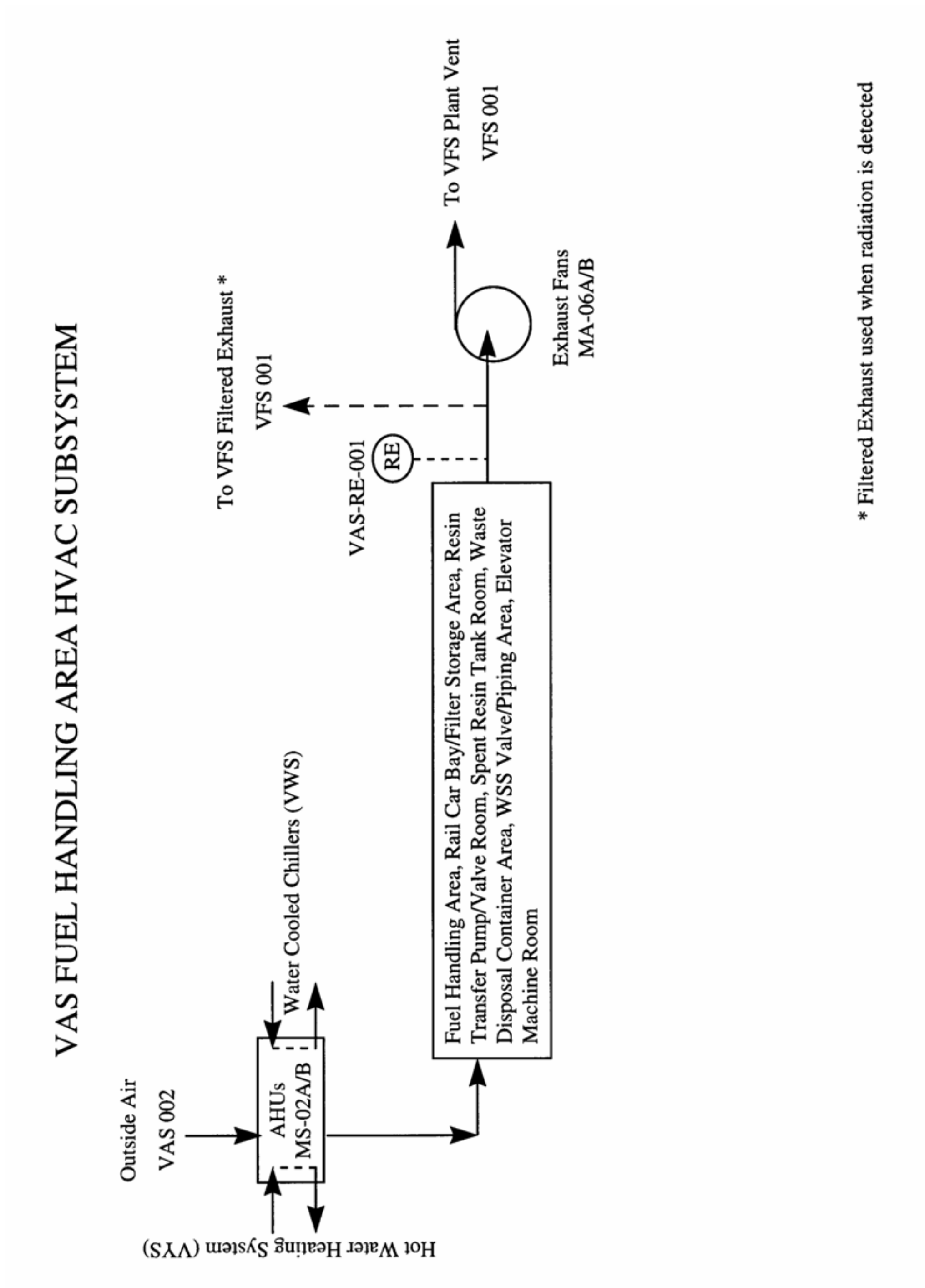


Figure 9.4.3-1 (Sheet 3 of 3)

Radiologically Controlled Area Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 005

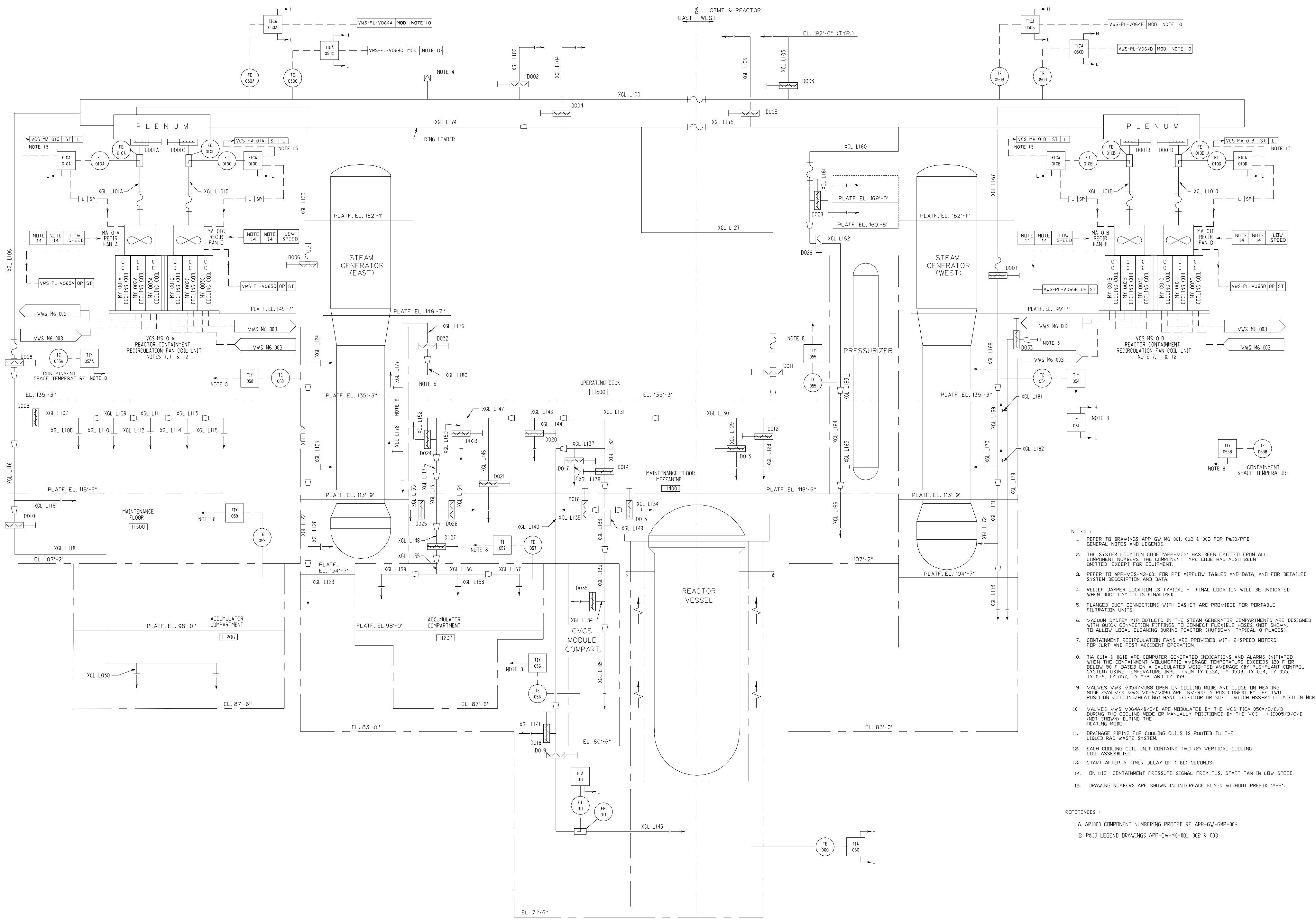


Figure 9.4.6-1

Containment Recirculation Cooling System
Piping and Instrumentation Diagram
(REF) VCS 001

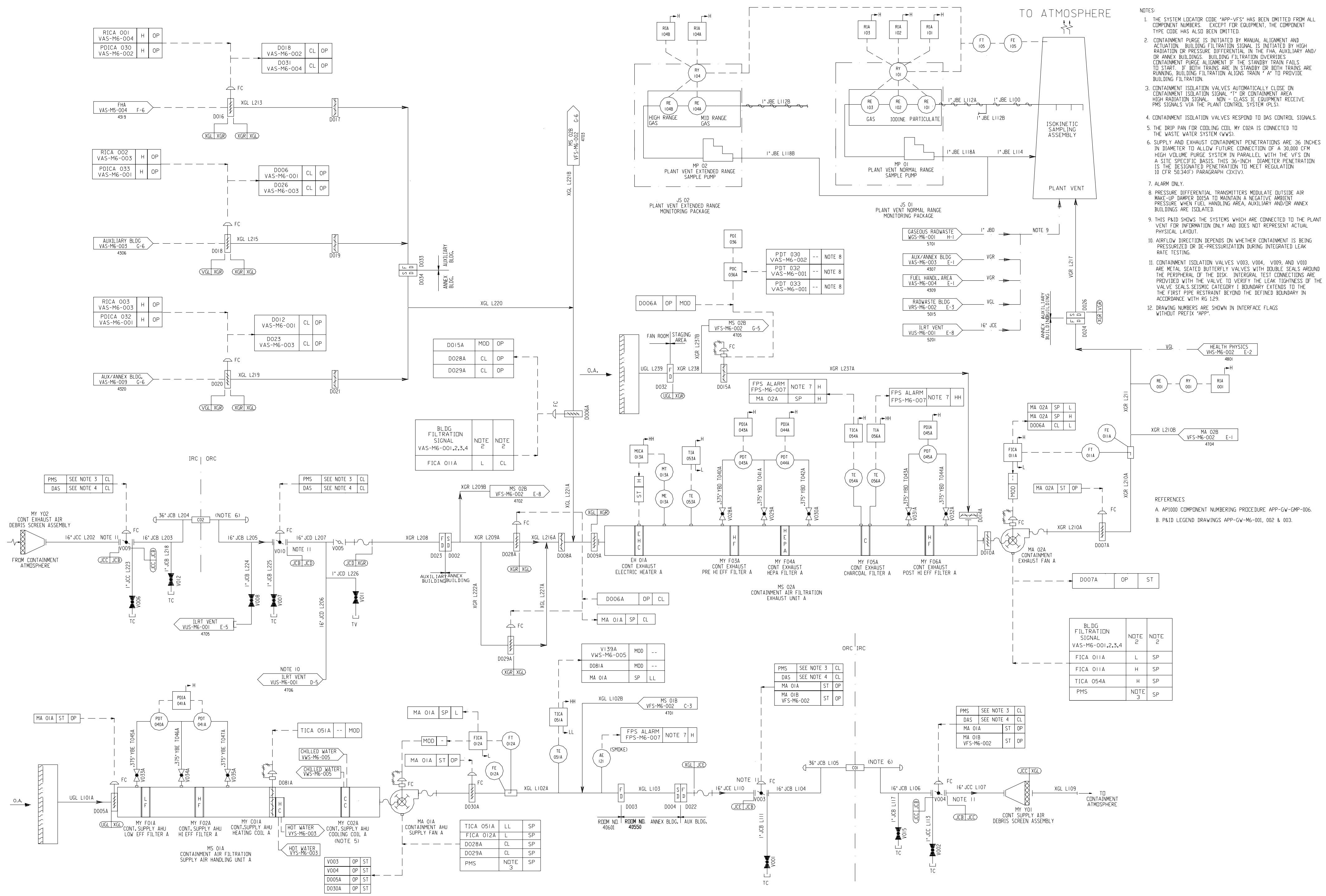


Figure 9.4.7-1 (Sheet 1 of 2)

Containment Air Filtration System
Piping and Instrumentation Diagram
(REF) VFS 001

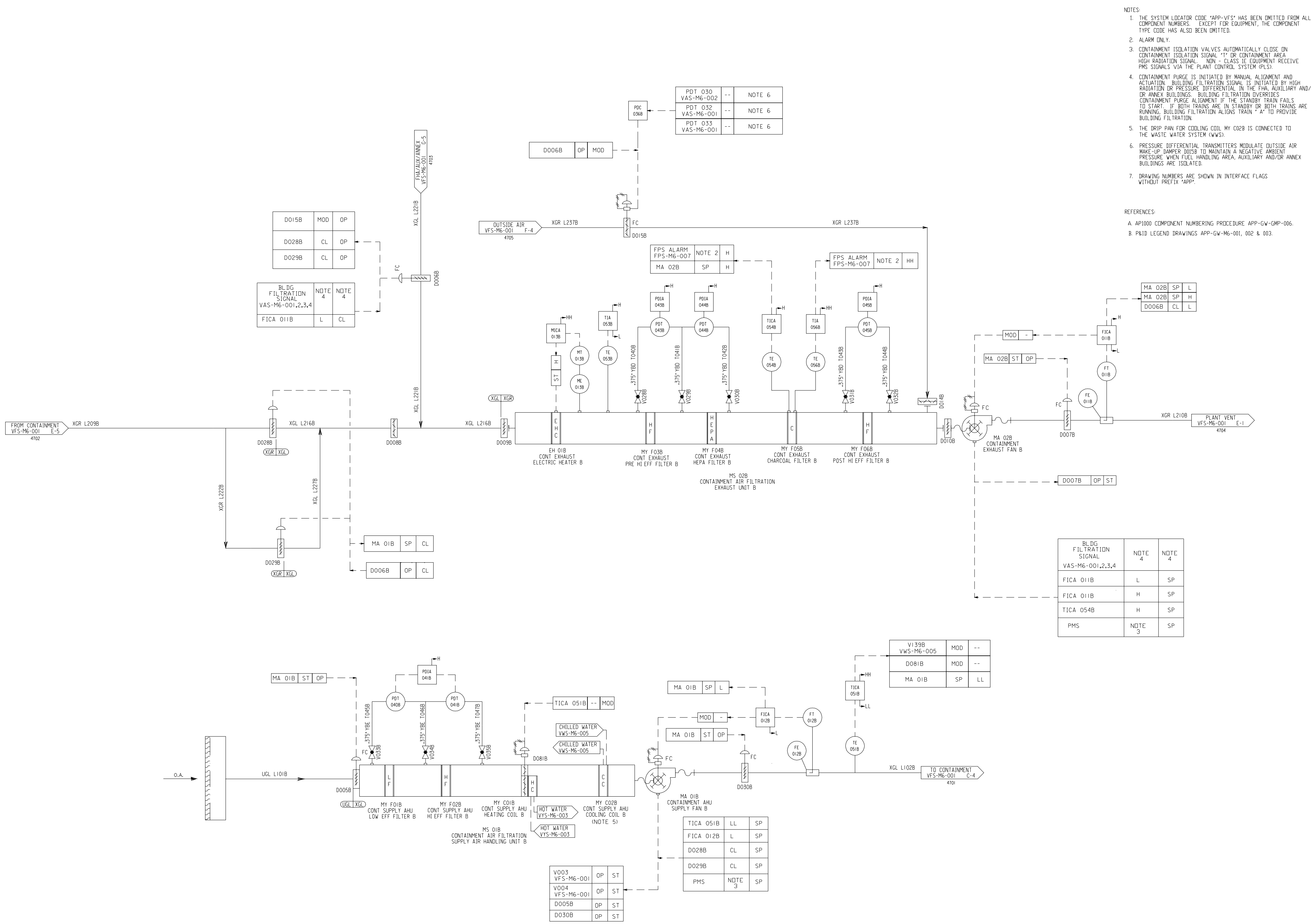


Figure 9.4.7-1 (Sheet 2 of 2)

Containment Air Filtration System
Piping and Instrumentation Diagram
(REF) VFS 002

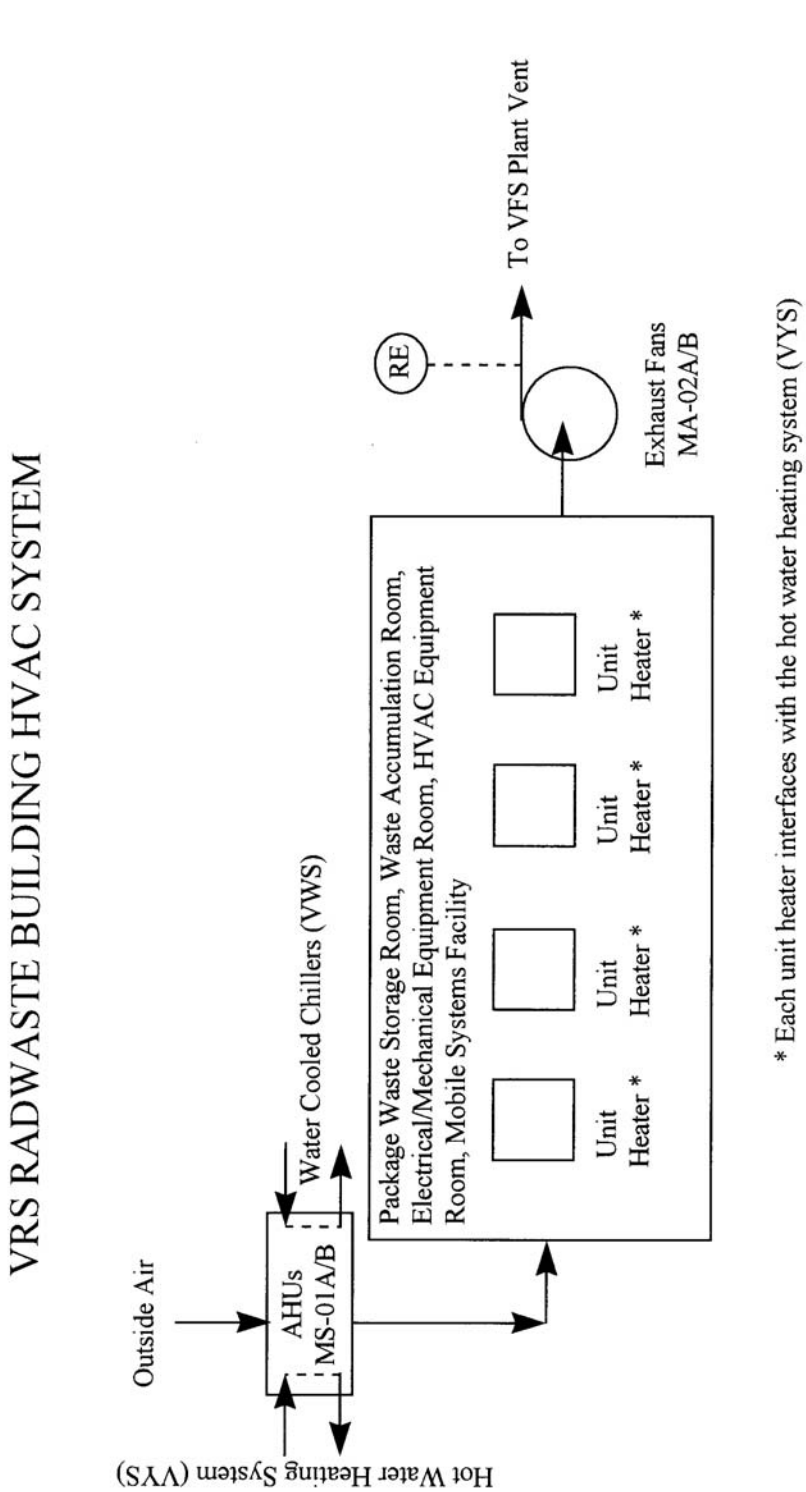


Figure 9.4.8-1

Radwaste Building HVAC System
(REF) VRS 001, 002, 003

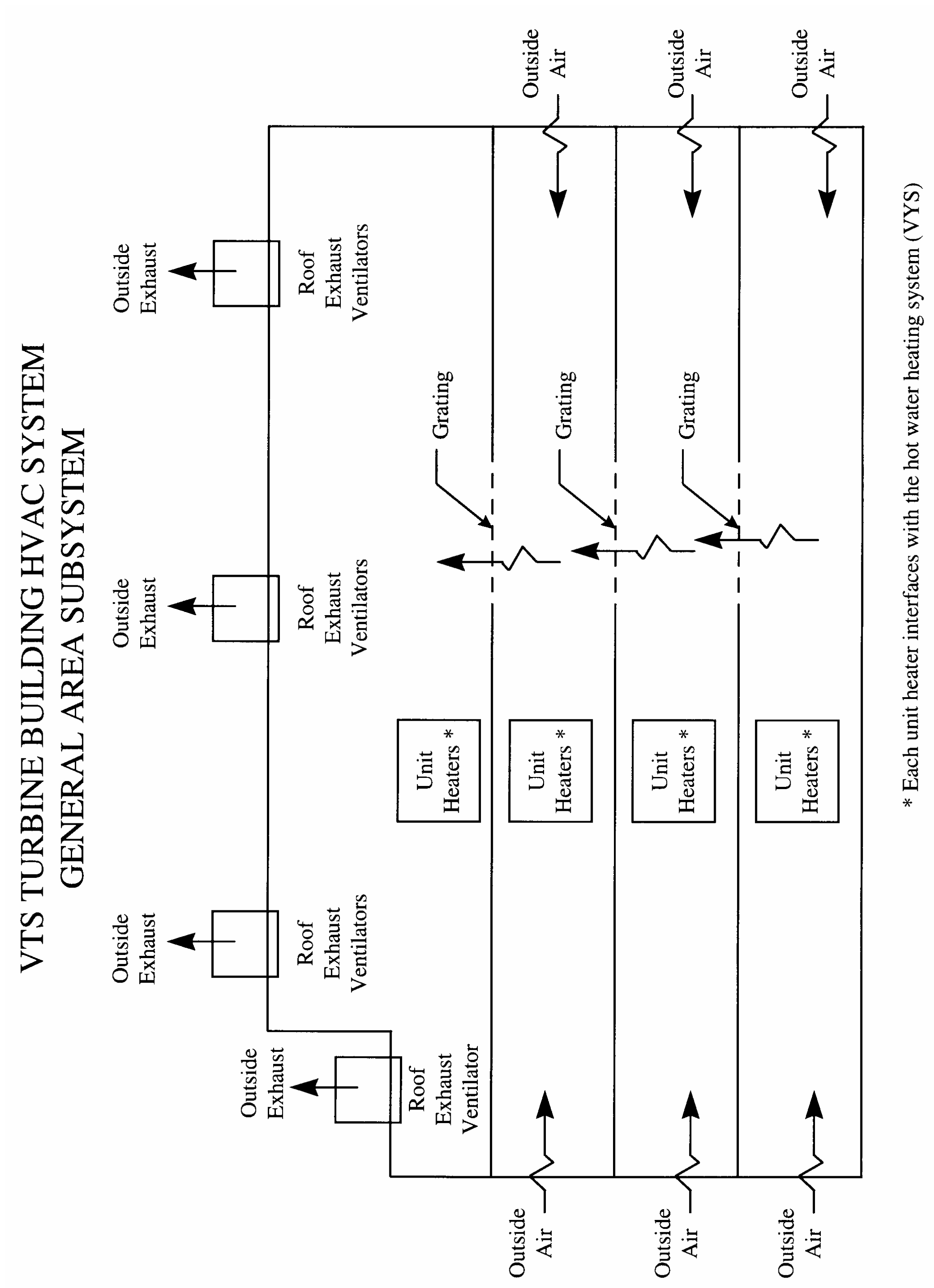
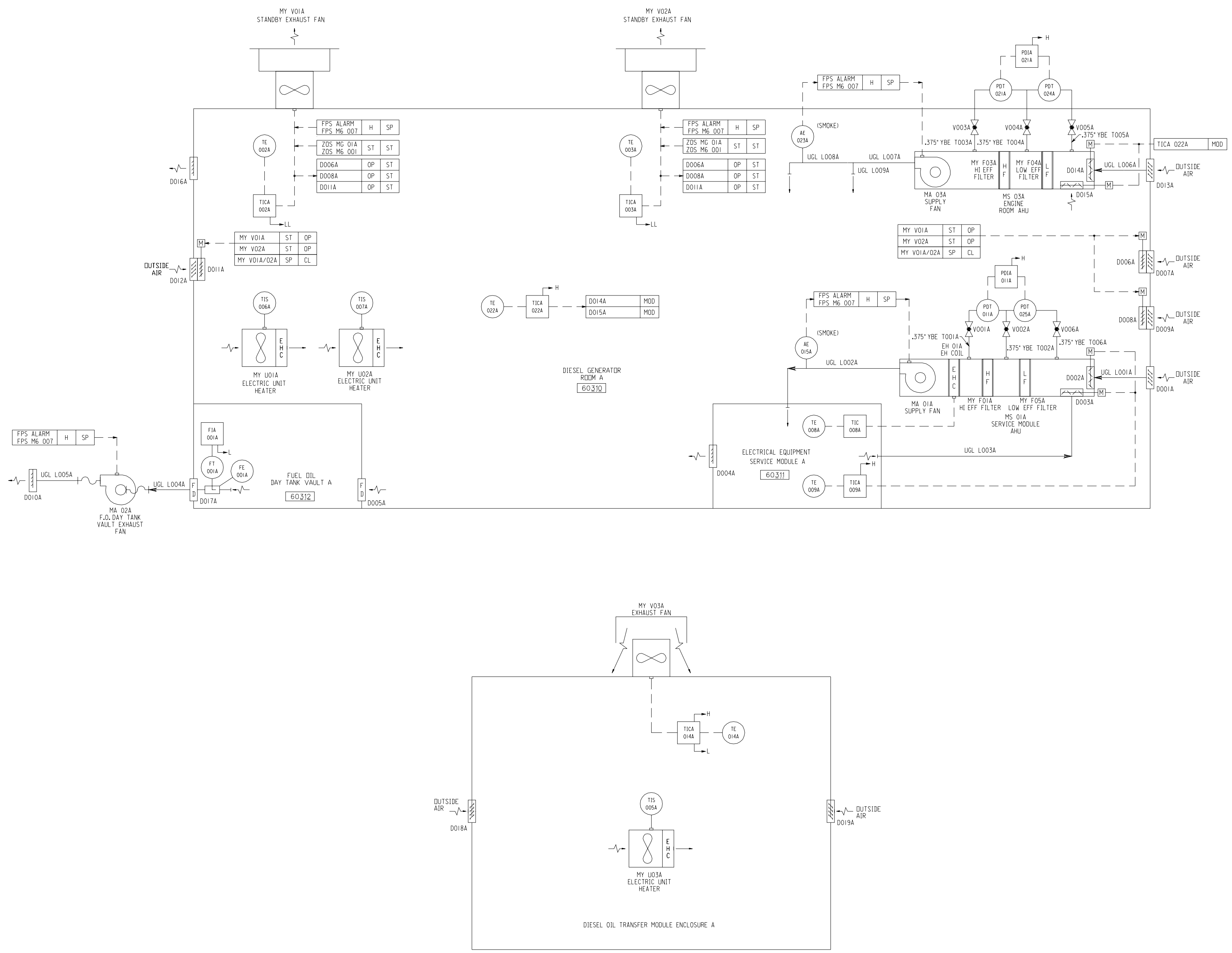


Figure 9.4.9-1

Turbine Building HVAC System
(REF) VTS 001

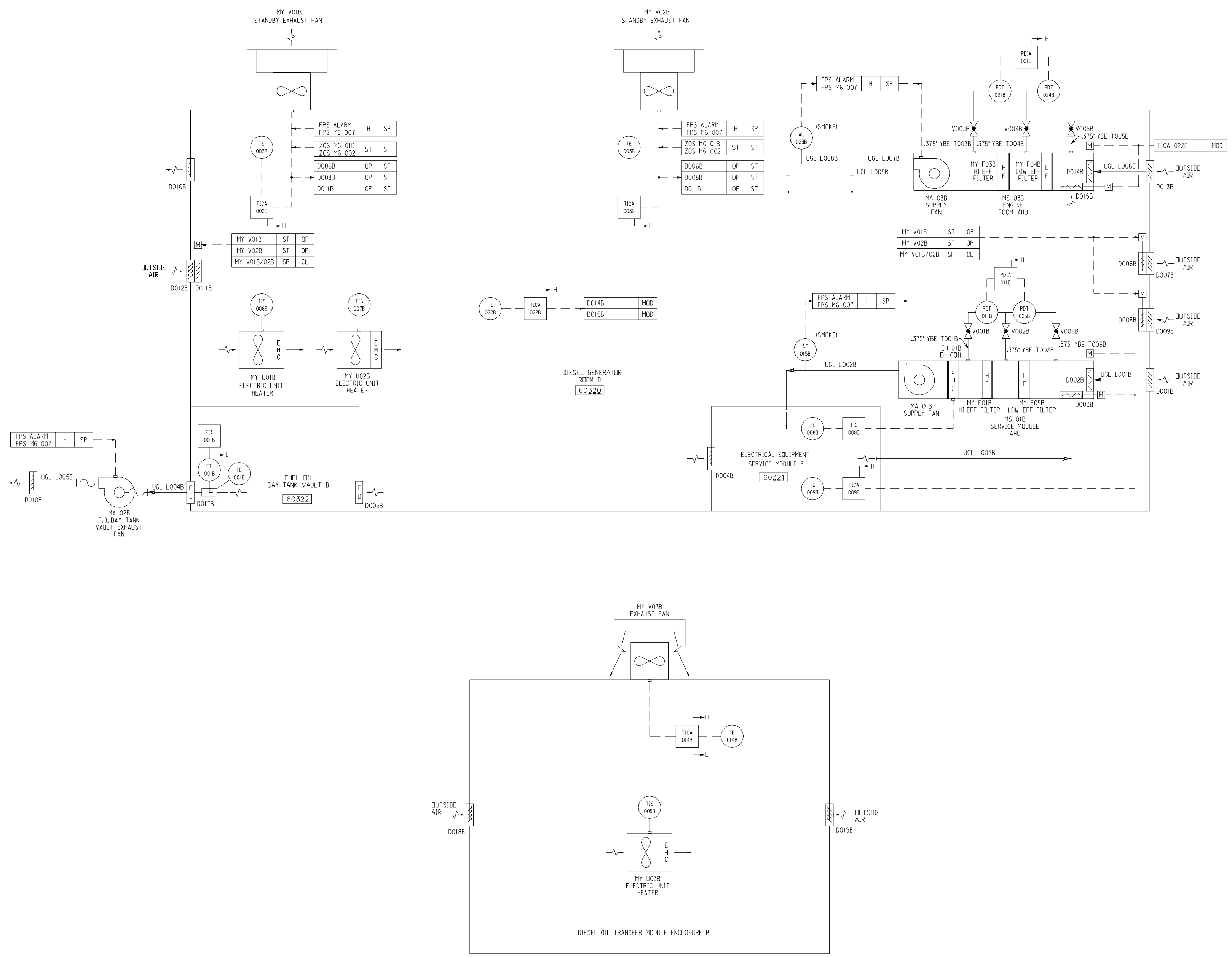


NOTES

1. ALL EQUIPMENT TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS.
2. ALL INSTRUMENT TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS-JE.
3. ALL DAMPER/LOUVER TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS-MD.
4. THE SYSTEM LOCATOR CODE "APP-VZS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. EXCEPT FOR EQUIPMENT, THE COMPONENT TYPE CODE HAS ALSO BEEN OMITTED.

Figure 9.4.10-1 (Sheet 1 of 2)

Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram
(REF) VZS 001



NOTES

1. ALL EQUIPMENT TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS.
2. ALL INSTRUMENT TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS-JE.
3. ALL DAMPER/LOUVER TAG NUMBERS SHOWN ON THIS DRAWING ARE PREFIXED WITH VZS-MD.
4. THE SYSTEM LOCATOR CODE 'APP-VZS' HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. EXCEPT FOR EQUIPMENT, THE COMPONENT TYPE CODE HAS ALSO BEEN OMITTED.

Figure 9.4.10-1 (Sheet 2 of 2)

Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram

(REF) VZS 002

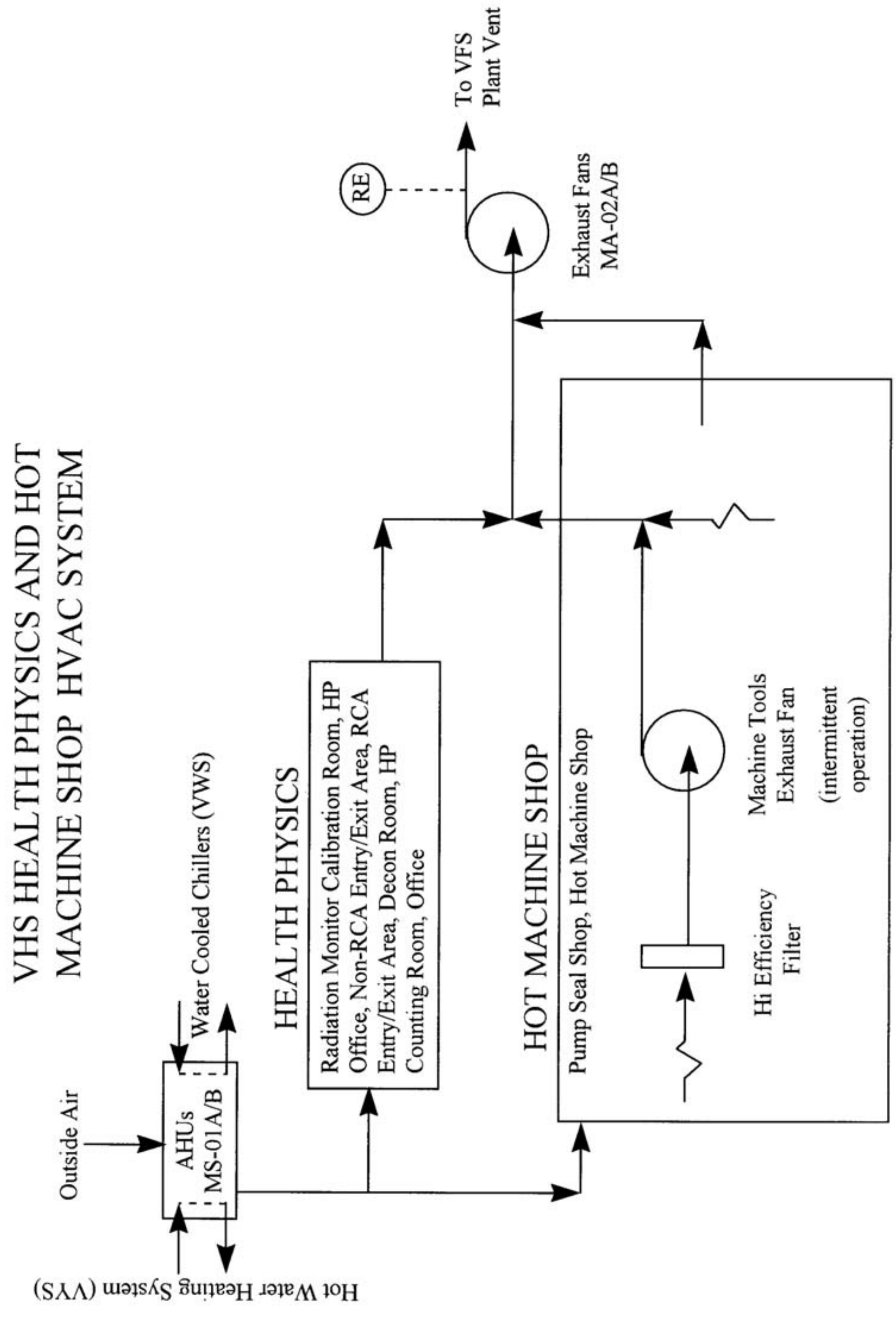


Figure 9.4.11-1

Health Physics and Hot Machine Shop HVAC System
(REF) VHS 001, 002, 003

9.5 Other Auxiliary Systems

9.5.1 Fire Protection System

The primary objectives of the AP1000 fire protection program are to prevent fires and to minimize the consequences should a fire occur. The program provides protection so that the plant can be shut down safely following a fire. The fire protection system (FPS) detects and suppresses fires, and is an integral part of the AP1000 fire protection program. The AP600 fire protection system was licensed as part of 10CFR52, Appendix C, AP600 Design Certification. Since AP1000 is very similar to AP600, the basis for the AP1000 fire protection system is that of AP600. The AP1000 compliance with BTP CMEB 9.5-1 is the same as for AP600.

9.5.1.1 Design Basis

9.5.1.1.1 Safety Design Basis

To achieve the required high degree of fire safety, and to satisfy fire protection objectives, the AP1000 is designed to:

- Prevent fire initiation by controlling, separating, and limiting the quantities of combustibles and sources of ignition

- Isolate combustible materials and limit the spread of fire by subdividing plant buildings into fire areas separated by fire barriers

- Separate redundant safe shutdown components and associated electrical divisions to preserve the capability to safely shut down the plant following a fire

- Provide the capability to safely shut down the plant using controls external to the main control room, should a fire require evacuation of the control room or damage the control room circuitry for safe shutdown systems

- Separate redundant trains of safety-related equipment used to mitigate the consequences of a design basis accident (but not required for safe shutdown following a fire) so that a fire within one train will not damage the redundant train

- Prevent smoke, hot gases, or fire suppressants from migrating from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions

- Provide confidence that failure or inadvertent operation of the fire protection system cannot prevent plant safety functions from being performed

- Preclude the loss of structural support, due to warping or distortion of building structural members caused by the heat from a fire, to the extent that such a failure could adversely affect safe shutdown capabilities

- Provide floor drains sized to remove expected firefighting water flow without flooding safety-related equipment
- Provide firefighting personnel access and life safety escape routes for each fire area
- Provide emergency lighting and communications to facilitate safe shutdown following a fire
- Minimize exposure to personnel and releases to the environment of radioactivity or hazardous chemicals as a result of a fire

The fire protection system is classified as a nonsafety-related, nonseismic system. Special seismic design requirements are applied to portions of the standpipe system located in areas containing equipment required for safe shutdown following a safe shutdown earthquake, as described in subsection 9.5.1.2.1.5. In addition, the containment isolation valves and associated piping for the fire protection system are safety-related (Safety Class 2) and seismic Category I. The fire protection system is not required to remain functional following a plant accident or the most severe natural phenomena, except as indicated below for a safe shutdown earthquake.

The fire protection system is designed to perform the following functions:

- Detect and locate fires and provide operator indication of the location
- Provide the capability to extinguish fires in any plant area, to protect site personnel, limit fire damage, and enhance safe shutdown capabilities
- Supply fire suppression water at a flow rate and pressure sufficient to satisfy the demand of any automatic sprinkler system plus 500 gpm for fire hoses, for a minimum of 2 hours
- Maintain 100 percent of fire pump design capacity, assuming failure of the largest fire pump or the loss of offsite power
- Following a safe shutdown earthquake, provide water to hose stations for manual firefighting in areas containing safe shutdown equipment
- Satisfy the requirements of the passive containment cooling system as an alternate source of water to wet the containment dome or to refill the passive containment cooling water storage tank after a loss-of-coolant accident, if the fire protection system is available
- Provide an alternate supply of cooling water to the normal residual heat removal system heat exchanger after a loss of normal component cooling water system function.

9.5.1.1.2 Power Generation Design Basis

AP1000 fire prevention, control, detection, and suppression features provide plant and personnel safety. The fire protection analysis (see Appendix 9A) evaluates the adequacy of fire protection for systems and plant areas important to the generation of electricity.

9.5.1.1.3 Nonsafety-Related Containment Spray Function

The fire protection system provides a nonsafety-related containment spray function. This function is discussed in subsection 6.5.2.

9.5.1.2 System Description

9.5.1.2.1 General Description

The fire protection program and the design of the fire protection system conform to the applicable codes and standards listed in Section 3.2, and the following:

- 10 CFR 50.48, Fire Protection (Reference 15)
- General Design Criterion 3, Fire Protection (Reference 16)
- SECY-93-087, Section I.E., Fire Protection (Reference 17)

Table 9.5.1-1 is a point-by-point description of the conformance of the fire protection program with the guidelines of Branch Technical Position (BTP) CMEB 9.5-1 (Reference 1). AP1000 meets the enhanced fire protection provisions of SECY-93-087 as demonstrated in the fire protection analysis (Appendix 9A).

The plant includes features to minimize the likelihood that a fire will occur and to limit the spread of fire.

The fire protection system detects fires and provides the capability to extinguish them using fixed automatic and manual suppression systems, manual hose streams, and/or portable firefighting equipment. The fire protection system consists of a number of fire detection and suppression subsystems, referred to as systems, including:

- Detection systems for early detection and notification of a fire

- A water supply system including the fire pumps, yard main, and interior distribution piping

- Fixed automatic fire suppression systems

- Manual fire suppression systems and equipment, including hydrants, standpipes, hose stations and portable fire extinguishers

The fire detection and suppression systems are described later in this subsection.

9.5.1.2.1.1 Plant Fire Prevention and Control Features

Architectural and Structural Features

Plant buildings use noncombustible structural materials, primarily reinforced concrete, gypsum, masonry block, structural steel, steel siding, and concrete/steel composite material. Fireproofing of structural steel is not normally required, but the effects of heat generated by a fire are considered in the design. Localized structural steel fireproofing is provided as required, based on a realistic

analysis of the time-temperature fire effects on the structural members. Heat transfer analyses based on the postulated fire are used to determine whether the fire will heat the structural members to a specified critical temperature. Where structural failures could adversely affect safe shutdown capabilities, this analysis of the fire resistance of structural steel members establishes the need for fireproofing.

Firefighting personnel access routes and life safety escape routes are provided for each fire area. Fire exit routes are clearly marked.

Buildings outside primary containment generally have two enclosed stairways for emergency access. Stairwells serving as escape routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown of the plant are equipped with emergency lighting. Such stairwells, and elevator shafts, which penetrate fire barrier floors, are enclosed in towers. The majority of the stairwell towers in the auxiliary building contain both concrete structural walls and nonstructural walls, consisting of a concrete/steel composite material having a fire resistance rating of at least 2 hours. These auxiliary building stairwells are protected from potential missiles by other structures or by the selection of the location of the stairwell remote from potential missile sources. Openings are protected with approved automatic or self-closing doors having a rating of 1.5 hours.

Some of the walls of the turbine building and annex building stairwell enclosures, which are exposed to the interior of the buildings, are also constructed with a concrete/steel composite material. However, the turbine building and annex building stairwell enclosure walls that face the yard area are constructed with an exterior siding common to the overall siding used for the turbine and annex buildings.

The main control room is designed to permit rapid detection and location of fires in the underfloor and ceiling spaces and allow ready access for manual firefighting. Due to the need to provide passive cooling capability into the main control room ceiling, it will not be protected against fires from within the main control room. The ceiling will be a fire barrier from fires in the room above the main control room.

Plant Arrangement

The plant is subdivided into fire areas to isolate potential fires and minimize the risk of the spread of fire and the resultant consequential damage from corrosive gases, fire suppression agents, smoke, and radioactive contamination.

Some fire areas are subdivided into fire zones to permit more precise identification of the type and locations of combustible materials, fire detection, and suppression systems. The subdivision into fire zones is based on the configuration of interior walls and floor slabs, and the location of major equipment within each fire area.

Fire barriers are provided in accordance with BTP CMEB 9.5-1. Three-hour fire barriers are non-combustible and surround fire areas containing safety-related components. The resistance of fire barriers in nonsafety-related areas of the plant may be less than 3 hours, where justified by the fire protection analysis (Appendix 9A).

Three-hour fire barriers provide complete separation of redundant safe shutdown components, including equipment, electrical cables, instrumentation and controls, except where the need for physical separation conflicts with other important requirements, specifically:

- Fire barrier separation is not provided within the main control room fire area because functional requirements make such separation impractical. The risk of fires in the control room is minimized by the reduction in the quantity of electrical cables. Continuous occupancy provides confidence that fires would be quickly detected and suppressed. Should a fire require evacuation of the main control room, the plant can be safely shut down using independent controls at the remote shutdown workstation, located in a separate fire area.

- Fire barrier separation is not provided between the main control room and the room above it from fires in the main control room. There are no safe shutdown components in the room above. There is fire barrier separation between the main control room and the room above it for fires in the room above.

- Fire barrier separation is not provided within the remote shutdown room fire area because the remote shutdown workstation is not required for safe shutdown unless a fire requires evacuation of the main control room.

- Complete fire barrier separation necessary to define a fire area is not provided throughout the primary containment fire area (including the middle and upper annulus zones of the shield building) because of the need to satisfy other design requirements, such as allowing for pressure equalization within the containment following a high-energy line break. Fire protection features and equipment arrangement which define fire zones within the containment fire area provide confidence that at least one train of safe shutdown equipment will remain undamaged following a fire in any fire zone. The quantity of combustible materials is minimized. The use of canned reactor coolant pump motors has eliminated the need for an oil lubrication system. Redundant trains of safe shutdown components are separated whenever possible by existing structural walls, or by distance. Selected cables of a safety-related division which pass through a fire zone of an unrelated division are protected by fire barriers. The fire protection system provides appropriate fire detection and suppression capabilities.

Outside of the primary containment and the main control room, the arrangement of plant equipment and routing of cable are such that safe shutdown can be achieved with all components (except those protected by 3-hour fire barriers) in any one fire area rendered inoperable by fire.

Openings and penetrations through fire barriers are protected in accordance with the guidelines of BTP CMEB 9.5-1.

The fire protection analysis contains a description of plant fire areas, fire zones, fire barriers, and the protection of fire barrier openings, as well as a description of the separation between redundant safe shutdown components.

Electrical Cable Design, Routing, and Separation

Electrical cable (including fiber optic cable) and methods of raceway construction are selected in accordance with BTP CMEB 9.5-1. Metal cable trays are used. Rigid metal conduit or metal raceways are used for cable runs not embedded in concrete or buried underground. Flexible metallic tubing is used in short lengths for equipment connections.

The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202 (Reference 18) or IEEE Standard 383 (Reference 3) excluding the option to use flame source, oil, or burlap.

The design, routing, and separation of cable and raceways are further described in Section 8.3.

Control of Combustible Materials

The plant is constructed of noncombustible materials to the extent practicable. The selection of construction materials and the control of combustible materials are in accordance with BTP CMEB 9.5-1 and Section 3.3 of NFPA 804 (Reference 2) as specified in WCAP-15871 (Reference 20).

The storage and use of hydrogen are according to NFPA 50A and NFPA 50B (Reference 2). Hydrogen lines in safety-related areas are designed to seismic Category I requirements.

Ventilation systems are designed to maintain the hydrogen concentration in the battery rooms well below 2 percent by volume, as described in subsections 9.4.1 and 9.4.2.

The turbine lubrication oil system, located in the turbine building, is separated from areas containing safety-related equipment by 3-hour rated fire barriers.

Outdoor oil-filled transformers are separated from plant buildings according to NFPA 804 (Reference 2).

The diesel fuel oil storage tanks and the diesel fuel oil transfer pump enclosure are located in the yard area more than 50 feet from any safety-related structure. Potential oil spills from the storage tanks are confined by a diked enclosure. A diesel generator fuel day tank is located within each diesel generator room and is enclosed in a 3-hour fire rated barrier.

The diesel fuel supply for the ancillary diesel generators is in the same room as the diesel generators. The ancillary diesel generator room is separated from the rest of the annex building by a 3-hour rated fire barrier.

The diesel fuel supply for the diesel-driven fire pump is in the diesel-driven fire pump enclosure. The diesel pump enclosure is located in the yard more than 50 feet from safety-related structures. The enclosure includes a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by operation of an automatic sprinkler system or manually, using hose streams or portable extinguishers.

Quantities and locations of other combustible materials are identified in the fire protection analysis (see Appendix 9A).

Control of Radioactive Materials

As described in the fire protection analysis, materials that collect or contain radioactivity, such as spent ion exchange resins and filters, are protected and stored in accordance with BTP CMEB 9.5-1.

9.5.1.2.1.2 Fire Detection and Alarm Systems

Fire detection and alarm systems are provided where required by the fire protection analysis, in accordance with BTP CMEB 9.5-1 and NFPA 72 (Reference 2). Fire detection and alarm systems are generally in accordance with NFPA 804 (Reference 2). See WCAP-15871 (Reference 20) for details.

Fire detectors respond to smoke, flame, heat, or the products of combustion. The installation of fire detectors is in accordance with NFPA 72 (Reference 2) and the manufacturer's recommendations. The selection and installation of fire detectors is also based on consideration of the type of hazard, combustible loading, the type of combustion products, and detector response characteristics. The types of detectors used in each fire area are identified in the fire protection analysis.

The fire detection system provides audible and visual alarms and system trouble annunciation in the main control room and the security central alarm station. Annunciation circuits connecting zone, main, and remote annunciation panels are electrically supervised.

Each fire detection, indicating, and alarm unit is provided with reliable ac electrical power from the non-Class 1E uninterruptible power supply system. This system is described in subsection 8.3.2.1.2.

9.5.1.2.1.3 Fire Water Supply System

The fire water supply system is designed in accordance with BTP CMEB 9.5-1 and the applicable NFPA standards.

Fire water is supplied from two separate fresh water storage tanks. The primary fire water tank is dedicated to the fire protection system. The secondary fire water tank serves the raw water system but contains water for use by the fire protection system and the containment spray system.

There are two 100-percent capacity fire pumps. The lead pump is electric motor-driven and the secondary pump is diesel engine-driven. A motor-driven jockey pump is used to keep the fire water system full of water and pressurized, as required. For additional information regarding the fire water tanks and pumps, see subsection 9.5.1.2.3.

The fire water tanks are permanently connected to the fire pumps suction piping and are arranged so that the pumps can take suction from either or both tanks. Piping between the fire water sources

and the fire pumps is in accordance with NFPA 20 (Reference 2). A failure in one tank or its piping cannot cause both tanks to drain.

Fire protection water is distributed by an underground yard main loop, designed in accordance with NFPA 24 (Reference 2). The yard main includes a building interior header that distributes water to suppression systems within the main plant buildings. Indicator valves provide sectionalized control and permit isolation of portions of the yard main for maintenance or repair. An indicator valve also separates the individual fire pump connections to the main.

Sprinkler and standpipe systems are supplied by connections from the yard main. Where plant areas, other than the containment and outlying buildings, are protected by both sprinkler systems and standpipe systems, the connections from the yard main are arranged so that a single active failure or a crack in a moderate energy line cannot impair both systems.

Manual valves for sectionalized control of the yard main or for shutoff of the water supply to suppression systems are electrically supervised if located above ground and administratively controlled if located underground.

Hydrants are provided on the yard main in accordance with NFPA 24 (Reference 2), at intervals of up to about 250 feet. They provide hose stream protection for every part of each building and two hose streams for every part of the interior of each building not covered by standpipe protection, excluding certain remote areas of the shield building. The lateral to each hydrant is controlled by an isolation valve.

Hose houses are in accordance with NFPA 24 (Reference 2). They are located at intervals of not more than 1000 feet along the yard main.

Outdoor fire water piping and water suppression systems located in unheated areas of the plant are protected from freezing.

A permanent connection between the fire protection system and the component cooling water system in the annex building is normally isolated by two valves in series.

A permanent connection between the fire protection system and the containment spray system in the containment is normally isolated by two valves in series.

9.5.1.2.1.4 Automatic Fire Suppression Systems

Automatic fire suppression systems are in accordance with BTP CMEB 9.5-1 and the applicable NFPA standards, with consideration of the unique aspects of each application, including building characteristics, materials of construction, environmental conditions, fire area contents, and adjacent structures.

Fixed automatic fire suppression systems are provided based on the results of the fire protection analysis.

The selection of automatic suppression systems for each plant area is based on the guidance of NFPA 804 (Reference 2) as stated in WCAP-15871 (Reference 20). Water systems are preferred,

but the use of automatic water suppression systems for firefighting in radiation areas is minimized because of the possible spread of contamination. Halon and carbon dioxide fixed flooding systems are not used.

The fire protection analysis describes the fire suppression systems provided for each fire area.

Automatic Water Suppression Systems

Automatic sprinkler and water spray systems are provided in accordance with the applicable requirements of NFPA 13 and NFPA 15 (Reference 2). Each system consists of overhead piping and components from a water supply valve to the point where water discharges from the system. Some systems have a control valve that is actuated automatically by the fire detection system. Each system has a status monitoring device for actuating an alarm when the system is in operation.

Preaction sprinkler systems are used where the leakage or inadvertent actuation of water-filled sprinkler systems could produce undesirable consequences, such as water discharge on equipment important to continued plant operation.

Each type of automatic sprinkler and automatic water spray system used on AP1000 is briefly described below:

- **Wet Pipe -** A sprinkler system employing closed (fusible link operated) sprinklers attached to a water-filled piping network. Water discharges immediately from those sprinklers where the heat from a fire is sufficient to melt the fusible link. System operation is terminated manually by shutting the water-supply valve.

- **Dry Pipe -** A sprinkler system employing closed sprinklers attached to a piping network containing pressurized air. Heat from a fire opens one or more sprinklers, releasing the air and permitting water supply pressure to open the dry pipe valve. Water flows into the piping network and discharges from the open sprinklers. System operation is terminated manually by shutting the water-supply valve.

- **Preaction -** A sprinkler system employing closed sprinklers attached to a dry piping network, with fire detector(s) installed in the same areas as the sprinklers. Operation of the fire detection system opens a preaction valve, which permits water to flow into the sprinkler piping network and to be discharged from any sprinklers that may have been opened by the fire. System operation is terminated manually by shutting the water-supply valve.

- **Deluge Sprinkler or Water Spray System -** A system employing open sprinklers or spray nozzles attached to a dry piping network, with fire detector(s) installed in the same areas as the sprinklers. Operation of the fire detection system opens a deluge valve, which permits water to flow into the sprinkler piping network and to be discharged from all the sprinklers or spray nozzles. System operation is terminated manually by shutting the water-supply valve.

9.5.1.2.1.5 Manual Fire Suppression Systems

Manual fire suppression capability is provided in areas that do not require an automatic suppression system. Plant areas that have an automatic suppression system also have manual backup fire suppression capability.

Manual fire suppression capabilities include the yard main fire hydrants and hose stations described in subsection 9.5.1.2.1.3.

Standpipe and Hose Systems

Standpipe systems are provided for each building in accordance with NFPA 14 (Reference 2) requirements for Class III service. Wet standpipe systems are used except inside containment. Individual standpipes are at least 4 inches in diameter for multiple hose connections and 2.5 inches in diameter for single hose connections.

Hose stations are located to facilitate access for firefighting, as described in the fire protection analysis. Areas that contain, or could present a fire exposure event to, safety-related equipment are within reach of at least one effective hose stream. Alternative hose stations are provided for an area where the fire could block access to a single hose station serving that area. To the maximum extent practical, hose stations are located outside of high-radiation areas.

Each hose station has not more than 100 feet of 1.5-inch woven-jacket lined fire hose. Nozzles are provided at each station.

Seismic Standpipe System

The standpipe system serving areas containing equipment required for safe shutdown following a safe shutdown earthquake is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional. The seismically analyzed standpipe system is illustrated on Figure 9.5.1-1. This system also supplies water to automatic suppression systems inside containment and in the nonradiologically controlled portion of the auxiliary building (see Appendix 9A).

The seismic standpipe system is operated in the same manner during normal plant operation or following a safe shutdown earthquake. It is supplied with water from the safety related passive containment cooling system storage tank and normally operates independently of the rest of the fire protection system. The supply line draws water from a portion of the storage tank, using water allocated for fire protection. This volume of water is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for 2 hours.

The portion of the system outside containment is a wet standpipe system that is pressurized by the static head of water in the passive containment cooling system tank. The portion of the system inside containment is a dry standpipe system. The supply valve is normally closed for containment isolation. During shutdown periods when the containment is occupied, when operation of containment automatic suppression systems is required, or when containment access is required to fight a fire, the valve is opened to pressurize the system.

In the unlikely event that the water supply from the passive containment cooling system is unavailable or additional water is needed, the seismic standpipe system can be supplied from the fire main by opening the normally closed cross-connect valve with the plant fire main.

A passive containment cooling ancillary water storage tank is provided to supply the seismic standpipe system following a safe shutdown earthquake and after actuation of the passive containment cooling system. The tank is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional. A dedicated portion of the storage capacity of the tank is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for 2 hours. Normally much more water is available. (Refer to subsection 6.2.2 for additional information.)

A failure of the seismic standpipe system does not prevent successful operation of the passive containment cooling system. A leak in the standpipe system could result in the loss of only a limited amount of water from the passive containment cooling system storage tank, even if no action were taken to isolate the leak. The volume of water allocated for fire protection is not required for passive containment cooling.

Portable Fire Extinguishers

Portable fire extinguishers are provided throughout the plant. Portable extinguishers are readily accessible for use in high radiation areas but are not located within those areas unless the fire protection analysis indicates that a specific requirement exists.

9.5.1.2.2 System Operation

The fire protection system normally operates in an active standby mode. The fire water supply piping is kept full and pressurized by operation of the jockey pump. Shutoff valves controlling fire suppression systems are normally aligned in the open position. Fire detection and alarm circuits are normally energized and monitored for trouble or loss of power as described in subsection 9.5.1.2.1.2.

When a fire is detected, the fire detection system produces an audible alarm locally, and both visual and audible alarms in the main control room and security central alarm station.

Where the fire area is protected by an automatic suppression system, operation of the suppression system begins as described in subsection 9.5.1.2.1.4. Where the fire area is protected by manual suppression methods, the fire brigade reacts to control and extinguish the fire.

Ventilation system fire dampers close automatically against full airflow on high temperature to control the spread of fire and combustion products. Fire dampers serving certain safety-related, smoke-sensitive areas are also closed in response to an initiation signal from the fire detection system. Smoke is removed from the fire area as described in the fire protection analysis.

When water pressure in the yard main begins to fall, due to a demand for water from automatic or manual suppression systems, the motor-driven pump starts automatically on a low-pressure signal. If the motor-driven pump fails to start, the diesel-driven pump starts upon a lower pressure signal. The pump continues to run until it is stopped manually.

Firefighting activities continue until the fire is extinguished. Suppression systems are stopped manually. Operator actions are taken to repair and restore affected detection, alarm, and suppression systems to standby status.

9.5.1.2.3 Component Description

Selected fire protection system components are described below. Table 9.5.1-2 contains additional component data for fire protection equipment.

Fire Water Storage Tanks

Two separate fresh water storage tanks are provided for fire protection in accordance with NFPA 22 (Reference 2). The storage capacity of each tank is sufficient to maintain the design fire pump flow rate for at least 2 hours. Either tank can be automatically refilled from the raw water system within 8 hours. Freeze protection is provided as needed using electric immersion heaters.

Passive Containment Cooling Ancillary Water Storage Tank

See subsection 6.2.2.2.3 for a description of this component.

Fire Pumps

Two 100-percent capacity fire pumps are provided in accordance with NFPA 20 (Reference 2). Each pump is rated for 2000 gpm. The lead pump is electric motor-driven and the second pump is diesel engine-driven. The pumps and their controllers are UL-listed. Fire pump status alarms are provided in the main control room.

The motor-driven fire pump is supplied with power from the turbine building 480 Vac non-Class 1E switchgear. The fuel tank for the diesel-driven pump holds enough fuel to operate the pump for at least 8 hours.

Valves

Valves used in the fire protection system are of an approved type for fire protection service. See the Fire Protection Handbook (Reference 4) for typical descriptions of these valves.

Fire Detectors

The types of fire detectors used in specific applications are identified in the fire protection analysis. See Reference 4 for descriptions of these fire detectors and their principles of operation.

9.5.1.3 Safety Evaluation (Fire Protection Analysis)

The fire protection analysis evaluates the potential for occurrence of fires within the plant and describes how fires are detected and suppressed. It also confirms that the plant can be safely shut down following a postulated fire. The fire protection analysis is in Appendix 9A.

The fire protection analysis includes a set of fire area drawings and a discussion of the analysis methodology. It also provides the following information for each fire area in the plant:

- A description of the fire area and its fire barriers, its associated fire zones, as well as fire detection and suppression capabilities

- Identification of the type, quantity, and location of in-situ and anticipated transient combustible materials, and combustible loading

- A listing of safety-related mechanical and electrical equipment

- Fire severity category and equivalent duration

- An evaluation of fire protection system adequacy and the consequences of a fire, including a discussion of the control and removal of smoke and hot gases, and drainage system adequacy.

For fire areas containing safety-related structures, systems, and components the following information is also provided:

- An evaluation of fire protection system integrity. This includes a determination of whether the credible failure of a fire protection system component could cause inadvertent operation of an automatic fire suppression system in the fire area, and the resulting consequences. Also included is verification that no potential single impairment of the fire protection system could incapacitate both the automatic suppression system and the backup manual suppression system (generally a hose station), for fire areas where both types of suppression systems are provided.

- A safe shutdown evaluation confirming the capability to safely shut down the reactor and maintain it in a safe shutdown condition following a fire

The safe shutdown evaluation is based upon all components in a single fire area outside containment or any fire zone inside containment being disabled by the fire. Success is based upon the plant being able to achieve safe shutdown as discussed in Section 7.4. Safe shutdown is a safe, stable condition that can be maintained indefinitely with the reactor subcritical and reactor coolant pressure at a small fraction of its design pressure. As described in Section 7.4.1.1, safety-related systems achieve this condition automatically using reliable, passive processes. The passive residual heat removal heat exchanger transfers heat to the in-containment refueling water storage tank. Steam from this tank enters the containment which is cooled by the passive containment cooling system. These systems reduce the reactor temperature and pressure to less than 420°F and 600 psia in 36 hours. See Appendix 19E for additional details about the shutdown evaluation. This is a safe and acceptable end state which is used to show compliance with BTP 9.5-1. The safe shutdown fire evaluation in Appendix 9A shows that there is sufficient safety-related equipment available after a fire which destroys a single fire area outside containment or any fire zone inside containment, to bring the plant to this safe shutdown condition.

It should be noted that following most fires, that nonsafety-related systems are expected to be available to bring the plant to a cold shutdown for repairs. These systems are defense in depth

systems with redundant active components. These systems are expected to be available because of the use of redundant equipment and fire protection features, including separation or automatic fire suppression.

Table 9.5.1-4 lists the system capabilities that are expected to be available following a fire to bring the plant to a cold shutdown. This list does not contain the nonsafety-related support systems that are not necessary to operate following a fire. For example, chilled water cooling and non-1E instrumentation are not required following a fire. Heating and ventilation are not required except for two fans used to ventilate the non-1E switchgear rooms. The following safety-related capabilities are used together with these nonsafety-related capabilities to achieve cold shutdown:

- Insertion of control rods to provide reactor shutdown,
- Instrumentation to monitor reactor coolant system conditions,
- Operation of one core makeup tank in a natural circulation mode to provide reactor coolant makeup and boration in case the chemical and volume control system makeup is unavailable due to a fire,
- Manual partial opening (and closing) of one first stage automatic depressurization valve to provide a controlled, limited depressurization of the reactor coolant system to allow initiation of the normal residual heat removal system in case the chemical and volume control system auxiliary spray is unavailable due to a fire.

The use of these safety-related capabilities does not result in significant plant transients. The reactor coolant system pressure boundary is maintained and containment pressure and temperature conditions are not affected by the use of these safety-related capabilities.

If a less likely, more severe fire occurs, these systems are expected to be recovered after reasonable actions are taken to utilize temporary connections or to perform repairs (see subsections 9.2.2.4.5.5 and 9.5.1.1.1). Recovery of these systems allows the plant to be brought to a cold shutdown for plant repairs. No credit is taken in the Appendix 9A fire evaluation for nonsafety-related systems. As a result, fire separation is not required for these systems.

9.5.1.4 Testing and Inspection

The fire pumps are initially tested by the manufacturer in accordance with NFPA 20 (Reference 2) to verify pressure integrity and performance.

Preoperational testing is in accordance with the Initial Test Program (Chapter 14).

9.5.1.5 Instrumentation Applications

Pressure sensors start the fire pumps on decreasing fire main water pressure. Pressure indicators confirm adequate pressures for automatic and manual suppression systems. Valve position sensors are used to monitor the positions of water supply valves.

Temperature instrumentation is used to monitor fire water storage tank temperature. Level instrumentation is used to monitor levels in the fire water storage tanks and the diesel-driven fire pump fuel storage tank.

9.5.1.6 Personnel Qualification and Training

Preparation and review of the fire protection analysis, and design and selection of fire protection equipment, is performed by fire protection and nuclear safety systems engineers.

The qualification requirements for individuals responsible for development of the fire protection program, training of firefighting personnel, as well as associated administrative procedures, is the responsibility of the Combined License applicant.

9.5.1.7 Quality Assurance

Quality assurance controls are applied to the activities involved in the design, procurement, installation, testing, and maintenance of fire protection systems for safety-related areas, in accordance with the programs outlined in Chapter 17.

9.5.1.8 Combined License Information

The Combined License applicant will address qualification requirements for individuals responsible for development of the fire protection program, training of firefighting personnel, administrative procedures and controls governing the fire protection program during plant operation, and fire protection system maintenance.

The Combined License applicant will provide site-specific fire protection analysis information for the yard area, the administration building, and for other outlying buildings consistent with Appendix 9A.

The Combined License applicant will address BTP CMEB 9.5-1 issues identified in Table 9.5.1-1 by the acronym "WA."

The Combined License applicant will address updating the list of NFPA exceptions after design certification, if necessary.

The Combined License applicant will provide an analysis that demonstrates that operator actions which minimize the probability of the potential for spurious ADS actuation as a result of a fire can be accomplished within 30 minutes following detection of the fire and the procedure for the manual actuation of the valve to allow fire water to reach the automatic fire system in the containment maintenance floor.

The Combined License applicant will address the process for identifying deviations between the as-built installation of fire barriers and their tested configurations.

The Combined License applicant will establish procedures to minimize risk when fire areas are breached during maintenance. These procedures will address a fire watch for fire areas breached during maintenance.

The Combined License applicant will provide 2-hour fire resistance test data in accordance with ASTM E-119 and NFPA 251 for the composite material selected for stairwell fire barriers.

9.5.2 Communication System

The communication system (EFS) provides effective intraplant communications and effective plant-to-offsite communications during normal, maintenance, transient, fire, and accident conditions, including loss of offsite power. The communication system consists of the following subsystems:

- Wireless telephone system
- Telephone/page system
- Private automatic branch exchange (PABX) system
- Sound-powered system
- Emergency offsite communications
- Security communication system.

The communications system allows each guard, watchman, or armed response individual on duty to maintain continuous communication with an individual in each manned alarm station and with other agencies both onsite and offsite, as required by 10 CFR 73, Sections 55 (e) and (f) (Reference 13). This is accomplished by both the PABX system and the wireless communications system. Each system can provide these communication functions.

Communications equipment used with respiratory protection devices will be designed and selected in accordance with EPRI NP-6559 (Reference 8).

9.5.2.1 Design Basis

The communication system serves no safety-related function and therefore has no nuclear safety design basis.

The communication subsystems are independent of one another; therefore, a failure in one subsystem does not degrade performance of the other subsystems.

The communication system is in accordance with applicable codes and standards minimizing electromagnetic interference and its potential effects to equipment. "Low-powered" type equipment is used, where possible, which has been demonstrated to have a limited potential for causing interference with electronic equipment (Reference 8) (EPRI NP-6559, Section 5). Communication equipment is shielded, as necessary, from the detrimental effects of electromagnetic interference.

9.5.2.2 System Description

9.5.2.2.1 Wireless Telephone System

The wireless telephone system consists of wireless belt-clip portable handsets, hands-free type portable headsets, a comprehensive antenna system, and a wireless telephone switch. The wireless

telephone system is the primary means of communication for plant operations and maintenance personnel. The telephone-page, PABX telephone, and sound-powered communication systems are for general plant communications and serve as a backup to the wireless system.

The wireless telephone system has the ability to dial fixed PABX telephone stations and vice versa. The wireless system has the capability to access the page circuit of the telephone-page system and the capability to access offsite emergency communication links.

Normal 120-V ac power supplies the wireless telephone switch. Upon loss of the normal power, the switch is powered from the non-Class 1E dc and uninterruptible power supply system and supplies power for system operation for 120 minutes.

9.5.2.2.2 Telephone/Page System

The telephone/page system consists of handsets, amplifiers, loudspeakers, siren tone generators, a centralized test and distribution cabinet, and associated equipment. The system consists of one paging line and five party lines. The lines are independent of one another without crosstalk or interference. One party line is designed for communication between zones. Communication is established by selecting the same clear party line at each desired station using the party line selector switch provided with each unit and then talking into the handset. Intrazone announcements are made by pushing the paging button and speaking into the handset microphone at the handset station. Interzone announcements are made by first merging the required zones and then pushing the paging button and speaking into the handset microphone at the handset station. Remote zone merging control units are provided at the main control room, the security central alarm station, and the security secondary alarm station.

A five-tone siren generator annunciates alarms using the telephone page system amplifiers and speakers. Alarm initiation and tone selection capability are provided in the main control room.

Since volume control adjustment knobs are provided with each amplifier, a volume control bypass relay is provided. These relays bypass the volume controls upon initiation of an alarm by the siren tone generator, thereby providing full volume for alarms. Zones are automatically merged during an alarm condition.

Within the plant and outside area zones, subcircuits are provided which break the zone into several sections. Each subcircuit can be disconnected from the rest of the system at a central location should a disabling failure occur.

Power to the telephone/page system is provided from the non-Class 1E dc and uninterruptible power supply system sized to supply power for 120 minutes after a loss of ac power.

9.5.2.2.3 Private Automatic Branch Exchange System

The private automatic branch exchange (PABX) system provides communications between the system stations, with capability for transferring calls and providing conference calls at up to five stations.

A portion of the PABX, specifically in the main control room and technical support center area, has additional capability. The telephones in these areas are programmable. Buttons on the phone can be dedicated and color coded to specific telephone numbers.

The PABX system also interfaces with the following communication systems:

- The wireless telephone system
- Hotlines to Combined License applicant specified locations; for example, dedicated communication lines with the Combined License applicant load dispatcher to support and coordinate the system grid
- Local area telephone system lines
- Access to the page circuit in the telephone page system
- Direct extensions from the PABX locations exterior to the plant as dictated by the Combined License applicant

The hotline circuits are dedicated channels that provide direct communication between the main control room and the Combined License applicant headquarters or other facilities as required.

Commercial telephone lines are provided by the local area telephone company. Telephone lines may not terminate at the PABX. There are private lines that bypass the switch and ring directly at a telephone set. These numbers are located in the main control room, the alarm stations and at specific management offices located throughout the site. The local telephone company lines that terminate at the switch are programmed to reserve part of the lines for outgoing calls only. Others are programmed for incoming only so that some lines are available for calling onto and offsite. The number of lines will be defined by the Combined License applicant.

Power to the PABX is provided from the non-Class 1E dc and uninterruptible power supply system sized to supply power for 120 minutes after a loss of ac power.

9.5.2.2.4 Sound-Powered System

Two unitized systems are provided as follows:

- A loop sound-powered system for refueling
- A multiloop system throughout the plant for startup and maintenance testing

The sound-powered system does not require external power supply for operation.

9.5.2.3 System Operation Communication Stations

Table 9.5.2-1 lists the communication stations provided for operator use during transients.

The main control room and remote shutdown room are designed and instrumented to bring the plant to a safe shutdown condition without relying on communications equipment. Various communication stations are provided throughout the plant.

9.5.2.4 Inspection and Testing Requirements

Communication systems of the types described above are conventional and have a history of reliable operation. Most of these systems are in routine use, and this routine use will demonstrate their availability. Those systems not frequently used, but required during emergency situations, are tested at periodic intervals to demonstrate operability when required.

9.5.2.5 Combined License Information

9.5.2.5.1 Offsite Interfaces

Combined License applicants referencing the AP1000 certified design will address interfaces to required offsite locations; this will include addressing the recommendations of BL-80-15 (Reference 21) regarding loss of the emergency notification system due to a loss of offsite power.

9.5.2.5.2 Emergency Offsite Communications

The emergency offsite communication system, including the crisis management radio system, will be addressed by the Combined License applicant.

9.5.2.5.3 Security Communications

Specific details for the security communication system are the responsibility of the Combined License applicant as described in subsections 13.6.9 and 13.6.10.

9.5.3 Plant Lighting System

The plant lighting system includes normal, emergency, panel, and security lighting. The normal lighting provides normal illumination during plant operating, maintenance, and test conditions. The emergency lighting provides illumination in areas where emergency operations are performed upon loss of normal lighting. The panel lighting in the control room is designed to provide the minimum illumination required at the safety panels. The security lighting system is described in separate security documents. See subsection 13.6.8.

9.5.3.1 Design Basis

9.5.3.1.1 Safety Design Basis

- The normal and emergency lighting in the main control room and in the remote shutdown room is non-Class 1E. The emergency lighting in these plant areas is fed from a Class 1E uninterruptible power supply through two series fuses that are coordinated for isolation. The emergency lighting provides illumination for 72 hours upon loss of normal lighting. In other plant areas, the emergency lighting provides illumination for 8 hours.

- Lighting for the safety panels in the control room is provided by the panel lighting system. The power for the panel lighting is from the Divisions B and C Class 1E inverters through Class 1E distribution panels. The panel lighting circuits up to the lighting fixture are classified as associated and are routed in Seismic Category I raceways. The bulbs are not seismically qualified.

- During the 72 hour period following a loss of all ac power sources, lighting in the main control room can be provided as described in subsection 9.5.3.2.2.

9.5.3.1.2 Power Generation Design Basis

- The plant lighting system is non-Class 1E.

- The plant lighting system provides illumination levels for normal and emergency lighting as recommended in Illuminating Engineering Society Lighting Handbook (Reference 5).

- Mercury vapor lamps and mercury switches are not used in fuel handling areas.

- High-intensity discharge (HID) and fluorescent lamps are not used in the containment and fuel handling areas due to their mercury content. Incandescent lighting or other lighting not containing restricted materials is used in these areas.

9.5.3.2 System Description

9.5.3.2.1 Normal Lighting

Power to the normal lighting system is supplied from the non-Class 1E ac power distribution system at the following voltage levels:

- 480/277 V, three-phase, four-wire, grounded neutral system lighting panels are fed from the 480 V motor control centers; this source is for the lighting fixtures rated at 480/277 V and for the welding receptacles.

- 208/120 V, three-phase, four-wire, grounded neutral system distribution panels are fed from the 480 V motor control centers through dry-type 480-208/120 V transformers; this source is for lighting and utility receptacles.

- 208/120 V, three-phase, four-wire, grounded neutral regulated power fed from the 480 V motor control centers through the Class 1E 480 - 208/120 V voltage regulating transformers (divisions B and C); this source is for the normal and emergency lighting in the main control room and remote shutdown room and is isolated through two series fuses for isolation. The normal lighting in these plant areas is non-Class 1E.

The normal lighting system has the following features:

- The normal lighting system is powered from the diesel-backed buses and the lighting load is distributed between the two onsite standby diesel generator buses.

- The motor control centers powering the normal lighting system are energized from the 480 V load centers connected in a tie-breaker configuration.

- Lighting distribution panel branch circuit breakers are controlled by a lighting control system. Approximately 75 percent of the normal lighting is tripped off automatically upon loss of normal ac power (except in the main control room and in the remote shutdown room) to limit the load on the onsite standby diesel generators. The lighting control system allows the operator to energize or de-energize lighting in selected areas based on the actual need and available power from the onsite standby diesel generators.

- The lighting circuits are staggered as much as practical. The staggered circuits receive power from separate buses to prevent complete loss of light in the event of a bus or a circuit failure.

- The lighting fixtures located in the vicinity of safety-related equipment are supported so that they do not adversely impact this equipment when subjected to the seismic loading of a safe shutdown earthquake.

- The control room and remote shutdown room lighting uses semi-indirect, low-glare lighting fixtures and programmable dimming features. The normal control room lighting provides at least 50 foot candles of illumination at the safety panel and at the workstations when the dimming features are adjusted for maximum illumination. The normal remote shutdown room lighting provides at least 50 foot candles of illumination at the remote shutdown workstation when the dimming features are adjusted for maximum illumination.

9.5.3.2.2 Emergency Lighting

Emergency lighting is designed to provide the required illumination levels in the areas as described below:

- The main control room and remote shutdown room each has emergency lighting consisting of 120 V ac fluorescent lighting fixtures which are continuously energized. The fixtures are powered from the Class 1E 125 V dc switchboards through the Class 1E 208Y/120 V ac inverters and are isolated through two series fuses. Three hour fire barrier separation is provided between redundant emergency lightning power supplies and cables outside the main control room and the remote shutdown area. The control room lighting complies with the human factor requirements by utilizing semi-indirect, low-glare lighting fixtures and programmable dimming features. The control room emergency lighting is integrated with normal lighting that consists of identical lighting fixtures and dimming features. The emergency lighting system is designed so that, to the extent practical, alternate emergency lighting fixtures are fed from separate divisions of the Class 1E dc and uninterruptible power supply system. Both normal and emergency lighting fixtures, controllers, dimmers, and associated cables used in the main control room and remote shutdown room are non-Class 1E. The ceiling grid network, raceways and fixtures utilize seismic supports. A single fault cannot interrupt all of the lighting in the main control room and at the remote shutdown workstation simultaneously. The emergency lighting provides at least 10 foot candles of illumination at the safety panel, at the workstations in the control room, and at the

remote shutdown workstation when the dimming features are adjusted for maximum illumination.

- Following the 72 hour period after a loss of all ac power sources, the lighting in the main control room is powered from two ancillary ac generators as described in subsection 8.3.1.1.1.

- Emergency lighting in areas outside the main control room and remote shutdown room is accomplished by 8-hour, self-contained, battery pack lighting units. These units are non-Class 1E and provide illumination for safe ingress and egress of personnel following a loss of normal lighting and for those areas which could be involved in power recovery (for example, onsite standby diesel-generators and their controls). In addition, these units are provided in areas where manual actions are required for operation of equipment needed during a fire. These units are normally powered from the non-Class 1E 480/277 V ac motor control centers and they automatically switch to their internal dc source once normal ac power is lost.

9.5.3.2.3 Panel Lighting

Panel lighting is designed to provide lighting in the control room at the safety panels as described below:

- Panel lighting consists of lighting fixtures located on or near safety panels in the control room. The panel lights are continuously energized. The fixtures are powered from the Divisions B and C Class 1E inverters through Class 1E distribution panels.

- The circuits are treated as Class 1E. The panel lighting circuits up to the lighting fixture are classified as associated and are routed in Seismic Category I raceways.

- The bulbs are not seismically qualified.

9.5.3.3 Safety Evaluation

The areas that require lighting for safe shutdown are the main control room and the remote shutdown room when the main control room is not accessible.

- Lighting fixtures in the main control room and remote shutdown room are seismic Category II.

- Emergency and panel lighting circuits up to the lighting fixture are routed in seismic Category I raceways.

- Panel Lighting circuits up to the lighting fixture are treated as Class 1E and Classified as associated. This is acceptable to the Class 1E power supply because of the over current protective device coordination.

- Bulbs are not seismically qualified. However, the bulbs can only fail open and therefore do not represent a hazard to the Class 1E power sources.

- Power to normal and emergency lighting in the main control room and in the remote shutdown room is supplied from the redundant divisions of Class 1E dc and UPS system through two series fuses for isolation. The fuses protect the batteries from failures of the non-1E lighting circuits. The Class 1E batteries provided in the Class 1E dc and UPS system are capable of powering the emergency lighting in these rooms for 72 hours when the normal ac sources are not available. Operation beyond 72 hours is described in subsection 8.3.1.1.1.

9.5.3.4 Test and Inspections

The ac lighting circuits are normally energized and require no periodic testing. The 8-hour battery pack lighting is inspected and tested periodically.

9.5.3.5 Combined License Information for Plant Lighting

This section has no requirements to be provided in support of Combined License application.

9.5.4 Standby Diesel and Auxiliary Boiler Fuel Oil System

This subsection describes the features of the standby diesel and auxiliary boiler fuel oil system. Both the standby diesel generators and the auxiliary boiler are supplied by a combined storage system of fuel oil storage tanks. Two above-ground fuel oil storage tanks for the combined system service are provided. These tanks store diesel grade fuel suitable for either service. The standby diesel generators are described in subsection 8.3.1.1.2 and the auxiliary boiler is described in subsection 10.4.10.

9.5.4.1 Design Basis

9.5.4.1.1 Safety Design Basis

The standby diesel and auxiliary boiler fuel oil system serves no safety-related function and therefore has no nuclear safety design basis.

9.5.4.1.2 Power Generation Design Basis

The standby diesel and auxiliary boiler fuel oil system serves no power generation function. Its function is to store and transfer fuel oil for the onsite standby diesel generators and the auxiliary boiler. The system is designed to meet the following requirements:

- Provide a supply of fuel sufficient to operate each diesel generator at continuous rating for 7 days

- Provide a 7-day fuel supply for auxiliary boiler operation, with half of the required fuel stored in each tank

- Provide a 4-day fuel supply for the two ancillary diesel generators

9.5.4.1.3 Codes and Standards

The codes and standards that are applicable to the components of the Standby Diesel and Auxiliary Boiler Fuel Oil System that support the standby diesel generators are listed in Section 3.2. The portions of the Standby Diesel and Auxiliary Boiler Fuel Oil System that support the standby diesel generators follow the guidance for distillate fuel oil supply contained in Chapter 13 of the DEMA Standard Practices (Reference 19).

9.5.4.2 System Description Storage and Transfer

9.5.4.2.1 General Description

The standby diesel and auxiliary boiler fuel oil system is shown in Figure 9.5.4-1. The system consists of two fuel oil storage tanks, a diesel generator fuel oil transfer system, an auxiliary boiler fuel oil supply system, and an ancillary diesel generator fuel oil supply system.

Two fuel oil storage tanks are provided, one for each of the standby diesel generators. Both tanks also provide fuel oil for the auxiliary boiler. Diesel fuel oil for the diesel generator is reserved by tapping auxiliary boiler fuel oil from elevated nozzles above the diesel generator storage level.

The plant finished grade elevation will be higher than the probable maximum flood level (refer to subsection 3.4.1.1, Protection From External Flooding). Therefore the system will be safe from flooding.

The diesel generator fuel oil transfer system consists of two independent fuel storage, transfer and recirculation flow paths; that is, one path per diesel generator. Each path consists of a fuel oil storage tank, one fuel transfer pump, diesel fuel oil supply and fuel return piping, a day tank, and the associated specialties valves, fittings, and instrumentation. The supply lines from the transfer pumps to the daytanks include fuel oil heaters, filters and moisture separators. The system is protected from the effects of low temperatures by the inline electric oil heater in the transfer line.

The auxiliary boiler fuel oil supply portion of the system consists of a single supply line to the auxiliary boiler, two 100-percent capacity pumps each supplied by a fuel oil storage tank and a recirculation fuel oil return line from the boiler to the storage tanks.

The ancillary diesel generator fuel oil supply portion of the system consists of a single 100 percent capacity tank serving both ancillary diesel generators. The tank is located inside the annex building and is served by the annex building heating and ventilation system. The tank is insulated and provided with heaters to maintain the fuel oil above the oil cloud point. Fuel oil lines from the tank to the diesels are insulated.

Two separate prefabricated insulated, heated and ventilated weather enclosures are provided for the transfer systems. Each enclosure houses one diesel fuel oil transfer pump assembly and one auxiliary boiler fuel oil transfer pump assembly. The enclosures are sufficiently separated to prevent a fire in either enclosure from causing an interruption in the other flow path.

Characteristics of the system components are provided in Table 9.5.4-1.

9.5.4.2.2 Component Description

9.5.4.2.2.1 Fuel Storage Tanks

The two fuel oil storage tanks are located on grade. The tanks are designed and fabricated to API-650 Standards. Fittings are provided for each tank for level instrumentation, ventilation, sampling, water removal and sounding. Flanged openings are provided as manholes for access to the tank interior and each tank is equipped with an internal sump and a drain connection. Each tank is erected on a continuous concrete slab totally contained within a concrete dike to contain spills and prevent damage to the environment and seepage into the ground water.

The location and arrangement of the suction nozzles at the storage tank for the auxiliary boilers limit their fuel supply to the top section of the tank. The fuel stored below the level of the auxiliary boiler suction is reserved for the diesel generators, and cannot be taken by the auxiliary boiler fuel transfer pumps. The entire stored capacity of the tank can be used by the diesel generators, if necessary.

The design of the standby diesel and auxiliary boiler fuel oil system allows replenishment of fuel without interrupting operation of the diesel generator or auxiliary boiler. The tank fill connection includes an internal pipe and diffuser to limit inlet filling velocities to prevent turbulence of sediment on the bottom of the tank. In addition, the diesel fuel oil transfer connections at the fuel oil storage tanks are 6 inches above the tank bottom to reduce the potential of sediment entry into the pipe line. A moisture separator and duplex filters are provided in the diesel fuel oil piping and a duplex fuel oil filter is provided on each engine to prevent detrimental effects on diesel performance from sediment.

9.5.4.2.2.2 Diesel Generator Fuel Oil Transfer

The diesel generator fuel oil transfer system consists of two modularized skid mounted assemblies, each consisting of suction strainers, a transfer pump, a fuel oil heater, a moisture separator, and a fuel filter with the interconnecting piping, valves and instrumentation.

The fuel oil transfer pumps are of the motor driven gear positive displacement type. Each pump capacity is approximately four times the full-load consumption rate of the associated diesel generator. The pump and pump motor are mounted on a common baseplate. A prefabricated weather enclosure protects the strainer, transfer pumps, heater, moisture separator, and duplex filters and associated piping. There is no fixed fire protection water system inside the enclosure; therefore, spurious actuation of a fire protection system cannot occur.

9.5.4.2.2.3 Standby Diesel Generator Fuel Oil Day Tanks

The diesel generator fuel oil day tanks each provide four hours of operation for its associated diesel engine at continuous rating without resupply from a fuel oil storage tank. The day tanks are located within the diesel generator building and are separated from the remainder of the diesel generator building by 3-hour rated fire barriers. The day tanks are separate from sources of ignition or high-temperature surfaces. The day tank elevation is selected to provide the necessary suction head for the diesel engine fuel oil pump. The fuel oil piping is run in a piping trench from the tank to the engine. The fuel oil piping on the engine is located away from hot surfaces. Tank

fittings provide for external tank fill, water removal, recirculation, and instrumentation. The fuel oil day tank is vented to atmosphere with a line which has a ball float check valve, and flame arrestor at the end. Since venting is to the outside atmosphere, there is not a buildup of combustible fumes within the diesel generator building.

9.5.4.2.2.4 Ancillary Diesel Generator Fuel Oil Storage Tank

The ancillary diesel generator fuel oil storage tank provides four days of operation of the ancillary diesel generators. The tank is analyzed to show that it will withstand an SSE and is located in the same room as the ancillary diesel generators in the annex building. This room is separated from the rest of the annex building by a 3-hour rated fire barrier. The tank elevation is selected to provide the necessary head for the diesels. The ancillary diesel generator fuel oil storage tank is vented to the atmosphere with a line which has a ball float check valve, and flame arrestor at the end. Since venting is to the outside atmosphere, there is not a buildup of combustible fumes within the annex.

9.5.4.2.2.5 Piping and Tank Surfaces

The exterior and interior surfaces of the fuel oil storage tanks are painted with a primer and finish coat system for corrosion protection of the tank surface. Exterior surfaces of the diesel fuel oil transfer piping and the auxiliary boiler supply piping are painted for corrosion protection. Buried sections are enclosed in guard pipes to prevent leakage to the environment.

The guard pipe containment system is corrosion resistant plastic, designed and fabricated for the site overburden wheel loads which result from equipment removal and replacement.

9.5.4.2.2.6 Auxiliary Boiler Fuel Oil Supply

The auxiliary boiler fuel oil supply system consists of two modularized skid mounted assemblies. Each consists of a suction strainer, supply pump and motor drive, and the associated piping, valves, fittings and instrumentation. The outdoor part of the system is designed to pump oil at ambient temperature for firing in the boiler. No special provisions are required for oil heating, moisture removal or filtration. One modularized skid mounted auxiliary boiler fuel oil supply assembly is installed in each diesel fuel oil transfer enclosure.

9.5.4.2.3 System Operation

The fuel oil storage tanks for the diesel generators and auxiliary boiler are replenished from trucks (or other mobile suppliers) as required to maintain an adequate supply for the auxiliary boilers, and a seven day supply for each standby diesel generator. Each storage tank is equipped with a vent line to atmosphere at the top of the tank that ends with a flame arrester. A tank fill line runs to each tank and is extended to the truck unloading station. The fill line incorporates a normally closed valve and a filler cap at the end to preclude the entrance of water. The fill line is above grade. The fill line has a strainer located downstream of the isolation valve to prevent entrance of deleterious solid material into the tank. A water removal port is located at the tank sump.

Each diesel oil transfer pump takes suction from a fuel oil storage tank and discharges fuel oil to the diesel generator fuel oil day tank. Each pump is capable of supplying its diesel generator and,

simultaneously, increasing the inventory in the fuel oil day tank. The fuel oil transfer pump is automatically started and stopped on day tank level control. Part of the pump discharge flow is returned to the storage tank via the recirculation line. The filter in the discharge line to the day tank is monitored by measuring differential pressures across the filter and by providing a high differential pressure alarm.

Fuel oil to the auxiliary boiler is supplied by two suction supply lines, (one from each tank), to two separate fuel oil supply pumping stations. One auxiliary boiler fuel oil pumping station is located in each diesel generator fuel transfer pump enclosure. Each pumping station includes a full size duplex suction strainer in the suction line to the electric motor driven auxiliary boiler fuel oil gear type supply pump. Both pumps discharge to the auxiliary boiler through a common discharge line. The pumps are full capacity with one for service and the other as standby. The pump motor and pump are mounted on a common base plate. The system includes a recirculation fuel oil return line from the boiler back to the storage tanks.

In the event the diesel fuel oil degrades during storage, biocides and other fuel additives are introduced to the tanked fuel oil to prevent deterioration of the oil, accumulation of sludge in the storage tanks, and the growth of algae and fungi.

Site-specific conditions determine the requirements for oil supply and emergency fuel delivery.

Provisions are included in the fuel oil storage tanks and day tanks to check and remove accumulated water.

The fuel oil storage tank for the ancillary diesel generators is replenished from trucks (or other mobile supplier) as required to maintain a 4-day supply for both ancillary diesel generators.

9.5.4.3 Safety Evaluation

The standby diesel and auxiliary boiler fuel oil system serves a defense in depth function and requires no nuclear safety evaluation.

9.5.4.4 System Evaluation

The standby diesel generator fuel oil transfer system supplies fuel oil to the diesel generators which provide defense in depth electric power for investment protection.

The fuel oil storage tanks are sized to provide sufficient capacity for seven days of operation for each standby diesel generator and also for seven days of operation of the auxiliary boiler. Within this period, the operator can arrange for additional fuel to be delivered to the plant site. An independent fuel supply path consisting of a fuel storage tank, a day tank, strainer, transfer pump, piping, oil heater, oil filter, moisture separator and valves is provided for each diesel generator. Each pump is powered from the electrical bus on which the diesel generator it serves is connected. Failure of a pump or a diesel generator would not affect the operability of components in the other train.

Maintenance of the fuel oil temperature above the cloud point is achieved automatically on low temperatures by an electric fuel oil heater at the discharge of the transfer fuel oil pump and by

burial of the transfer piping below the frostline. The fuel oil system can be maintained above the cloud point temperature with the system electric heater in service and operation in the recirculation mode (by passing the day tank) back to the fuel oil storage tank. Above grade piping and inline equipment outdoors are insulated.

Electrical power supply for the diesel fuel oil transfer pumps and electric heater is from the associated diesel generator backed 480 V bus.

The auxiliary boiler fuel oil supply system supplies fuel to the auxiliary boiler for plant heating. Electric power supply for these pumps is provided from the onsite standby diesel generator backed 480 V ac distribution system.

The fuel oil storage tank for the ancillary diesel generators is sized to provide sufficient capacity for four days of operation for both ancillary diesel generators. The ancillary diesel generators are not needed for the first 72 hours following a loss of all ac. Therefore, the operator has seven days to arrange for additional fuel to be delivered to the plant site. Maintenance of the fuel oil temperature above the cloud point when a normal ac source is available is achieved by the normal annex building heating and ventilation system maintaining room temperature within its normal range. Maintenance of the fuel oil temperature above the cloud point during operation of the ancillary diesel generators is achieved by electric tank heaters and tank insulation.

9.5.4.5 Tests and Inspections

9.5.4.5.1 Diesel Generator Fuel Oil Supply

The standby diesel generator fuel oil storage and transfer system operability may be demonstrated during tests of the diesel generator, or testing may be performed by operation of the system in recirculation mode (bypassing the day tank) and pumping fuel through the recirculation line back to the fuel oil storage tank. Fuel reserve for testing is supplied by sizing the storage tanks to contain fuel in excess of the volume required for seven days of operation at full load. Provisions are made to sample and analyze diesel fuel periodically to verify the fuel quality requirements.

9.5.4.5.2 Auxiliary Boiler Fuel Oil Supply

The auxiliary boiler fuel oil supply operability may be tested by pump operation through the recirculation line from the boiler back to the storage tank.

9.5.4.6 Instrumentation Applications

9.5.4.6.1 Standby Diesel Generator Fuel Oil Supply

The transfer pumps can be operated from the control room. Alarms and indications of tank levels and transfer pump status are displayed in the control room. A secondary means of tank level determination is provided by dipsticks or sounding ports. Day tank fuel oil transfer pumps start and stop on low and high level, respectively, and the tank level transmitter activates a day tank high or low level alarm. The diesel oil transfer pumps start automatically when the level in the day tank decreases to set capacity. The day tank low level alarm annunciates when the level decreases

to a point where 2 hours of fuel remain. The diesel oil transfer pumps are automatically stopped when the day tank level has increased to a higher set level.

Low fuel oil level in the standby diesel fuel oil storage tanks section reserved for the diesel engines is also alarmed.

9.5.4.6.2 Auxiliary Boiler Fuel Supply

The instrumentation associated with auxiliary boiler fuel oil supply is discussed in subsection 10.4.10. The system alarms on low fuel oil pressure due to loss of supply pump pressure, on low level in the fuel oil storage tanks and high differential pressure across the suction strainer.

9.5.4.6.3 Ancillary Diesel Generator Fuel Oil Supply

There is no control room monitoring or control associated with the ancillary diesel generator fuel oil supply system. All controls and instruments are local/manual only. Provision is made to locally monitor fuel level in the tank.

9.5.4.7 Combined License Information

Combined License applicants referencing the AP1000 certified design will address the site-specific need for cathodic protection in accordance with NACE Standard RP-01-69 for external metal surfaces of metal tanks in contact with the ground.

Combined License applicants referencing the AP1000 certified design will address site-specific factors in the fuel oil storage tank installation specification to reduce the effects of sun heat input into the stored fuel, the diesel fuel specifications grade and the fuel properties consistent with manufacturers' recommendations, and will address measures to protect against fuel degradation by a program of fuel sampling and testing.

9.5.5 References

1. NUREG-0800, U. S. Nuclear Regulatory Commission Standard Review Plan, Section 9.5.1, "Fire Protection Program," Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, July 1981.

2. National Fire Protection Association Codes and Standards:

   NFPA 10, 1998: Standard for Portable Fire Extinguishers; NFPA 13, 1999: Standard for the Installation of Sprinkler Systems; NFPA 14, 2000: Standard for the Installation of Standpipe, Private Hydrants, and Hose Systems; NFPA 15, 2001: Standard for Water Spray Fixed Systems for Fire Protection; NFPA 20, 1999: Standard for the Installation of Stationary Pumps for Fire Protection; NFPA 22, 1998: Standard for Water Tanks for Private Fire Protection; NFPA 24, 1995: Standard for Installation of Private Fire Service Mains and Their Appurtenances; NFPA 30, 2000: Flammable and Combustible Liquids Code; NFPA 50A, 1999: Standard for Gaseous Hydrogen Systems at Consumer Sites; NFPA 50B,

1999: Standard for Liquefied Hydrogen Systems at Consumer Sites; NFPA 72, 1999: National Fire Alarm Code; NFPA 780, 2000: Standard for the Installation of Lightning Protection Systems; NFPA 804, 2001: Standard for Fire Protection for Advanced Light Water Reactor Electric Generating Plants.

3. "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations," IEEE Std 383-1974.

4. Fire Protection Handbook, Edited by A. E. Cote, National Fire Protection Association, 16th edition.

5. IES - 1987 Lighting Handbook.

6. IEEE Standard 281, "IEEE Standard Service Conditions for Power System Communication Equipment," 1984.

7. Beranek, Lee L., Noise Reduction, McGraw Hill Book Co., 1960.

8. EPRI Report NP 6559, "Voice Communication Systems Compatible with Respiratory Protection."

9. NRC IE Circulator No. 80-89, "Problems with Plant Internal Communications Systems," April 18, 1990.

10. 10 CFR 50, Appendix E, IV.E.9, "ERF Communications."

11. NRC IEN 87-58, "Continuous Communication Following Emergency Notifications."

12. NRC IEN 86-097, "Emergency Communication Systems."

13. 10 CFR 73, Sections 55 (e) and (f), "Physical Protection of Plants and Materials."

14. NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plan."

15. 10 CFR 50, Section 50.48 "Fire Protection."

16. 10 CFR 50, Appendix A, Criterion 3 "Fire Protection."

17. NRC Policy Issue SECY-97-087, "Policy, Technical and Licensing Issues Pertaining to Evolutionary and Advanced Light Water Reactor (ALWR) Designs," Section I.E, "Fire Protection."

18. IEEE Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies, IEEE Std. 1202 - 1991.

19. Standard Practices for Medium Speed Stationary Diesel and Gas Engines, Sixth Edition, Diesel Engine Manufacturers Association, 1972. (Note: Although this standard is obsolete, the guidance for distillate fuel systems in Chapter 13 is applicable for AP1000.)

20. WCAP-15871, Revision 1, "AP1000 Assessment Against NFPA 804," December 2002.

21. NRC Bulletin 80-15, "Possible Loss of Emergency Notification System (ENS) with Loss of Offsite Power," June 18, 1980.

Table 9.5.1-1 (Sheet 1 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
Fire Protection Program			
1. Direction of fire protection program; availability of personnel.	C.1.a(1)	WA	See Note 2
2. Defense-in-depth concept; objective of fire protection program.	C.1.a(2)	WA	See Note 2
3. Management responsibility for overall fire protection program; delegation of responsibility to staff.	C.1.a(3)	WA	See Note 2
4. The staff should be responsible for: (a) Fire protection program requirements. (b) Post-fire shutdown capability. (c) Design, maintenance, surveillance, and quality assurance of fire protection features. (d) Fire prevention activities. (e) Fire brigade organization and training. (f) Prefire planning.	C.1.a(3)	WA	See Note 2
5. The organizational responsibilities and lines of communication pertaining to fire protection should be defined through the use of organizational charts and functional descriptions.	C.1.a(4)	WA	See Note 2
6. Personnel qualification requirements for fire protection engineer, reporting to the position responsible for formulation and implementation of the fire protection program.	C.1.a(5)(a)	WA	See Note 2
7. The fire brigade members' qualifications should include a physical examination for performing strenuous activity, and the training described in Position C.3.d.	C.1.a(5)(b)	WA	See Note 2
8. The personnel responsible for the maintenance and testing of the fire protection systems should be qualified by training and experience for such work.	C.1.a(5)(c)	WA	See Note 2
9. The personnel responsible for the training of the fire brigade should be qualified by training and experience for such work.	C.1.a(5)(d)	WA	See Note 2

Table 9.5.1-1 (Sheet 2 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
10. The following NFPA publications should be used for guidance to develop the fire protection program: No. 4, No. 4A, No. 6, No. 7, No. 8, and No. 27.	C.1.a(6)	WA	See Note 2
11. On sites where there is an operating reactor, and construction or modification of other units is underway, the superintendent of the operating plant should have a lead responsibility for site fire protection.	C.1.a(7)	WA	See Note 2
Fire Protection Analysis			
12. The fire protection analysis should demonstrate that the plant will maintain the capability to perform safe shutdown functions and minimize radioactive releases to the environment in the event of a fire.	C.1.b	C	
13. The fire protection analysis should be performed by fire protection and reactor systems engineers to (1) consider potential in situ and transient fire hazards; (2) determine the consequences of a fire in any location in the plant; and (3) specify measures for fire prevention, detection, suppression, and containment.	C.1.b	C	
14. Fires involving facilities shared between units should be considered.	C.1.b	WA	
15. Fires due to man-made site-related events that have a reasonable probability of occurring and affecting more than one reactor unit should be considered.	C.1.b	WA	To be evaluated on a site-specific basis. Plant siting decisions are expected to preclude the need to consider such events.
16. Establishing three levels of fire damage limits according to safety function (hot shutdown, cold shutdown and design basis accidents).	C.1.b	C	AP1000 uses two levels of damage limits: safe shutdown and design basis accidents. Safe shutdown capability is protected from damage caused by a single fire.
17. The fire protection analysis should separately identify hazards and provide appropriate protection in locations where safety-related losses can occur.	C.1.b	C	

Table 9.5.1-1 (Sheet 3 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Fire Suppression System Design Basis			
18. Total reliance should not be placed on a single fire suppression system. Backup fire suppression capability should be provided.	C.1.c(1)	C	Automatic fire suppression systems are backed up by manual suppression systems (standpipe) and portable extinguishers.
19. A single active failure or a crack in a fire suppression system moderate energy line should not impair both the primary and backup fire suppression capabilities.	C.1.c(2)	AC	Criteria followed except for containment and outlying buildings. The fire suppression systems located inside the containment are qualified to seismic Category I criteria, which reduces the potential for a failure of the system. The buildings outside the auxiliary building do not contain safety-related equipment, or present an exposure hazard to structures containing safety-related equipment. Manual fire suppression capability using hose lines connected to the outside hydrants of the yard main can be provided in the event of a failure of the interior fire suppression systems.
20. The fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe shutdown following a safe shutdown earthquake (SSE).	C.1.c(3)	AC	Criteria followed except for the PCS valve room, Room 12701 (Fire Zone 1270 AF 12701). The quantity of combustible material in this fire zone is extremely low, consisting primarily of cable insulation related to the six PCS valves and related PCS instrumentation. Portable fire extinguishers are provided on both the lower level (El. 264′-6″) and the upper level (El. 286′-6″) of the PCS valve room for manual fire fighting.

Table 9.5.1-1 (Sheet 4 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Fire Suppression System Design Basis			
21. Fire protection systems should retain their design capability for natural phenomena of less severity and greater frequency than the most severe natural phenomena.	C.1.c(4)	C	Structures housing the fire protection system meet the applicable requirements of Chapter 3 to provide protection from natural phenomena.
22. Fire protection systems should retain their original design capability for potential man-made, site-related events that have a reasonable probability of occurring at a specific plant site.	C.1.c(4)	WA	To be evaluated on a site-specific basis. Plant siting decisions are expected to preclude the need to consider such events.
23. The effects of lightning strikes should be included in the overall plant fire protection program.	C.1.c(4)	C	Lightning protection will be provided per NFPA 780.
24. The consequences of inadvertent operation or of a crack in a moderate energy line in the fire suppression system should meet the guidelines specified for moderate energy systems outside containment in SRP Section 3.6.1.	C.1.c(5)	C	
Alternate or Dedicated Shutdown			
25. Alternative or dedicated shutdown capability should be provided where the protection of systems whose functions are required for safe shutdown is not provided by established fire suppression methods or by Position C.5.b.	C.1.d	AC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/ dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP.

Table 9.5.1-1 (Sheet 5 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Fire Protection Program Implementation			
26. The fire protection program for buildings storing new reactor fuel and for adjacent fire areas that could affect the fuel storage area should be fully operational before fuel is received at the site.	C.1.e(1)	WA	See Note 2
27. The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that unit.	C.1.e(2)	WA	See Note 2
28. Special considerations for the fire protection program on reactor sites where there is an operating reactor and construction or modification of other units is under way.	C.1.e(3)	WA	See Note 2
29. Establishing administrative controls to maintain the performance of the fire protection system and personnel.	C.2	WA	See Note 2
Fire Brigade			
30. The guidance in Regulatory Guide 1.101 should be followed as applicable.	C.3.a	WA	See Note 2
31. Establishing site brigade: minimum number of fire brigade members on each shift; qualification of fire brigade members; competence of brigade leader.	C.3.b	WA	See Note 2
32. The minimum equipment provided for the brigade should consist of turnout coats, boots, gloves, hard hats, emergency communications equipment, portable ventilation equipment, and portable extinguishers.	C.3.c	WA	See Note 2
33. Recommendations for breathing apparatus for fire brigade, damage control, and control room personnel.	C.3.c	WA	See Note 2. A breathing air compressor and receiver is provided in the compressed and instrument air system (CAS) to replenish the exhausted air supply bottles used by the fire brigade. Additionally, an equivalent 6-hour supply of reserve air (e.g., the 12 additional SCBA bottles) will be maintained in an area located outside of the turbine building. See subsection 9.3.1 for further information.

Table 9.5.1-1 (Sheet 6 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
34. Recommendations for the fire brigade training program.	C.3.d	WA	See Note 2
Quality Assurance Program			
35. Establishing quality assurance (QA) programs by applicants and contractors for the fire protection systems for safety-related areas; identification of specific criteria for quality assurance programs.	C.4	WA	Fire protection quality assurance programs are incorporated in procurement documents. Deviations are evaluated and controlled. See Items 1. through 11. of this table for on-site implementation. See Note 2.
Building Design			
36. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate safety-related systems from any potential fires in nonsafety-related areas.	C.5.a(1)(a)	C	Structures housing safety-related systems are separated from nonsafety-related structures by 3-hour rated fire walls.
37. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate redundant divisions of safety-related systems from each other.	C.5.a(1)(b)	C	See subsection 9.5.1.2.1.1 for discussion of exceptions for the containment, main control room, and remote shutdown room.
38. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate individual units on a multiple-unit site.	C.5.a(1)(c)	NA	See discussion of GDC 5 in subsection 3.1.1. The AP1000 is a single-unit plant.
39. Fire barriers should be provided within a single safety division to separate components or cabling that present a fire hazard to other safety-related components.	C.5.a (2)	C	
40. Openings through fire barriers for pipe, conduit, and cable trays that separate fire areas should be sealed or closed to provide a fire resistance rating equal to that required of the barrier.	C.5.a (3)	C	
41. Recommendations for internal sealing of conduits penetrating fire barriers.	C.5.a (3)	C	

Table 9.5.1-1 (Sheet 7 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
42. Fire barrier penetrations that must maintain environmental isolation or pressure differentials should be qualified by test.	C.5.a (3)	C	Fire penetration seals that also perform other barrier functions are qualified by test for intended functions. The fire barrier penetration seal does not perform other barrier functions simultaneously.
43. Penetration designs should use only noncombustible materials.	C.5.a (3)	C	
44. The penetration qualification tests should use the time-temperature exposure curve specified by ASTM E-119.	C.5.a (3)	C	
45. Criteria for penetration qualification tests.	C.5.a (3)	C	
46. Penetration openings for ventilation systems should be protected by fire dampers having a rating equivalent to that required of the barrier.	C.5.a (4)	C	Penetration openings are protected in accordance with NFPA 90A. Fire dampers generally not provided for roof or exterior wall penetrations.
47. Flexible air duct couplings in ventilation and filter systems should be noncombustible.	C.5.a (4)	C	
48. Door openings in fire barriers should be protected with equivalently rated doors, frames, and hardware that have been tested and approved by a nationally recognized lab.	C.5.a (5)	C	
49. Fire doors should be self-closing or provided with closing mechanisms.	C.5.a (5)	C	
50. Fire doors should be inspected semiannually to verify that automatic hold-open, release, and closing mechanisms and latches are operable.	C.5.a (5)	WA	See Note 2
51. Alternative means for verifying that fire doors protect the door opening as required in case of fire.	C.5.a (5)	WA	See Note 2
52. The fire brigade leader should have ready access to keys for any locked fire doors.	C.5.a (5)	WA	See Note 2

Table 9.5.1-1 (Sheet 8 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
53. Areas protected by automatic total flooding gas suppression systems should have electrically supervised self-closing fire doors or should satisfy guideline (49) above.	C.5.a (5)	NA	No automatic gas suppression systems are used on AP1000.
54. Personnel access routes and escape routes should be provided for each fire area.	C.5.a (6)	C	
55. Stairwells serving as escape routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown should be enclosed in masonry or concrete towers with a minimum fire resistance rating of 2 hours and self-closing Class B fire doors.	C.5.a(6)	AC WA	AP1000 deviates from this guideline with a design that meets applicable building codes and fire protection requirements. Auxiliary building stairwells are enclosed in towers constructed using both concrete structural walls and nonstructural walls, consisting of a concrete/steel composite material, having a fire resistance rating of at least 2 hours, and self-closing doors, having a rating of 1.5 hours. The COL applicant will provide fire-resistance test data using the concrete/steel composite material for 2 hours in accordance with the ASTM E-1999 NFPA 251 acceptance criteria to ensure that stairwell fire-related enclosure will be maintained in accordance with Regulatory Position C.5.a.6 of BTP CMEB 9.5-1. The staff will review the stairwell fire barriers fire-resistance performance test results of the COL applicant. There are no missile hazards in the vicinity of such stairwells. This alternative protection provides an equivalent level of safety as that prescribed in the BTP.

Table 9.5.1-1 (Sheet 9 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
56. Fire exit routes should be clearly marked.	C.5.a (7)	WA	See Note 2
57. Each cable spreading room should contain only one redundant safety division.	C.5.a (8)	NA	There are no cable spreading rooms in AP1000.
58. Cable spreading rooms should be separated from each other and from other areas of the plant by barriers having a minimum fire resistance of 3 hours.	C.5.a (8)	NA	There are no cable spreading rooms in AP1000.
59. Interior wall and structural components, thermal insulation materials, radiation shielding materials, and soundproofing materials should be noncombustible.	C.5.a (9)	C	
60. Interior finishes should be noncombustible.	C.5.a (9)	C	
61. Metal deck roof construction should be noncombustible and listed as "acceptable for fire" in the UL Building Materials Directory, or listed as Class I in the Factory Mutual Approval Guide.	C.5.a (10)	C	
62. Suspended ceilings and their supports should be of noncombustible construction.	C.5.a (11)	C	
63. Concealed spaces should be devoid of combustibles except as noted in Position C.6.b.	C.5.a(11)	AC	Underfloor or ceiling spaces, contain combustible cable insulation in the main control room, technical support center and remote shutdown room. Fire detectors are provided in these areas. The cables used in the plant are qualified in accordance with the criteria specified in IEEE 1202. This alternative protection provides an equivalent level of safety as that specified in the BTP.
64. Transformers installed inside fire areas containing safety-related systems should be of the dry type or insulated and cooled with noncombustible liquid.	C.5.a(12)	C	

Table 9.5.1-1 (Sheet 10 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
65. Outdoor oil-filled transformers should have oil containment features or drainage away from the buildings.	C.5.a(13)	C	
66. Outdoor oil-filled transformers should be located at least 50 feet distant from the building, or building walls within 50 feet of oil-filled transformers should be without openings and have a 3-hour fire resistance rating.	C.5.a (13)	C	
67. Floor drains sized to remove expected firefighting water flow without flooding safety-related equipment should be provided in areas where fixed water fire suppression systems are installed.	C.5.a (14)	C	
68. Floor drains should be provided in areas where hand hose lines may be used if such firefighting water could cause unacceptable damage to safety-related equipment.	C.5.a (14)	C	
69. Where gas suppression systems are installed, the drains should be provided with adequate seals, or the gas suppression system should be sized to compensate for the loss of the suppression agent through the drains.	C.5.a (14)	NA	No fixed gas suppression systems are used on AP1000.
70. Drains in areas containing combustible liquids should have provisions for preventing the back flow of combustible liquids to safety-related areas through the interconnected drain systems.	C.5.a (14)	C	
71. Water drainage from areas that may contain radioactivity should be collected, sampled, and analyzed before discharge to the environment.	C.5.a(14)	WA	See Note 2. Capability is provided.
Safe Shutdown Capability			
72. Fire damage should be limited so that one train of systems necessary to achieve and maintain hot shutdown conditions from either the main control room or emergency control station is free of fire damage.	C.5.b(1)	C	

Table 9.5.1-1 (Sheet 11 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
73. Fire damage should be limited so that systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station can be repaired within 72 hours.	C.5.b (1)	AC	Safe shutdown following a fire is defined for the AP1000 as the ability to achieve and maintain the reactor coolant system (RCS) temperature below 215.6°C (420°F) without uncontrolled venting of the primary coolant from the RCS. This is a departure from the criteria applied to the evolutionary plant designs, and the existing plants where safe shutdown for fires applies to both hot and cold shutdown capability. AP1000 can maintain safe shutdown conditions indefinitely. Therefore, repairs to systems necessary to reach cold shutdown need not be completed within 72 hours.
74. Separation requirements for verifying that one train of systems necessary to achieve and maintain hot shutdown is free of fire damage.	C.5.b (2)	C	

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
75. Provision of alternative or dedicated shutdown capability in certain fire areas.	C.5.b (3)	AC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP.
76. Alternative or dedicated shutdown capability.	C.5.c	NC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP.

Table 9.5.1-1 (Sheet 13 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
			The criteria concerning cold shutdown capability deviates from the criteria applied to the evolutionary reactor designs, but is consistent with the criteria applicable to existing plants. To enhance the survivability of the normal safe shutdown and cold shutdown capability in the event of a fire, and to reduce the reliance on the infrequently utilized safety-related passive systems, automatic suppression is provided in those fire areas outside containment where a fire could damage the normal shutdown capability, or result in a spurious operation of equipment that could result in a venting of the RCS. This criterion does not ensure that the normal shutdown capability will be free of fire damage, or that the equipment necessary to achieve and maintain cold shutdown can be repaired within 72 hours.
Control of Combustibles			
77. Safety-related systems should be separated from combustible materials where possible; where not possible, special protection should be provided to help prevent a fire from defeating the safety system function.	C.5.d (1)	C	Concentrations of combustible materials are located outside structures containing safety-related components. Where this is not possible, appropriate fire protection is provided (see Appendix 9A).

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
78. Bulk gas storage (compressed or cryogenic) should not be permitted inside structures housing safety-related equipment. Flammable gases should be stored outdoors or in separate detached buildings.	C.5.d (2)	AC	Breathing air storage tanks for the main control room habitability system are safety-related and are provided with overpressure protection. There is no other bulk gas storage in structures housing safety-related equipment.
79. High pressure gas storage containers should be located with the long axis parallel to building walls.	C.5.d (2)	C	
80. Use of compressed gases inside buildings should be controlled.	C.5.d (2)	WA	See Note 2
81. The use of plastic materials should be minimized. Halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute noncombustible materials are not available.	C.5.d (3)	C	
82. Storage of flammable liquids should comply with NFPA 30.	C.5.d (4)	C	See Note 3
83. Hydrogen lines in safety-related areas should be either designed to seismic Category I requirements, or sleeved, or equipped with excess flow valves.	C.5.d (5)	C	Hydrogen lines in safety-related areas are designed to seismic Category I requirements.
Electrical Cable Construction, Cable Trays, and Cable Penetrations			
84. Only metal should be used for cable trays.	C.5.e (1)	C	Cable trays are of all-metal construction.
85. Only metallic tubing should be used for conduit. Thin-wall metallic tubing should not be used.	C.5.e (1)	C	Conduit that is not buried or embedded in concrete is metallic.
86. Flexible metallic tubing should only be used in short lengths to connect components to equipment.	C.5.e (1)	C	
87. Other raceways should be made of noncombustible materials.	C.5.e (1)	C	

Table 9.5.1-1 (Sheet 15 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
88. Redundant safety-related cable systems outside the cable spreading room should be separated from each other and from potential fire exposure hazards in nonsafety-related areas by 3-hour rated fire barriers.	C.5.e (2)	C	
89. These cable trays should be provided with continuous line-type heat detectors.	C.5.e (2)	C	
90. Cables should be designed to allow wetting down with fire suppression water without electrical faulting.	C.5.e (2)	C	
91. Redundant safety-related cable trays outside the cable spreading room should be accessible for manual firefighting. Manual hose stations and portable hand extinguishers should be provided.	C.5.e (2)	C	
92. Safety-related cable trays of a single division, which are separated from redundant divisions by a 3-hour rated fire barrier and are accessible for manual firefighting, should be protected from the effects of a potential exposure fire by providing automatic water suppression, unless specific conditions are met.	C.5.e (2)	C	Automatic water suppression is not provided because there is no significant exposure fire hazards and the specified conditions are met.
93. Safety-related cable trays that are not accessible for manual firefighting should be protected by an automatic water system.	C.5.e (2)	AC	Safety-related cable trays outside containment are accessible for manual firefighting. Protection of safe shutdown components inside containment is discussed in Appendix 9A.
94. Safety-related cable trays that are not separated from redundant divisions by 3-hour rated fire barriers should be protected by automatic water suppression systems.	C.5.e (2)	AC	Protection of safe shutdown components inside containment and the main control room is discussed in Appendix 9A.

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
95. In areas where 3-hour fire barrier separation of redundant cable systems is precluded by overriding design considerations, the capability to achieve safe shutdown considering the effects of a fire involving fixed and transient combustibles should be evaluated with and without actuation of the automatic suppression system.	C.5.e (2)	C	
96. Electric cable construction should pass the flame test in IEEE Std 383.	C.5.e (3)	C	Use IEEE Standard 1202 or IEEE 383 excluding the option to use the alternate flame source, oil, or burlap.
97. Cable raceways should be used only for cables.	C.5.e (4)	C	
98. Miscellaneous storage and piping for combustible liquids or gases should not create a potential exposure hazard to safety-related systems.	C.5.e (5)	C	
Ventilation			
99. Smoke and corrosive gases should be discharged directly outside to an area that will not affect safety-related plant areas.	C.5.f (1)	C	
100. To facilitate manual firefighting, separate smoke and heat vents should be provided in certain areas.	C.5.f (1)	C	Smoke and heat venting capability is provided as described in Appendix 9A.
101. Release of smoke and gases containing radioactive materials to the environment should be monitored.	C.5.f (2)	C	
102. Any ventilation system designed to exhaust potentially radioactive smoke or gases should be evaluated to verify that inadvertent operation or single failures will not violate the radiologically controlled areas of the plant.	C.5.f (2)	C	
103. The power supply and control for mechanical ventilation systems should be run outside the fire area served by the system.	C.5.f (3)	C	

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
104. Engineered safety feature filters should be protected in accordance with the guidelines of Regulatory Guide 1.52.	C.5.f (4)	NA	There are no engineered safety feature filters on AP1000.
105. Air intakes for ventilation systems serving areas containing safety-related equipment should be located remote from the exhaust air outlets and smoke vents of other fire areas.	C.5.f (5)	C	
106. Stairwells should be designed to minimize smoke infiltration during a fire.	C.5.f (6)	C	Stair towers are provided with self-closing doors. Additional measures to minimize smoke infiltration to stair-wells are described in Appendix 9A.
107. Where total flooding gas extinguishing systems are used, ventilation dampers should be controlled in accordance with NFPA 12 and NFPA 12A.	C.5.f (7)	NA	Fixed flooding gas suppression systems are not used on AP1000.
Lighting and Communication			
108. Fixed self-contained lighting units with individual 8-hour battery power supplies should be provided in areas that must be manned for safe shutdown and for access and egress routes to and from all fire areas.	C.5.g (1)	AC	Alternate emergency lighting is provided for the main control room and the remote shutdown workstation as described in subsection 9.5.3. Emergency lighting in other plant areas is provided by 8-hour battery-powered, fixed, self-contained units to provide safe ingress and egress of personnel and the operation of equipment following a fire, in the event of a loss of the normal lighting. Portable battery-powered lighting is provided for emergency use by plant personnel.
109. Sealed beam battery-powered portable hand lights should be provided for emergency use.	C.5.g (2)	C	

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
110. Fixed emergency communications, independent of the normal plant communication system, should be installed at preselected stations.	C.5.g (3)	C	
111. A portable radio communications system should be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown.	C.5.g (4)	WA	
Fire Detection			
112. Fire detection systems should be provided for areas that contain or present a fire exposure to safety-related equipment.	C.6.a (1)	C	
113. Fire detection systems should comply with the requirements of Class A systems as defined in NFPA 72D and Class I circuits as defined in NFPA 70.	C.6.a (2)	C	See Note 3
114. Fire detectors should be selected and installed in accordance with NFPA 72E.	C.6.a (3)	C	See Note 3
115. Testing of pulsed line-type heat detectors should demonstrate that the frequencies used will not affect the actuation of protective relays in other plant systems.	C.6.a (3)	C	
116. Fire detection systems should give audible and visual alarm and annunciation in the main control room.	C.6.a (4)	C	
117. Where zoned detection systems are used in a given fire area, local means should be provided to identify which zone has actuated.	C.6.a (4)	C	
118. Local audible alarms should sound in the fire area.	C.6.a(4)	C	
119. Fire alarms should be distinctive and unique so they will not be confused with any other plant system alarms.	C.6.a (5)	C	
120. Primary and secondary power supplies, which satisfy the provisions of Section 2220 of NFPA 72D, should be provided for the fire detection system and for electrically operated control valves for automatic suppression systems.	C.6.a (6)	C	See Note 3

Table 9.5.1-1 (Sheet 19 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
Fire Protection Water Supply Systems			
121. An underground yard fire main loop should be installed to furnish anticipated water requirements.	C.6.b (1)	C	An underground yard fire main loop is provided in accordance with NFPA 24.
122. Type of pipe and water treatment should be design considerations with tuberculation as one of the parameters.	C.6.b (1)	C	
123. Means of inspecting and flushing the systems should be provided.	C.6.b (1)	C	Flushing of the loop can be accomplished through the use of sectional control valves to direct the flow and yard hydrants to serve as discharge points.
124. Approved visually indicating sectional control valves should be provided to isolate portions of the yard fire main loop for maintenance or repair.	C.6.b (2)	C	Indicator valves are provided for sectionalized control and isolation of portions of the yard fire main loop.
125. Valves should be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression systems.	C.6.b (3)	C	A visually indicating or key-operated valve is provided in each lateral from the yard fire main loop to a fire hydrant.
126. The fire main system piping should be separate from service or sanitary water system piping.	C.6.b (4)	C	
127. A common yard fire main loop may serve multi-unit nuclear power plant sites if cross-connected between units. Sectional control valves should permit maintaining independence of the loop around each unit.	C.6.b (5)	NA	See discussion of GDC 5 in subsection 3.1.1. The AP1000 is a single-unit plant.
128. A sufficient number of pumps should be provided so that 100 percent capacity will be available assuming failure of the largest pump or loss of offsite power.	C.6.b (6)	C	Two 100 percent capacity fire pumps (one diesel-driven and one electric motor-driven) are provided.
129. Individual fire pump connections to the yard fire main loop should be separated with sectionalizing valves between connections.	C.6.b (6)	C	

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
130. Each pump and its driver and controls should be separated from the remaining fire pumps by a 3-hour rated fire wall.	C.6.b (6)	C	
131. The fuel for the diesel fire pump should be separated so that it does not provide a fire source exposing safety-related equipment.	C.6.b (6)	C	
132. Alarms indicating pump running, driver availability, failure to start, and low fire main pressure should be provided in the main control room.	C.6.b (6)	C	
133. The fire pump installation should conform to NFPA 20.	C.6.b (6)	C	See Note 3
134. Outside manual hose installation should be sufficient to provide an effective hose stream to any onsite location where fixed or transient combustibles could jeopardize safety-related equipment. Hydrants should be installed approximately every 250 feet on the yard main system.	C.6.b (7)	C	
135. Recommendations for hose houses and hose carts.	C.6.b (7)	C	
136. Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings, and standpipe risers.	C.6.b (8)	C	
137. Two separate, reliable freshwater supplies should be provided.	C.6.b (9)	C	Two water storage tanks are provided.
138. Recommendations for tanks used to supply fire protection water.	C.6.b (9)	C	See Note 3

Table 9.5.1-1 (Sheet 21 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
139. Recommendations for common tank used to supply fire protection water and other system.	C.6.b (10)	C	The configuration of the water supply for the seismic standpipe system is described in subsection 9.5.1.2.1. Both fire water supply tanks have a water volume that is dedicated for fire protection purposes. The fire pumps can be aligned through normally closed valves or through temporary connections to supply water for post-accident services. These include refilling of the passive containment cooling water supply tank or supplying the containment spray following a severe accident. This provides adequate defense in depth and will not adversely affect the performance of the fire protection water supply.
140. The fire water supply should be based on the largest expected flow rate for a period of 2 hours, but not less than 300,000 gallons.	C.6.b (11)	C	
141. The fire water supply should be capable of delivering the design demand over the longest route of the water supply systems.	C.6.b (11)	C	
142. Recommendations for freshwater lakes or ponds used to supply fire protection water.	C.6.b (12)	NA	Lakes or ponds are not utilized for fire protection water supply.
143. Recommendations concerning use of a common water supply for fire protection and the ultimate heat sink.	C.6.b (13)	C	
144. Recommendations concerning use of other water systems as the source of fire protection water.	C.6.b (14)	NA	The fire protection system does not rely on the operation of another water system as a second water source.

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
Water Sprinkler and Hose Standpipe Systems			
145. Recommendations concerning connection of sprinkler systems and manual hose station standpipes to the yard fire main loop.	C.6.c (1)	AC	See remarks for Guideline 19.
146. Each sprinkler and standpipe system should be equipped with OS&Y gate valve or other approved shutoff valve and waterflow alarm.	C.6.c (1)	C	Waterflow alarms are provided for sprinkler and seismic standpipe systems only.
147. Safety-related equipment should be protected from sprinkler discharge if such discharge could result in unacceptable damage to the equipment.	C.6.c (1)	C	
148. Control and sectionalizing valves in the fire water systems should be electrically supervised (with indication in the main control room) or administratively controlled.	C.6.c (2)	C	
149. All valves in the fire protection system should be periodically checked to verify position.	C.6.c (2)	WA	See Note 2
150. Fixed water extinguishing systems should conform to requirements of NFPA 13 and NFPA 15.	C.6.c (3)	AC	Automatic sprinkler systems are designed and installed in accordance with the criteria specified in NFPA 13, with the exception of providing individual fire department connections to each sprinkler system. Because the sprinkler systems are supplied by the plant's fire protection water supply, individual connections are not necessary. See Note 3.
151. Recommendations for interior manual hose installations.	C.6.c (4)	C	
152. Individual standpipes should be at least 4 inches in diameter for multiple hose connections and 2-1/2 inches in diameter for single hose connections.	C.6.c (4)	C	

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
153. Standpipe and hose station installations should follow the requirements of NFPA 14.	C.6.c (4)	AC	Standpipes for each building are designed and installed in accordance with the criteria specified in NFPA 14 for Class III service except: (1) the water supply to the standpipe inside containment is manually operated, and (2) the containment isolation valves controlling the water supply to standpipes inside containment are not listed by independent testing laboratories for fire protection service. These exceptions will not adversely affect the performance of the hose station and standpipe system. See Note 3.
154. Hose stations should be located as dictated by the fire hazard analysis to facilitate access and use for firefighting operations.	C.6.c (4)	C	
155. Recommendations concerning seismic design of standpipes and hose connections.	C.6.c (4)	C	
156. Recommendations concerning hose nozzle selection.	C.6.c (5)	C	
157. The fire hose should be hydrostatically tested in accordance with NFPA 1962. Hoses stored in outside hose houses should be tested annually. The interior standpipe hose should be tested every 3 years.	C.6.c (6)	WA	See Note 2
158. Consideration of foam suppression systems for flammable liquid fires.	C.6.c (7)	NA	Foam suppression systems are not used on AP1000.
Halon Suppression Systems			
159. Design and testing considerations for Halon fire suppression systems.	C.6.d	NA	Fixed Halon fire suppression systems are not used on AP1000.

Table 9.5.1-1 (Sheet 24 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Carbon Dioxide Suppression Systems			
160. Carbon dioxide suppression systems should comply with the requirements of NFPA 12.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
161. Automatic carbon dioxide systems should be equipped with a predischarge alarm system and a discharge delay to permit personnel egress.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
162. Provisions for locally disarming automatic carbon dioxide systems should be key locked and under administrative control. Disarming of systems should be controlled as described in Position C.2.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
163. Considerations for design of carbon dioxide suppression systems.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
Portable Extinguishers			
164. Fire extinguishers should be provided in areas that contain, or could present a fire exposure hazard to, safety-related equipment in accordance with NFPA 10.	C.6.f	C	See Note 3
165. Dry chemical extinguishers should be installed with due consideration given to possible adverse effects on safety-related equipment.	C.6.f	C	
Primary and Secondary Containment			
166. Fire protection for the primary and secondary containment areas should be provided for hazards identified by the fire protection analysis.	C.7.a (1)	C	Fires are identified and fire suppression systems are provided accordingly.
167. Because of the general inaccessibility of primary containment during normal plant operation, protection should be provided by automatic fixed systems.	C.7.a (1)	AC	No automatic suppression systems are needed due to the canned motor reactor coolant pumps (RCPs) having no external lube oil system. Automatic suppression is provided in one fire zone as described in Appendix 9A.

Table 9.5.1-1 (Sheet 25 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
168. Operation of the fire protection systems should not compromise the integrity of the containment or other safety-related systems.	C.7.a(1)(a)	C	
169. Recommendations for protection of safety-related cables and equipment inside non-inerted containments.	C.7.a(1)(b)	AC	See Appendix 9A for a description of protection inside containment.
170. Recommendations concerning fire detection inside the primary containment.	C.7.a(1)©	C	
171. Standpipe and hose stations inside containment may be connected to a high quality water supply of sufficient quantity and pressure other than the fire main loop if plant-specific features prevent extending the fire main supply inside containment.	C.7.a(1)(d)	C	
172. Recommendations for reactor coolant pump oil collection systems in non-inerted containments.	C.7.a(1)(e)	NA	The reactor coolant pumps are canned motor pumps and do not require an oil collection system.
173. For secondary containment areas, cable fire hazards that could affect safety should be protected as described in Position C.5.e.(2).	C.7.a (1)(f)	NA	
174. Self-contained breathing apparatus should be provided near the containment entrances for firefighting and damage control personnel. These units should be independent of any breathing apparatus provided for general plant activities.	C.7.a (2)	WA	See Note 2
Main Control Room Complex			
175. The main control room complex should be separated from other areas of the plant by 3-hour rated fire barriers.	C.7.b	C	
176. Recommendations concerning peripheral rooms in the main control room complex.	C.7.b	NC	The MCR/tagging room wall is not fire-rated based on other design criteria. Manual fire suppression is provided for peripheral rooms. See Appendix 9A.

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
177. Recommendations concerning the use of Halon and carbon dioxide flooding systems.	C.7.b	NA	No Halon or carbon dioxide flooding systems are used on AP1000.
178. Recommendations concerning manual firefighting capability in the main control room.	C.7.b	C	
179. Recommendations concerning fire detection in the main control room.	C.7.b	NC	Smoke detectors are not provided in cabinets and consoles. The control room is continuously occupied so that a fire is promptly detected and extinguished.
180. Breathing apparatus for main control room operators should be readily available.	C.7.b	WA	See Note 2
181. Recommendations concerning main control room ventilation.	C.7.b	C	
182. Cables that enter the main control room should terminate in the main control room.	C.7.b	C	
183. Cables in underfloor and ceiling spaces should meet the separation criteria necessary for fire protection.	C.7.b	C	
184. Air-handling functions should be ducted separately from cable runs in such spaces.	C.7.b	NC	The underfloor space is used as a distribution plenum for ventilation of the main control room. Smoke detectors in the underfloor space cause prompt closure of combination fire/smoke dampers to shut off air flow.
185. Fully enclosed electrical raceways located in underfloor and ceiling spaces, if over 1 ft^2 in cross-sectional area, should have automatic fire suppression inside.	C.7.b	NA	AP1000 does not have enclosed raceways in the control complex with a cross-sectional area greater than 1 ft^2.

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AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
186. Recommendations concerning automatic fire suppression in underfloor and ceiling spaces.	C.7.b	NC	Manual fire suppression is to be used for underfloor and ceiling spaces. The control room is continuously occupied so that a fire is promptly detected and extinguished.
187. There should be no carpeting in the main control room.	C.7.b	C	
Cable Spreading Room			
188. Design guidelines for the cable spreading room.	C.7.c	NA	There is no cable spreading room in AP1000.
189. Recommendations concerning fire protection for computers performing safety-related functions.	C.7.d	C	The data display and processing system does not perform safety-related functions.
190. Nonsafety-related computers outside the control room should be separated from safety-related areas by 3-hour rated fire barriers and should be protected as needed to prevent damage to safety-related equipment.	C.7.d	C	
Switchgear Rooms			
191. Switchgear rooms containing safety-related equipment should be separated from the remainder of the plant by 3-hour rated fire barriers. Redundant switchgear safety divisions should be separated from each other by 3-hour rated fire barriers.	C.7.e	C	The electrical equipment and penetration rooms associated with each safety-related division are separated from the rooms associated with other divisions and from the remaining areas of the plant by 3-hour rated fire barriers.
192. Automatic fire detectors should alarm locally and alarm and annunciate in the main control room.	C.7.e	C	
193. Fire hose stations and portable fire extinguishers should be readily available outside the switchgear rooms.	C.7.e	C	

Table 9.5.1-1 (Sheet 28 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
194. Drains should be provided to prevent water accumulation from damaging safety-related equipment.	C.7.e	C	
195. Remote manually actuated ventilation should be provided for venting smoke when manual fire suppression effort is needed.	C.7.e	C	See subsection 9.4.1 for a description of smoke removal capability for Class 1E equipment rooms.
Remote Safety-Related Panels			
196. Recommendations concerning separation and electrical isolation of remote safety-related panels.	C.7.f	C	
197. The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the main control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be readily available in the general area.	C.7.f	C	
Safety-Related Battery Rooms			
198. Safety-related battery rooms should be separated from each other and other areas of the plant by 3-hour rated fire barriers.	C.7.g	C	Safety-related battery rooms are separated from associated electrical rooms of the same division by 1-hour rated fire barriers.
199. Dc switchgear and inverters should not be located in safety-related battery rooms.	C.7.g	C	
200. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.g	C	
201. Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration below 2 percent.	C.7.g	C	
202. Main loss of ventilation should be alarmed in the main control room.	C.7.g	C	

Table 9.5.1-1 (Sheet 29 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
203. Portable extinguishers and manual hose stations should be readily available outside the battery rooms.	C.7.g	C	
Turbine Building			
204. The turbine building should be separated from adjacent structures containing safety-related equipment by 3-hour rated fire barriers.	C.7.h	C	
205. The fire barriers should be designed to maintain structural integrity in the event of collapse of the turbine structure.	C.7.h	C	
206. Openings and penetrations in the fire barrier should be minimized and should not be located where the turbine oil system or generator hydrogen cooling system creates a fire exposure hazard to the barrier.	C.7.h	C	
Diesel Generator Areas			
207. Diesel generators should be separated from each other and from other areas of the plant by 3-hour rated fire barriers.	C.7.i	AC	The standby diesel generators are separated from each other by a 3-hour rated fire barrier and are housed in a separate structure, remote from safety-related areas. The ancillary diesel generators are separated from other areas of the plant by 3-hour rated fire barriers. The ancillary diesel generators are not separated from each other, but can be easily replaced with transportable diesel generators.
208. Automatic fire suppression should be installed to combat diesel generator or lubricating oil fires. Such systems should be designed for operation when the diesel is running without affecting the diesel.	C.7.i	C	

Table 9.5.1-1 (Sheet 30 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
209. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.i	NC	Automatic detection is provided for the diesel generator service modules only. The dry pipe sprinklers provide detection in the diesel generator and fuel storage rooms. This does not adversely affect safety.
210. Portable extinguishers and manual hose stations should be readily available outside the area.	C.7.i	C	
211. Drainage for firefighting water and means for local manual venting of smoke should be provided.	C.7.i	C	
212. Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under specified conditions.	C.7.i	NC	Each DG day tank has a total capacity of up to 1500 gallons. Separate 3-hour enclosures and automatic suppression are provided. Tanks are located more than 50 feet from buildings containing safety-related equipment.
213. The day tank should be located in a separate enclosure with a 3-hour fire rating.	C.7.i	AC	The fuel supply for the ancillary diesel generators is not separated from the diesels by a barrier. The ancillary diesels and the tank are separated from the rest of the plant by an enclosure with a 3-hour fire rating.
214. The day tank enclosure should be capable of containing the entire contents of the tank.	C.7.i	C	
215. The day tank enclosure should be protected by an automatic fire suppression system.	C.7.i	C	
Diesel Fuel Oil Storage Areas			
216. Recommendations concerning diesel fuel oil tanks.	C.7.j	C	

Table 9.5.1-1 (Sheet 31 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
217. Above-ground tanks should be protected by an automatic fire suppression system.	C.7.j	AC	The diesel fuel oil storage tanks are well-separated from each other and from safety-related structures. Automatic fire suppression systems are not provided.
Safety Related Pumps			
218. Design guidelines for safety-related pump rooms.	C.7.k	NA	There are no safety-related pumps on AP1000.
New Fuel Area			
219. Recommendations for fire protection of the new fuel area.	C.7.l	C	
Spent Fuel Pool Areas			
220. Protection should be provided by hose stations and portable extinguishers.	C.7.m	C	
221. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.m	C	
Radwaste and Decontamination Areas			
222. Fire barriers, automatic fire suppression and detection, and ventilation controls should be provided.	C.7.n	C	Automatic fire suppression is provided for specific areas in accordance with the fire protection analysis.
Safety-Related Water Tanks			
223. Fire protection provisions for safety-related water tanks.	C.7.o	C	
Records Storage Areas			
224. Records storage areas should be so located and protected that a fire in these areas does not expose safety-related systems or equipment.	C.7.p	C	

Table 9.5.1-1 (Sheet 32 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Cooling Towers			
225. Cooling towers should be of noncombustible construction or so located and protected that a fire will not adversely affect any safety-related systems or equipment.	C.7.q	WA	The cooling tower configuration is site-specific. See Note 2
226. Cooling towers should be of noncombustible construction when the basins are used for the ultimate heat sink or for the fire protection water supply.	C.7.q	NA	The cooling tower basin is not used for an ultimate heat sink or as a source of fire water.
Miscellaneous Areas			
227. Location and protection of miscellaneous areas.	C.7.r	C	
Storage of Acetylene-Oxygen Fuel Gases			
228. Gas cylinder storage locations should not be in areas that contain or expose safety-related equipment or the fire protection systems that serve those safety-related areas.	C.8.a	WA	See Note 2
229. A permit system should be required to use this equipment in safety-related areas of the plant.	C.8.a	WA	See Note 2
Storage Areas for Ion Exchange Resins			
230. Unused ion exchange resins should not be stored in areas that contain or expose safety-related equipment.	C.8.b	WA	See Note 2
Hazardous Chemicals			
231. Hazardous chemicals should not be stored in areas that contain or expose safety-related equipment.	C.8.c	WA	See Note 2
Materials Containing Radioactivity			
232. Materials that collect and contain radioactivity should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles.	C.8.d	C	
233. These materials should be protected from exposure to fires in adjacent areas.	C.8.d	C	

Table 9.5.1-1 (Sheet 33 of 33)

AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
243. Consideration should be given to requirements for removal of decay heat from entrained radioactive materials.	C.8.d	C	

Notes:

1. Compliance with NUREG-0800 Section 9.5.1, Branch Technical Position CMEB 9.5-1 is indicated by the following codes:
   - WA - Will Address: The Combined License applicant will address this subject.
   - C - Compliance: AP1000 is committed to compliance with the guideline.
   - AC - Alternate Compliance: compliance with the guideline by alternate means or intent. Alternative means or design are provided in the remarks column.
   - N/A - Not Applicable: The guideline is not applicable to AP1000.
   - NC - Not in Compliance: AP1000 is not in compliance (explanations in the remarks column.)
2. Procedures and administrative controls governing the fire protection program during plant operation, as well as responsibilities and organizational details for personnel involved in fire protection activities, are the responsibility of the Combined License applicant.
3. It is intended to fully comply with NFPA standards referenced in subsection 9.5.5, as they apply to AP1000. However, due to conflicting design considerations, there may be a need to take exception to specific guidance. Known exceptions to NFPA requirements are identified in Table 9.5.1-3. The combined license applicant will address updating the list of NFPA exceptions after design certification, if necessary.

Table 9.5.1-2

COMPONENT DATA - FIRE PROTECTION SYSTEM (NOMINAL VALUES)

Fire Water Storage Tanks	
Primary Fire Water Tank	
Nominal capacity (gal)	325,000
Volume dedicated to fire protection (gal)	300,000
Design Pressure	Atmospheric
Material	Carbon steel
Secondary Fire Water Tank	
Nominal capacity (gal)	400,000
Volume dedicated to fire protection (gal)	300,000
Design Pressure	Atmospheric
Material	Carbon steel
Fire Pumps	
Motor-Driven	
Pump type	Horizontal centrifugal
Rated flow (gpm)	2000
Required head, approximate (ft)	300
Structural material	Cast iron
Diesel-Driven	
Pump type	Horizontal centrifugal
Rated flow (gpm)	2000
Required head, approximate (ft)	300
Structural material	Cast iron
Fuel tank capacity (min. gal)	240
Motor-Driven Jockey Pump	
Pump type	Centrifugal
Rated flow (gpm)	30
Required head, approximate (ft)	210
Structural material	Cast iron
Containment Spray Nozzles	
Type	Lechler (SPRACO) 1713A
Number	68
Rated flow (gpm)	15.2
Rated pressure design (psi)	40
Structural material	Stainless steel

Table 9.5.1-3 (Sheet 1 of 2)

EXCEPTIONS TO NFPA STANDARD REQUIREMENTS

Requirement	AP1000 Exception or Clarification
NFPA 13 Sections 5-14.1.1.2 and 5-15.2 require fire department connections to individual sprinkler system headers, with no intervening shutoff valves.	Individual connections are not provided. Sprinkler systems are supplied from the proprietary fire water supply system, which can be accessed by the fire department at any hydrant along the yard main. Valves between these connection points and the sprinkler systems are electrically supervised or locked open.
NFPA 14 Section 2-5 requires that listed valves be used to control connections to standpipes.	Containment isolation valves controlling the water supply to standpipes inside containment are nuclear safety-related and meet or exceed the requirements for listed valves.
NFPA 14 Section 3-5 prohibits use of dry standpipes for Class II or Class III systems, and in areas not subject to freezing.	The standpipe system inside containment is classified as a dry standpipe system because it is normally isolated by the outboard containment isolation valve as described in subsection 9.5.1.2.1.5.
NFPA 14 Section 3-6.1 requires listed dial spring pressure gauges at specific locations.	Pressure instruments with remote readout at fire protection system panels are provided. These instruments meet or exceed the requirements for listed gauges.
NFPA 14 Section 4-2.2 requires an isolation valve for each standpipe.	One valve is used to isolate two or more short standpipes that supply a small number of hose stations.
NFPA 14 Sections 4-3 and 5-12 require fire department connections for each standpipe system, with no intervening shutoff valves.	Individual connections are not provided. Standpipe systems are supplied from the proprietary fire water supply system, which can be accessed by the fire department at any hydrant along the yard main. Valves between these connection points and the standpipe systems are electrically supervised or locked open, except as described in subsection 9.5.1.2.1.5.
NFPA 14 Section 5-3.2 requires Class I hose connections at each intermediate landing of exit stairways, on each side of horizontal exit openings, in each exit passageway, and on the roof or at the highest landing of stairways.	Class I hose connections are provided in exit stairways at one intermediate landing between most floors, and at other protected exit locations accessible to firefighters entering the buildings from outside. Flow testing of Class I hose connections is accomplished without providing additional connections on the roofs of buildings or at the highest stairway landings.
NFPA 14 Section 5-5 requires standpipes to be interconnected at the bottom, and when supplied by elevated tanks, also at the top.	Standpipes interconnections are constrained by layout considerations and do not always meet these requirements. Each standpipe receives an adequate water supply at an adequate pressure.
NFPA 14 Section 5-11.2 requires a separate drain connection for each standpipe.	For standpipes located outside radiologically controlled areas and supplied at an elevation above the lowest hose connection, the hose connection is used to provide a means of draining the standpipe.

Table 9.5.1-3 (Sheet 2 of 2)

EXCEPTIONS TO NFPA STANDARD REQUIREMENTS

Requirement	AP1000 Exception or Clarification
NFPA 22 contains requirements for water tanks and supply lines for private fire protection.	The seismic standpipe system is normally supplied from the passive containment cooling system (PCS) water storage tank as described in subsection 9.5.1.2.1.5. The passive containment cooling system tank and supply line are not designed to NFPA 22 but meet or exceed the applicable requirements of that standard.
NFPA 804 contains requirements specific to light water reactors.	Compliance with portions of this standard is as identified within Section 9.5.1 and WCAP-15871.

Table 9.5.1-4

CAPABILITIES USED TO ACHIEVE COLD SHUTDOWN FOLLOWING A FIRE

Function	System Capability	Fire Protection
RCS Reactivity Control - Short Term - Long Term	 - Control Rods - (1)	 - separation (6) - (1)
RCS Makeup	- (1)	- (1)
RCS Pressure Control - Increase - Decrease	 - Pressurizer heaters - (2)	 - fire suppression - (2)
Decay Heat Removal (high temperature)	- SFW pumps feeding CST water to SG - SG PORV discharge to atm.	- fire suppression - separation
Decay Heat Removal (cold temperature)	- RNS pumps circulating RCS - CCS cooling RNS - SWS cooling CCS	- separation - fire suppression - fire suppression
Process Monitoring	- RCS monitoring instruments (PMS) - Non-1E Instrumentation and Control (3)	- separation - fire suppression or separation
Support Systems	- Instrument Air - Standby Diesel Generators - Non-1E AC Power and Control (3)	- fire suppression - fire suppression and separation - fire suppression or separation

Notes:

(1) CVS makeup from the BAT provides RCS makeup and boration. Automatic suppression is provided in the CVS makeup pump room and in the Non-Class 1E equipment/penetration room. If the CVS is damaged by a fire, one CMT can provide this capability.

(2) CVS auxiliary spray provides pressurizer pressure reduction. Automatic suppression is provided in the CVS makeup pump room and in the Non-Class 1E equipment/penetration room. If the CVS is damaged by a fire, one ADS stage 1 valve used in a low capacity throttled vent mode of operation can slowly depressurize the RCS without loss of RCS pressure boundary.

(3) The portions of the non-1E AC power and the non-1E instrumentation and control system required are those needed to operate cold shutdown components; local control is sufficient (switchgear/control cabinet).

(4) Portions of the non-1E heating and ventilating systems are required to ventilate the main control room, non-1E switchgear rooms, and the required portions of the non-1E instrumentation and control system (see note 3).

(5) The term "separation" means that fire barriers provide separation of redundant components, including equipment, electrical cables, instrumentation and controls, except in the main control room, remote shutdown room, and containment. See section 9A.3.1.1 for discussion on containment and section 9A.3.1.2.5 for discussions on the main control room and remote shutdown room.

(6) Separation is provided for the reactor trip function. The reactor trip breakers are separated.

Table 9.5.2-1

COMMUNICATION EQUIPMENT[1] AND LOCATIONS

Provided for Operator Transient Response[2]
in Addition to Main Control Room and Remote Shutdown Room

Area Locator	Elevation	Primary Area/Location Served
1212	66′-6″	Divisions A, B, C, D Battery Rooms
1222	82′-6″	Divisions A, B, C, D dc Equipment Rooms
1121	96′-0″	Passive Core Cooling System Valve/Accumulator Rooms and Steam Generator
1123		Compartments
1124		
1231	100′-0″	Divisions A and C, I&C Rooms; Divisions B and D, I&C/Penetration Rooms; Valve/Piping Penetration Room
1234	107′-2″	Maintenance Floor Staging Area
1134	107′-2″	Maintenance Floor
1132		
1243	117′-6″	Non-1E Equipment/Penetration Room
1254	135′-3″	Access Corridor Serving Personnel Access Area
1151	135′-3″	Operating Deck
1152		
1251	135′-3″	MSIV Compartments
1162	159′-7″	Steam Generator Feedwater Nozzle Area

Notes:
(1) Stations have Telephone/Page, PABX, and maintenance sound-power capability.
(2) See Standard Review Plan 9.5.2.

Table 9.5.4-1 (Sheet 1 of 2)

NOMINAL COMPONENT DATA
STANDBY DIESEL AND AUXILIARY BOILER FUEL OIL SYSTEM

Above Ground Storage Tanks	
Service	Diesel engine and auxiliary boiler supply
Quantity	2
Type	Vertical, cylindrical
Total capacity (gal) per tank	85,000
Capacity reserved for diesel generator (gal) per tank	55,000
Capacity available for auxiliary boiler (gal) per tank	30,000
Operating pressure	Atmospheric
Operating temperature	Ambient
Diesel Oil Transfer System	
Fuel Oil Transfer Pumps	
Quantity	2
Type	Gear, positive displacement
Operating Flow (gpm)	8
Required design capacity (gpm)	30
Fuel Oil Strainer	
Quantity	2
Type	Duplex
Design Capacity (gpm)	30
Fuel Oil Heater	
Quantity	2
Type	Electric
Rating @30 gpm	90 kw
Fuel Oil Water Separator	
Quantity	2
Type	Pressurized/coalesced
Design Capacity (gpm)	30
Duplex Filters	
Quantity	2
Type	Duplex/stacked disc
Design Capacity (gpm)	30
Diesel Fuel Oil Day Tanks	
Quantity	2
Type	Horizontal, cylindrical
Minimum Design Capacity (gal)	1300
Available capacity (gal)	1200
Operating pressure	Atmospheric
Code	Non-Stamped ASME VIII

Table 9.5.4-1 (Sheet 2 of 2)

NOMINAL COMPONENT DATA
STANDBY DIESEL AND AUXILIARY BOILER FUEL OIL SYSTEM

Auxiliary Boiler Supply System	
Fuel Oil Strainer	
Quantity	2
Type	Duplex
Design Capacity (gpm)	20
Fuel Oil Supply Pumps	
Quantity	2
Type	Gear, positive displacement
Design Capacity (gpm)	20
Ancillary Diesel Fuel Oil Tank	
Quantity	1
Type	Horizontal, cylindrical
Minimum Design Capacity (gal)	650
Available capacity (gal)	625
Operating pressure	Atmospheric
Code	Non-Stamped ASME VIII

Table 9.5.4-2

INDICATING AND ALARM DEVICES - STANDBY DIESEL AND AUXILIARY BOILER FUEL SYSTEM

Parameter	Indication		Alarm	
	Control Room	Local	Control Room	Local
Fuel Oil Storage Tank Level - Diesel Oil (DO) Transfer	Yes	Yes	Yes	Yes
Auxiliary Boiler Supply Pump Motor-Running Indication	Yes	Yes(2)	Yes	Yes(2)
DO Day Tank Level	Yes	Yes	Yes	Yes
DO Transfer Pump Motor-Running Indication	Yes	Yes	No	No
DO Low Fuel Oil Pressure	Yes	Yes	Yes(1)	Yes
Auxiliary Boiler Supply Low Fuel Oil Pressure	Yes	Yes(2)	Yes(1)	Yes(2)
DO Water Separator Differential Pressure	Yes	Yes	Yes(1)	Yes
DO Filter Differential Pressure	Yes	Yes	Yes(1)	Yes
DO Pump Suction Strainer Differential Pressure	Yes	Yes	Yes(1)	Yes
Auxiliary Boiler Supply Pump Suction Strainer Differential Pressure	Yes	Yes(2)	Yes(1)	Yes(2)
DO Fuel Oil Heater in Service	Yes	Yes	Yes(1)	Yes
DO Fuel Oil Heater Temp Out	Yes	Yes	Yes(1)	Yes
Fuel Oil Tank Fill Strainer Differential Pressure	No	Yes	No(1)	Yes

Notes:
(1) Combined trouble alarm in control room
(2) Local indication or alarm at auxiliary boiler panel

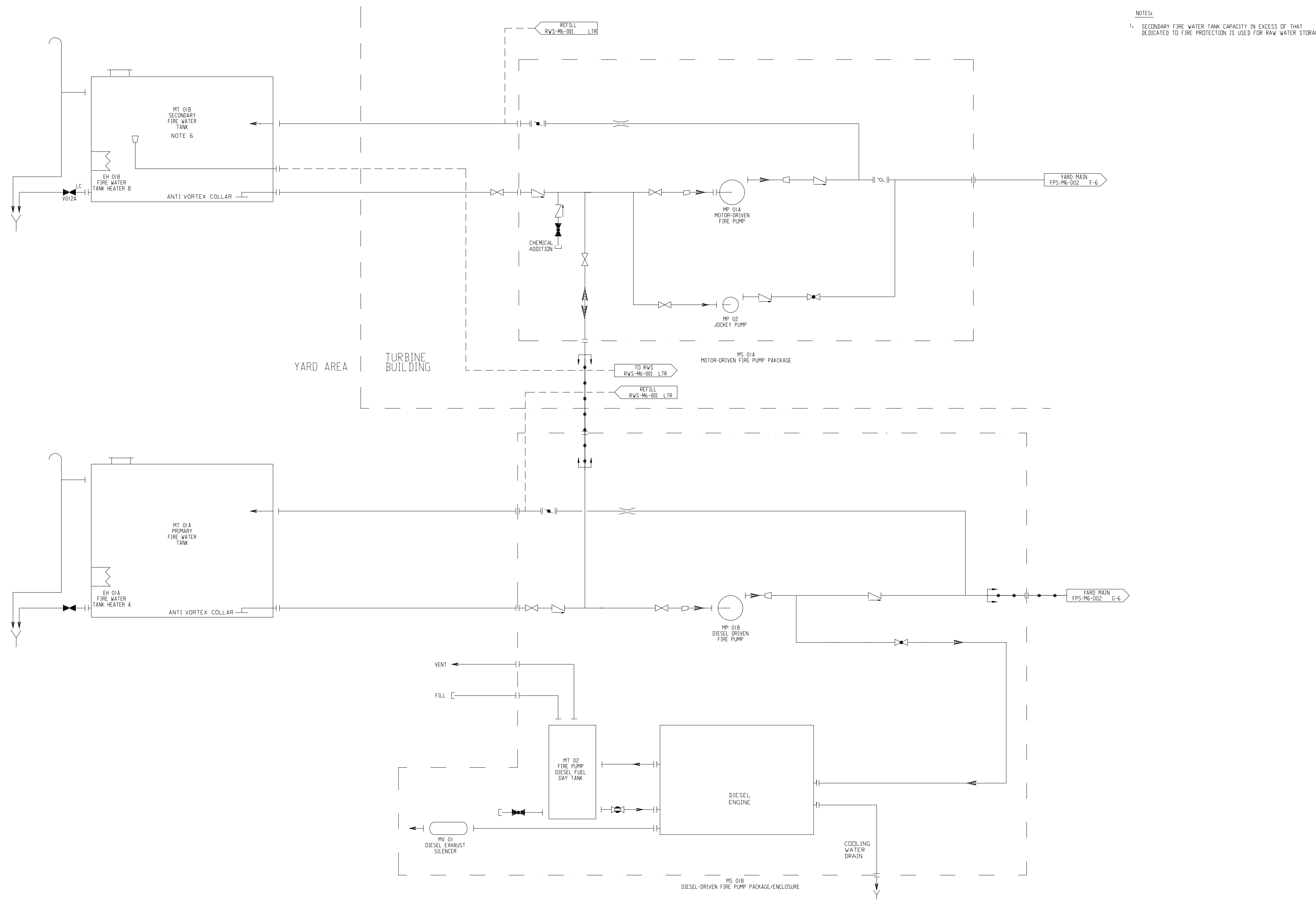

Figure 9.5.1-1 (Sheet 1 of 3)

Fire Protection System
Piping and Instrumentation Diagram
(REF FPS 001)

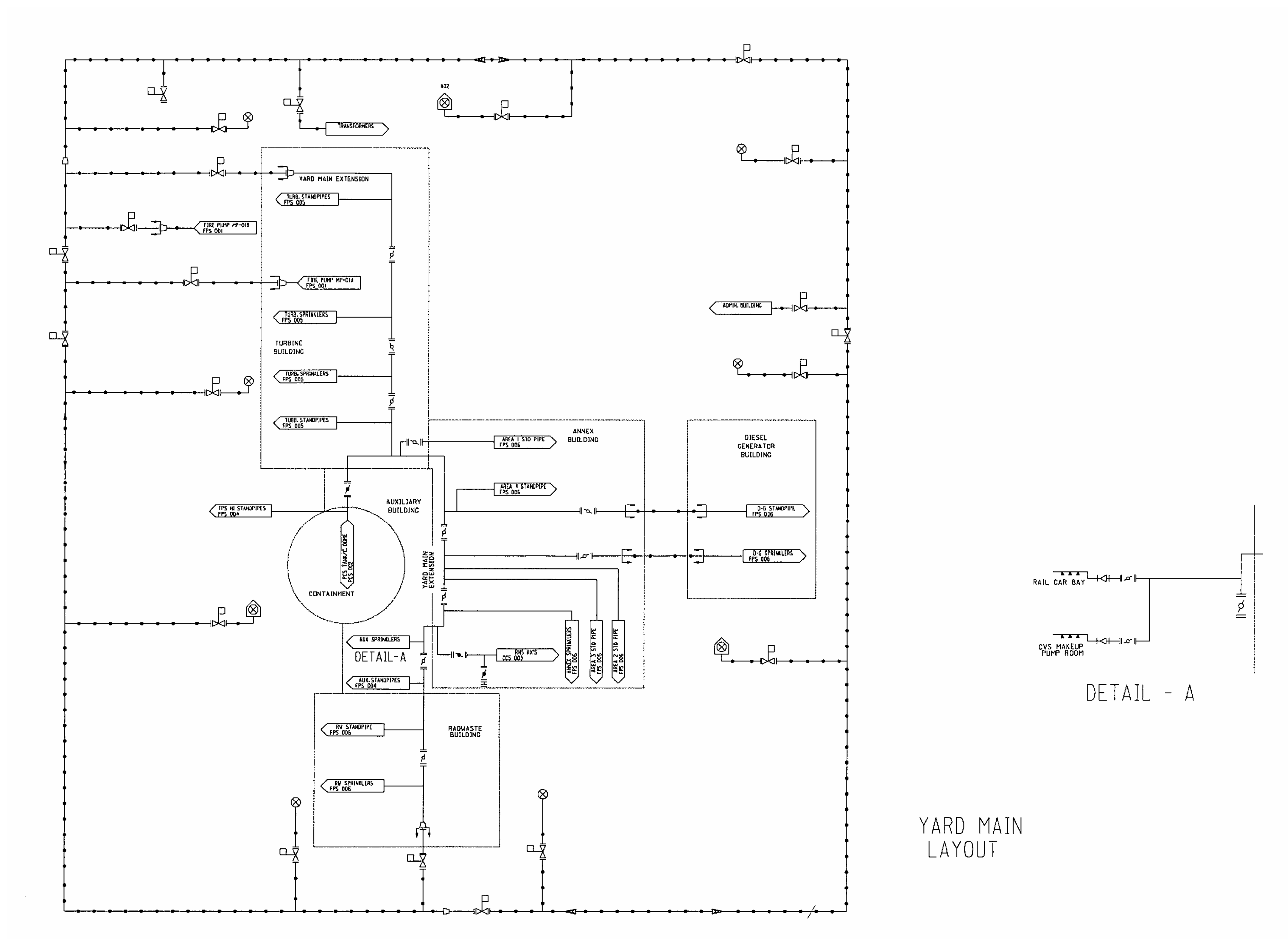

Figure 9.5.1-1 (Sheet 2 of 3)

Fire Protection System
Piping and Instrumentation Diagram
(REF) FPS 002, 004

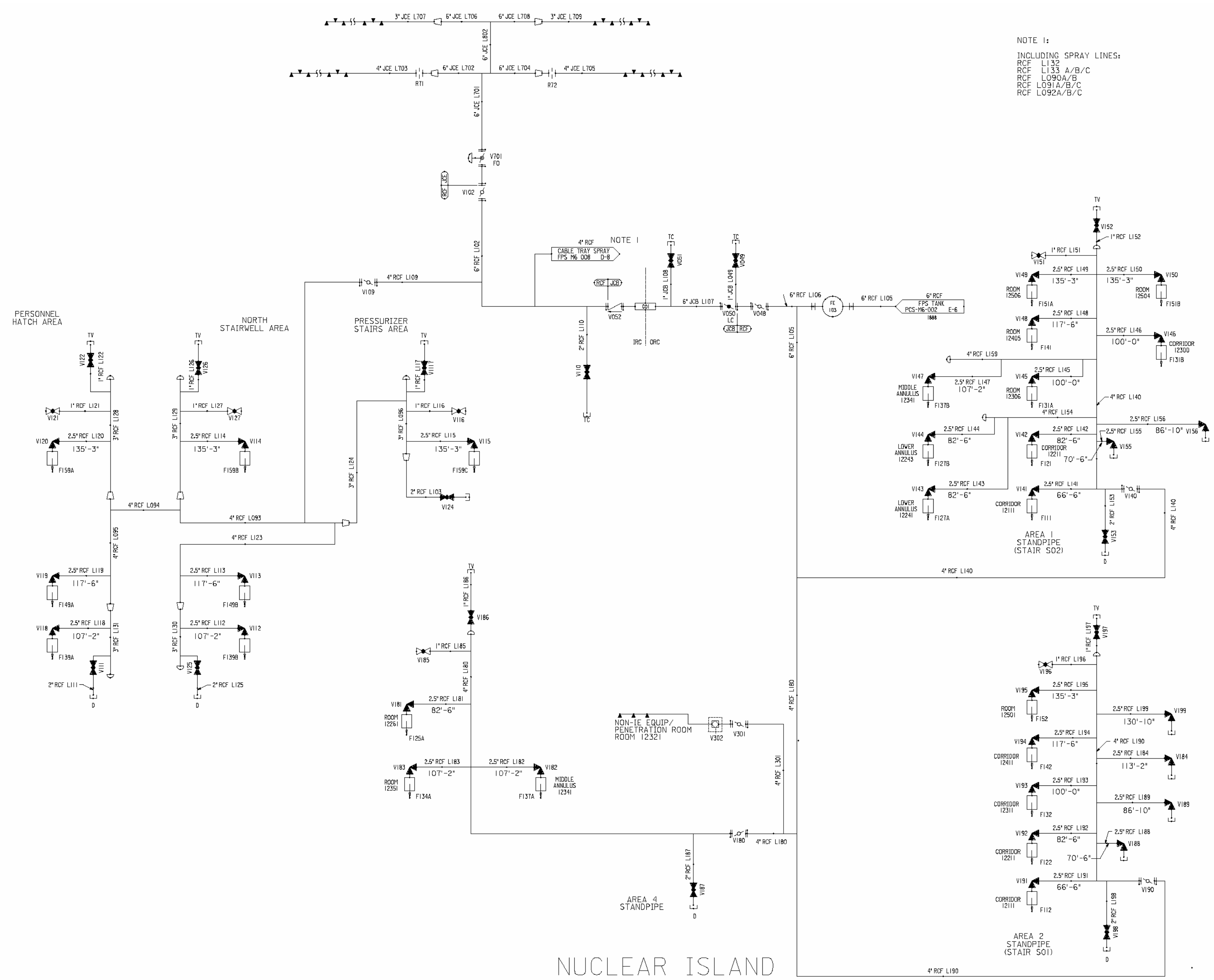

Figure 9.5.1-1 (Sheet 3 of 3)

Fire Protection System
Piping and Instrumentation Diagram
(REF FPS 004)

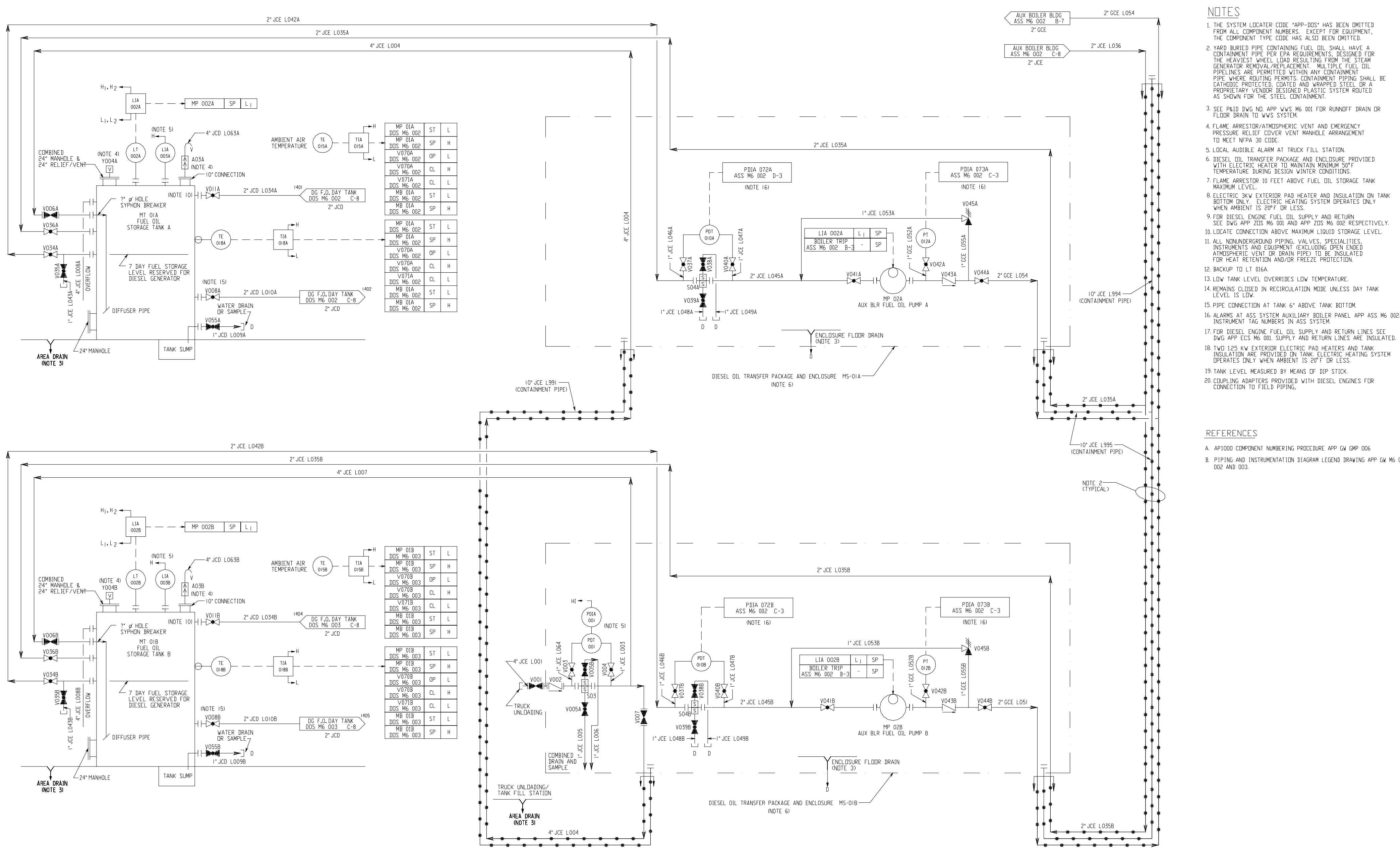

Figure 9.5.4-1 (Sheet 1 of 3)

Standby Diesel and Auxiliary Boiler Fuel Oil System
Piping and Instrumentation Diagram
(REF) DOS 001

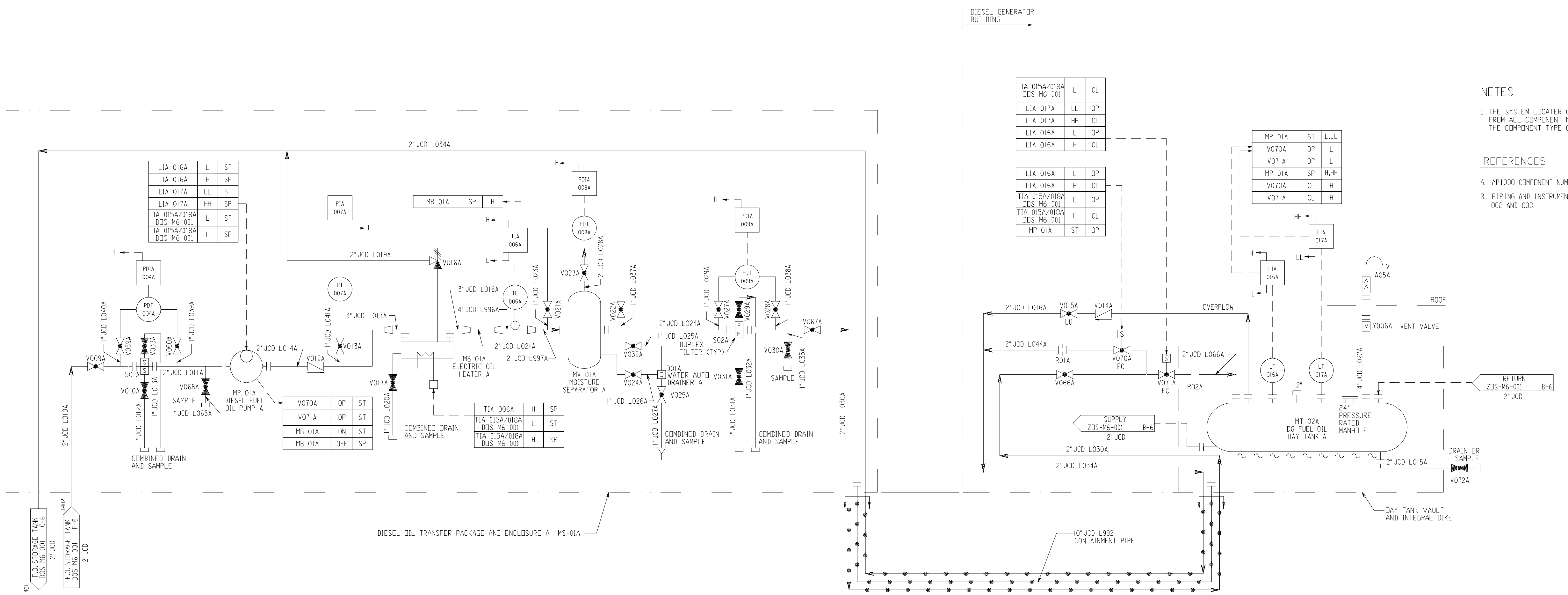

Figure 9.5.4-1 (Sheet 2 of 3)

Standby Diesel and Auxiliary Boiler Fuel Oil System
Piping and Instrumentation Diagram
(REF) DOS-002

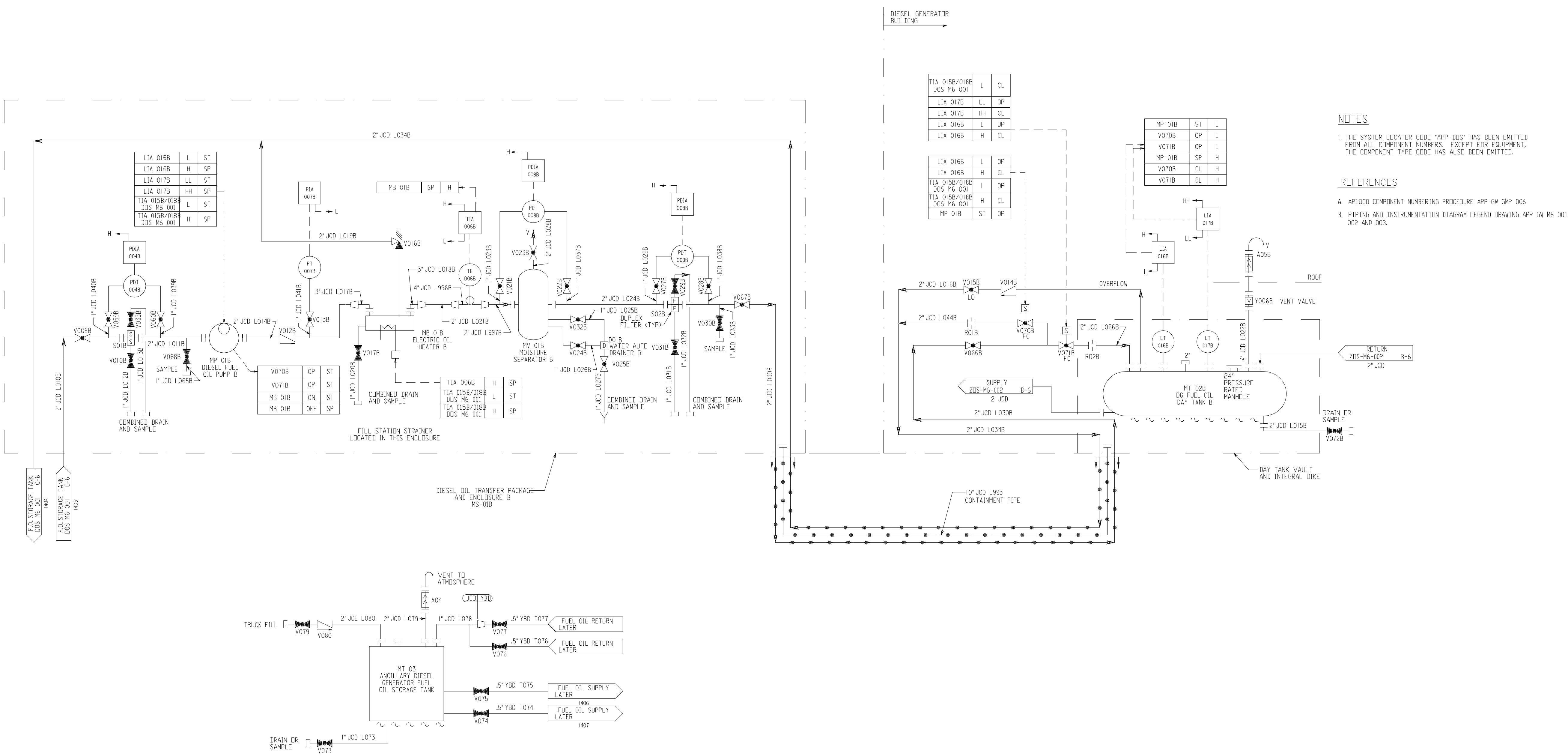

Figure 9.5.4-1 (Sheet 3 of 3)

Standby Diesel and Auxiliary Boiler Fuel Oil System
Piping and Instrumentation Diagram
(REF) DOS-003

APPENDIX 9A

FIRE PROTECTION ANALYSIS

9A.1 Introduction

The AP1000 fire protection analysis is largely based upon the AP600 fire protection analysis that supported the AP600 Design Certification. It evaluates the potential for occurrence of fires within the plant and documents the capabilities of the fire protection system and the capability to safely shut down the plant. The fire protection analysis is an integral part of the process of selecting fire prevention, detection, and suppression methods, and provides a design basis for the fire protection system. The design of the fire protection system is described in subsection 9.5.1.

The purpose of the fire protection analysis is as follows:

- Identify the potential for fires based on the type, quantity, and location of combustible materials
- Determine the consequences of postulated fires
- Provide a basis for decisions on how to prevent, detect, contain, and suppress fires
- Assess fire protection system adequacy
- Confirm the capability to safely shut down the plant following a fire

The fire protection analysis is performed for each fire area using the methodology described in Section 9A.2. This methodology follows the guidance of Branch Technical Position (BTP) CMEB 9.5-1 (Reference 1). The results of the analysis are provided in Section 9A.3.

The fire protection analysis is performed for areas of the plant containing safety-related components and for areas containing systems important to the generation of electricity. It is performed on an area by area basis outside containment and a zone by zone basis inside containment. This approach provides confidence that plant safety is preserved.

9A.2 Fire Protection Analysis Methodology

9A.2.1 Fire Area Description

The plant is divided into fire areas and fire zones as described in subsection 9.5.1.2.1.1. These fire areas/zones and their boundaries are illustrated on Figures 9A-1 through 9A-5.

The analysis for each fire area briefly describes the fire area and associated fire zones, and identifies the principal systems and safety-related components in the fire area. Fire detection and suppression features are listed and the means of smoke control is discussed. The term "smoke" is used throughout this document to imply "smoke and products of combustion".

This document also uses terminology defined in NFPA 13, such as "light hazard", "ordinary hazard", and "extra hazard". Normally, these terms apply to sprinkler installations and their water supplies only. However, as used herein, the terms apply to the quantity and combustibility of the contents of a given fire area or fire zone irrespective of whether or not sprinklers are present.

9A.2.2 Combustible Material Survey

Each fire area and fire zone is surveyed to determine the type, quantity and distribution of in-situ combustible materials. Where the presence of transient combustibles is anticipated (for example, materials required to support refueling activities or scheduled maintenance) these materials are also identified.

When estimating quantities of electrical cable insulation, cable trays are assumed to have a cable fill of 30 percent of the usable tray depth. Cable enclosed in conduit or in closed metal cabinets is not included in the combustible material survey.

9A.2.3 Fire Severity Categorization

For purposes of evaluating fire barrier adequacy, the expected fire severity for each area/zone is categorized from A (slight) to E (severe) in accordance with Table 7-9E of the NFPA Fire Protection Handbook, 16th edition (Reference 2), based on the type of materials present.

Fire severity category A is used for battery cases, category C is used for electrical cable insulation, and category E is used for combustible liquids. For fire areas containing mixed combustibles, an average category is used. If there are significant concentrations of combustible materials in the area/zone, the category assigned is generally more severe than that used for a uniform distribution.

9A.2.4 Combustible Loading and Equivalent Fire Duration Calculations

Fire barriers, detection and suppression methods are based on several factors, including regulatory guidance, the type of combustibles present, and investment protection considerations. Regulatory guidance takes precedent over the other considerations.

Combustible loading and equivalent fire duration calculations are performed for each fire area and each fire zone. The preliminary calculations provide information used in the selection of fire detection and suppression methods.

Combustible Loading Calculations

The calculation of combustible loading provides an indication of the maximum heat that is released if all the combustibles in a given fire area/zone are consumed.

The potential heat release (expressed in British thermal units, or Btus) for each type of combustible material in the fire area/zone is the product of the quantity of each combustible multiplied by its heat of combustion. The heat of combustion values used for these calculations are listed in Table 9A-1. The maximum heat release for all combustibles in the fire area/zone is found by adding the potential heat release of each combustible material.

The combustible loading for the fire area/zone is the maximum heat release per square foot (Btus per square foot). It is determined by dividing the maximum heat release for all combustibles in the fire area/zone by the floor area of the fire area or zone.

For fire areas that are not protected based on regulatory guidance and that do not have concentrations of volatile or radioactive combustibles, fire detection and suppression needs are established based on combustible loading, using the following guidelines:

Combustible Loading (Btu/ft^2)	Detection Capability	Suppression Capability
0 to 8,000	None	Manual
8,000 to 80,000	Yes	Manual
Above 80,000	Yes	Automatic and Manual

In addition, concentrations of combustibles were evaluated, including their proximity to fire barriers.

Equivalent Fire Duration

The duration of a fire in a given fire area or zone is influenced by many factors, including:

- The properties of the material (ease of ignition and rate of heat release)
- The surface area of the combustible material
- The presence of fire retardant coatings
- Ventilation parameters and availability of oxygen
- The degree of separation or the presence of barriers between groups of combustible materials

Fire duration is estimated based on the fire severity category and the equivalent combustible loading. Equivalent combustible loading is defined as the weight per square foot of ordinary combustibles (wood or paper) having a heat of combustion of 8,000 Btu/lb, that releases the same total heat as the combustibles in the fire area/zone. The equivalent combustible loading is calculated by dividing the maximum heat release per square foot by 8,000 Btu/lb. The fire endurance lines of Figure 7-9B of the NFPA Fire Protection Handbook, 16th edition (Reference 2), are used to estimate the fire duration in minutes.

Fire barriers are tested by exposure to a fire whose severity follows a time varying temperature curve known as the standard time-temperature curve (NFPA Fire Protection Handbook, 18th edition [Reference 5], Figure 7-5A.) The estimated fire duration for each fire area is normalized based on the standard time-temperature curve to obtain an equivalent fire duration. This value is compared with the fire resistance of the fire area boundaries. This comparison is used in conjunction with other factors, including those listed above, in making a determination of the adequacy of the fire area boundaries.

9A.2.5 Fire Protection Adequacy

The adequacy of the fire protection features for a postulated fire in each fire area or fire zone is evaluated. This evaluation includes the following points:

- A review of the AP600 Design Certification and other regulatory guidance
- A review of how the fire is detected and suppressed
- Verification of the adequacy of the fire resistance of the fire area boundaries
- Verification that the ventilation system for the fire area does not contribute to the spread of fire or smoke
- Verification that a fire in a nonsafety-related area does not threaten safety-related areas of the plant
- Verification that, for a fire in an area containing radioactive materials, the capability to minimize and control a potential release of radioactivity is not adversely affected
- A determination of the need for structural steel fireproofing
- A determination of the capability of the drainage systems to handle fire protection water flow.

9A.2.6 Fire Protection System Integrity

For fire areas containing safety-related components, the potential for a credible inadvertent actuation of automatic suppression systems is determined and the consequences are evaluated.

The design of automatic and manual suppression systems is reviewed to verify that there is no potential single impairment which incapacitates both the automatic suppression system and the manual suppression system.

9A.2.7 Safe Shutdown Evaluation

This subsection describes the methodology for evaluation of the effects of postulated fires in each fire area on the ability of the operator to achieve a safe shutdown of the plant. The criteria and assumptions upon which the evaluation is based are described in subsection 9A.2.7.1. The safety-related features of the plant designed to provide the safe shutdown capability are described in subsection 9A.2.7.2.

As indicated in subsection 9.5.1, this evaluation is based upon satisfying the requirements of BTP CMEB 9.5-1. This basis includes using safe shutdown as defined in Section 16.1 in lieu of cold shutdown wherever stated in BTP CMEB 9.5-1. The automatic depressurization system is not used as the method for achieving safe shutdown after a fire and spurious actuation of the automatic depressurization system is avoided. The passive residual heat removal heat exchanger is used to remove decay heat for safe shutdown as described in subsection 7.4.1.3.

In addition, the plant has enhanced capability to achieve cold shutdown following a fire as discussed in subsection 9.5.1. This capability is not relied upon in the fire evaluation contained in Appendix 9A.

The criteria concerning cold shutdown capability deviates from the criteria applied to the evolutionary reactor designs, but is consistent with the criteria applicable to existing plants. To enhance the survivability of the normal safe shutdown and cold shutdown capability in the event of a fire, and to reduce the reliance on the infrequently utilized safety-related passive systems, automatic suppression is provided in those fire areas outside containment where a fire could damage the normal shutdown capability, or result in a spurious operation of equipment that could result in a venting of the RCS. This criterion is unique to the AP1000 and does not ensure that the normal shutdown capability will be free of fire damage, or that the equipment necessary to achieve and maintain cold shutdown can be repaired within 72 hours.

9A.2.7.1 Criteria and Assumptions

The criteria and assumptions described below are used in performing the safe shutdown evaluation.

Postulated Fire

Only one fire is assumed to occur within the plant at any given time. A postulated fire is assumed to occur in any area (or zone in containment), whether or not the area contains in-situ combustible materials.

Any damage which would prevent proper operation of equipment and which the fire is capable of causing is assumed to occur immediately. Except where explicitly noted, no credit is taken for proper operation of equipment or moving of valves to proper position when not protected from the effects of a postulated fire.

Fire Barriers

As described in subsection 9.5.1.2.1.1, non-combustible fire barriers are provided in accordance with BTP CMEB 9.5-1. The equivalent fire barrier ratings are shown in Figures 9A-1 through 9A-5 and are those of the barrier itself. Fire-proofing of structural steel is determined as described in subsections 9.5.1.2.1.1 and 9A.2.5.

Fire Areas

Fire areas are three dimensional spaces designed to contain a fire that may exist within them. They are separated by fire barriers, fire barrier penetration protection, and other devices, such as those within the heating and air conditioning ducts, that isolate a fire to within the fire area.

A postulated fire does not extend beyond the boundary of the fire area. For fire areas outside the main control room, remote shutdown room, and containment fire areas, the zone of influence is defined as the entire fire area and all equipment in any one fire area is assumed to be rendered inoperable by the fire and re-entry into the fire area for repairs and operator actions is assumed to be impossible. However, no credit is taken for complete fire damage in cases in which complete

damage is beneficial and partial damage is not. Chases for electrical cables, piping or ducts that pass through the fire area but are separated from it by 3-hour fire barriers are outside that fire area.

Zone of Influence

Outside containment, zone of influence is not defined. A fire outside containment is assumed to affect its entire fire area. Inside the containment fire area, the zone of influence is defined as the entire fire zone containing the fire. All equipment in any one fire zone is assumed to be rendered inoperable by the fire unless the fire protection analysis demonstrates otherwise. Class 1E electrical cables that are located in or pass through the fire zone but are separated from it by a 3-hour fire barrier are outside that fire zone.

Fire Zones

Fire zones are three dimensional spaces within fire areas. Fire zones are identified uniquely to indicate that they have fire protection features or attributes different than other fire zones in a given area. In containment, fire zones are identified to establish "zones of influence."

Independence of Affected Fire Areas

Only systems, components, and circuits free of fire damage are credited for achieving safe shutdown for a given fire. Systems, components, and circuits outside the zone of influence are considered free of fire damage if the effects of the fire do not prevent them from performing their required safe shutdown functions.

Event Assumptions

Plant accidents and severe natural phenomena are not assumed to occur concurrently with a postulated fire. Furthermore, a concurrent single active component failure (independent of the fire) is not assumed.

Offsite Power

A loss of offsite power is assumed concurrent with the postulated fire only when the safe shutdown evaluation indicates the fire could initiate the loss of offsite power.

Availability of Nonsafety-Related Systems

Only safety-related components and systems are assumed to be available to perform safe shutdown functions. (This is more stringent than required by BTP CMEB 9.5-1.) For each fire area or zone, the safe shutdown evaluation is valid for the worst case fire in the area or zone and initial use of nonsafety-related equipment. Fire protection and smoke control systems are assumed to function as designed to detect and mitigate the effects of the fire.

If offsite power is available, nonsafety-related systems are assumed to continue to operate if a more conservative evaluation would result. Each safe shutdown evaluation is also valid considering the possibility that the operator may initiate safe shutdown using available

nonsafety-related systems and that, should the fire later cause those systems to fail, safety-related systems may be automatically or manually actuated to continue the safe shutdown process.

Automatic Suppression Features Assessment

An assessment is performed to demonstrate the ability of the AP1000 to withstand a fire in fire areas outside containment, and achieve safe shutdown without the need for actuating the passive safety-related decay heat removal system. This evaluates the capability of the AP1000 nonsafety-related systems to achieve safe shutdown.

Fire suppression is provided outside containment in locations that would degrade the normal nonsafety-related systems used to achieve safe shutdown following a fire, such that the operation of the passive residual heat removal heat exchanger would be required to provide shutdown decay heat removal. Fire suppression minimizes the challenges to the safety-related decay heat removal systems by enhancing the survivability of nonsafety-related systems used for shutdown decay heat removal.

The safe shutdown process, using nonsafety-related systems, is described in subsection 7.4.1.2. This assessment credits the use of selected safety-related systems other than the passive residual heat removal system to facilitate the transition to cold shutdown conditions. The following safety-related features may be used:

- Insertion of the control rods to provide reactor shutdown,
- Operation of the core makeup tanks to provide boration and reactor coolant system makeup,
- Manual throttling and closing of a first stage automatic depressurization valve to reduce the reactor coolant system pressure to the operating pressure of the normal residual heat removal system,
- Instrumentation used to monitor reactor coolant system conditions.

The use of these safety-related systems do not result in significant plant transients. If the automatic depressurization system is actuated, the operators align the normal residual heat removal system to provide injection to the reactor coolant system. This action causes the core makeup tank level to remain above the fourth stage valve actuation setpoint and prevents significant steaming to and flooding of the containment.

Process Monitoring

Direct process signals are provided to monitor the shutdown process and to assist in determining proper actions for operation of the shutdown methods.

Manual Operation

One of the required manual actions to achieve plant shutdown for a postulated fire event is to scram the reactor.

Manual actions by operations personnel include manipulation of equipment located anywhere outside the affected fire area, if accessibility and staffing levels permit such actions. Entry into the fire area for repairs or operator actions is assumed to be impossible.

Although the typical shutdown sequence does not require manual actions by the operator, fire damage may not be sufficient in many cases to trip the plant. The operator may take appropriate actions to expedite an orderly shutdown. These actions are performed in the main control room. If the fire occurs in the main control room, these actions are performed at the remote shutdown workstation.

High-Low Pressure Interfaces

NRC Generic Letter 81-12 (Reference 3) requests the identification and evaluation of the interfaces between the high pressure reactor coolant system and low pressure systems such as the normal residual heat removal system. Typically, these high-low pressure interfaces contain two redundant and independent remotely-operated valves in series. These two valves and their control and power cables may be subject to a single fire. This fire may potentially cause the two valves to open, resulting in a fire-initiated loss-of-coolant accident (LOCA) through the high-low pressure system interface. Electrically controlled valves which provide such an interface are identified. These interface valves are considered to be required for safe shutdown.

Associated Circuits

The AP1000 was designed with separation of safety-related circuits and equipment as a primary objective. As a result of the concern for separation from the beginning of the design, the use of associated circuits has been minimized.

The safe shutdown equipment and systems for each fire area are isolated from associated circuits in the fire area so that hot shorts, open circuits, or shorts to ground in the associated circuits will not prevent operation of the safe shutdown equipment. No postulated fire involving associated circuits will prevent safe shutdown.

Associated circuits comply with Regulatory Guide 1.75 position 4 related to associated circuits and IEEE 384-1981 (Section 5.5.2).

Spurious Actuation of Equipment

Fire-caused damage is assumed to be capable of resulting in the following types of circuit faults: hot shorts, open circuits, and shorts to ground. Spurious actuation of components caused by these circuit faults are evaluated. Components are assumed to be energized or de-energized by one or more of the above circuit faults. For example, air operated and solenoid operated valves are assumed to fail open or closed; pumps are assumed to fail running or not running; electrical distribution breakers could fail open or closed. For three-phase ac circuits, the probability of getting a hot short on all three phases in the proper sequence to cause spurious operation of a motor is considered sufficiently low as to not require evaluation, except for cases involving high-low pressure interfaces. For ungrounded dc circuits, if spurious operation could only occur as a result of two ungrounded hot shorts of the proper polarity, then no further evaluation is necessary, except for any cases involving a high-low pressure interface. Therefore, spurious

operation of ac or dc motor operated valves as a result of power cable hot shorts is not assumed, except for cases involving a high-low pressure interface.

It is assumed that a fire results in the loss of all automatic function (signals and logic) from the circuits located in the fire area. In addition, spurious actuations or signals resulting from the fire are postulated one at a time (except for high/low pressure interfaces). The spurious actuations and signals that are evaluated are those that could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

Spurious actuation of the redundant valves in any one high-low pressure interface line are postulated if the circuits for those valves are located in the fire area.

Most control room controls use soft-controls which communicate over multiplexed data channels. Fire-induced spurious actuation from these multiplexed soft controls is not assumed.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation. In the event of a fire in the main control room, control may be transferred to the remote shutdown workstation, depending on the extent of the fire. For a small fire which can be quickly extinguished, control is maintained in the main control room, and the potential for damage or spurious signals is limited. For larger postulated fires, the main control room is evacuated and control is transferred to the remote shutdown workstation. Once control is transferred, the dedicated switches in the main control room are disabled by a transfer switch.

Spurious actuation of squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Automatic depressurization system stages 1, 2, and 3 consist of parallel paths, each path having two motor-operated valves in series. Spurious stage 1, 2, or 3 actuation is prevented by the use of physical separation of control circuits for the two series valves and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Multiple High-Impedance Faults

It is postulated that fire-induced circuit faults may occur with high enough impedance to prevent tripping of the affected circuit breaker. If multiple high-impedance faults occur simultaneously, affecting branch circuits fed from a common power source, there is a potential for the sum of the currents from these multiple high-impedance faults to be high enough to trip the main circuit breaker feeding the bus. Once the main breaker trips, components powered from the bus lose their power source. Multiple high-impedance faults are considered in the evaluation of safe shutdown capability.

Plant Personnel

The plant operating staff available for manual actions to achieve safe shutdown, during and after the fire, is limited to the minimum number of posted operator positions minus those assigned to the fire brigade.

Equipment Environment

The environment of the equipment required to function for shutdown should not become so severe as to prevent the equipment from functioning. If the environment does exceed the conditions for which the equipment is capable of functioning, it is assumed that the equipment no longer is capable of performing its intended function.

Emergency Lighting

In situations where the safe shutdown evaluation identifies the need for manual operator action in response to a fire, the estimate of the time required for this action considers the availability of emergency lighting in locations where these actions are performed and along the access and egress routes thereto.

Emergency Communications

The safe shutdown evaluations consider the need for and availability of emergency communications within the plant following a fire.

9A.2.7.2 Safe Shutdown Methodology

The safe shutdown process, the systems used, and the functional requirements for safe shutdown are described in Section 7.4. As noted above, only safety-related equipment is utilized for safe shutdown. A description of this equipment is provided in the applicable sections.

Table 9A-2 lists the safety-related components used for safe shutdown and their associated electrical divisions. Each fire area is reviewed to identify the potential scope of fire damage and to verify that the capability to achieve and maintain safe shutdown is preserved.

The shutdown process uses controls located in the main control room. In the event of a fire in the main control room, controls located at the remote shutdown workstation are used.

9A.3 Fire Protection Analysis Results

The fire protection analysis is conducted for the following primary plant structures, which are shown on the site plot plan, Figure 1.2-2:

- Nuclear island
- Turbine building
- Annex building
- Radwaste building
- Diesel generator building

Table 9A-3 identifies the type and quantity of combustible materials in each fire area of the primary plant structures and indicates the equivalent fire duration. Fire detection and suppression features are also summarized in Table 9A-3.

Openings through fire barriers for pipe, conduit, and cable trays are sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Penetration designs conform to the guidelines of BTP CMEB 9.5-1. Fire barrier penetration openings for ventilation are protected by fire dampers having a rating equivalent to that of the fire barrier. For 1-hour rated fire barriers, fire dampers are not required since the duct itself is an adequate barrier. The protection of door openings conforms to the guidelines of BTP CMEB 9.5-1.

Structural steel fireproofing is provided as described in subsection 9.5.1.2.1.1.

The fire detection and suppression capabilities for each fire area are selected based on the criteria described in subsection 9A.2.1 and are consistent with the importance of the equipment in the fire area to plant availability. Portable fire extinguishers are accessible throughout the plant.

The presence of radioactive systems is noted in the description of each fire area. Potential releases of radioactivity as a consequence of a fire in these areas is mitigated by measures such as:

- Control and confinement of sources of radioactivity per ALARA principles
- Use of fire dampers to isolate ventilation ducts serving the fire area
- Use of fire suppression systems to quickly suppress the fire
- Provision of curbed floor areas and sizing of sumps to collect and retain fire protection water within the affected fire area or building

The safe shutdown evaluation of spurious equipment actuation as a result of a fire is addressed in subsection 9A.3.7. The protection of accident mitigation equipment (as opposed to safe shutdown equipment) is also addressed in subsection 9A.3.7.

9A.3.1 Nuclear Island

Figure 9A-1 identifies fire areas and fire zones within the nuclear island and illustrates the fire resistance of the fire area boundaries. The nuclear island is comprised of the following primary areas:

- Containment/shield building
- Auxiliary building – nonradiologically controlled areas (non-RCA)
- Auxiliary building – radiologically controlled areas (RCA)

The containment/shield building comprises a single fire area for the purposes of this analysis.

The auxiliary building is divided into the radiologically controlled areas and nonradiologically controlled areas which are physically separated by structural walls and floor slabs. These structural barriers are designed to prevent fire propagation across the boundary between these areas.

The auxiliary building is further subdivided into fire areas separated by fire-rated structural barriers. These barriers provide physical separation between the four Class 1E electrical divisions and between these divisions and nonsafety-related areas.

Floor drains accommodate water flow from fire protection systems without a significant accumulation of water in a fire area. Flooding of components required for safe shutdown is also precluded by the fact that only a limited volume of fire water can be discharged from the fire protection system in fire areas containing those components. This subject is further discussed in Section 3.4.

Drain systems in the radiological controlled area of the nuclear island Annex Building and Radwaste Building drain to fire zones in the nuclear island where there are no safe shutdown components. Fires in these zones due to potential combustible liquid transport by the drains do not affect safe shutdown.

There is no drain path which could drain combustible liquids to the fire areas in the electrical portion of the nuclear island.

For mechanical equipment fire areas in the nonradioactive auxiliary building, fires caused by potential transport of combustible liquid through the drain system are included in the fire hazards analysis.

9A.3.1.1 Containment/Shield Building

This building comprises one fire area - 1000 AF 01. This fire area is separated into fire zones and includes the spaces inside containment as well as the valve room for the passive containment cooling system (PCS), the middle annulus, the upper annulus, and the operating deck staging area outside containment.

The fire protection and the safe shutdown analysis for the containment identifies the location and the separation of the safe shutdown components located inside the containment. The safe shutdown components located inside the containment are primarily components of the passive core cooling system (PXS), the reactor coolant system (RCS), the steam generator system (SGS), and containment isolation.

For this evaluation, the containment shield building is divided into the following fire zones. These zones are based on the establishment of boundaries (structures or distance) that inhibit fire propagation from zone to zone. Complete fire barrier separation cannot be provided inside containment because of the need to maintain the free exchange of gases for purposes such as passive containment cooling. The location of safety-related equipment and the routing of Class 1E electrical cable in each fire zone enhances the separation of redundant safe shutdown components.

Fire Zone

- 1100 AF 11105 Reactor cavity
- 1100 AF 11204 Vertical access and reactor coolant drain tank room
- 1100 AF 11206 Accumulator room A
- 1100 AF 11207 Accumulator room B
- 1100 AF 11208 Normal residual heat removal valve room
- 1100 AF 11209 Chemical and volume control system room
- 1100 AF 11300A Maintenance floor (southeast quadrant access)
- 1100 AF 11300B Maintenance floor (north half)
- 1100 AF 11301 Steam generator compartment 1
- 1100 AF 11302 Steam generator compartment 2
- 1100 AF 11303 Pressurizer compartment
- 1100 AF 11303A Automatic depressurization system lower valve area
- 1100 AF 11303B Automatic depressurization system upper valve area
- 1100 AF 11500 Operating deck
- 1200 AF 12341 Middle annulus
- 1200 AF 12541 Upper annulus
- 1250 AF 12555 Main control room emergency habitability system air storage/operating deck staging area
- 1270 AF 12701 Passive containment cooling system valve room

The equipment and components in this fire area contain radioactive material with the exception of passive containment cooling system and main control room emergency habitability system components.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers (during reactor shutdown for maintenance)
- Water spray systems in specific locations

Smoke Control Features

Containment air filtration system (VFS) containment isolation valves, if open to the containment atmosphere, are closed by operator action to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by operation of a fire detector, which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of electrical cable insulation. Concentrations of combustibles are described in the evaluation of each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

Inadvertent operation of an automatic suppression system is prevented by the normally closed containment isolation valve in the water supply line. Operator action is required to open this valve and admit water to the system.

The consequences of a break in a fire protection line during normal plant operation are limited because the containment isolation valve for the fire water supply line to the containment hose stations is normally closed and are bounded by other flooding events inside containment. See Section 3.4 for further discussion of flooding events inside containment.

9A.3.1.1.1 Fire Zone 1100 AF 11105

This fire zone is comprised of the following room(s):

<u>Room No.</u>

11105	Reactor vessel cavity
11205	Reactor vessel nozzle area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation associated with the instrumentation in this zone. These cables and instruments are located in the lower part of the fire zone. This fire zone is separated from adjacent fire zones by the thick concrete walls and floor of the reactor vessel cavity, except at the top of the fire zone, where there are penetrations associated with reactor coolant system piping and where the annular space around the reactor vessel flange is closed by the cavity seal ring. There is a doorway to the reactor coolant drain tank room (fire zone 1100 AF 11204) that is closed and a ventilation duct that provides cool air from the containment recirculation cooling system.

Smoke and hot gases from a fire accumulate within this fire zone and gradually migrate via reactor coolant system piping penetrations to adjacent fire zones 1100 AF 11204, 1100 AF 11206, 1100 AF 11301, and 1100 AF 11302. The smoke and hot gases are expected to rise due to their buoyancy and be replaced by air coming from the containment recirculation cooling system. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 identifies the safe shutdown components located in this fire zone. They are the four excore flux instrumentation channels, one for each division. Although it is unlikely that all of the components would be damaged, a fire in this fire zone is conservatively assumed to disable all of the above instrumentation. The source, intermediate and power range excore detectors are not required for automatic safe shutdown initiation or maintenance during or following a fire in this fire zone. These detectors are used to monitor and verify that the reactor is shut down. The redundant instrumentation used for monitoring core reactivity indirectly are the core exit thermocouples located in fire zone 1100 AF 11500. These thermocouples are mounted within the reactor and integrated head package and have exposed cable high in the integrated head package in fire zone 1100 AF 11500. The thermocouple cables will be unaffected by smoke from a fire in the reactor cavity. In addition, reactor subcriticality after shutdown is maintained by an adequate boron concentration in the reactor coolant. This concentration is establish by the automatic actions taken upon reactor trip such as, isolation of non-borated makeup sources and opening of the flow paths to sources of borated water. Boron concentrations can be checked periodically to determine if adequate levels exist.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.2 Fire Zone 1100 AF 11204

This fire zone is comprised of the following room(s):

Room No.	
11104	Reactor coolant drain tank room
11204	Vertical access area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation associated with the instrumentation in this zone. The cable raceways are located against one structural concrete wall of the fire zone and in the reactor coolant drain tank room at the bottom of the fire zone. The floor of this fire zone is solid concrete at the bottom of containment. Thick concrete walls separate this fire zone from adjacent fire zones, except for access passageways to and from the steam generator compartments (fire zones 1100 AF 11301/11302). Steel grating and the vertical access stairway form the boundary between this fire zone and the maintenance floor above (fire zone 1100 AF 11300B). There is a doorway between the reactor coolant drain tank room and the bottom of the reactor cavity (fire zone 1100 AF 11105) that is closed.

Smoke and hot gases from a fire in this fire zone rise through the grating at the top of the vertical access area and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. Although it is unlikely that all of the components would be damaged, a fire in this fire zone is conservatively assumed to disable the passive core cooling system containment floodup level and reactor coolant system hot leg instrumentation. The redundant reactor coolant system hot leg instrumentation located in 1100 AF 11206 and passive core cooling system floodup level instrumentation located in 1100 AF 11105 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.3 Fire Zone 1100 AF 11206

This fire zone is comprised of the following room(s):

<u>Room No.</u>

11206	Passive core cooling system valve/accumulator room A

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation related to the valves located in this fire zone. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with minimum concrete thicknesses of one foot, except for an access hatch and a small CMT pipe penetration in the ceiling. The penetration is beneath core makeup tank A, located on the maintenance floor (fire zone 1100 AF 11300A).

Smoke and hot gases from a fire in this fire zone rise through the CMT pipe penetration and access hatch and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. A fire in this fire zone is conservatively assumed to disable control of all of the valves and instrumentation in this fire zone. The passive core cooling system safe shutdown components located in fire zones 1100 AF 11207 and 1100 AF 11300B are redundant to those in this fire zone, and are sufficient to perform applicable functions to achieve and maintain safe shutdown. The spent fuel pool cooling system containment isolation valve located outside the containment fire area is redundant to the containment isolation valve inside containment in this fire zone and is sufficient to maintain containment integrity.

Redundant reactor coolant hot leg instruments in fire zone 1100 AF 11204 provide the operator with information required to take corrective action during reduced inventory operation.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.4 Fire Zone 1100 AF 11207

This fire zone is comprised of the following room(s):

<u>Room No.</u>

11207 Passive core cooling system valve/accumulator room B

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation related to the valves located in this fire zone. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for a closed access hatch and a CMT pipe penetration in the ceiling, and a passageway to the adjacent RNS valve room (fire zone 1100 AF 11208). The large accumulator vessel stands in front of this passageway and provides a barrier to fire propagation between the two fire zones. The ceiling blockout is beneath core makeup tank B, located on the maintenance floor (fire zone 1100 AF 11300B). The physical arrangement of the small penetration and the large tank and its support results in a tortuous path for fire propagation between these two fire zones. A fire is not expected to propagate to fire zone 1100 AF 11208. If it did, however, fire zone 1100 AF 11206 provides redundant safe shutdown equipment.

Smoke and hot gases from a fire in this fire zone rise through the ceiling CMT pipe penetration and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. Although it is unlikely that more than one valve would be damaged, a fire in this fire zone is conservatively assumed to disable control of all of the valves in this fire zone. The passive core cooling system safe shutdown components located in fire zone 1100 AF 11206 and 1100 AF 11300A are redundant to those in this fire zone, and are sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.5 Fire Zone 1100 AF 11208

This fire zone is comprised of the following room(s):

Room No.

11208	Normal residual heat removal valve room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation associated with the valves in this zone. There are no significant concentrations of combustible materials. This small fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for a passageway to the adjacent PXS valve/accumulator room (fire zone 1100 AF 11207). The large accumulator vessel stands in front of this passageway and provides a barrier to fire propagation between the two fire zones. If fire were to propagate to fire zone 1100 AF 11207, however, fire zone 1100 AF 11206 provides redundant safe shutdown equipment.

Smoke and hot gases from a fire in this fire zone migrate into the adjacent PXS valve/accumulator room (fire zone 1100 AF 11207). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this zone. Although it is unlikely that more than one valve would be damaged, a fire in this fire zone is conservatively assumed to disable control of all of the valves in this fire zone. During normal power operation, power to the hot leg suction isolation valves is locked out to protect the high-low pressure interface between the reactor coolant system and the normal residual heat removal such that they will be unaffected by the fire in maintaining the reactor coolant pressure boundary. The normal residual heat removal containment isolation valve, located outside the containment fire area, is redundant to the four containment isolation valves in this zone and is sufficient to maintain containment and reactor coolant pressure boundary integrity.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.6 Fire Zone 1100 AF 11209

This fire zone is comprised of the following room(s):

Room No.

11209	Chemical and volume control system room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this fire zone does not propagate to the extent that it damages safe shutdown components outside this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation associated with the valves and instrumentation in this zone. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for an access stairway and a small hatch from the maintenance floor above (fire zone 1100 AF 11300B).

Smoke and hot gases from a fire in this fire zone rise through the access hatch and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

There are no safe shutdown components in this fire zone. No further evaluation is required.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.7 Fire Zone 1100 AF 11300A

This fire zone is comprised of the following room(s):

Room No.

11300	Maintenance floor (southern part)
11400	Maintenance floor mezzanine (southern part)

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation. There are small concentrations of cables at the top of the zone and at several separate locations along the walls. This fire zone is physically separated from fire zones below by the maintenance floor, with a concrete thickness of more than one foot, except for openings described in the evaluation of fire zone 1100 AF 11206. This fire zone is separated from the operating deck above (fire zone 1100 AF 11500) by a ceiling with a concrete thickness of more than one foot, except for the hatches near the containment maintenance hatch, which are covered with steel grating. The walls of this fire zone are the steel containment vessel, the steel wall of the in-containment refueling water storage tank, or walls with a concrete thickness of more than one foot, except for two designated boundaries with the adjacent portion of the maintenance floor (fire zone 1100 AF 11300B). These boundaries are approximately at the centerline of containment, one located in the narrow annular space behind the in-containment refueling water storage tank and the other near the personnel hatch. The steam generator compartments, the refueling cavity, and the in-containment refueling water storage tank provide barriers between the two large maintenance floor fire zones. Safe shutdown components fire zone 1100 AF 11300A are separated from redundant safe shutdown components in fire zone 1100 AF 11300B by these barriers or by a horizontal distance of more than 20 feet with no intervening combustible or fire hazards. In addition, safety-related cables in both of these fire zones are routed in closed cable trays or conduit, minimizing the likelihood that a fire originating in a raceway of one division can propagate to a raceway of another division. Furthermore, open-nozzle water spray suppression systems are provided for nonsafety-related electrical cables routed in open cable trays in fire zone 1100 AF 11300B (there are no such cable trays in fire zone 1100 AF 11300A), providing additional assurance that a fire will not propagate between these fire zones.

Most of the smoke and hot gases from a fire in this fire zone rises through the large steel grating covered hatches between the containment maintenance hatch and the steam generator 2 compartment into the large air space in the upper portion of containment (fire zone 1100 AF 11500). Small quantities of smoke, especially that which has already cooled, may migrate horizontally into the adjacent portion of the maintenance floor (fire zone 1100 AF 11300B). The smoke and gases are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Temperature effects on the electrical cables routed high above the operating deck and passing over the large steel-grating covered hatches are not expected to be significant, but are not a concern as these are the same cables that continue into this fire zone and are assumed to be lost. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. The passive core cooling system has two IRWST gutter isolation valves located in this zone. These valves close to divert condensate from the passive containment cooling system (on the inside of the containment shell) into the IRWST. This condensate maintains the passive residual heat removal heat exchanger heat sink for the long term. These valves are fail closed air operated valves. They are located at least 12 feet apart horizontally and at least 10 feet apart vertically. One valve is located on the south end of the refueling cavity, the other is located on the east side of the refueling cavity. In addition, a fire detector is located close to each valve. Given the low combustible materials in this fire zone, a fire will only affect one of the valves initially. The fire detector located near the valve that is initially affected will alert the operators so that they can actuate the unaffected valve before the

fire can prevent operation of the second valve. These valves are qualified to operate with elevated temperatures of 340°F.

Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to eventually disable all of the safe shutdown components in this fire zone.

The redundant passive core cooling system, passive containment cooling system and steam generator system safe shutdown components (listed in Table 9A-2), located in fire zones 1100 AF 11207 and 1100 AF 11300B, are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The primary sampling system and containment air filtration system containment isolation valves, located outside the containment fire area, are redundant to the containment isolation valves in this fire zone and are sufficient to maintain containment integrity.

The redundant reactor coolant system hot leg flow instrumentation located in fire zones 1100 AF 11300B and 1100 AF 11301 is sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.8 Fire Zone 1100 AF 11300B

This fire zone is comprised of the following room(s):

Room No.

11300	Maintenance floor (northern part)
11400	Maintenance floor mezzanine (northern part)

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation in the termination boxes and cable trays. There is a concentration of cables on the south side of the zone near the refueling cavity and small concentrations of cables at the top of the zone and at several locations along the walls. This fire zone is physically separated from fire zones below by the maintenance floor, which has a concrete thickness of more than one foot, except for access stairways and hatches. This fire zone is separated from the operating deck above (fire zone 1100 AF 11500) by a ceiling that has a concrete thickness of more than one foot, except for several openings for an access stairway, elevator, hatches and blockouts. The walls of this fire

zone are the steel containment vessel, the steel wall of the in-containment refueling water storage tank, the noncombustible enclosure for the division B and D penetrations and raceways (fire zone 1100 AF 11500), or walls with a concrete thickness of more than one foot, except for the designated boundaries with the adjacent portion of the maintenance floor, described in the evaluation of fire zone 1100 AF 11300A. There is a doorway between the lower pressurizer compartment (fire zone 1100 AF 11303) and the steam generator #1 lower manway platform (fire zone 1100 AF 11301).

Safety-related cables are routed in closed cable trays or conduit. For open cable trays, which represent the only significant in-situ combustibles in this fire zone, open-nozzle water spray suppression systems are provided. These systems are automatic except that, to preclude inadvertent actuation, operator action is required to open the outboard containment isolation valve. These suppression systems rapidly extinguish a fire in these cable trays and prevent fire propagation to adjacent fire zones.

The use of water spray systems for the open cable trays in this fire zone limits smoke and heat generation. Small quantities of smoke and hot gases from a fire in this fire zone rise through openings in the ceiling, or migrate via the large steel grating covered hatches between the containment maintenance hatch and the steam generator 2 compartment in the adjacent portions of the maintenance floor (fire zone 1100 AF 11300A), into the large air space in the upper portion of containment. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. The division A and C electrical penetrations listed in Table 9A-2 are conservatively assumed to be disabled as a result of a fire in this fire zone. The B and D electrical penetrations and their cable trays routed from the electrical penetrations up to the operating deck are functionally part of fire zone 1100 AF 11500. These two divisions are sufficient to perform applicable functions to achieve and maintain safe shutdown as described in section 9A.2.7.

These division B and D electrical penetrations and their associated raceways are protected from a fire in this fire zone by a combination of barriers, distance and fire suppression systems. Noncombustible barriers of steel or steel-composite construction form vertical shaft(s) from the floor up to the operating deck, surrounding the division B and D penetrations and the associated cable trays. The significant combustible materials in this fire zone are the nonsafety-related cables routed in open cable trays. These cable trays are located at least 20 feet from the division B and D penetrations and their associated raceways, and they are protected by water spray suppression systems.

The passive core cooling system has two passive residual heat removal heat exchanger control valves which are located in this fire area. These valves are fail-open air-operated valves. They are located within several feet of each other. The valves are separated from each other by a noncombustible barrier of steel or steel composite materials. One of the valves is located close to the IRWST wall. This valve is assigned to division B. The cables for this valve are enclosed in conduit or enclosed raceways and routed up through the operating deck. Separate fire detectors are

provided near each valve. The only combustibles in the area are the valves themselves and their cables. A fire that would affect these valves would be expected to start at one of the valves. The barrier protects the other valve from the initial effects of the fire. The fire detectors would alert the operators and allow them to actuate the other valve before the fire could spread and damage it. These valves are qualified to operate with elevated temperatures of 340°F.

Reactor coolant system, and steam generator system instrumentation located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The redundant passive core cooling system instrumentation, and the passive containment cooling system, reactor coolant system pressurizer and steam generator system instrumentation located in fire zones 1100 AF 11206, 1100 AF 11300A, 1100 AF 11301 and 1100 AF 11500 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Reactor coolant system temperature instrumentation located in fire zones 1000 AF 11301 and 1000 AF 11302 are sufficient to provide the monitoring function accomplished by the passive residual heat removal heat exchanger flow instrumentation located in this fire zone.

The reactor coolant system to chemical and volume control system stop valves located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The chemical and volume control system containment isolation valves located outside of this fire zone provide backup isolation capability to maintain the reactor coolant pressure boundary.

The redundant reactor coolant system hot leg flow instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11301 is sufficient to perform applicable functions to achieve and maintain safe shutdown.

The chemical and volume control system and the liquid radwaste system containment isolation valves located outside the containment fire area are redundant to the containment isolation valves inside containment in this fire zone and are sufficient to perform the applicable functions to maintain containment integrity.

The redundant steam line pressure instruments located in fire area 1201 AF 05 for steam generator 1 and in fire area 1201 AF 06 for steam generator 2 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The redundant core exit thermocouples located in fire zone 1100 AF 11500 are sufficient to provide the applicable safe shutdown monitoring function.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.9 Fire Zone 1100 AF 11301

This fire zone is comprised of the following room(s):

Room No.	
11201	Steam generator compartment 1
11301	Steam generator 1 lower manway area
11401	Steam generator 1 tubesheet area
11501	Steam generator 1 operating deck
11601	Steam generator 1 feedwater nozzle area
11701	Steam generator 1 upper manway area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation related to the reactor coolant pump motors and other components in this fire zone. These cables are generally located at separate locations near the perimeter of the fire zone and there are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial barriers. The bottom of this fire zone is the solid concrete floor of the steam generator compartment. Up to an elevation more than 17 feet above the operating deck the fire zone is enclosed by walls with a concrete thickness of more than one foot, except for access passageways to and from the pressurizer compartment (fire zone 1100 AF 11303) and the adjoining portion of the vertical access area (fire zone 1100 AF 11204), and the floor grating interface between the vertical access area and the steam generator 1 access room (fire zone 1100 AF 11303). Above the top of these concrete walls, the fire zone is open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Depending on fire location, smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the steam generator or through the pressurizer compartment (fire zone 1100 AF 11303) and into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

The redundant reactor coolant system hot leg/cold leg instrumentation located in fire zone 1100 AF 11302, and redundant reactor coolant system pressurizer and steam generator system steam generator level instrumentation located in 1100 AF 11300B are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four divisions of reactor coolant system/reactor coolant pump bearing water temperature instrumentation are assumed to be disabled and would not be available to detect and provide a trip signal on a loss of component cooling water to the pump. If the fire in this fire zone does not disable the pump, the component cooling water flow to the pump will be unaffected by the fire and will continue to provide cooling water to the pump bearings until the pump is tripped by other means.

The reactor coolant system reactor coolant pump shaft speed instruments are conservatively assumed to be disabled. The redundant reactor coolant system cold leg flow instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11300B is sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four reactor coolant system reactor head vent valves are assumed to be disabled. If power is lost while in the closed position, the head vent valves will maintain reactor coolant pressure boundary integrity. Refer to subsection 9A.3.7.1.1 for a discussion on spurious actuation of reactor coolant system reactor head vent valves.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.10 Fire Zone 1100 AF 11302

This fire zone is comprised of the following room(s):

Room No.	
11202	Steam generator compartment 2
11302	Steam generator 2 lower manway area
11402	Steam generator 2 tubesheet area
11502	Steam generator 2 operating deck
11602	Steam generator 2 feedwater nozzle area
11702	Steam generator 2 upper manway area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of cable insulation related to the reactor coolant pump motors and other components in this fire zone.

These cables are generally located at separate locations near the perimeter of the fire zone and there are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial barriers. The bottom of this fire zone is the solid concrete floor of the steam generator compartment. Up to an elevation of more than 17 feet above the operating deck the fire zone is enclosed by walls with a concrete thickness of more than one foot, except for access passageways from the vertical access area (fire zone 1100 AF 11204) and the maintenance floor (fire zone 1100 AF 11300B). Above the top of these concrete walls, the fire zone is open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the steam generator into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

The redundant reactor coolant system hot leg/cold leg instrumentation located in fire zone 1100 AF 11301 are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four divisions of reactor coolant system/reactor coolant pump bearing water temperature instrumentation are assumed to be disabled and would not be available to detect and provide a trip signal on a loss of component cooling water to the pump. If the fire in this fire zone does not disable the pump, the component cooling water flow to the pump will be unaffected by the fire and will continue to provide cooling water to the pump bearings until the pump is tripped by other means.

The reactor coolant system reactor coolant pump shaft speed instruments are conservatively assumed to be disabled. The redundant reactor coolant system flow instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11300B are sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.11 Fire Zone 1100 AF 11303

This fire zone is comprised of the following room(s):

Room No.	
11303	Lower pressurizer compartment
11304	Steam generator 1 access room
11503	Upper pressurizer compartment

Safe Shutdown Evaluation

There are no safe shutdown components located in this fire zone.

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of the cable insulation for the pressurizer heaters. There are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial barriers. The bottom of this fire zone is solid concrete except for floor grating in the steam generator 1 access room (above fire zone 1100 AF 11301). Up to an elevation more than 33 feet above the operating deck this fire zone is enclosed by walls with a minimum concrete thickness of more than one foot, except for access passageways to and from the steam generator 1 compartment (fire zone 1100 AF 11301) and a closed doorway from the maintenance floor (fire zone 1100 AF 11300B). Several feet above the top of these walls, a steel platform separates the top this fire zone from fire zone 1100 AF 11303A directly above. Between the top of the walls and this platform the sides of this fire zone are open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the pressurizer into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.12 Fire Zone 1100 AF 11303A

This fire zone is comprised of the following room(s):

Room No.	
11603	Lower automatic depressurization system valve area

Safe Shutdown Evaluation

There are no safe shutdown components located in this fire zone that are required to operate as a result of a fire.

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of the cable insulation for the automatic depressurization system valves. There are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers. The floor is a thick structural steel plate that provides separation from the pressurizer compartment (fire zone 1100 AF 11303). The ceiling is a thick structural steel plate that provides separation from the upper automatic depressurization system valve area (fire zone 1100 AF 11303B). The sides of this fire zone are open to the large containment air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone are deflected horizontally by the ceiling into the surrounding air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.13 Fire Zone 1100 AF 11303B

This fire zone is comprised of the following room(s):

Room No.	
11703	Upper automatic depressurization system valve area

Safe Shutdown Evaluation

There are no safe shutdown components located in this fire zone that are required to operate as a result of a fire.

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is very low, consisting primarily of the cable insulation for the automatic depressurization system valves. There are no significant cable concentrations. The floor of this fire zone is a thick structural steel plate that provides separation from the lower automatic depressurization system valve area (fire zone 1100 AF 11303A). The top and sides of this fire zone are open to the large containment air space above the operating deck (fire zone 1100 AF 11500), which has no nearby combustibles. A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise into the large air space in the upper portion of containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.14 Fire Zone 1100 AF 11500

This fire zone is comprised of the following room(s):

Room No.

11500	Operating deck
11504	Refueling cavity

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separates this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation. There are small concentrations of cables in horizontal raceways around the circumference of this fire zone high above the operating deck, in vertical raceways at separate locations near the boundaries of this fire zone, and at the center of the fire zone in the vicinity of

the reactor vessel integrated head package. This fire zone encompasses much of the containment. It is physically separated from fire zones below by the operating deck or the bottom of the refueling cavity, which have a concrete thicknesses of more than one foot, except for penetrations described in the evaluations of fire zones below this fire zone. There also is a few inch clearance annulus around the entire operating deck. The walls of this fire zone are the steel containment vessel or walls with a concrete thickness of more than one foot, with exceptions as described earlier for fire zones 1100 AF 11301, 1100 AF 11302, 1100 AF 11303, and 1100 AF 11303A & B. The boundary of this fire zone also includes the 3-hour fire barriers that protect the division B and D containment penetrations on elevation 107'-2" and the associated raceways from these penetrations up to the operating deck. A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise into the large air space above the operating deck. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

Control of all division B and D components in the containment is conservatively assumed to be disabled. The primary division A and C electrical cables that provide power supply to safe shutdown components in containment are located in 1100 AF 11300B and are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The in-core instrumentation system core exit temperature instrument termination cabinets located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The reactor coolant system hot leg temperature (wide range) instrumentation located in fire zones 1100 AF 11301 and 1100 AF 11302 provide a diverse means of observing temperature conditions in the reactor vessel to support the safe shutdown process.

The reactor coolant system narrow range level instrumentation is conservatively assumed to be disabled. The redundant reactor coolant system narrow range level instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The central chilled water system containment isolation valve located outside the containment fire area is redundant to the containment isolation valve inside containment in this fire zone and is sufficient to perform the applicable functions to maintain containment integrity.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.15 Fire Zone 1200 AF 12341

This fire zone is comprised of the following room(s):

Room No.

12341 Middle annulus

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation in the non-Class 1E electrical penetration assemblies, located in the northeast quadrant of the fire zone. The Class 1E electrical penetration assemblies also pass through this fire zone, but are enclosed by 3-hour fire barriers and are considered extensions of the associated Class 1E divisional fire areas on the other side of the shield building wall. This fire zone is physically separated from other fire zones by the steel wall of containment and by the steel and concrete vessel stiffener and flexible ventilation seal above, and it is separated from adjacent fire areas by the walls and floor of the shield building, which have concrete thicknesses of more than one foot, and the 3-hour fire barriers enclosing the Class 1E electrical penetrations. The access doorway to the middle annulus fire zone is closed by a door.

The radiologically controlled area ventilation system serves this fire area on a once-through basis. Smoke and hot gases are confined in this fire zone following automatic closure of the fire dampers on high temperature, while the balance of the radiologically controlled area ventilation system continues to operate at the discretion of the operator. There is no propagation of the fire beyond this fire zone. Smoke and gases are removed from the fire zone by reopening the fire dampers after a fire. The radiologically controlled area ventilation system exhausts the smoke and gases to the atmosphere.

There are no safe shutdown components in this fire zone. The Class 1E electrical penetrations are separated from this fire zone by 3-hour fire barriers and are part of the associated divisional fire areas outside the shield building.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.16 Fire Zone 1200 AF 12541

This fire zone is comprised of the following room(s):

Room No.

12541 Upper annulus

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is extremely low, consisting primarily of cable insulation. There are no cable concentrations. This fire zone is physically separated from other fire zones by the steel wall of containment and the steel and concrete vessel stiffener and flexible ventilation seal below, and it is separated from adjacent fire areas by the walls of the shield building, which have a concrete thickness of more than one foot. Access doorways are closed by doors. The physical separation between this fire zone and fire zone 1270 AF 12701 are described in the evaluation for that zone. This fire zone communicates with the environment via the passive containment cooling system air inlets at the top perimeter of the shield building and the passive containment cooling system air outlet at the center of the shield building roof. These openings have screens that prevent the entry of external debris.

Smoke and hot gases from a fire in this fire zone rise to the top of the fire zone and into the atmosphere and thus do not cause propagation of a fire beyond this fire zone.

The safe shutdown components in this fire zone are the Division B and C electrical cables that serve the redundant passive containment cooling system valves and instruments located in the passive containment cooling system valve room. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable these safe shutdown valves and instruments.

The valves for each passive containment cooling system water delivery path are arranged with a normally open motor-operated valve and normally closed/fail open air-operated valve in series. If the fire causes a loss of power to the valves, the air-operated valves will open and passive containment cooling system flow, which has no adverse impact on achieving and maintaining safe shutdown, will be initiated. Refer to subsection 9A.3.7.1.2 for a discussion of potential spurious actuation of a passive containment cooling system water delivery valve as a result of a fire.

The passive containment cooling system water delivery flow and storage tank level instrumentation are conservatively assumed to be disabled as a result of a fire in this fire zone. The applicable function of verification of passive containment cooling system water delivery can be performed by visual observation via access to the passive containment cooling system air diffuser from the passive containment cooling system valve room.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.17 Fire Zone 1270 AF 12701

This fire zone is comprised of the following room(s):

Room No.	
12701	Passive containment cooling system valve room
S06	Stairwell

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation related to the valves and instruments in this fire zone. There are no cable concentrations. This fire zone is physically separated from fire zone 1200 AF 12541 by structural partitions and closed doorways.

In the unlikely event of a fire, the fire brigade would approach the PCS valve room (Room 12701, Fire Zone 1270 AF, Fire Area 1000 AF 01) by using stairwell S03 or the adjacent elevator attached to the outside wall on the shield building. The fire brigade would egress from stairwell S03 (Fire Area 1204 AF 02) into the lower level of the PCS valve room (Room 12701) at the El. 264′-6″ platform (Fire Zone 1270 AF, Fire Area 1000 AF 01). Two types of portable fire extinguishers (a dry chemical and a water fire extinguisher) are provided at this lower level for manual fire fighting. The fire brigade would proceed up the inclined stairs S06 to the upper level of the PCS valve room (Room 12701) located on El. 286′-6″. Two types of portable fire extinguishers (a dry chemical and a water fire extinguisher) are also provided at this upper level for manual fire fighting.

Smoke and hot gases from a fire in this fire zone are exhausted by normal operation of the room exhaust fan to fire zone 1200 AF 12541, where they rise through openings in the top of that fire zone into the atmosphere. There are no combustible materials in the vicinity of the exhaust location and thus the smoke and hot gases do not cause propagation of a fire beyond this fire zone. If the exhaust fan is disabled by the fire, smoke and gases are later removed using portable fans and ductwork.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although it is unlikely that all components would be damaged, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown valves and instruments in this fire zone.

The valves for each passive containment cooling system water delivery path are arranged in three flow paths. Two paths have a normally open motor-operated valve and normally closed/fail open air-operated valve in series. The third path has a normally open motor-operated and a normally closed motor operated valve in series. If the fire causes a loss of power to the air-operated valves, they will open and passive containment cooling system flow, which has no adverse impact on achieving and maintaining safe shutdown, will be initiated. Refer to

subsection 9A.3.7.1.2 for a discussion of potential spurious actuation of a passive containment cooling system water delivery valve as a result of a fire.

The passive containment cooling system water delivery flow and storage tank level instrumentation are conservatively assumed to be disabled as a result of a fire in this fire zone. The applicable function of verification of passive containment cooling system water delivery can be performed by visual observation via access to the passive containment cooling system air diffuser from the passive containment cooling system valve room or from the upper annulus.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.18 Fire Zone 1250 AF 12555

This fire zone is comprised of the following room(s):

Room No.	
12555	Main control room emergency habitability system air storage/operating deck staging area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is normally low, consisting primarily of cable insulation, but concentrations of transient combustibles may be present in the floor area outside the main equipment hatch. This fire zone is separated from adjacent fire areas by 3-hour fire barriers and it is separated from adjacent containment fire zones 1100 AF 11500 and 1200 AF 12541 by the main equipment hatch and its enclosure and the shield building wall, which has a concrete thickness of more than one foot.

Smoke and hot gases from a fire are confined in this fire zone following automatic closure of the fire dampers on high temperature and thus do not cause propagation of the fire beyond this fire zone. Smoke and gases are removed from the fire area by reopening the fire dampers after a fire. The radiologically controlled area ventilation system exhausts the smoke and gases to the atmosphere.

This fire zone contains no components required for safe shutdown after a fire. The pressurized main control room emergency habitability system air storage bottles are not required for safe shutdown after a fire, but are protected from fire-induced overpressure by pressure relief valves.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2 Auxiliary Building - Nonradiologically Controlled Areas

General Arrangement

The safe shutdown systems and components located in the nonradiologically controlled area are portions of the protection and safety monitoring system and the Class 1E dc system, and containment isolation.

The safe shutdown components in the protection and safety monitoring system are the instrumentation and control cabinets located in the nonradiologically controlled area on level 3 (elevation 100′-0″). The safe shutdown components in the Class 1E dc system are the Class 1E batteries on level 1 (elevation 66′-6″) and level 2 (elevation 82′-6″) and the dc electrical equipment, also on level 2.

The nonradiologically controlled areas of the auxiliary building are designed to provide separation between the mechanical and electrical equipment areas.

The piping compartments in the nonradiologically controlled area are the main steam isolation valve compartments on levels 4 and 5 (elevations 117′-6″ and 135′-3″, respectively) and the valve/piping penetration compartment on level 3 (elevation 100′-0″). The mechanical equipment rooms in the nonradiologically controlled area are the HVAC compartments on levels 4 and 5.

The nonradiologically controlled areas of the auxiliary building are also designed to provide separation between the Class 1E and the non-Class 1E electrical equipment.

Smoke Control

Table 9A-4 identifies the ventilation systems serving fire areas containing Class 1E electrical components. This section describes the approach to smoke control for fire areas in the nonradiologically controlled portion of the auxiliary building that contain the main Class 1E electrical equipment rooms served by the nuclear island nonradioactive ventilation system (VBS). Smoke control for fire areas containing other Class 1E components, such as valves, instrumentation and electrical cable, is discussed in the text for the individual fire areas.

The Class 1E electrical equipment room fire areas have been designed to prevent the migration of smoke, hot gases, and fire suppressant to the extent that they could adversely affect safe shutdown capabilities, including operator actions. These fire areas are separated from each other and from other plant areas by 3-hour fire barriers. Smoke from a fire in the turbine building or other nearby fire areas is prevented from affecting the Class 1E areas by isolation of the nuclear island nonradioactive ventilation system outdoor air intakes, as described in subsection 9.4.1.

The nuclear island nonradioactive ventilation system is designed to control the migration of smoke and hot gases produced by a fire. As described in subsection 9.4.1, two independent ventilation subsystems, located in separate fire areas, serve the Class 1E electrical equipment rooms. The division A and C Class 1E electrical room HVAC subsystem has three distribution headers. One header supplies the two division A electrical equipment room fire areas, a second header supplies the division C electrical equipment room fire area, and a third header supplies other related fire areas. The division B and D class 1E electrical room HVAC subsystem also has

three distribution headers. One header supplies the division B electrical equipment room fire area, a second header supplies the division D electrical equipment room fire area, and a third header supplies other related fire areas.

A fire affecting a division A or C electrical equipment room fire area does not affect operation of the ventilation subsystem serving the division B & D electrical equipment room fire areas and vice versa. In addition, a fire affecting an electrical equipment room fire area affects the operation of only one of the three distribution headers in the subsystem. As described in subsection 9.4.1.2.3.2, the affected subsystem continues to provide ventilation to the remaining fire areas served by the other two distribution headers.

Similarly, the ventilation subsystem serving the main control room and the ventilation subsystem serving the remote shutdown room operate independently of each other and are located in separate fire areas. A fire affecting the main control room does not affect operation of the ventilation subsystem serving the remote shutdown room and vice versa.

The migration of smoke and hot gases produced by a fire occurring in a Class 1E electrical equipment room fire area is controlled by operation of the nuclear island nonradioactive ventilation system as described in subsection 9.4.1.2.3. Further information on smoke control is provided in the discussions for the individual fire areas.

9A.3.1.2.1 Division A Electrical Rooms

9A.3.1.2.1.1 Fire Area 1202 AF 04

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1212 AF 12101	12101	Division A battery room
• 1222 AF 12201	12201	Division A dc equipment room
• 1232 AF 12301	12301	Division A instrumentation and control room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to

provide ventilation to the unaffected fire areas, which includes the Division C fire area (1202 AF 03). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Backdraft dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control room, to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment in this fire area. There are concentrations of battery cells on opposite walls of the battery room fire zone. There are small concentrations of cable in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located in the middle of the instrument and control room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The three fire zones in this fire area are separated from each other by 1-hour fire barriers, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. These division A electrical rooms are physically separated from the other safety-related divisions and by 3-hour fire barriers. In the event of a fire in one of these rooms, it is assumed that control of all division A components is lost. Because of the physical separation, the fire does not adversely affect the other

safety-related electrical divisions. For this event, the division B, C, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in the instrumentation and control room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the passive residual heat removal heat exchanger inlet isolation valve is normally locked out at power to prevent spurious closing.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.1.2 Fire Area 1242 AF 02

This fire area is comprised of the following room(s):

Room No.

12412	Electrical penetration room division A

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division C electrical penetration room (in fire area 1202 AF 03). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the containment electrical penetrations. There are small concentrations of cable at the electrical penetrations and in the overhead cable trays. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The division A penetration room is physically separated from the other safety-related divisions and nonsafety-related equipment by 3-hour fire barriers. In the event of a fire in this room, it is assumed that control of all division A active components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this

event, the division B, C, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Following detection of a fire in this fire area, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the penetration room.

Power to the passive residual heat removal heat exchanger inlet isolation valve is normally locked out at power to prevent spurious closing.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.2 Division B Electrical Rooms

9A.3.1.2.2.1 Fire Area 1201 AF 02

This fire area contains division B electrical rooms. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1211 AF 12104	12104	Division B battery room 1
• 1221 AF 12204	12204	Division B battery room 2
• 1222 AF 12207	12207	Division B dc equipment room
• 1231 AF 12304	12304	Division B instrumentation and control/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division D fire area (1201 AF 03). The system may be manually realigned to the once-through ventilation mode to

minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Backdraft dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control/penetration room, to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector, which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of each of the two battery room fire zones. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead, at the electrical penetrations, and in the electrical cabinets located in the middle of the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery rooms are also separated from the adjacent division B electrical rooms by 1-hour fire barriers, and the dc equipment room is separated from adjacent division B electrical rooms by 1-hour fire barriers, which limit the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. Division B electrical rooms are physically separated from the other safety-related divisions and nonsafety-related

equipment by 3-hour fire barriers. In the event of a fire in a division B electrical room, it is assumed that control of all division B active components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this event, the division A, C, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in the instrumentation and control/penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control/penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the normal residual heat removal hot leg suction isolation valves is normally locked out at power to prevent spurious opening.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.2.2 Fire Area 1220 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1222 AF 12212	12212	Division B reactor coolant pump trip switchgear room
• 1222 AF 12213	12213	Spare room
• 1220 AF 12211	12211	Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, including the fire area for the division C trip switchgear room (1202 AF 03). Fire areas 1200 AF 03 and 1210 AF 01 are served by the same air distribution header as this fire area, but they continue to receive ventilation because they have separate supply ducts. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation. There are small concentrations of cable in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets in the reactor coolant pump trip switchgear room and spare room fire zones. There are small concentrations of cable overhead and at the east end of the corridor fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. See Section 3.4 for a discussion of the consequences of a break in a fire protection line in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. A fire in this fire area is assumed to disable the safe shutdown components in the fire area.

The reactor coolant pumps can be tripped by the redundant division C reactor coolant pump trip switchgear, located in fire area 1202 AF 03. The division B and D cable tray in the fire area includes signals to the reactor trip switchgear and inputs to other division protection logic. Inputs from divisions A and C are sufficient to trip the reactor when needed, or the reactor can be tripped manually. Loss of division B and D data input to the division A and C protection logic does not disable the safe shutdown functions of the four Class 1E divisions.

Cable trays in the fire areas include signals to B and D isolation valves outside containment. Containment isolation is provided by redundant containment isolation valves, located in another fire area inside containment. Redundant division C valves control water flow from the passive containment cooling system storage tank. The components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.3 Division C Electrical Rooms

9A.3.1.2.3.1 Fire Area 1202 AF 03

This fire area contains division C electrical rooms. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1212 AF 12102	12102	Division C battery room 1
• 1222 AF 12202	12202	Division C battery room 2
• 1222 AF 12203	12203	Division C dc equipment room
• 1232 AF 12302	12302	Division C instrumentation and control room
• 1232 AF 12312	12312	Division C reactor coolant pump trip switchgear room
• 1232 AF 12313	12313	Instrumentation and control/division C penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division A fire area (1202 AF 04). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Backdraft dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control room, and in the supply duct to the penetration room, to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of each of the two battery room fire zones. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located in the middle of the instrument and control room fire zone. There are small concentrations of cable overhead and at the electrical penetrations in the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery rooms are also separated from the adjacent division C electrical rooms by 1-hour fire barriers, and the dc equipment room is separated from adjacent division C electrical rooms by 1-hour fire barriers, which limit the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. Division C electrical rooms are physically separated from the other safety-related divisions and nonsafety-related equipment by 3-hour fire barriers. In the event of a fire in a division C electrical room, it is assumed that control of all division C components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. The reactor coolant pumps can be tripped by the redundant division B reactor coolant pump trip switchgear, located in fire area 1220 AF 01. For this event, the division A, B, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in either the instrumentation and control room or the instrumentation and control/division C penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control room or the instrumentation and control/division C penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.4 Division D Electrical Rooms

9A.3.1.2.4.1 Fire Area 1201 AF 03

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1211 AF 12105	12105	Division D battery room
• 1221 AF 12205	12205	Division D dc equipment room
• 1231 AF 12305	12305	Division D instrumentation and control/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division B fire area (1201 AF 02). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Backdraft dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control/penetration room, to delay smoke migration between these fire zones and facilitate operator action to preclude certain postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of the battery room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead, at the electrical penetrations, and in the electrical cabinets located in the middle of the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The three fire zones in this fire area are separated from each other by 1-hour fire barriers, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. These division D electrical rooms are physically separated from the other safety-related divisions by 3-hour fire barriers. In the event of a fire in one of these rooms, it is assumed that control of all division D components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this event, the division A, B, and C components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in the instrumentation and control/penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor

operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control/penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the normal residual heat removal hot leg suction isolation valves is normally locked out at power to prevent spurious opening.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5 Principal Class 1E Areas

9A.3.1.2.5.1 Fire Area 1242 AF 01

This fire area consists of the main control room. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1242 AF 12401A	12401	Main control area/tagging room/vestibule
• 1242 AF 12401B	12401	Shift supervisor/clerk/operator area

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors (including detectors in the subfloor spaces)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by the main control room/technical support center HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

Since the main control room is continuously manned, a fire is likely to be initially detected by an operator. Otherwise, a fire in this fire area is detected by a fire detector, which produces visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using portable extinguishers or, if necessary, using hose streams.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and paper. There are concentrations of cable under the floor in the north and east portions of this fire area and within the control consoles and display panels in the main control area. There are concentrations of paper in the main control area, the tagging room and offices. Most of this paper is contained within metal filing cabinets, desks, or bookcases. This is a light hazard fire area and the rate of fire growth is expected to be slow. The fire area is continuously manned and prompt manual fire suppression is expected.

Generally, three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. Due to the need to provide passive cooling capability into the main control room ceilings, it will not be protected against fires from within the main control room. The ceiling will be a fire barrier from fires in the room above the main control room.

The two fire zones are also separated from each other by a 1-hour fire barrier, which limits the spread of fire within the fire area. Within fire zone 1242 AF 12401A the wall that separates the main control area from the tagging room is not fire-rated because it does not extend to the ceiling. This design improves the ceiling heat-absorbing characteristics provided for post-accident main control room habitability.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The main control room contains circuits from the four Class 1E electrical divisions. Electrical separation to and inside the control panels is maintained per industry standards. The remote shutdown workstation is provided as an alternate to the main control room. The transfer of operations to the remote shutdown workstation is controlled by a transfer switch located outside the main control room. In the event of a fire in the main control room, control may be transferred to the remote shutdown workstation, depending on the extent of the fire. For a small fire, control is maintained in the main control room, and the potential for damage or spurious signals is limited. For larger postulated fires, the main control room is evacuated and control is transferred to the remote shutdown workstation. Once control is transferred, spurious control signals potentially caused by the fire are isolated from

the actuated devices by the transfer switch. In this event, the main control room is assumed to be lost for the duration of the event. Safe shutdown is controlled from the remote shutdown workstation. The extent of spurious signals is limited by the time to transfer control to the remote shutdown workstation.

Most control room controls use soft-controls which communicate over multiplexed data channels. Fire-induced spurious actuation from these multiplexed soft controls is not assumed.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation. Following control room evacuation, the dedicated switches are disabled by the transfer switch.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5.2 Fire Area 1232 AF 01

This fire area is comprised of the following room(s):

Room No.	
12303	Remote shutdown room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, except for adjacent stairwell fire area 1202 AF 05 which is ventilated via this fire area. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other

ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and paper. There are concentrations of cable under the floor and within the control console. There are concentrations of paper, most of which is contained within metal filing cabinets or bookcases. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The remote shutdown room contains circuits from the four Class 1E electrical divisions. Electrical separation to and inside the remote shutdown room is maintained per industry standards. The remote shutdown room is an alternate to the main control room. The transfer of operations to the remote shutdown workstation is controlled by a transfer switch set located in the remote shutdown workstation area. In the unlikely event that the fire damages the transfer switch set, causing transfer of control from the main control room to the remote shutdown workstation, the operator restores control to the main control room by de-energizing the remote shutdown multiplexer cabinets in the instrumentation and control rooms. Safe shutdown is achieved using the safe shutdown components listed in Table 9A-2.

Most remote shutdown workstation controls use soft-controls which communicate over multiplexed data channels. Fire-induced spurious actuation from these multiplexed soft controls is not assumed.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5.3 Fire Area 1243 AF 01

This fire area is comprised of the following room(s):

Room No.	
12423	Reactor trip switchgear 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the reactor trip switchgear, located in the center of this small fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. This fire area contains cable from each of the four Class 1E electrical divisions. This cable provides trip input from each of the four divisions and is separated per industry standards. The safety-related trip inputs are normally energized, so a fire in this area may result in a reactor trip. In the event the fire generates multiple hot shorts, interfering with the reactor trip signal, a reactor trip can be produced in the redundant trip cabinets located outside of this fire area in fire area 1243 AF 02. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

This fire does not affect other equipment in the Class 1E divisions. Therefore, the safe shutdown components listed in Table 9A-2 are available to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.5.4 Fire Area 1243 AF 02

This fire area is comprised of the following room(s):

Room No.

12422 Reactor trip switchgear 2

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or

high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the reactor trip switchgear, located in the center of this small fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. This fire area contains cable from each of the four Class 1E electrical divisions. This cable provides trip input from each of the four divisions and is separated per industry standards. The safety-related trip inputs are normally energized, so a fire in this area may result in a reactor trip. In the event the fire generates multiple hot shorts, interfering with the reactor trip signal, a reactor trip can be produced in the redundant trip cabinets located outside of this fire area in fire area 1243 AF 01. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

This fire does not affect other equipment in the Class 1E divisions. Therefore, the safe shutdown components listed in Table 9A-2 are available to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.5.5 Fire Area 1210 AF 01

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1210 AF 12111	12111	Corridor
• 1212 AF 12103	12103	Spare battery room
• 1212 AF 12112	12112	Spare room
• 1212 AF 12113	12113	Spare battery charger room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, except for fire area 1220 AF 01 which is ventilated by ducts that are isolated by a fire in this fire area. The ventilation system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

If the spare batteries are being used as a backup power source for any division, a fire in this fire area is assumed to disable that division. Smoke from a fire in this fire area does not adversely affect components associated with divisions redundant to that supplied by the spare battery. Fire area 1200 AF 03 is served by the same air distribution header as this fire area, but it continues to receive ventilation because it has a separate supply duct. Fire area 1220 AF 01 is isolated by combination fire-smoke dampers in response to a smoke detector signal. The division B reactor

trip switchgear and the division B and D electrical cable in this fire area is not sensitive to the small quantity of smoke that may leak into this fire area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the spare batteries and the spare battery charger. There are concentrations of battery cells on opposite walls of the spare battery room fire zone. There are small concentrations of cable along the north wall of the spare battery charger room fire zone. There are assumed to be small concentrations of ordinary combustibles in the spare room. There are small concentrations of cable overhead in the eastern portion of corridor fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery room is also separated from the other fire zones within this fire area by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The spare batteries may be connected as a backup power source for any one of the four Class 1E electrical divisions. The terminations of the cables to these divisions from the spare batteries are not normally energized or connected, so a fire in this area has no impact on the unconnected divisions. If the spare batteries are being used as a backup to a Class 1E division, then the consequence of a fire in this area is the same as a fire in the battery room of the division to which they are connected.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.6 Non-Class 1E Electrical Rooms

9A.3.1.2.6.1 Fire Area 1230 AF 02

The fire area is comprised of the following room:

Room No.

12321 Non-Class 1E equipment/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Preaction sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the preaction sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are small concentrations of cable overhead, at the electrical penetrations, and at the electrical cabinets located along the east and west walls of room 12321. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. An automatic suppression system is provided to increase the availability of non-safety related systems required to achieve cold shutdown.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system in this fire area is considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division B and D cables are routed through this area. In the event of a fire, the division B and D cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions B and D are not affected.

This fire can also disable the division B and D inputs to the reactor trip switchgear. The signals from the remaining two divisions are sufficient to trip the reactor. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

Spurious DAS actuation of squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire area. No postulated fire can spread to the hot short locations before the operator can remove power from the fire area.

Following detection of a fire in the non-Class 1E equipment/penetration room, the operators can close the automatic depressurization system stage 4 block valves, then remove DAS actuation power. This operator action will prevent spurious actuation of squib valves resulting from multiple hot shorts in the non-Class 1E equipment/penetration room.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.6.2 Fire Area 1240 AF 01

The fire area is comprised of the following room:

Room No.	
12421	Non-Class 1E equipment/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are small concentrations of cable overhead, at the electrical penetrations, and at the RCC rod control cabinets in the southern portion of room 12321. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected.

This postulated fire can disable control of the division A containment isolation valves outside containment. For this event, containment isolation is provided by the redundant containment isolation valves located inside containment outside of this fire area.

Such a fire can also disable control of the divisions A and C passive containment cooling system isolation valves. The redundant division B passive containment cooling system isolation valves are not affected. Therefore, the safe shutdown capability of the passive containment cooling system is maintained.

This fire can also disable the division A and C inputs to the reactor trip switchgear. The signals from the remaining two divisions are sufficient to trip the reactor. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7 Mechanical/Piping Areas

9A.3.1.2.7.1 Fire Area 1201 AF 04

This fire area consists of two nuclear island nonradioactive ventilation system equipment rooms servicing divisions B and D equipment rooms. Division B and D safe shutdown equipment is located within the fire area. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1241 AF 12405	12405	Lower nuclear island nonradioactive ventilation system divisions B and D equipment room (117′-6″)
• 1251 AF 12505	12505	Upper nuclear island nonradioactive ventilation system divisions B and D equipment room (135′-3″)

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area houses and is served by the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these fire dampers interrupts the operation of the division B & D Class 1E electrical room HVAC subsystem. Operation of the independent division A & C Class 1E electrical room HVAC subsystem continues unaffected. Smoke is

subsequently removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems and subsystems. The division A and C electrical cables in fire area 1230 AF 01 are unaffected by the small quantity of smoke that may leak into that fire area. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of electrical cable insulation for cables supplying fans and valves within this fire area. There are cable concentrations overhead and in the west half of each fire zone. This is an light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is conservatively assumed to disable control of all division D active components, as well as the compressed and instrument air system, component cooling water system, passive core cooling system and central chilled water system containment isolation valves within the fire area. The redundant containment isolation valves in the lines for the compressed and instrument air system, component cooling water system, passive core cooling system and central chilled water system are located inside the containment (fire area 1000 AF 01) are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The redundant steam generator 1 steam line pressure instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The steam generator system steam generator 1 startup feedwater flow instrumentation is assumed to be disabled. The steam generator system steam generator 1 wide range level instrumentation located in fire zone 1100 AF 11300B provides a diverse means of performing the applicable

function of generating a passive residual heat removal actuation signal to achieve and maintain safe shutdown.

The redundant steam generator 2 steam line pressure instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The steam generator system steam generator 2 startup feedwater flow instrumentation is assumed to be disabled. The steam generator system steam generator 2 wide range level instrumentation located in fire area 1000 AF 01 provides a diverse means of performing the applicable function of generating a passive residual heat removal actuation signal to achieve and maintain safe shutdown.

The remaining division A, B and C components located in other fire areas are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.2 Fire Area 1201 AF 05

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1241 AF 12506	12406	Lower main steam isolation valve compartment A
	12506	Upper main steam isolation valve compartment A
• 1231 AF 12306	12306	Valve/piping penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Each of the two fire zones in this fire area is served by independent air handling units of the annex/auxiliary buildings nonradioactive HVAC system (VXS), located within the fire zones served. No ventilating system ducts penetrate the MSIV compartment fire zone. One supply duct enters the valve piping penetration room from the turbine building. A fire damper in this duct closes automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke

from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the motor-operated valves, fans and other components in this fire area. Small quantities of lubricating oil are contained within the housings of some of these components. There are small concentrations of cable overhead in each room. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The recirculation type ventilation system does not contribute to the spread of the fire or smoke to other fire areas.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is assumed to disable the safe shutdown components in the fire area. The redundant chemical and volume control system containment isolation valves located inside containment outside of this fire area are sufficient to perform the applicable functions to maintain containment integrity. The steam generator, main steam line, feedwater line, and blowdown line piping located inside containment outside of this fire area is sufficient to perform the applicable functions to maintain containment integrity.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.3 Fire Area 1201 AF 06

This fire area is comprised of the following room(s):

Room No.

12404	Lower main steam isolation valve compartment B
12504	Upper main steam isolation valve compartment B

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by independent air handling units of the annex/auxiliary buildings nonradioactive HVAC system (VXS), located within the fire zones served. No ventilating system ducts penetrate the fire area. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the motor-operated valves, fans and other components in this fire area. Small quantities of lubricating oil are contained within the housings of some of these components. There are small concentrations of cable overhead in each room. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The recirculation type ventilation system does not contribute to the spread of the fire or smoke to other fire areas.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is assumed to disable the safe shutdown components in the fire area. The steam generator, main steam line, feedwater line, and blowdown line piping located inside containment outside of this fire area is sufficient to perform the applicable functions to maintain containment integrity.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.4 Fire Area 1250 AF 01

This fire area is comprised of the following room(s):

Room No.	
12501	Nuclear island nonradioactive ventilation system main control room/ division A and C equipment room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area houses and is served by the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these fire dampers interrupts the operation of the VBS division A & C Class 1E electrical room and the main control room/technical support center HVAC subsystems that are located in this fire area. Operation of the independent division B & D Class 1E electrical room HVAC subsystem continues unaffected. Smoke is removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. The division B reactor coolant pump trip switchgear and the division B and D electrical cable in fire areas 1200 AF 03 and 1220 AF 01 are unaffected by the small quantity of smoke that may leak into these fire areas. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector, which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. A fire in the fire area is extinguished manually using hose streams or portable extinguishers.

This fire area contains two charcoal adsorbers, located in the nuclear island nonradioactive ventilation system supplemental air filtration units. Fixed fire suppression systems are not required for these adsorbers because of the high charcoal ignition temperature. The normal temperature of the air flowing through the charcoal adsorbers is well below 200°F, while the minimum charcoal ignition temperature is greater than 600°F. Two independent temperature sensors interface with the fire detection system, providing charcoal temperature indication and high and high-high temperature alarms. The filtration unit fan trips at the high temperature alarm setpoint. The setpoints of both alarms are well below the charcoal ignition temperature, allowing the operator time to investigate and take corrective action. In the unlikely event of a fire in the adsorber, the filtration unit can be manually isolated and sprayed with water from a nearby hose station to cool the charcoal and extinguish the fire.

Combustible materials in this fire area are listed in Table 9A-3. Aside from the charcoal contained within the air filtration units, these materials primarily consist of electrical cable insulation for cables supplying fans and pumps within this fire area. There are cable concentrations near the ceiling and adjacent to the west wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Generally, three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. Fire barrier separation is not provided between the main control room and this fire area from fires in the main control room. There are no safe shutdown components in this room. There is fire barrier separation between the main control room and this fire area for fires originating in this area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

This fire area contains no components required for safe shutdown after a fire. No safe shutdown evaluation is required.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8 Miscellaneous Areas

9A.3.1.2.8.1 Fire Area 1230 AF 01

This fire area is comprised of the following room(s):

Room No.

12300 Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these dampers interrupts ventilation of adjacent fire areas 1201 AF 02 (division B electrical rooms), 1202 AF 05 (stair S05), and 1232 AF 01 (remote shutdown room) because their ducts are routed through this corridor. The ventilation system continues to provide ventilation to other unaffected fire areas, and may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of small quantities of cable insulation for cables routed overhead through the fire area. This is a light

hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The Class 1E divisions A and C cables for data communication between divisions are in this fire area.

In the event of a fire in the division A and C corridor, it is assumed that data output from divisions A and C to the division B and D protection logic is lost. This loss of data does not disable the safe shutdown functions of the four Class 1E divisions.

The division A and C instrument cables serving safe shutdown components are assumed to be disabled. The division B and D instrument cables routed outside of this fire area that serve redundant safe shutdown components are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8.2 Fire Area 1201 AF 01

This fire area is comprised of the following room(s):

Room No.	
S02	Stairwell

The stairwell serving the northwest portion of the auxiliary building is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. There are no safe shutdown components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

This fire area is served by the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Air at a positive pressure is supplied near the top of the stairwell and exfiltrates through an opening near the bottom of the stairwell. During a fire, the pressure difference across the doors in the stairwell is maintained in accordance with the guidance of NFPA 92A (Reference 4), using a dedicated stairwell pressurization fan.

9A.3.1.2.8.3 Fire Area 1202 AF 01

This fire area is comprised of the following room(s):

Room No.	
S01	Stairwell

The stairwell serving the northeast portion of the auxiliary building is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

This fire area is served by the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Air at a positive pressure is supplied near the top of the stairwell and exfiltrates through an opening near the bottom of the stairwell. During a fire, the pressure difference across the doors in the stairwell is maintained in accordance with the guidance of NFPA 92A (Reference 4), using a dedicated stairwell pressurization fan.

9A.3.1.2.8.4 Fire Area 1202 AF 05

This fire area is comprised of the following room(s):

Room No.	
S05	Stairwell

The stairwell provides an emergency egress path from the main control room to the emergency shutdown workstation. It is enclosed by 3-hour fire barriers. These barriers are made of concrete. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

This fire area is served by the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Air at a positive pressure is supplied to the stairwell and exfiltrates through an opening to neighboring fire area 1232 AF 01, the remote shutdown room. For a fire in the remote shutdown room fire area, combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, and may be manually realigned to the

once-through ventilation mode to further minimize the potential for migration of smoke and hot gases.

9A.3.1.2.8.5 Fire Area 1202 AF 02

This fire area contains an elevator and elevator shaft serving five levels on the north side of the auxiliary building, and the associated elevator mechanical room, 12601. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detector
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

No ventilation system serves this fire area. The nuclear island nonradioactive ventilation system provides ventilation to neighboring fire areas, and may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery. There are small concentrations of these materials in the elevator mechanical room at the top of the elevator shaft. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

Safe Shutdown Evaluation

This fire area contains no components required for safe shutdown after a fire. No safe shutdown evaluation is required.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8.6 Fire Area 1200 AF 03

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1230 AF 12311	12311	Elevation 100′-0″ corridor
• 1242 AF 12411	12411	Elevation 117′-6″ corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas. Fire areas 1220 AF 01 and 1210 AF 01 are served by the same air distribution header as this fire area, but they continue to receive ventilation because they have separate supply ducts. The ventilation system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of small quantities of cable insulation for cables routed overhead in each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. Class 1E divisions B and D cables are routed through this corridor.

The division B and D control cables to the reactor trip switchgear are assumed to be disabled. Inputs from divisions A and C, which are routed in a separate fire area, are sufficient to trip the reactor when needed. The reactor can also be tripped with the diverse actuation system described in Section 7.7.

The division B and D instrument and control cables serving other safe shutdown components are assumed to be disabled. The instrument and control cables routed outside of this fire area that serve redundant safe shutdown components are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3 Auxiliary Building - Radiologically Controlled Areas

The safe shutdown components located in the radiologically controlled areas are primarily containment isolation valves, which are located near the containment vessel in the lower annulus. Containment isolation valves are also located in the pipe chases southeast of containment. These containment isolation valves are required to either close or remain closed during a safe shutdown operation.

9A.3.1.3.1 Principal Areas

9A.3.1.3.1.1 Fire Area 1200 AF 01

This fire area includes most of the radiologically controlled areas of the auxiliary building outside the fuel handling area. This fire area contains one of the two normal residual heat removal pumps and the heat exchangers, the liquid radwaste system, spent fuel pool cooling system, radiologically controlled area ventilation system, chemical and volume control system makeup pump,

containment isolation valve area, and lower annulus areas. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1200 AF 12241	12241	Lower annulus east
• 1200 AF 12241	12242	Lower annulus southeast
• 1200 AF 12461	12461	Corridor
• 1205 AF 12362	12362	Normal residual heat removal heat exchanger room
• 1205 AF 12365	12365	Waste monitor tank room B
• 1210 AF 12151	12151	Demineralizer/filter room
• 1210 AF 12151	12155	Gaseous radwaste system equipment room
• 1210 AF 12151	12156	Liquid radwaste system equipment room
• 1210 AF 12151	12158	Degasifier discharge pump room
• 1210 AF 12151	12258	Degasifier column
• 1210 AF 12171	12171	Effluent holdup tank room A
• 1214 AF 12152	12152	Primary sample room
• 1214 AF 12154	12154	Auxiliary building sump room
• 1214 AF 12154	12254	Spent fuel pool cooling system penetration room
• 1214 AF 12354	12354	Mid-annulus access room
• 1215 AF 12161	12161	Corridor
• 1215 AF 12162	12162	Normal residual heat removal pump room A
• 1216 AF 12166	12166	Waste holdup tank room A
• 1216 AF 12167	12167	Waste holdup tank room B
• 1216 AF 12169	12168	Corridor
• 1216 AF 12169	12169	Corridor
• 1216 AF 12169	12268	Liquid radwaste system pump room
• 1216 AF 12264	12264	Chemical waste tank room
• 1216 AF 12264	12265	Waste monitor tank room C
• 1216 AF 12172	12172	Effluent holdup tank room B
• 1220 AF 12251	12251	Demineralizer/filter access area
• 1220 AF 12251	12255	Chemical and volume control system makeup pump room
• 1220 AF 12259	12259	Pipe chase
• 1220 AF 12256	12256	Containment isolation valve area
• 1220 AF 12269	12269	Pipe chase
• 1220 AF 12256	12253	Pipe chase
• 1220 AF 12272	12272	Spent fuel pool cooling system pump room A
• 1220 AF 12272	12273	Spent fuel pool cooling system heat exchanger room A
• 1220 AF 12272	12274	Spent fuel pool cooling system pump room B
• 1220 AF 12272	12275	Spent fuel pool cooling system heat exchanger room B
• 1224 AF 12252	12252	Radiation chemistry laboratory
• 1225 AF 12261	12261	Corridor
• 1225 AF 12261	12271	Liquid radwaste system pump room
• 1225 AF 12262	12262	Piping/valve room

• 1234 AF 12351	12351	Maintenance floor staging area
• 1234 AF 12352	12352	Personnel hatch
• 1235 AF 12363	12363	Waste monitor tank room A
• 1244 AF 12451	12451	Security room
• 1244 AF 12452	12452	Containment air filtration system penetration room
• 1244 AF 12454	12454	Containment air filtration system/spent fuel pool cooling system/primary sampling system penetration room
• 1235 AF 12361	12361	Corridor
• 1250 AF 12561	12551	Access corridor
• 1250 AF 12561	12561	Component cooling water system valve room
• 1254 AF 12553	12553	Personnel access area
• 1254 AF 12554	12554	Security room
• 1264 AF 12651	12651	Radiologically controlled area ventilation system equipment room

The equipment and piping in this fire area normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers (Fire Zone 1220 AF 12251, room 12255)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system (VAS) serves this fire area on a once-through basis. Some of the ventilation system equipment is also located within this fire area. For a fire that does not disable the ventilation system, the system continues to ventilate the fire area unless the operator decides to shut down the system, or until heat from the fire is sufficient to close the fire dampers. Fire dampers close automatically on high temperature to control the spread of fire and smoke. If the radiologically controlled area ventilation system is not affected by the fire, smoke is removed from the fire area by reopening the fire dampers after a fire and exhausting to the atmosphere. If the radiologically controlled area ventilation system is unavailable, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by fire detectors which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this large fire area are listed in Table 9A-3, and consist primarily of cable insulation for cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of lubricants in fire zones containing pumps and the radiologically controlled area ventilation system equipment. There are small concentrations of

paper and plastic in some fire zones. Concentrations of paper or plastic anti-contamination clothing may also be present in some fire zones. There are small concentrations of cable in the overhead cable trays in many fire zones. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. An automatic suppression system is provided to increase the availability of non-safety related systems required to achieve cold shutdown.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

The consequences of inadvertent operation of an automatic suppression system in this fire area or of fire suppression systems that drains to this fire area from the radwaste building, or of a break in a fire protection line in this fire area, are considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected.

The normal residual heat removal, primary sampling system, spent fuel pool cooling system and containment air filtration system containment isolation valves are conservatively assumed to be disabled as a result of a fire in this fire area. The redundant normal residual heat removal, primary sampling system, spent fuel pool cooling system and containment air filtration system containment isolation valves located inside containment are outside of this fire area and are sufficient to perform the applicable functions to maintain containment integrity and achieve and maintain safe shutdown. Cable trays supplying these valves and other components are not required for safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.2 Fire Area 1200 AF 02

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1200 AF 12562	12462	Cask washdown pit
• 1200 AF 12562	12463	Cask loading pit
• 1200 AF 12562	12472	New fuel storage pit
• 1200 AF 12562	12563	Spent fuel storage pool
• 1200 AF 12562	12564	Fuel transfer canal
• 1230 AF 12371	12371	Rail car bay/filter storage area
• 1230 AF 12371	12374	Waste disposal container area
• 1236 AF 12372	12372	Resin transfer pump/valve room
• 1236 AF 12373	12373	Spent resin tank room
• 1246 AF 12471	12471	Solid waste system valve/piping area

The spent fuel storage pool, spent fuel handling systems and components, and the solid radwaste rooms normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers (Fire Zone 1230 AF 12371, room 12371 rail car bay only)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. In the event of a fire the system continues to ventilate the fire area unless the operator decides to shut down the system, or until heat from the fire is sufficient to close the fire dampers. Fire dampers close automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers. The radiologically controlled area ventilation system exhausts the smoke and hot gases to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this large fire area are listed in Table 9A-3, and consist primarily of cable insulation for the cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of lubricants associated with equipment such as the overhead cranes and the fuel handling machine. Diesel fuel may be present when there is a truck

in the rail car bay. Concentrations of paper or plastic anti-contamination clothing may also be present. There are small concentrations of cable in the overhead cable trays. This is generally a light hazard fire area and the rate of fire growth is expected to be slow. Concentrations of transient combustibles in the rail car bay may produce a rapidly growing fire, so an automatic suppression system is provided in that area. Three-hour fire barriers provide adequate separation from adjacent fire areas. The roof and building exterior walls are unrated because there are no significant exposure fire hazards in nearby outdoor areas. Automatic or manual fire suppression activities prevent the fire from propagating beyond the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system or of a break in a fire protection line in this fire area are considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

There are no safe shutdown components in this area, so a fire in this area has no impact on safe shutdown. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected. Safe shutdown is possible from equipment in other fire areas.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.3 Fire Area 1204 AF 01

This fire area is comprised of the following room:

<u>Room No.</u>

12163	Normal residual heat removal pump room B

Some of the piping in this fire area normally contains radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. The system continues to ventilate the fire area unless the operator decides to shut down the system, or until heat from the fire is sufficient to close the fire dampers. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area by reopening the fire damper(s) after a fire and exhausting to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation for the cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of cable in overhead cable trays. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.4 Fire Area 1220 AF 02

This fire area is comprised of the following room(s):

Room No.

12244 Lower annulus valve area

Some of the piping in this fire area normally contains radioactive material.

Fire Detection and Suppression Features

- Fire detector
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. In the event of a fire the system continues to ventilate the fire area unless the operator decides to shut down the system, or until heat from the fire is sufficient to close the fire dampers. Fire damper(s) close automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers. The radiologically controlled area ventilation system exhausts the smoke and hot gases to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation for cables associated with the few containment isolation valves in this fire area. There are no significant concentrations of combustible materials. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The chemical and volume control system and liquid radwaste system containment isolation valves are conservatively assumed to be disabled as a result of a fire in this fire area. The redundant chemical and volume control system and liquid radwaste system containment isolation valves located inside containment are outside of this fire area and are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.2 Miscellaneous Areas

9A.3.1.3.2.1 Fire Area 1204 AF 02

This fire area is comprised of the following room(s):

Room No.

S03	Stairwell

This fire area is the stairwell serving the shield building. The portion of the stairwell below the elevation of the auxiliary building roof is enclosed by fire barrier walls partially constructed of concrete and partially constructed of a concrete/steel composite material, having a minimum rating of 3 hours. Above the auxiliary building roof, the stairwell enclosure is not fire-rated. There are no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

No ventilation system directly serves this fire area.

9A.3.1.3.2.2 Fire Area 1204 AF 03

This fire area contains the elevator and elevator shaft serving the south side of the shield building. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

No ventilation system directly serves this fire area. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery which is attached to the top of the elevator car. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas below the elevation of the auxiliary building roof. Manual fire suppression activities prevent the fire from propagating beyond the nonrated building exterior walls above the roof.

Safe Shutdown Evaluation

There are no safe shutdown components in this fire area. No safe shutdown evaluation is required.

9A.3.1.3.2.3 Fire Area 1205 AF 01

This fire area is comprised of the following room(s):

<u>Room No.</u>

S04 Stairwell

This stairwell, serving the southeast portion of the auxiliary building, is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

The radiologically controlled area ventilation system (VAS) serves this fire area on a once-through basis. Air at a positive pressure is supplied to the stairwell and exfiltrates through small openings such as under the fire doors. For a fire in the fire area outside the stairwell in which the supply penetration is located, a fire damper closes automatically on high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, minimizing the potential for migration of smoke and hot gases.

9A.3.1.3.2.4 Fire Area 1205 AF 02

This fire area contains the elevator and elevator shaft serving the radiologically controlled area of the auxiliary building, and the associated elevator mechanical room, 12661. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system serves the elevator mechanical room portion of this fire on a once-through basis. There is no direct ventilation of the elevator or the elevator shaft. In the event of a fire in the mechanical room the system continues to ventilate the fire area unless the operator decides to shut down the system, or until heat from the fire is sufficient to close the fire dampers. The fire dampers close automatically on high temperature to control the spread of fire, smoke and hot gases. Smoke is removed from the elevator mechanical room by reopening the fire dampers after a fire and operating the ventilation system to exhaust them to the atmosphere. For a fire in the elevator or elevator shaft, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery. There are small concentrations of these materials in the elevator mechanical room at the top of the elevator shaft. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Safe Shutdown Evaluation

There are no safe shutdown components in this fire area. No safe shutdown evaluation is required.

9A.3.2 Turbine Building

Figure 9A-2 identifies fire areas and fire zones within the turbine building and illustrates the fire resistance of the fire area boundaries.

A fire in the turbine building fire areas does not affect safe shutdown capability. Fire areas located in the turbine building are separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall. The closing of fire dampers in the ventilation systems serving turbine building fire areas does not affect safe shutdown systems because safe shutdown systems are served by independent ventilation systems.

Neither a fire nor fire suppression activities in turbine building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fixed automatic fire suppression systems without significant accumulation of water in the fire area. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the turbine building.

No fire in the turbine building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.2.1 Fire Area 2000 AF 01

This fire area contains the main condenser, lubrication equipment, turbine-generator and auxiliaries, switchgear rooms, electrical equipment room, feedwater pumps, chemical feed equipment, chiller area, plant air compressors, digital-electrohydraulic skid, main steam piping, office area, and a sampling laboratory. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 2030 AF 20300	20300	Elevation 100′-0″ (base slab) general floor area
• 2030 AF 20300	20306	Steam generator blowdown heat exchanger area
• 2030 AF 20300	20309	Circulating water pipe trench
• 2038 AF 20300	----	Main feedwater pump area
• 2039 AF 20301	20301	Chemical storage area
• 2040 AF 20400	20400	Elevation 117′-6″ general floor area
• 2040 AF 20400	20409	Condensate polishing area
• 2040 AF 20400	20410	Access to annex building
• 2040 AF 20400	20411	Access corridor to auxiliary building
• 2050 AF 20500	20500	Elevation 135′-3″ general floor area
• 2050 AF 20500	20512	Access to annex building
• 2050 AF 20500	20513	Access corridor to auxiliary building
• 2050 AF 20502	----	Digital-electrohydraulic skid
• 2052 AF 20504	20510	HVAC equipment area
• 2053 AF 20506	20509	Variable frequency driver power converter room
• 2057 AF 20503	20511	Generator seal oil unit

• 2060 AF 20600	20600	Elevation 161′-0″ general floor area
• 2060 AF 20600	20603	Restroom
• 2060 AF 20600	20604	Restroom
• 2060 AF 20600	20605	Surge tank platform
• 2063 AF 20601	20601	Tool room/storage area
• 2063 AF 20602	20602	Office area/engineering workstation at elevation 171′-0″

This fire area designation consists of the entire turbine building floor areas except those special areas contained within fire rated enclosures and discussed below as separate fire areas. In zones within this area where there is a potential for spills of oil or other combustibles, such as the digital-electrohydraulic skid, condensate polishing area, chemical storage area and the generator seal oil unit, spill control curbs are provided to limit the spread of fire should one occur. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors

- Automatic suppression for the oil spill areas around the turbine-generator, the generator seal oil unit, the main feedwater pump area, the digital-electrohydraulic skid, and the chemical storage area.

  Automatic suppression for the following equipment: the component cooling water pumps, the service water pumps, the start-up feedwater pumps and MCCs and control equipment at elevation 135′-3″ (in the area defined by column 13.1 to 14 and P.1 to O).

  Automatic suppression is provided over elevation 100′-0″ down the corridor between the condenser and the main feedwater pumps defined by column 13.1 to column 18, continuing down another corridor defined by column L.2 to column K.5 and for the equipment access area in fire zone 2030-AF-20300, room 20300.

  See Table 9A-3 for identification of the specific types of automatic suppression systems for this fire area.

- Hose station(s)

- Portable fire extinguishers

Smoke Control Features

The general area heating and ventilation subsystem of the turbine building ventilation system (VTS), as described in DCD subsection 9.4.9, uses roof mounted exhaust ventilators to pull in air through wall louvers. Dedicated roof mounted smoke and heat vents are also provided. The smoke and heat vents and, if available, the roof mounted exhaust ventilators, vent smoke to outside areas and prevent migration of smoke to adjacent fire areas. The dedicated smoke and heat vents provide additional assurance that excessive smoke and heat cannot buildup at the turbine building

ceiling. The design of the smoke and heat vents is in conformance with the guidelines of NFPA 204M.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by operation of the automatic suppression system, if applicable, or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. This area contains fire zones with a low quantity of combustible materials and other zones which have moderate to high quantities of combustible materials. Zones containing a low quantity of low heat release combustibles are generally protected by manual suppression. Zones containing moderate to high quantities of high heat release combustibles, such as oil spill areas, are protected by automatic suppression.

The limited amount of combustible material or automatic fire suppression activities prevent fire from propagating to other fire zones in the area and prevent fire from propagating through the exterior walls or roof of the turbine building to other fire areas. The south end of the turbine building is formed by the 3-hour fire barrier exterior walls of the annex and auxiliary building. There are no concentrations of combustibles in the turbine building adjacent to these walls. Therefore, a turbine building fire will not propagate through these exterior walls of the annex or auxiliary building.

The turbine building ventilation system (VTS) serves the turbine building only and therefore does not contribute to the spread of the fire or smoke to fire areas outside the turbine building. The turbine building ventilation system does not contribute to the spread of fire or smoke to other fire areas within the turbine building because fire dampers isolate the other fire areas.

9A.3.2.2 Fire Area 2000 AF 02

This fire area is comprised of the following room(s):

Room No.

S02 Stairwell

This stairwell serves the southwest portion of the turbine building. The walls of this enclosure that are exposed to the turbine building interior are constructed with a concrete/steel composite material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the turbine building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the turbine building. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. A fire protection hose riser is located in the stairwell with NFPA Class I hose connections at intermediate stair landings.

This stairwell is not served by a ventilation system.

9A.3.2.3 Fire Area 2009 AF 01

This fire area is comprised of the following room(s):

<u>Room No.</u>

S01 Stairwell

This stairwell serves the northeast portion of the turbine building. The walls of this enclosure that are exposed to the turbine building interior are constructed with a concrete/steel composite material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the turbine building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the turbine building. There are no safety-related components or systems in this fire area which contain radioactive material. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. A fire protection hose riser is located in the stairwell with NFPA Class I hose connections at intermediate stair landings.

This stairwell is not served by a ventilation system.

9A.3.2.4 Fire Area 2009 AF 02

This fire area is comprised of the following room(s):

<u>Room No.</u>

20701 Elevator machine room

This elevator serving the turbine building from elevation 100′-0″ to elevation 161′-0″ and its machine room are enclosed by fire barrier walls having a minimum rating of 2 hours. These nonstructural walls are metal lined gypsum board. The elevator machine room is above the elevator tower at elevation 171′-0″. There are no radioactive systems in this fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is not served by a ventilation system. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas since the fire will be contained within this fire area.

No ventilation systems penetrate the elevator enclosure.

9A.3.2.5 This section has been deleted.

9A.3.2.6 Fire Area 2003 AF 01

This fire area is comprised of the following room(s):

Room No.

20304 Auxiliary boiler room

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the auxiliary boiler room is supplied by the turbine building ventilation system (VTS) as described in DCD subsection 9.4.9. During normal operation, exhaust ventilators mounted on an exterior wall pull air in from the turbine building through wall louvers and maintain the auxiliary boiler room at a lower pressure than turbine building general areas. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Following a fire, the exhaust ventilators, if available, can be used to vent smoke to outside the turbine building.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by the automatic suppression system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Due to the concentration of fuel oil and lubricating oil, this fire area is an extra hazard fire area. This area has a high combustible loading and fires with high heat release rates could develop rapidly. Therefore, an automatic fire suppression system is provided. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The west wall of the auxiliary boiler room is part of the exterior wall of the turbine building. Due to the explosion hazard associated with an oil fired boiler, this wall contains blowout panels to relieve the pressure of an explosion to outside the turbine building.

The auxiliary boiler room ventilation system portion of the turbine building ventilation system does not contribute to the spread of the fire or smoke to other fire areas. Fire area boundaries are equipped with fire dampers to prevent the propagation of fire between fire areas.

9A.3.2.7 This section has been deleted.

9A.3.2.8 Fire Area 2033 AF 02

This fire area is comprised of the following room(s):

<u>Room No.</u>

20303 Motor driven fire pump room

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the motor driven fire pump room is supplied by the turbine building ventilation system (VTS) as described in DCD subsection 9.4.9. During normal operation, a wall mounted exhaust ventilator pulls in outside air through a wall louver. Should there be a turbine building fire outside the motor driven fire pump room, the use of outside air for ventilation prevents smoke from affecting the operation of the motor driven fire pump. Following a fire, the wall mounted exhaust ventilator, if available, can be used to vent smoke to outside the turbine building. If the exhaust ventilator is not available, an exterior door can be opened.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by operation of manual hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. There are no concentrations of combustibles that could challenge the fire area barrier. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

As the motor driven fire pump room ventilation system supply and exhaust are both from outside the turbine building and as no ductwork penetrates the motor driven fire pump room fire area boundary, this ventilation system does not contribute to the spread of the fire or smoke to other fire areas.

9A.3.2.9 Fire Area 2040 AF 01

This fire area is comprised of the following room(s):

Room No.

20407 Lube oil storage room

This fire area contains the clean and dirty lube oil storage tanks and the waste oil storage tank. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Automatic water spray system
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the lube oil storage room is supplied by the turbine building ventilation system (VTS) as described in DCD subsection 9.4.9. During normal operation, an exhaust ventilator mounted on an exterior wall pulls air in from the turbine building through a wall louver and maintains the lube oil storage room at a lower pressure than turbine building general areas. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Following a fire, the exhaust ventilator, if available, can be used to vent smoke to outside the turbine building.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by operation of an automatic sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Due to the concentration of lubricating oil, this fire area is an extra hazard fire area. This area has a high combustible loading

and fires with high heat release rates could develop rapidly. Therefore, an automatic fire suppression system is provided. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond this fire area.

The lube oil storage area ventilation system portion of the turbine building ventilation system does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.10 Fire Area 2043 AF 01

This fire area is comprised of the following room(s):

Room No.

20401 Secondary sampling laboratory

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) personnel area HVAC subsystem, as described in DCD subsection 9.4.9, provides heating and cooling to the secondary sampling laboratory. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by the automatic suppression system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. As volatile chemicals are likely to be present, this fire area is an extra hazard fire area. Due to high heat release rates, fires could develop rapidly. Therefore, an automatic fire suppression system is provided. There are no concentrations of combustibles that could challenge the fire area barrier. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS personnel area HVAC subsystem serving the secondary sampling laboratory does not contribute to the spread of the fire or smoke to other fire areas. Fire area boundaries are equipped with fire dampers to prevent the propagation of fire between fire areas.

9A.3.2.11 Fire Area 2050 AF 01

This fire area is comprised of the following room(s):

Room No.	
20504	Turbine lube oil reservoir room

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Automatic water spray system
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the turbine lube oil reservoir room is supplied by the turbine building ventilation system (VTS) as described in DCD subsection 9.4.9. During normal operation, an exhaust ventilator mounted on an exterior wall pulls air in from the turbine building through a wall louver and maintains the turbine lube oil reservoir room at a lower pressure than turbine building general areas. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Following a fire, the exhaust ventilator, if available, can be used to vent smoke to outside the turbine building.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished by operation of automatic sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Due to the concentration of lubricating oil, this fire area is an extra hazard fire area. This area has a high combustible loading and fires with high heat release rates could develop rapidly. Therefore, an automatic fire suppression system is provided. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The turbine lube oil reservoir ventilation system portion of the turbine building ventilation system does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.12 Fire Area 2052 AF 01

This fire area is comprised of the following room(s):

Room No.

20502	Switchgear room 1

This fire area is the turbine building switchgear room 1 and contains high voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in DCD subsection 9.4.9, provides heating and cooling to switchgear room 1. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving switchgear room 1 does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.13 Fire Area 2053 AF 01

This fire area is comprised of the following room(s):

Room No.

20503	Electrical equipment room

This fire area is the electrical equipment room and contains high voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in DCD subsection 9.4.9, provides heating and cooling to the electrical equipment room. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. There are no concentrations of combustibles that could challenge the fire area barrier. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving the electrical equipment room does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.14 Fire Area 2053 AF 02

This fire area is comprised of the following room(s):

Room No.	
20501	Switchgear room 2

This fire area contains high voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in DCD subsection 9.4.9, provides heating and cooling to switchgear room 2. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. There are no concentrations of combustibles that could challenge the fire area barrier. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving switchgear room 2 does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.3 Yard Area and Outlying Buildings

The fire protection system yard main and the location of hydrants and hose houses are described in subsection 9.5.1. Fire protection analysis discussions for the yard area, the administration building, and other outlying buildings are site-specific and are covered by the Combined License application.

9A.3.4 Annex Building

Figure 9A-4 identifies fire areas and fire zones within the annex building and illustrates the fire resistance of the fire area boundaries.

A fire in the annex building fire areas does not affect safe shutdown capability. A fire is confined to the fire area, and fire areas within the annex building are separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall, except for those fire areas which include portions of the auxiliary building. Closing of fire dampers in the ventilation system serving the annex building fire areas does not affect safe shutdown systems. Safe shutdown systems are generally served by independent ventilation systems. Fire areas which include portions of the auxiliary building are discussed later in this subsection.

Neither a fire nor fire suppression activities in annex building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fire protection systems without a significant accumulation of water in the fire area. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the annex building.

No fire in the annex building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.4.1 Fire Area 4001 AF 01

This fire area is comprised of the following room(s):

Room No.

S01 Stairwell

This stairwell is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) serves this fire area. Air at a positive pressure is supplied to the stairwell and exfiltrates through small openings such as under the fire doors. For a fire in the fire area outside the stairwell in which the supply penetration is located, a fire damper closes automatically on high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, minimizing the potential for migration of smoke.

9A.3.4.2 Fire Area 4001 AF 02

This fire area is comprised of the elevator shaft and elevator.

This elevator is enclosed by fire barrier walls having a minimum rating of 2 hours.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

A wall exhaust fan and air intake louvers provide normal ventilation for the elevator shaft. After the fire, smoke is removed from the fire area by using the wall exhaust fan or portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas since the fire will be contained within this fire area.

9A.3.4.3 Fire Area 4002 AF 01

This fire area is comprised of the following room(s):

Room No.

S02 Stairwell

This stairwell, serving the annex building, is enclosed by fire barrier walls having a minimum rating of 2 hours. The four walls of this enclosure are nonstructural walls, which are constructed with concrete/steel composite material. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

The health physics and hot machine shop HVAC system (VHS) serves this fire area. Air at a positive pressure is supplied to the stairwell and exfiltrates through small openings such as under the fire doors. For a fire in the fire area outside the stairwell in which the supply penetration is located, a fire damper closes automatically on high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, minimizing the potential for migration of smoke.

9A.3.4.4 Fire Area 4002 AF 02

This fire area is comprised of the following room(s):

Room No.

S04 Stairwell

This stairwell serves the southeast corner of the annex building. The walls of this enclosure that are exposed to the annex building interior are constructed with a concrete/steel composite material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the annex building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the annex building. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

The general area HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) serves this fire area. Air at a positive pressure is supplied to the stairwell and exfiltrates through small openings such as under the fire doors. For a fire in the fire area outside the stairwell in which the supply penetration is located, a fire damper closes automatically on high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, minimizing the potential for migration of smoke.

9A.3.4.5 Fire Area 4003 AF 01

This fire area encompasses four levels of the annex building and contains demineralized water deoxygenating equipment and air handling equipment. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4003 AF 40340	40340	Demineralized water deoxygenating room
• 4003 AF 40442	40442	Boric acid batching room
• 4003 AF 40503	40503	Lower south air handling equipment room
• 4003 AF 40503	40504	Air intake plenum 2
• 4003 AF 40601	40601	Upper south air handling equipment room
• 4003 AF 40601	40602	Air intake plenum 3

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The mechanical equipment areas HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. This action controls the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as wood and paper. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.6 Fire Area 4003 AF 02

This fire area is comprised of the following room(s):

Room No.	
S03	Stairwell

This stairwell serves the east side of the annex building. The walls of this enclosure that are exposed to the annex building interior are constructed with a concrete/steel composite material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the annex building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the annex building. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

The mechanical equipment areas HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) serves this fire area. Air at a positive pressure is supplied to the stairwell and exfiltrates through small openings such as under the fire doors. For a fire in the fire area outside the stairwell in which the supply penetration is located, a fire damper closes automatically on high temperature to prevent the spread of fire and smoke into the stairwell. For fires not affecting the ventilation system, the system continues to provide ventilation to the stairwell, minimizing the potential for migration of smoke.

9A.3.4.7 Fire Area 4031 AF 01

This annex building fire area contains one train of the non-Class 1E batteries and battery charging equipment. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4031 AF 40307	40307	Battery room 1
• 4031 AF 40308	40308	Battery charger room 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. The combustible materials are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The battery room is also separated from the adjacent charging room by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.8 Fire Area 4031 AF 02

This annex building fire area contains one train of the non-Class 1E batteries and battery charging equipment. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4031 AF 40309	40309	Battery room 2
• 4031 AF 40310	40310	Battery charger room 2
• 4041 AF 40411	40411	Computer room B
• 4041 AF 40411	40412	Shift turnover room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing fire zones 4031 AF 40309 and 4031 AF 40310 stops upon detection of smoke in the supply duct. Combination-fire dampers close automatically in response to a smoke detector signal or high temperature to isolate fire zone 4031 AF 40310. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire dampers in the main control room/technical support center HVAC subsystem of the NI non-radioactive ventilation system (VBS) close automatically on high temperature to isolate fire zone 4041 AF 40411. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The balance of this and other VBS subsystems continue to provide ventilation to the unaffected fire areas. The subsystem may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. The combustible materials are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The battery room is also separated from the adjacent charging room by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.9 Fire Area 4031 AF 05

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4031 AF 40300	40300	Access area
• 4031 AF 40300	40301	Access corridor
• 4031 AF 40300	40305	Security room 2
• 4031 AF 40303	40303	Corridor
• 4031 AF 40303	40304	Restroom

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as paper, wood, and plastic. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. Fire zones within this fire area are separated by walls as shown in Figure 9A-4. The walls for the exit corridors are rated for a minimum of 1 hour in accordance with the Uniform Building Code. The building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.10 Fire Area 4031 AF 06

This fire area is comprised of the following room(s):

<u>Room No.</u>

40306	Central alarm station
40302	Security room 1

This fire area contains computer and communication equipment. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as paper, wood, and plastic. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.11 Fire Area 4032 AF 01

This fire area is comprised of the following room(s):

Room No.	
40326	Non-radiologically controlled area entry/exit area
40327	Health physics office
40350	Radiologically controlled area entry/exit area
40351	Protective clothes pickup and suitup
40352	Radiation monitoring calibration room
40353	Office
40354	Health physics counting
40355	Decontamination room
40356	Corridor

The area is used for decontamination and monitoring of personnel leaving the radiological control area of the plant. Low levels of radioactive materials may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The health physics and hot machine shop HVAC system (VHS) servicing this fire area stops upon detection of smoke in the area or in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and starting the exhaust fans serving this area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.12 Fire Area 4032 AF 02

This fire area is comprised of the following room(s):

<u>Room No.</u>

40357	Containment access corridor elevation 107′-2″

This fire area is the corridor used to transport equipment and personnel through the annex building and auxiliary building to and from containment. As such, low levels of radioactive material may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers (Elevation 107′-2″)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The auxiliary/annex building subsystem of the radiologically controlled area ventilation system (VAS) servicing this fire area alarms in the main control room upon detection of smoke in the area or in the supply or exhaust duct. Fire dampers close automatically on high temperature to isolate this fire area. The balance of the VAS auxiliary/annex building ventilation subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. The balance of VAS remains in operation. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers. The ventilation exhaust system serving the area exhausts smoke to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Diesel fuel may be present when there is a truck in the containment access corridor. Combustibles are relatively uniformly distributed throughout the fire area except when transient combustibles are present. This is an ordinary hazard fire area when transient combustibles are present and the rate of fire growth may be rapid. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. An automatic suppression system is provided to address transient combustibles.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.13 Fire Area 4033 AF 01

This fire area is comprised of the following room(s):

Room No.

40358	Hot machine shop
40359	Pump seal shop

The shop is used for decontamination and repair of equipment from the radiological control area of the plant. As such, low levels of radioactive materials may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The health physics and hot machine shop HVAC system (VHS) servicing this fire area stops upon detection of smoke in the area or in the duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and starting the exhaust fans serving this area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is an ordinary hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.14 Fire Area 4034 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4034 AF 40311	40311	Corridor
• 4034 AF 40311	40312	Corridor
• 4034 AF 40311	40319	Corridor
• 4034 AF 40313	40313	Office
• 4034 AF 40313	40314	Office
• 4034 AF 40313	40315	Office
• 4034 AF 40313	40316	Office
• 4034 AF 40318	40317	Office
• 4034 AF 40318	40318	ALARA briefing room and operational support center
• 4034 AF 40320	40320	Women's change room
• 4034 AF 40322	40321	Janitor closet
• 4034 AF 40322	40322	Men's change room
• 4034 AF 40322	40323	Water heater room
• 4034 AF 40322	40324	Drying area
• 4034 AF 40322	40325	Shower room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The general area HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate portions of this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, an exhaust fan serving the change rooms, mounted on the roof over the fire area, is used to exhaust smoke to the atmosphere from the change rooms. Smoke from other areas may be exhausted using portable exhaust fans and flexible ductwork.

Fire zone 4034 AF 40311 is an exit corridor for the area and is protected with fire dampers on duct penetrations of the corridor envelope in accordance with the Uniform Building Code.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. Fire zones within this fire area are separated by walls as shown in Figure 9A-4. The walls of fire zone 4034 AF 40311 are rated for 1-hour in accordance with Uniform Building Code requirements for exit corridors.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.15 Fire Area 4035 AF 01

This fire area is comprised of the following room(s):

Room No.

40341 Ancillary diesel generator room

This annex building fire area contains two diesel generator sets and one fuel storage tank. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Automatic dry pipe sprinkler system
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The mechanical equipment areas HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected through the operation of the automatic dry pipe sprinkler system which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the automatic dry pipe

sprinkler system. Water from the sprinklers rapidly fills and cools the small diked area under the fuel oil storage tank. If necessary the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the fuel oil storage tank. The tank is located in the southwest corner of the room. The remaining combustibles are relatively uniformly distributed throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.16 Fire Area 4041 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4041 AF 40403	40403	Technical support center operations area
• 4041 AF 40403	40404	Restroom
• 4041 AF 40403	40405	Rest area, kitchen
• 4041 AF 40403	40406	Conference room
• 4041 AF 40403	40407	Conference room
• 4041 AF 40403	40408	NRC room
• 4041 AF 40403	40409	Conference room
• 4041 AF 40410	40410	Computer room A
• 4041 AF 40410	40402	Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Combination fire-smoke dampers in the main control room/technical support center HVAC subsystem of the NI non-radioactive ventilation system (VBS) close automatically upon detection of smoke or on high temperature to isolate this fire area. The balance of this and other VBS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. Fire zones within this fire area are separated by walls as shown in Figure 9A-4. The corridor walls of fire zone 4041 AF 40410 are rated for one-hour in accordance with Uniform Building Code requirements for exit corridors.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.17 Fire Area 4041 AF 02

This fire area is comprised of the following room(s):

Room No.	
40400	Corridor
40401	Restroom

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. There are cable concentrations near the ceiling in the southern half of the corridor. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.18 Fire Area 4042 AF 01

This fire area is comprised of the following room(s):

Room No.

40413	Electrical switchgear room 1 including vertical electrical chase from room 40413 to room 40350 (floor slab Elevation 100′-0″)

This annex building fire area contains the non-Class 1E switchgear for one train, and two motor generator sets and power cabinet. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The switchgear room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation within electrical equipment, cabinets, and raceways. There are cable concentrations near the ceiling and the exterior wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.19 Fire Area 4042 AF 02

This fire area is comprised of the following room(s):

Room No.

40414 Electrical switchgear room 2

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The switchgear room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation within electrical equipment, cabinets, and raceways. There are cable concentrations near the ceiling and the exterior wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.20 Fire Area 4051 AF 01

This fire area is comprised of the following room(s):

Room No.	
40500	North air handling equipment room
40501	Air intake plenum 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by using portable exhaust fans and flexible ductwork or by reopening the fire dampers and operating the ventilation system in the smoke exhaust mode if it is still functional.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. There are cable concentrations along the west and south walls. This is a light hazard zone and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the exterior wall is not rated.

The ventilation systems contained in this fire area are equipped with fire dampers on their duct penetrations out of and into this fire area. The systems contained in this area are recirculating HVAC systems serving personnel and equipment areas in the annex building, and one train of HVAC equipment serving the main control room.

The ventilation system does not contribute to the spread of fire or smoke as described in the Smoke Control Features section above.

9A.3.4.21 Fire Area 4052 AF 01

This fire area contains the staging, storing, and assembly area for the containment. It also houses the exhaust fans for the health physics area and the containment air filtration exhaust units. The containment air filtration units remove radioactive halogens and particulates from the containment air prior to discharge to the atmosphere. Low levels of radioactive material may be present within the fire area during normal plant operation. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4052 AF 40550	40550	Staging and storage area
• 4052 AF 40551	40551	Containment air filtration exhaust room A
• 4052 AF 40552	40552	Containment air filtration exhaust room B

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The auxiliary/annex building subsystem of the radiologically controlled area ventilation system (VAS) servicing this fire area alarms in the main control room upon detection of smoke in the area or in the supply or exhaust duct. The balance of the this and other VAS subsystems remain in operation unless plant operators determine that there is a need to manually shut down the subsystem. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers. The ventilation exhaust system serving the area exhausts smoke to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished manually using hose streams or portable extinguishers.

This fire area contains two charcoal adsorbers, located in the containment air filtration system exhaust units. Fixed fire suppression systems are not required for these adsorbers because of the high charcoal ignition temperature. The normal temperature of the air flowing through the charcoal adsorbers is well below 200°F, while the minimum charcoal ignition temperature is greater than 600°F. Two independent temperature sensors interface with the fire detection system, providing charcoal temperature indication, and high and high-high temperature alarms. The filtration unit fan trips at the high temperature alarm setpoint. The setpoints of both alarms are well below the charcoal ignition temperature, allowing the operator time to investigate and take corrective action. In the unlikely event of a fire in the adsorber, the filtration unit can be manually

isolated and sprayed with water from a nearby hose station to cool the charcoal and extinguish the fire.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and charcoal. The charcoal is contained within the sheet metal housings of the containment air filtration system exhaust units. There are cable concentrations along the south and west walls of the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.5 Radwaste Building

Figure 9A-5 identifies fire zones within the radwaste building fire area and illustrates the fire resistance of the fire area boundaries.

A fire in the radwaste building does not affect safe shutdown capability. A fire is confined to the fire area. The radwaste building fire area is separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall. The radwaste building is served by the dedicated radwaste building HVAC system. Closing of fire dampers in the ventilation system serving the radwaste building does not affect safe shutdown systems because the safe shutdown systems are served by other ventilation systems.

Neither a fire nor fire suppression activities in the radwaste building affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fixed automatic fire protection systems without a significant accumulation of water in the fire area. Curbed areas within the radwaste building have sufficient capacity to retain fire protection water to prevent an unmonitored release to the environment.

No fire in the radwaste building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.5.1 Fire Area 5031 AF 01

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 5031 AF 50300	50300	Electrical/mechanical equipment room
• 5031 AF 50350	50350	Mobile systems facility
• 5031 AF 50351	50351	Waste accumulation room
• 5031 AF 50352	50352	Packaged waste storage room
• 5031 AF 50353	50353	HVAC equipment room

Various radwaste processing and packaging operations are performed utilizing the mobile system facilities. Moderate quantities of radioactive materials are present in the fire area during all modes of plant operation.

Fire Detection and Suppression Features

- Fire detectors
- Preaction sprinklers (fire zones 5031 AF 50350, -50351, and -50352)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radwaste building HVAC system (VRS) stops upon actuation of the fire suppression system in this fire area or if smoke is detected in the common supply duct from the air handling units. The VRS remains in operation and an alarm is sent to the main control room and the central alarm station if a fire is detected in the duct or if the suppression system is actuated. The plant operators will determine if there is a need to manually shut down the system. The fire damper to the plant vent closes automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area and exhausted to atmosphere by reopening the fire damper and operating the ventilation system exhaust fans.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the preaction sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as cloth and trash. There are concentrations of combustibles in the waste accumulation room and potentially in the mobile systems facility. Depending upon the processes being performed in the mobile systems facility, the locations of combustible concentrations may change. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum three-hour barriers are provided and the building exterior wall is not rated. An automatic suppression system is provided due to the localized areas of high combustible loading. This system provides confidence that the fire will be promptly extinguished, thus minimizing the potential for release of radioactivity and the radiation exposure of firefighters.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6 Diesel Generator Building

Figure 9A-6 identifies fire areas and fire zones within the diesel generator building and illustrates the fire resistance of the fire area boundaries.

A fire in the diesel generator building does not affect safe shutdown capability. The diesel generator building is not adjacent to any building or area containing safety-related equipment. The diesel generator building heating and ventilation system is dedicated to the diesel generator building and independent of other ventilation systems.

Neither a fire nor fire suppression activities in the diesel generator building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle low water flow rates. Water from fixed automatic fire protection systems flows out of the building through opened doors. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the diesel generator building.

No fire in the diesel building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.6.1 Fire Area 6030 AF 01

This fire area contains the diesel generator and supporting equipment for one train of the onsite standby ac power system. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 6030 AF 60310	60310	Diesel generator room A
• 6030 AF 60311	60311	Service module A
• 6030 AF 60313	60313	Combustion air cleaner area A

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors in the service module
- Dry pipe sprinklers in the diesel generator room
- Hose station(s)
- Portable fire extinguishers (including carbon dioxide)

Smoke Control Features

The diesel generator building ventilation system (VZS) serves this fire area by means of the engine room air handling unit, the service module air handling unit, and the standby exhaust fans. The engine room air handling unit stops upon actuation of the fire suppression system in the fire area or if smoke is detected in the supply air duct from the air handling unit. The service module air handling unit stops upon actuation of the fire suppression system in the fire area or if smoke is detected in the supply air duct from the air handling unit. The standby exhaust fans stop upon actuation of the fire suppression system in the fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area by manually turning on the

ventilation exhaust fans mounted on the roof over the fire area, or by opening the roll-up door and personnel doors and utilizing portable exhaust fans.

Fire Protection Adequacy Evaluation

A fire in the diesel generator room is detected through the operation of the dry pipe sprinkler system which produces an audible alarm locally and both visual and audible alarms in the main control room and security central alarm station. A fire in the service module is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. A fire in the diesel generator room is extinguished by the automatic fire suppression system or manually, using hose streams or portable extinguishers. A fire in the service module is extinguished manually using hose streams or portable extinguishers.

The area under the diesel generator is shielded from direct impingement of the spray from the dry pipe sprinkler system, but water accumulating on the floor will find its way into this space. The area under the diesel generator is also accessible for manual firefighting. The roll-up door permits access to this space for manual hose streams from outside the building.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation, lube oil and fuel oil. Combustibles concentrations occur at the diesel generator equipment and in the service module. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.2 Fire Area 6030 AF 02

This fire area contains the diesel generator and supporting equipment for one train of the onsite standby ac power system. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 6030 AF 60320	60320	Diesel generator room B
• 6030 AF 60321	60321	Service module B
• 6030 AF 60323	60323	Combustion air cleaner area B

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors in the service module
- Dry pipe sprinklers in the diesel generator room
- Hose station(s)
- Portable fire extinguishers (including carbon dioxide)

Smoke Control Features

The diesel generator building ventilation system (VZS) serves this fire area by means of the engine room air handling unit, the service module air handling unit, and the standby exhaust fans. The engine room air handling unit stops upon actuation of the fire suppression system in the fire area or if smoke is detected in the supply air duct from the air handling unit. The service module air handling unit stops upon actuation of the fire suppression system in the fire area or if smoke is detected in the supply air duct from the air handling unit. The standby exhaust fans stop upon actuation of the fire suppression system in the fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area by manually turning on the ventilation exhaust fans mounted on the roof over the fire area, or by opening the roll-up door and personnel doors and utilizing portable exhaust fans.

Fire Protection Adequacy Evaluation

A fire in the diesel generator room is detected through the operation of the dry pipe sprinkler system which produces an audible alarm locally, and both visual and audible alarms in the main control room and security central alarm station. A fire in the service module is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. A fire in the diesel generator room is extinguished by the automatic fire suppression system or manually, using hose streams or portable extinguishers. A fire in the service module is extinguished manually using hose streams or portable extinguishers.

The area under the diesel generator is shielded from direct impingement of the spray from the dry pipe sprinkler system, but water accumulating on the floor will find its way into this space. The area under the diesel generator is also accessible for manual firefighting. The roll-up door permits access to this space for manual hose streams from outside the building.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation, lube oil and fuel oil. Combustibles concentrations occur at the diesel generator equipment and in the service module. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.3 Fire Area 6030 AF 03

This fire area is comprised of the following room(s):

<u>Room No.</u>

60312 Diesel fuel day tank vault A

This fire area contains the fuel oil day tank for one train of the onsite standby ac power diesel generator. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Dry pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Fire dampers in the diesel generator building ventilation system (VZS) close automatically on high temperature to isolate this fire area. The tank vault exhaust fan stops upon actuation of the fire suppression system in this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected through the operation of the dry pipe sprinkler system which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the automatic dry pipe sprinkler system. Water from the sprinklers rapidly fills and cools the small diked area under the tank. If necessary, the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the oil storage tank. Due to the small vault size and the size of the storage tank, the combustible loading is uniform throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be high. Minimum three-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.4 Fire Area 6030 AF 04

This fire area is comprised of the following room(s):

<u>Room No.</u>

60322 Diesel fuel day tank vault B

This fire area contains the fuel oil day tank for one train of the onsite standby ac power diesel generator. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Dry pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Fire dampers in the diesel generator building ventilation system (VZS) close automatically on high temperature to isolate this fire area. The tank vault exhaust fan stops upon actuation of the fire suppression system in this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected through the operation of the dry pipe sprinkler system which produces an audible alarm locally and both visual and audible alarms in the main control room and the security central alarm station. The fire is extinguished by the automatic dry pipe sprinkler system. Water from the sprinklers rapidly fills and cools the small diked area under the tank. If necessary, the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the oil storage tank. Due to the small vault size and the size of the storage tank, the combustible loading is uniform throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be high. Minimum three-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.7 Special Topics

9A.3.7.1 Evaluation of Spurious Actuation

The potential for spurious actuation of equipment as a result of fire damage to electrical circuits is considered for each fire area containing safety-related equipment. As discussed in subsection 9A.2.7.1, one spurious actuation or signal is postulated at a time (except for high-low pressure interfaces). Principal spurious actuation are discussed below. In no case does the spurious actuation of equipment prevent safe shutdown.

9A.3.7.1.1 High-Low Pressure Interfaces

NRC Generic Letter 81-12 requests the identification and evaluation of high-low pressure interfaces between the reactor coolant system and interfacing systems such as the normal residual heat removal system. Per the Generic Letter, these interfaces typically contain two redundant and independent motor-operated valves in series. On a typical pressurized water reactor plant, these two valves and their control and power cables may be subject to a single fire. Potential high-low pressure system interfaces of particular interest are discussed below.

Reactor Coolant System Valve Actuation

NRC Generic Letter 81-12 specifically addresses the reactor coolant/residual heat removal system interface on pressurized water reactors. For AP1000, the reactor coolant system to normal residual heat removal system interface is similar to the typical pressurized water reactor configuration. However, the normal residual heat removal system is not a safety-related system and is not

required for safe shutdown. To preclude the spurious opening of the interface valves as a result of a fire, the power to the valves is locked out during power operations. Thus, spurious actuation of the reactor coolant system to normal residual heat removal system interface valves does not occur and the safe shutdown capability is not affected.

Automatic Depressurization System Valve Actuation

The automatic depressurization system valves are not considered to be high-low pressure interface valves when postulating spurious actuation following a fire. The safety issue related to high-low pressure interfaces is expressed in NRC Generic Letter 81-12. The concern is that the spurious opening of two or more isolation valves which form the boundary between the reactor coolant system and a low pressure system could lead to damage to the low pressure system and a loss of coolant outside the containment. Since automatic depressurization system valve actuation cannot damage a low pressure system, and since the system is entirely within containment, the automatic depressurization valves do not represent a high-low pressure interface as described in NRC Generic Letter 81-12.

Spurious actuation of automatic depressurization system stage 4 squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Automatic depressurization system stages 1, 2, and 3 consist of parallel paths, each path having two motor-operated valves in series. Spurious stage 1, 2, or 3 actuation is prevented by the use of physical separation of control circuits for the two series valves and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Reactor Coolant System Reactor Vessel Head Vent Valve Actuation

The reactor vessel head vent valves are connected to the reactor vessel head and discharge to the IRWST. The head vent valves are not required to operate following a fire. There are four head vent valves arranged in two flow paths with two series valves in each path. The head vent valves are fail-closed dc powered solenoid valves, and each valve is powered by a separate, safety-related power supply as shown on Table 9A-2. In the event that a spurious signal were to open a head vent valve, the flow path is blocked by the closed series head vent valve. The cables for the control of one head vent valve in each flow path is enclosed in steel conduit up to the valve to prevent a fire inside containment from spuriously actuating two head vent valves in one flow path. Therefore, a single fire is not postulated to result in an uncontrolled LOCA.

The head vent valves are controlled from switches mounted on the safety panels in the control room. Each safety panel contains a switch for controlling each head vent valve (4 switches per panel). Each switch is a three-position, hold-in-position switch (open-neutral-close). If both switches are in the neutral position, soft control of the valve from the operator's console is allowed. If both switches are in the open position the valve will open. Either switch in the close position will close the valve. If one switch is in neutral position and one in the open position, the

valve will hold its previous position but soft control is defeated. During a fire, switches on one panel may be shorted but none of the head vent valves will be opened because the switches on the other panel will be deactivated before the fire shorts them.

9A.3.7.1.2 Other Spurious Actuation

Principal spurious actuation not involving high-low pressure interfaces are discussed below.

Passive Core Cooling System Passive Residual Heat Removal Heat Exchanger Inlet Valve Actuation

One normally open valve is provided to isolate the inlet line to the passive residual heat removal heat exchanger. To preclude the spurious closing of the inlet valve as a result of a fire, the power to the valve is locked out during power operations. Thus, spurious closing of the passive core cooling passive residual heat removal heat exchanger inlet valve does not occur and the safe shutdown capability is not affected.

Passive Containment Cooling System Valve Actuation

Two valves in series isolate each of the three discharge flow paths from the passive containment cooling system storage tank. For purposes of system reliability, one valve in each flow path is normally open and the other is normally closed. Electrical division assignments are shown in Table 9A-2.

Spurious actuation of one of these valves is assumed to occur where a fire affects its electrical circuitry. Such a fire can occur in the main control room, an electrical equipment fire area, in the passive containment cooling system valve room, or in fire areas or fire zones through which the applicable electrical cables are routed.

Spurious actuation of one of these valves causes a passive containment cooling system flow path to be disabled or inadvertently opened, depending on which valve is affected. If a normally closed valve spuriously opens, passive containment cooling system water delivery from that flow path will be initiated which does not adversely affect the capability to achieve and maintain safe shutdown. If one of the normally open valves were spuriously closed to prevent passive containment cooling system water delivery through that flow path when called upon during the safe shutdown process, the redundant passive containment cooling system water delivery flow paths would be sufficient to achieve and maintain safe shutdown.

Containment Isolation Valve Actuation

Spurious actuation of a containment isolation valve is assumed to occur where a fire affects its electrical circuitry. Each containment penetration has redundant means of containment isolation.

Reactor Trip Switchgear

The reactor trip switchgear receives signals from each of the four Class 1E electrical divisions. The signals are de-energized to trip. Also, two out of four signals are required to trip. There are

two redundant sets of trip switchgear in separate fire areas. There is no single spurious signal which could prevent the reactor from being tripped.

Reactor Coolant Pump Trip Switchgear

There are two redundant sets of reactor coolant pump trip switchgear in separate fire areas. One is controlled from division B; the other from division C. Thus, a spurious signal in either train will not prevent trip of the reactor coolant pumps.

9A.3.7.2 Protection of Accident Mitigation Equipment

Based on the guidance in BTP CMEB 9.5-1, redundant trains of safety-related equipment used to mitigate the consequences of a design basis accident (but not required for safe shutdown following a fire) are separated so that a fire within one train will not damage the redundant train. Both trains are permitted to be damaged by a single exposure fire.

Either diverse methods of performing the accident mitigation function or adequate separation is provided.

9A.4 References

1. NUREG-0800, U. S. Nuclear Regulatory Commission Standard Review Plan, Section 9.5.1, "Fire Protection Program," Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, July 1981.

2. Fire Protection Handbook, Edited by A. E. Cote, National Fire Protection Association, 16th edition.

3. NRC Generic Letter 81-12, February 20, 1981.

4. NFPA 92A-2000, "Recommended Practice for Smoke Control Systems."

5. Fire Protection Handbook, National Fire Protection Association, 18th edition.

Table 9A-1

HEAT OF COMBUSTION VALUES

Material	Units	Heat of Combustion Btu/Unit
Acetylene	Pounds	21,500
Alcohol (Ethyl)	Gallons	84,100
Alcohol (Methyl)	Gallons	64,800
Batteries (cases, Note 1)	Cells	200,000
Cable Insulation	Pounds	10,200
Charcoal	Pounds	14,600
Cloth (cotton)	Pounds	8,000
Fuel Oil	Gallons	144,000
Gasoline	Gallons	128,000
Hydrogen	Pounds	61,000
Lube Oil	Gallons	151,000
Lubricant	Pounds	19,800
Methane	Pounds	23,900
Paper	Pounds	7,700
Plastic	Pounds	13,200
Propane	Pounds	21,700
Rubber	Pounds	12,200
Trash	Pounds	7,700
Volatiles (Note 2)	Gallons	136,000
Wood	Pounds	8,400

Notes:
1. Heat of combustion value depends on equipment selection.
2. Miscellaneous volatile liquids such as kerosene and toluene.

Table 9A-2 (Sheet 1 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11105	RCS	Reactor Vessel (MV-01)				
	RXS	Source Range Excore Detectors	NE-001A	NE-001C	NE-001B	NE-001D
		Intermediate Range Excore Detectors	NE-002A	NE-002C	NE-002B	NE-002D
		Power Range Excore Detectors (Lower)	NE-003A	NE-003C	NE-003B	NE-003D
		Power Range Excore Detectors (Upper)	NE-004A	NE-004C	NE-004B	NE-004D
1000 AF 01/ 1100 AF 11204	RCS	Hot Leg 1 Wide Range Pressure	PT-140A	PT-140C		
1000 AF 01/ 1100 AF 11206	PXS	Core Makeup Tank A Discharge Isolation Valve			V015A	V014A
	SFS	Suction Line Containment Isolation Valve			V034	
	RCS	Hot Leg 2 Wide Range Pressure			LT-140B	PT-140D
1000 AF 01/ 1100 AF 11207		Core Makeup Tank B Discharge Isolation Valve	V015B	V014B		
1000 AF01/ 1100 AF 11208	RNS	Suction from IRWST Cont. Isolation Valve			V023	
		Return from CVS Cont. Isolation Valve			V061	

Table 9A-2 (Sheet 2 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11300A	PSS	Containment Air Sample Cont. Isolation Valve			V008	
		Liquid Sample Line Cont. Isolation Valve			V010A	V010B
	RCS	Hot Leg 2 Flow			FT-102B	FT-102D
	VFS	Containment Purge Discharge Cont. Isolation Valve				V009
	VFS	Containment Purge Inlet Cont. Isolation Valve				V004
	PXS	IRWST Level			LT-046	LT-048
		IRWST Gutter Isolation Valve			V130A	V130B
		Core Makeup Tank (MT-02A)				
	PCS	Containment Pressure			PT-006	PT-008
	SGS	Steam Generator 2 Wide Range Level			LT-014	LT-018
1000 AF 01/ 1100 AF 11300B	CCS	Outlet Line Cont. Isolation Valve	V207			
	CVS	Letdown Containment Isolation Valve	V045			
		Makeup Line Cont. Isolation Valve	V091			
		RCS Purification Stop Valve (RCPB)	V001	V002		

Table 9A-2 (Sheet 3 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	Class 1E Division C	Class 1E Division B	Class 1E Division D
1000 AF 01/ 1100 AF 11300B	IDS	Class 1E Electrical Penetrations	EY-P11Z	EY-P27Z		
		Class 1E Electrical Penetrations	EY-P12Y	EY-P29Y		
		Class 1E Electrical Penetrations	EY-P13Y	EY-P28Y		
		Class 1E Cable Trays	Note 1	Note 1		
	PCS	Containment Pressure	PT-005	PT-007		
	PXS	PRHR Heat Exchanger Control Valve		V108B	V108A	
		IRWST Level	LT-045	LT-047		
		Core Makeup Tank (MT-02B)				
	RCS	Pressurizer Pressure	PT-191A	PT-191C		
		Reference Leg Temperature	TE-193A	TE-193C		
		Pressurizer Level	LT-195A	LT-195C		
		PRHR Heat Exchanger Outlet Temperature		TE-161		
		Hot Leg 1 Flow	FT-101A	FT-101C		
		Hot Leg 2 Flow	FT-102A	FT-102C		
	SGS	Steam Generator 1 Narrow Range Level	LT-001	LT-003		
		Steam Generator 2 Narrow Range Level	LT-005	LT-007		
		Steam Generator 2 Wide Range Level	LT-013	LT-017		

Table 9A-2 (Sheet 4 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1000 AF 01/ 1100 AF 11300B	SGS	Steam Generator 1 Wide Range Level	LT-011	LT-015		
		SG1 Steam Line Pressure	PT-030	PT-032		
		SG2 Steam Line Pressure	PT-034	PT-036		
	WLS	Sump Discharge Cont. Isolation Valve	V055			
		RCDT Gas Outlet Cont. Isolation Valve	V067			
1000 AF 01/ 1100 AF 11301	RCS	Reactor Head Vent Valve	V150A	V150C	V150B	V150D
		RCP 1A Bearing Water Temperature	TE-211A	TE-211C	TE-211B	TE-211D
		RCP 1B Bearing Water Temperature	TE-212A	TE-212C	TE-212B	TE-212D
		Cold Leg 1A Temperature (Narrow Range)	TE-121A			TE-121D
		Cold Leg 1B Temperature (Narrow Range)		TE-121C	TE-121B	
		Cold Leg 1A Temperature (Wide Range)	TE-125A			
		Cold Leg 1B Temperature (Wide Range)		TE-125C		
		Hot Leg 1 Temperature (Narrow Range)	TE-131A	TE-131C		
		Hot Leg 1 Temperature (Narrow Range)	TE-132A	TE-132C		
		Hot Leg 1 Temperature (Narrow Range)	TE-133A	TE-133C		

Table 9A-2 (Sheet 5 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1000 AF 01/ 1100 AF 11301	RCS	Hot Leg 1 Temperature (Wide Range)		TE-135A		
		Pressurizer Pressure			PT-191B	PT-191D
		Reference Leg Temperature			TE-193B	TE-193D
		Pressurizer Level			LT-195B	LT-195D
		RCP Shaft Speed	ST-281	ST-282		
		Hot Leg 1 Flow			FT-101B	FT-101D
	SGS	Steam Generator 1 Wide Range Level			LT-012	LT-016
1000 AF 01/ 1100 AF 11302	RCS	RCP 2A Bearing Water Temperature	TE-213A	TE-213C	TE-213B	TE-213D
		RCP 2B Bearing Water Temperature	TE-214A	TE-214C	TE-214B	TE-214D
		Cold Leg 2B Temper-ature (Narrow Range)	TE-122A			TE-122D
		Cold Leg 2A Temper-ature (Narrow Range)		TE-122C	TE-122B	
		Cold Leg 2A Temper-ature (Wide Range)			TE-125B	
		Cold Leg 2B Temper-ature (Wide Range)				TE-125D
		Hot Leg 2 Temperature (Narrow Range)			TE-131B	TE-131D
		Hot Leg 2 Temperature (Narrow Range)			TE-132B	TE-132D
		Hot Leg 2 Temperature (Narrow Range)			TE-133B	TE-133D
		Hot Leg 2 Temperature (Wide Range)			TE-135B	
		RCP Shaft Speed			ST-283	ST-284

Table 9A-2 (Sheet 6 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11500	IDS	Class 1E Cable Trays			Note 1	Note 1
		Class 1E Electrical Penetrations			EY-P30Z	EY-P14Z
		Class 1E Electrical Penetrations			EY-P31Y	EY-P15Y
		Class 1E Electrical Penetrations			EY-P32Y	EY-P16Y
	IIS	Core Exit Temperature		TE-002	TE-001	
		Core Exit Temperature		TE-004	TE-003	
		Core Exit Temperature		TE-005	TE-006	
		Core Exit Temperature		TE-007	TE-008	
		Core Exit Temperature		TE-010	TE-011	
		Core Exit Temperature		TE-012	TE-015	
		Core Exit Temperature		TE-014	TE-016	
		Core Exit Temperature		TE-017	TE-020	
		Core Exit Temperature		TE-018	TE-021	
		Core Exit Temperature		TE-019	TE-024	
		Core Exit Temperature		TE-022	TE-025	
		Core Exit Temperature		TE-023	TE-026	
		Core Exit Temperature		TE-027	TE-029	
		Core Exit Temperature		TE-028	TE-031	
		Core Exit Temperature		TE-032	TE-033	
		Core Exit Temperature		TE-035	TE-036	
		Core Exit Temperature		TE-037	TE-038	
		Core Exit Temperature		TE-040	TE-039	
		Core Exit Temperature		TE-042	TE-041	

Table 9A-2 (Sheet 7 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1000 AF 01/ 1100 AF 11500	SGS	Steam Generator 1 Narrow Range Level			LT-002	LT-004
		Steam Generator 2 Narrow Range Level			LT-006	LT-008
	VWS	Fan Coolers Return Cont. Isolation Valve			V082	
1000 AF 01/ 1200 AF 12341		None				
1000 AF 01/ 1200 AF 12541	IDS	Class 1E Cables		Note 1	Note 1	
1000 AF 01/ 1270 AF 12701	IDS	Class 1E Cables		Note 1	Note 1	
	PCS	PCCWST Isolation Valve	V001A	V001C	V001B	
		PCCWST Series Isolation Valve	V002A	V002C	V002B	
		PCS Water Delivery Flow		FT-001	FT-002	
		PCS Water Delivery Flow			FT-003	
		PCS Storage Tank Level		LT-010	LT-011	
1200 AF 01	IDS	Class 1E Cable Trays	Note 1	Note 1		
	SFS	Suction Line Cont. Isolation Valve	V035			
	VFS	Containment Purge Inlet Cont. Isolation Valve	V003			
	PSS	Liquid Sample Line Cont. Isolation Valve	V011			
		Sample Return Line Cont. Isolation Valve	V023			
		Air Sample Line Cont. Isolation Valve	V046			

Table 9A-2 (Sheet 8 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1200 AF 01	SFS	Discharge Line Cont. Isol. Valve	V038			
	VFS	Containment Purge Discharge Cont. Isolation Valve	V010			
	RNS	Discharge Cont. Isolation Valve	V011			
		Suction Header Cont. Isolation Valve	V022			
1200 AF 03	IDS	Class 1E Cable Trays			Note 1	Note 1
1201 AF 02	IDSB	24 Hr Battery 1A			DB-1A	
		24 Hr Battery 1B			DB-1B	
		72 Hr Battery 2A			DB-2A	
		72 Hr Battery 2B			DB-2B	
		125 Vdc Distribution Panel			DD-1	
		208/120 Vac Distribution Panel			EA-1	
		208/120 Vac Distribution Panel			EA-2	
		208/120 Vac Distribution Panel			EA-3	
		125 Vdc Switchboard			DS-1	
		125 Vdc Switchboard			DS-2	
		208/120 Vac Inverter			DU-1	
		208/120 Vac Inverter			DU-2	
		Regulating Transformer			DT-1	
		Battery Charger			DC-1	
		Battery Charger			DC-2	
		Voltage to Class 1E Battery Charger			--- 002	
		Voltage to Class 1E Battery Charger			--- 006	

Table 9A-2 (Sheet 9 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1201 AF 02	PMS	Protection and Safety Monitoring System Cabinets				
	IDSB	Electrical Penetration			EY-P32Y	
		125 Vdc MCC			DK-1	
		Electrical Penetration			EY-P30Z	
		Electrical Penetration			EY-P31Y	
1201 AF 03	IDSD	Battery 1A				DB-1A
		Battery 1B				DB-1B
		125 Vdc Distribution Panel				DD-1
		208/120 Vac Distribution Panel				EA-1
		208/120 Vac Distribution Panel				EA-2
		125 Vdc Switchboard				DS-1
		208/120 Vac Inverter				DU-1
		Regulating Transformer				DT-1
		Battery Charger				DC-1
		Voltage to Class 1E Battery Charger				--- 004
		Voltage to Class 1E Battery Charger				--- 008
	PMS	Protection and Safety Monitoring System Cabinets				
	IDSD	125 Vdc MCC				DK-1
		Electrical Penetration				EY-P14Z
		Electrical Penetration				EY-P15Y
		Electrical Penetration				EY-P16Z
1201 AF 04	IDS	Class 1E Cable Trays				Note 1
	CAS	Instrument Air Supply Cont. Isolation Valve				V014
	CCS	Inlet Line Cont. Isolation Valve				V200
	CCS	Outlet Line Cont. Isolation Valve				V208

Table 9A-2 (Sheet 10 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1201 AF 04	PXS	Nitrogen Supply Cont. Isolation Valve				V042
	VWS	Fan Coolers Supply Cont. Isolation Valve				V058
		Fan Coolers Return Cont. Isolation Valve				V086
	SGS	SG 1 Steam Line Pressure			PT-031	PT-033
		SG 1 Startup Feedwater Flow			FT-055A	FT-055B
		SG 2 Steam Line Pressure			PT-035	PT-037
		SG 2 Startup Feedwater Flow			FT-056A	FT-056B
1201 AF 05	CVS	Hydrogen Addition Cont. Isolation Valve				V092
	SGS	Steam Gen. Blowdown Cont. Isolation Valve			V075A	V074A
		Steam Gen. Blowdown Cont. Isolation Valve			V074B	V075B
		PORV and Block Valve-SG 1 Cont. Isolation Valves			V027A	V233A
		Steam Line Cond. Drain Cont. Isolation Valve				V036A
		Main Steam Line Cont. Isolation Valve			V040A	V040A
		Startup Feedwater Cont. Isolation Valve				V067A
		Main Steam Line Cond. Drain Control Valve			V086A	
		MSIV Bypass Cont. Isolation Valve			V240A	V240A

Table 9A-2 (Sheet 11 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1201 AF 06	SGS	PORV and Block Valve SG 2 Cont. Isolation Valve			V233B	V027B
		Steam Line Cond. Drain Cont. Isolation Valve				V036B
		Main Steam Line Cont. Isolation Valve			V040B	V040B
		Main Feedwater Cont. Isolation Valve			V057B	V057B
		Startup Feedwater Cont. Isolation Valve			V067B	
		Steam Line Cond. Drain Control Valve			V086B	
		MSIV Bypass Cont. Isolation Valve			V240B	V240B
1202 AF 03	IDSC	24 Hr Battery 1A		DB-1A		
		24 Hr Battery 1B		DB-1B		
		72 Hr Battery 2A		DB-2A		
		72 Hr Battery 2B		DB-2B		
		125 Vdc Distribution Panel		DD-1		
		208/120 Vac Distribution Panel		EA-1		
		208/120 Vac Distribution Panel		EA-2		
		208/120 Vac Distribution Panel		EA-3		
		125 Vdc Switchboard		DS-1		
		125 Vdc Switchboard		DS-2		
		208/120 Vac Inverter		DU-1		
		208/120 Vac Inverter		DU-2		
		Regulating Transformer		DT-1		
		Battery Charger		DC-1		
		Battery Charger		DC-2		

Table 9A-2 (Sheet 12 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	C	B	D
1202 AF 03	IDSC	Voltage to Class 1E Battery Charger		---003		
		Voltage to Class 1E Battery Charger		---007		
	PMS	Protection and Safety Monitoring System Cabinets				
	ECS	6900V RCP 1A Switchgear		ES-31		
		6900V RCP 2A Switchgear		ES-51		
		6900V RCP 1B Switchgear		ES-41		
		6900V RCP 2B Switchgear		ES-61		
	IDSC	Electrical Penetration		EY-P27Z		
		Electrical Penetration		EY-P29Y		
		Electrical Penetration		EY-P28Y		
		125 Vdc MCC		DK-1		
1202 AF 04	IDSA	Battery 1A	DB-1A			
		Battery 1B	DB-1B			
		125 Vdc Distribution Panel	DD-1			
		208/120 Vac Distribution Panel	EA-1			
		208/120 Vac Distribution Panel	EA-2			
		125 Vdc Switchboard	DS-1			
		208/120 Vac Inverter	DU-1			
		Regulating Transformer	DT-1			
		Battery Charger	DC-1			
		Voltage to Class 1E Battery Charger	--- 001			
		Voltage to Class 1E Battery Charger	--- 005			
	PMS	Protection and Safety Monitoring System Cabinets				

Table 9A-2 (Sheet 13 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1210 AF 01	IDS	Spare Battery (DB-1A)	Note 1	Note 1	Note 1	Note 1
		Spare Battery (DB-1B)	Note 1	Note 1	Note 1	Note 1
		Spare Battery Charger (DC-1)	Note 1	Note 1	Note 1	Note 1
		Spare Fuse Transfer Box (DF-1)	Note 1	Note 1	Note 1	Note 1
1220 AF 01	IDS	Class 1E Cable Trays			Note 1	Note 1
	ECS	6900V RCP 1A Switchgear			ES-32	
		6900V RCP 2A Switchgear			ES-52	
	ECS	6900V RCP 1B Switchgear			ES-42	
		6900V RCP 2B Switchgear			ES-62	
1220 AF 02	CVS	Letdown Containment Isolation Valve				V047
		Makeup Line Cont. Isolation Valve				V090
	WLS	Sump Discharge Cont. Isolation Valve				V057
		RCDT Gas Outlet Cont. Isolation Valve				V068
1230 AF 01	IDS	Class 1E Cable Trays	Note 1	Note 1		
1230 AF 02	IDS	Class 1E Cable Trays			Note 1	Note 1
1232 AF 01		Remote Shutdown Room				
	IDS	Class 1E Cable Trays	Note 1	Note 1	Note 1	Note 1
		Transfer Switch Set	Note 1	Note 1	Note 1	Note 1
1240 AF 01	IDS	Class 1E Cable Trays	Note 1	Note 1		

Table 9A-2 (Sheet 14 of 14)

SAFE SHUTDOWN COMPONENTS

Fire Area/ Fire Zone	System	Description	Class 1E Division A	Class 1E Division C	Class 1E Division B	Class 1E Division D
1242 AF 01		MCR Workstation				
	IDS	Class 1E Cable Trays	Note 1	Note 1	Note 1	Note 1
1242 AF 02	IDSA	Class 1E Electrical Penetration	EY-P11Z			
		Class 1E Electrical Penetration	EY-P12Y			
		Class 1E Electrical Penetration	EY-P13Y			
		125 Vac MCC	DK-1			
1243 AF 01		Reactor Trip Switchgear I				
	IDS	Class 1E Cables	Note 1	Note 1	Note 1	Note 1
1243 AF 02		Reactor Trip Switchgear II				
	IDS	Class 1E Cables	Note 1	Note 1	Note 1	Note 1

Note:
1. This represents equipment such as cables that have no associated tag number.

Table 9A-3 (Sheet 1 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1000 AF 01	YES								3	SMOKE HEAT	SEE ZONE
1100 AF 11105 REACTOR CAVITY		260	CABLE INS NET CAT.	C C	100 TOTAL:	1.0E+06 1.0E+06	3900	2			HOSE STATION
1100 AF 11204 VERTICAL ACCESS/ RCDT ROOM		790	CABLE INS NET CAT.	C C	100 TOTAL:	1.0E+06 1.0E+06	1300	1			HOSE STATION
1100 AF 11206 PXS VALVE/ ACCUMULATOR ROOM A		790	CABLE INS NET CAT.	C C	200 TOTAL:	2.0E+06 2.0E+06	2600	1			HOSE STATION
1100 AF 11207 PXS VALVE/ ACCUMULATOR ROOM B		750	CABLE INS NET CAT.	C C	200 TOTAL:	2.0E+06 2.0E+06	2700	1			HOSE STATION
1100 AF 11208 RNS VALVE ROOM		310	CABLE INS NET CAT.	C C	200 TOTAL:	2.0E+06 2.0E+06	6600	5			HOSE STATION
1100 AF 11209 CVS ROOM		570	CABLE INS NET CAT.	C C	500 TOTAL:	5.1E+06 5.1E+06	8900	7			HOSE STATION
1100 AF 11300A MAINTENANCE FLOOR SOUTHEAST		1550	CABLE INS TRASH VOLATILES NET CAT.	C B E D	2500 500 10 TOTAL:	2.6E+07 3.9E+06 1.4E+06 3.1E+07	20,000	15			HOSE STATION
1100 AF 11300B MAINTENANCE FLOOR NORTH		3725	CABLE INS TRASH VOLATILES NET CAT.	C B E D	10000 1000 40 TOTAL:	1.0E+08 7.7E+06 5.4E+06 1.2E+08	31,000	23			WATER SPRAY HOSE STATION
1100 AF 11300C MAINTENANCE FLOOR WEST			NEGLIGIBLE								HOSE STATION
1100 AF 11301 SG COMPARTMENT 1		810	CABLE INS NET CAT.	C C	500 TOTAL:	5.1E+06 5.1E+06	6300	5			HOSE STATION
1100 AF 11302 SG COMPARTMENT 2		620	CABLE INS NET CAT.	C C	500 TOTAL:	5.1E+06 5.1E+06	8200	6			HOSE STATION
1100 AF 11303 PRESSURIZER COMPARTMENT		220	CABLE INS NET CAT.	C C	200 TOTAL:	2.0E+06 2.0E+06	9300	7			HOSE STATION
1100 AF 11303A LOWER ADS VALVE AREA		144	CABLE INS NET CAT.	C C	100 TOTAL:	1.0E+06 1.0E+06	7100	5			HOSE STATION
1100 AF 11303B UPPER ADS VALVE AREA		144	CABLE INS NET CAT.	C C	100 TOTAL:	1.0E+06 1.0E+06	7100	5			HOSE STATION

Table 9A-3 (Sheet 2 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1100 AF 11500			CABLE INS	C	12000	1.2E+08					HOSE STATION
OPERATING DECK AND			PAPER	C	500	3.9E+06					
REFUELING CAVITY			VOLATILES		E	55	7.5E+06				
			LUBE OIL	E	10	1.5E+06					
		11150	NET CAT.	D	TOTAL:	1.4E+08	12000	9			
1200 AF 12341			CABLE INS	C	4000	4.1E+07					NONE
MIDDLE ANNULUS			RUBBER	D	1200	1.5E+07					
		1845	NET CAT.	D	TOTAL:	5.5E+07	30000	22			
1200 AF 12541			CABLE INS	C	500	5.1E+06					NONE
UPPER ANNULUS		1685	NET CAT.	C	TOTAL:	5.1E+06	3000	1			
1270 AF 12701			CABLE INS	C	500	5.1E+06					NONE
PCS VALVE ROOM		800	NET CAT.	C	TOTAL:	5.1E+06	6400	5			
1250 AF 12555			CABLE INS	C	4000	4.1E+07					HOSE STATION
VES AIR STORAGE/			PAPER	C	1000	7.7E+06					
OPERATING DECK			TRASH	B	1000	7.7E+06					
STAGING AREA			CLOTH	B	500	4.0E+06					
			WOOD	C	500	4.2E+06					
			PLASTIC	D	500	6.6E+06					
			RUBBER	D	100	1.2E+06					
			VOLATILES	E	10	1.4E+06					
		1200	NET CAT.	D	TOTAL:	7.4E+07	61000	49			
FIRE AREA TOTAL:		27363	NET CAT.	D	TOTAL:	4.5E+08	16000	12			
1200 AF 01	YES								3	SMOKE	SEE ZONE
1200 AF 12241			CABLE INS	C	200	2.0E+06					HOSE STATION
LOWER ANNULUS		1800	NET CAT.	C	TOTAL:	2.0E+06	1100	1			
1200 AF 12461			CABLE INS	C	1000	1.0E+07					HOSE STATION
CORRIDOR			TRASH	B	200	1.5E+06					
		480	NET CAT.	C	TOTAL:	1.2E+07	24000	19			
1205 AF 12362			CABLE INS	C	500	5.1E+06					
RNS HX ROOM			VOLATILES	E	10	1.4E+06					
		275	NET CAT.	E	TOTAL:	6.5E+06	23000	18			
1205 AF 12365			CABLE INS	C	500	5.1E+06					
WASTE MONITOR			PAPER	C	100	7.7E+05					
TANK ROOM B			VOLATILES	E	5	6.8E+05					
		330	NET CAT.	D	TOTAL:	6.6E+06	20000	15			
1210 AF 12151			CABLE INS	C	8000	8.2E+07					HOSE STATION
DEMIN./FILTER,			LUBE OIL	E	10	1.5E+06					
WLS & WGS			VOLATILES	E	10	1.4E+06					
EQUIPMENT ROOMS			PAPER	C	100	7.7E+05					
		1890	NET CAT.	D	TOTAL:	8.5E+07	45000	34			

Table 9A-3 (Sheet 3 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1210 AF 12171			CABLE INS	C	2000	2.0E+07					HOSE STATION
EFFLUENT HOLDUP			PAPER	C	500	3.9E+06					
TANK ROOM A			VOLATILES	E	10	1.4E+06					
		785	NET CAT.	D	TOTAL:	2.6E+07	33000	25			
1214 AF 12152			CABLE INS	C	500	5.1E+06					HOSE STATION
PRIMARY SAMPLE			PAPER	C	100	7.7E+05					
ROOM			PLASTIC	D	200	2.6E+06					
		280	NET CAT.	D	TOTAL:	8.5E+06	30000	23			
1214 AF 12154			CABLE INS	C	200	2.0E+06					HOSE STATION
AUX. BLDG SUMP AND		190	NET CAT.	C	TOTAL:	2.0E+06	11000	8			
SFS PENETRATION ROOM											
1214 AF 12354			CABLE INS	C	200	2.0E+06					
MID ANNULUS		200	NET CAT.	C	TOTAL:	2.0E+06	10000	8			
ACCESS ROOM											
1215 AF 12161			CABLE INS	C	1000	1.0E+07					HOSE STATION
CORRIDOR		580	NET CAT.	D	TOTAL:	1.0E+07	17000	14			
1215 AF 12162			CABLE INS.	C	500	5.1E+06					
RNS PUMP ROOM A			LUBE OIL	E	5	7.6E+05					
		205	NET. CAT.	D	TOTAL	5.9E+06	29000	22			
1216 AF 12166			CABLE INS	C	200	2.0E+06					HOSE STATION
WASTE HOLDUP			VOLATILES	E	10	1.4E+06					
TANK ROOM A		280	NET CAT.	E	TOTAL:	3.4E+06	12000	9			
1216 AF 12167			CABLE INS	C	200	2.0E+06					HOSE STATION
WASTE HOLDUP			VOLATILES	E	10	1.4E+06					
TANK ROOM B		300	NET CAT.	E	TOTAL:	3.4E+06	11000	9			
1216 AF 12169			CABLE INS	C	1000	1.0E+07					HOSE STATION
WLS PUMP ROOM/			LUBE OIL	E	5	7.6E+05					
CORRIDOR			VOLATILES	E	10	1.4E+06					
		475	NET CAT.	E	TOTAL:	1.1E+07	23000	17			
1216 AF 12172			CABLE INS	C	2000	2.0E+07					HOSE STATION
EFFLUENT HOLDUP			PAPER	C	500	3.9E+06					
TANK ROOM B			VOLATILES	E	10	1.4E+06					
		795	NET CAT.	D	TOTAL:	2.6E+07	32000	24			
1216 AF 12264			CABLE INS	C	500	5.1E+06					HOSE STATION
WASTE MONITOR			VOLATILES	E	10	1.4E+06					
TANK ROOM C & CHEM.		660	NET CAT.	E	TOTAL:	6.5E+06	9800	7			
WASTE TANK ROOM											
1220 AF 12251			CABLE INS	C	7000	7.1E+07					WET PIPE (6)
DEMIN./FILTER			PAPER	C	1000	7.7E+06					SPRINKLER
ACCESS AREA AND			PLASTIC	D	200	2.6E+06					HOSE STATION
CVS MAKEUP PUMP			LUBE OIL	E	5	7.6E+05					
ROOMS			VOLATILES	E	10	1.4E+06					
		1750	NET CAT.	D	TOTAL:	8.4E+07	48000	37			

Table 9A-3 (Sheet 4 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1220 AF 12256			CABLE INS.	C	400	4.1E+06					
EL 92′-6″ PIPE		1000	NET CAT.	C	TOTAL:	4.1E+06	4100	2			
CHASE/VALVE ROOM											
1220 AF 12269			CABLE INS	C	100	1.0E+06					HOSE STATION
EL 92′-6″ PIPE CHASE800		NET CAT.	C	TOTAL: 1.0E+06		1300	1				
1220 AF 12271			CABLE INS	C	5000	5.1E+07					HOSE STATION
SFS EQUIPMENT ROOMS			LUBE OIL	E	10	1.5E+06					
			VOLATILES	E	10	1.4E+06					
		1190	NET CAT.	D	TOTAL:	5.4E+07	45000	34			
1224 AF 12252			CABLE INS	C	800	8.2E+06					HOSE STATION
RADIOACTIVE			PAPER	C	500	3.9E+06					
CHEMISTRY			PLASTIC	D	500	6.6E+06					
LABORATORY			VOLATILES	E	5	6.8E+05					
		285	NET CAT.	D	TOTAL:	1.9E+07	68000	55			
1225 AF 12261			CABLE INS	C	3000	3.1E+07					HOSE STATION
WLS PUMP ROOM			LUBE OIL	E	5	7.6E+05					
AND CORRIDOR			VOLATILES	E	5	6.8E+05					
		865	NET CAT.	D	TOTAL:	3.2E+07	37000	28			
1225 AF 12262			CABLE INS.	C	200	2.0E+06					
PIPING/VALVE ROOM			VOLATILES	E	5	6.8E+05					
		475	NET. CAT.	C	TOTAL:	2.7E+06	6000	4			
1234 AF 12351			CABLE INS	C	4000	4.1E+07					
MAINTENANCE			PAPER	C	1000	7.7E+06					
FLOOR STAGING AREA			WOOD	C	1000	8.4E+06					
			TRASH	B	1000	7.7E+06					
			CLOTH	B	500	4.0E+06					
			PLASTIC	D	500	6.6E+06					
			RUBBER	D	200	2.4E+06					
			VOLATILES	E	50	6.8E+06					
		1100	NET CAT.	E	TOTAL:	8.4E+07	77000	58			
1234 AF 12352			CABLE INS	C	500	5.1E+06					
ELEVATION 107′-2″			TRASH	B	200	1.5E+06					
PERSONNEL HATCH		265	NET CAT.	C	TOTAL:	6.6E+06	25000	19			
1235 AF 12361			CABLE INS	C	2000	2.0E+07					HOSE STATION
CORRIDOR			TRASH	B	500	3.9E+06					
		480	NET CAT.	C	TOTAL:	2.4E+07	51000	39			
1235 AF 12363			CABLE INS	C	500	5.1E+06					
WASTE MONITOR			PAPER	C	100	7.7E+05					
TANK ROOM A			VOLATILES	E	5	6.8E+05					
		275	NET CAT.	D	TOTAL:	6.6E+06	24000	18			
1244 AF 12452			CABLE INS	C	500	5.1E+06					
VFS PENETRATION ROOM		265	NET CAT.	C	TOTAL:	5.1E+06	19000	14			
1244 AF 12454			CABLE INS	C	200	2.0E+06					
VFS/SFS/PSS		190	NET CAT.	C	TOTAL:	2.0E+06	11000	8			
PENETRATION ROOM											

Table 9A-3 (Sheet 5 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1250 AF 12561			CABLE INS	C	1000	1.0E+07					HOSE STATION
CCS VALVE ROOM AND			VOLATILES	E	5	6.8E+05					
ACCESS CORRIDOR		630	NET CAT.	D	TOTAL:	1.1E+07	17000	13			
1254 AF 12553			CABLE INS	C	5000	5.1E+07					
ELEVATION 135′-3″			PAPER	C	1000	7.7E+06					
PERSONNEL ACCESS			TRASH	B	500	3.9E+06					
AREA			VOLATILES	E	10	1.4E+06					
		1350	NET CAT.	D	TOTAL:	6.4E+07	47000	36			
1254 AF 12554			CABLE INS	C	400	4.1E+06					
SECURITY ROOMS			PAPER	C	1000	7.7E+06					
		190	NET CAT.	C	TOTAL:	1.2E+07	62000	51			
1264 AF 12651			CABLE INS	C	5000	5.1E+07					
VAS EQUIPMENT			LUBE OIL	E	10	1.5E+06					
ROOM			VOLATILES	E	10	1.4E+06					
		1480	NET CAT.	D	TOTAL:	5.4E+07	36000	27			
FIRE AREA TOTAL:		22115	NET CAT.	D	TOTAL:	6.8E+08	31000	24			HOSE STATION
1200 AF 02	YES								3/0	SMOKE	SEE ZONE
1200 AF 12562			CABLE INS	C	10000	1.0E+08					HOSE STATION
FUEL HANDLING AREA			PAPER	C	1500	1.2E+07					
			WOOD	C	1000	8.4E+06					
			TRASH	B	1000	7.7E+06					
			CLOTH	B	500	4.0E+06					
			PLASTIC	D	500	6.6E+06					
			LUBE OIL	E	15	2.3E+06					
			VOLATILES	E	5	6.8E+05					
		4725	NET CAT.	D	TOTAL:	1.4E+08	30000	23			
1230 AF 12371			CABLE INS	C	3000	3.1E+07					WET PIPE(6)
RAIL CAR BAY/			PAPER	C	1000	7.7E+06					SPRINKLER
FILTER STORAGE AREA			WOOD	C	1000	8.4E+06					HOSE STATION
			TRASH	B	1000	7.7E+06					
			LUBE OIL	E	10	1.5E+06					
			FUEL OIL	E	100	1.4E+07					
		1460	NET CAT.	D	TOTAL:	7.0E+07	48000	37			
1236 AF 12372			CABLE INS	C	200	2.0E+06					HOSE STATION
RESIN TRANSFER PUMP/			LUBE OIL	E	5	7.6E+05					
VALVE ROOM		80	NET CAT.	E	TOTAL:	2.8E+06	35000	26			
1236 AF 12373			CABLE INS	C	200	2.0E+06					HOSE STATION
SPENT RESIN TANK ROOM		70	NET CAT.	C	TOTAL:	2.0E+06	29000	22			
1246 AF 12471			CABLE INS	C	200	2.0E+06					HOSE STATION
WSS VALVE/PIPING AREA		90	NET CAT.	C	TOTAL:	2.0E+06	23000	17			
FIRE AREA TOTAL:		6425	NET CAT.	D	TOTAL:	2.2E+08	34000	26			HOSE STATION

Table 9A-3 (Sheet 6 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1200 AF 03	YES								3	SMOKE	HOSE STATION
1230 AF 12311			CABLE INS	C	1200	1.2E+07					
CORRIDOR		355	NET CAT.	C	TOTAL:	1.2E+07	34000	25			
1242 AF 12411			CABLE INS	C	1200	1.2E+07					
CORRIDOR		300	NET CAT.	C	TOTAL:	1.2E+07	41000	30			
FIRE AREA TOTAL:		655	NET CAT.	C	TOTAL:	2.4E+07	37000	28			
1201 AF 01	NO								2	NONE	NONE
STAIRWELL S02			NEGLIGIBLE								
1201 AF 02	YES								3	SMOKE	HOSE STATION
1211 AF 12104			BATTERIES	A	120	2.4E+07					
DIVISION B BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM 1		560	NET CAT.	C	TOTAL:	3.4E+07	61000	50			
1221 AF 12204			BATTERIES	A	120	2.4E+07					
DIVISION B BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM 2		560	NET CAT.	C	TOTAL:	3.4E+07	61000	50			
1222 AF 12207			CABLE INS	C	2500	2.6E+07					
DIVISION B		395	NET CAT.	C	TOTAL:	2.6E+07	65000	54			
DC EQUIPMENT ROOM											
1231 AF 12304			CABLE INS	C	3500	3.6E+07					
DIVISION B I&C/		585	NET CAT.	C	TOTAL:	3.6E+07	61000	50			
PENETRATION ROOM											
FIRE AREA TOTAL:		2100	NET CAT.	C	TOTAL:	1.3E+08	62000	51			
1201 AF 03	YES								3	SMOKE	HOSE STATION
1211 AF 12105			BATTERIES	A	120	2.4E+07					
DIVISION D BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM		560	NET CAT.	C	TOTAL:	3.4E+07	61000	50			
1221 AF 12205			CABLE INS	C	3500	3.6E+07					
DIVISION D DC		560	NET CAT.	C	TOTAL:	3.6E+07	64000	53			
EQUIPMENT ROOM											
1231 AF 12305			CABLE INS	C	3500	3.6E+07					
DIVISION D I&C/		550	NET CAT.	C	TOTAL:	3.6E+07	65000	55			
PENETRATION ROOM											
FIRE AREA TOTAL:		1670	NET CAT.	C	TOTAL:	1.1E+08	63000	53			

Table 9A-3 (Sheet 7 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1201 AF 04	YES								3	SMOKE	HOSE STATION
1241 AF 12405			CABLE INS	C	3000	3.1E+07					
LOWER VBS B&D			PAPER	C	1000	7.7E+06					
EQUIPMENT ROOM			VOLATILES	E	5	6.8E+05					
		670	NET CAT.	C	TOTAL:	3.9E+07	58000	47			
1251 AF 12505			CABLE INS	C	3000	3.1E+07					
UPPER VBS B&D			PAPER	C	1000	7.7E+06					
EQUIPMENT ROOM			VOLATILES	E	5	6.8E+05					
		705	NET CAT.	C	TOTAL:	3.9E+07	55000	44			
FIRE AREA TOTAL:		1375	NET CAT.	C	TOTAL:	7.8E+07	57000	46			
1201 AF 05	YES								3	SMOKE	HOSE STATION
1231 AF 12306			CABLE INS	C	2500	2.6E+07					
VALVE/PIPING		600	NET CAT.	C	TOTAL:	2.6E+07	43000	31			
PENETRATION ROOM											
1241 AF 12506			CABLE INS	C	3000	3.1E+07					
MSIV COMPARTMENT A			LUBE OIL	E	40	6.0E+06					
		705	NET CAT.	C	TOTAL:	3.7E+07	52000	40			
FIRE AREA TOTAL:		1305	NET CAT.	C	TOTAL:	6.2E+07	48000	37			
1201 AF 06	YES								3	SMOKE	HOSE STATION
MSIV COMPARTMENT B			CABLE INS	C	3000	3.1E+07					
			LUBE OIL	E	40	6.0E+06					
FIRE AREA TOTAL :		695	NET CAT.	E	TOTAL:	3.7E+07	53000	40			
1202 AF 01	NO								2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE								
1202 AF 02	NO								2	SMOKE	HOSE STATION
NORTHEAST ELEVATOR			CABLE INS	C	600	6.1E+06					
SHAFT/MACHINE ROOM			LUBRICANT	E	5	9.9E+04					
FIRE AREA TOTAL:		205	NET CAT.	E	TOTAL:	6.2E+06	30000	23			

Table 9A-3 (Sheet 8 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1202 AF 03	YES								3	SMOKE	HOSE STATION
1212 AF 12102			BATTERIES	A	120	2.4E+07					
DIVISION C BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM 1		560	NET CAT.	C	TOTAL:	3.4E+07	61000	50			
1222 AF 12202			BATTERIES	A	120	2.4E+07					
DIVISION C BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM 2		560	NET CAT.	C	TOTAL:	3.4E+07	61000	50			
1222 AF 12203			CABLE INS	C	2500	2.6E+07					
DIVISION C DC		395	NET CAT.	C	TOTAL:	2.6E+07	65000	54			
EQUIPMENT ROOM											
1232 AF 12302			CABLE INS	C	3500	3.6E+07					
DIVISION C I&C ROOM		550	NET CAT.	C	TOTAL:	3.6E+07	65000	55			
1232 AF 12312			CABLE INS	C	1500	1.5E+07					
DIVISION C RCP TRIP		395	NET CAT.	C	TOTAL:	1.5E+07	39000	29			
SWITCHGEAR ROOM											
1232 AF 12313			CABLE INS	C	2500	2.6E+07					
I&C/DIVISION C		555	NET CAT.	C	TOTAL:	2.6E+07	46000	35			
PENETRATION ROOM											
FIRE AREA TOTAL:		3015	NET CAT.	C	TOTAL:	1.7E+08	57000	45			
1202 AF 04	YES								3	SMOKE	HOSE STATION
1212 AF 12101			BATTERIES	A	120	2.4E+07					
DIVISION A BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM		525	NET CAT.	C	TOTAL:	3.4E+07	65000	55			
1222 AF 12201			CABLE INS	C	3500	3.6E+07					
DIVISION A DC		525	NET CAT.	C	TOTAL:	3.6E+07	68000	58			
EQUIPMENT ROOM											
1232 AF 12301			CABLE INS	C	3500	3.6E+07					
DIVISION A I&C ROOM		550	NET CAT.	C	TOTAL:	3.6E+07	65000	55			
FIRE AREA TOTAL:		1600	NET CAT.	C	TOTAL:	1.1E+08	66000	56			
1202 AF 05	NO								3	SMOKE	NONE
STAIRWELL S05			NEGLIGIBLE								
1204 AF 01	NO								3	SMOKE	HOSE STATION
			CABLE INS	C	500	5.0E+06					
RNS PUMP ROOM B			LUBE OIL	E	5	7.6E05					
		205	NET CAT.	D	TOTAL:	5.8E+06	28000	23			
FIRE AREA TOTAL:		205	NET CAT.	D	TOTAL:	5.8E+06	28000	23			

Table 9A-3 (Sheet 9 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1204 AF 02	NO								2/0	NONE	NONE
STAIRWELL S03			NEGLIGIBLE								
1204 AF 03	NO								2/0	SMOKE	HOSE STATION
SHIELD BLDG			CABLE INS	C	600	6.1E+06					
ELEVATOR			LUBRICANT	E	5	9.9E+04					
FIRE AREA TOTAL:		195	NET CAT.	C	TOTAL:	6.2E+06	32000	24			
1205 AF 01	NO								2	NONE	NONE
STAIRWELL S04			NEGLIGIBLE								
1205 AF 02	NO								2	SMOKE	HOSE STATION
SOUTHEAST ELEVATOR			CABLE INS	C	600	6.1E+06					
SHAFT/MACHINE ROOM			LUBRICANT	E	5	9.9E+04					
FIRE AREA TOTAL:		195	NET CAT.	C	TOTAL:	6.2E+06	32000	24			
1210 AF 01	YES								3	SMOKE	HOSE STATION
1210 AF 12111			CABLE INS	C	3000	3.1E+07					
CORRIDOR			TRASH	B	500	3.9E+06					
		1535	NET CAT.	C	TOTAL:	3.4E+07	22000	16			
1212 AF 12103			BATTERIES	A	120	2.4E+07					
SPARE BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM		825	NET CAT.	C	TOTAL:	3.4E+07	41000	30			
1212 AF 12112			CABLE INS	C	500	5.1E+06					
SPARE ROOM			PAPER	C	1000	7.7E+06					
			PLASTIC	D	500	6.6E+06					
			CLOTH	B	100	8.0E+05					
			TRASH	B	100	7.7E+05					
			VOLATILES	E	10	1.4E+06					
		340	NET CAT.	D	TOTAL:	2.2E+07	66000	53			
1212 AF 12113			CABLE INS	C	1500	1.5E+07					
SPARE BATTERY		190	NET CAT.	C	TOTAL:	1.5E+07	81000	73			
CHARGER ROOM											
FIRE AREA TOTAL:		2890	NET CAT.	C	TOTAL:	1.1E+08	37000	27			

Table 9A-3 (Sheet 10 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1220 AF 01	YES								3	SMOKE	HOSE STATION
1220 AF 12211			CABLE INS	C	3000	3.1E+07					
CORRIDOR			TRASH	B	500	3.9E+06					
		1510	NET CAT.	C	TOTAL:	3.4E+07	23000	17			
1222 AF 12212			CABLE INS	C	1500	1.5E+07					
DIVISION B RCP TRIP SWITCHGEAR ROOM		340	NET CAT.	C	TOTAL:	1.5E+07	45000	34			
1222 AF 12213			CABLE INS	C	1000	1.0E+07					
SPARE ROOM AND			PAPER	C	200	1.5E+06					
MOTOR CONTROL CTRS			TRASH	B	100	7.7E+05					
		190	NET CAT.	C	TOTAL:	1.3E+07	66000	56			
FIRE AREA TOTAL:		2040	NET CAT.	C	TOTAL:	6.2E+07	31000	23			
1220 AF 02	YES								3	SMOKE	HOSE STATION
LOWER ANNULUS			CABLE INS	C	500	5.1E+06					
VALVE AREA											
FIRE AREA TOTAL:		220	NET CAT.	C	TOTAL:	5.1E+06	23000	13			
1230 AF 01	YES								3	SMOKE	HOSE STATION
CORRIDOR			CABLE INS	C	2500	2.6E+07					
FIRE AREA TOTAL:		770	NET CAT.	C	TOTAL:	2.6E+07	33000	24			
1230 AF 02	YES								3	SMOKE	HOSE STATION
NON-1E EQUIPMENT/ PENETRATION ROOM			CABLE INS	C	3500	3.6E+07					PREACTION SPRINKLER
FIRE AREA TOTAL:		870	NET CAT.	C	TOTAL:	3.6E+07	41000	30			
1232 AF 01	YES								3	SMOKE	HOSE STATION
REMOTE SHUTDOWN			CABLE INS	C	1500	1.5E+07					
ROOM			PAPER	C	1000	7.7E+06					
			PLASTIC	D	500	6.6E+06					
FIRE AREA TOTAL:		410	NET CAT.	C	TOTAL:	3.0E+07	72000	63			
1240 AF 01	YES								3	SMOKE	HOSE STATION
NON-1E EQUIPMENT/ PENETRATION ROOM			CABLE INS	C	3500	3.6E+07					
FIRE AREA TOTAL:		800	NET CAT.	C	TOTAL:	3.6E+07	45000	34			

Table 9A-3 (Sheet 11 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
1242 AF 01	YES								3	SMOKE	HOSE STATION
1242 AF 12401A			CABLE INS	C	4000	4.1E+07					
MCR MAIN CONTROL			PAPER	C	3500	2.7E+07					
AREA/TAGGING			PLASTIC	D	1000	1.3E+07					
ROOM/VESTIBULE		1545	NET CAT.	C	TOTAL:	8.1E+07	52000	41			
1242 AF 12401B			CABLE INS	C	2000	2.0E+07					
MCR SHIFT SUP'R/			PAPER	C	3500	2.7E+07					
CLERK/OPERATOR			PLASTIC	D	1000	1.3E+07					
AREAS		845	NET CAT.	C	TOTAL:	6.1E+07	72000	63			
FIRE AREA TOTAL:		2390	NET CAT.	C	TOTAL:	1.4E+08	59000	48			
1242 AF 02	YES								3	SMOKE	HOSE STATION
DIVISION A ELECTRICAL PENETRATION ROOM			CABLE INS	C	2000	2.0E+07					
FIRE AREA TOTAL:		450	NET CAT.	C	TOTAL:	2.0E+07	45000	34			
1243 AF 01	YES								3	SMOKE	HOSE STATION
REACTOR TRIP SWITCHGEAR 1			CABLE INS	C	500	5.1E+06					
FIRE AREA TOTAL:		95	NET CAT.	C	TOTAL:	5.1E+06	54000	42			
1243 AF 02	YES								3	SMOKE	HOSE STATION
REACTOR TRIP SWITCHGEAR 2			CABLE INS	C	500	5.1E+06					
FIRE AREA TOTAL:		95	NET CAT.	C	TOTAL:	5.1E+06	54000	42			
1250 AF 01	NO								3	SMOKE	HOSE STATION
VBS MCR/A&C			CABLE INS	C	12000	1.2E+08					
EQUIPMENT ROOM			CHARCOAL	C	5000	7.3E+07					
			LUBE OIL	E	20	3.0E+06					
			VOLATILES	E	10	1.4E+06					
FIRE AREA TOTAL:		3575	NET CAT.	D	TOTAL:	2.0E+08	56000	44			

Table 9A-3 (Sheet 12 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[(1)]	Safety Area?[(2)]	Floor Area Sq Ft	Combust. Material[(3)]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[(4)] (Hours)	Detect. Cap.	Fixed Suppression Capability[(5)]
2000 AF 01	NO										
				0	SEE ZONE	SEE ZONE					
2030 AF 20300			CABLE INS	C	87000	8.9E+08				HEAT	WET PIPE
ELEVATION 100′-0″			LUBE OIL	E	4000	6.0E+08					SPRINKLERS[(6)]
(BASE SLAB)			PLASTIC	D	12000	1.6E+08					HOSE STATION
GENERAL FLOOR AREA			VOLATILES	E	250	3.4E+07					
			FUEL OIL	E	125	1.8E+07					
			TRASH	B	500	3.9E+06					
		41179	NET CAT.	E	TOTAL:	1.7E+09	41000	31			
2038 AF 20300			CABLE INS	C	3000	3.1E+07				HEAT	PREACTION
MAIN FEEDWATER			LUBE OIL	E	2250	3.4E+08					SPRINKLERS
PUMP AREA			PLASTIC	D	150	2.0E+06					
			VOLATILES	E	55	7.5E+06					
			TRASH	B	200	1.5E+06					
		1342	NET CAT.	E	TOTAL:	3.8E+08	284000	213			
2039 AF 20301			CABLE INS	C	300	3.1E+06				HEAT	WATER SPRAY
CHEMICAL			LUBE OIL	E	250	3.8E+07					HOSE STATION
STORAGE AREA			PLASTIC	D	125	1.7E+06					
			VOLATILES	E	600	8.2E+07					
			TRASH	B	250	1.9E+06					
		1684	NET CAT.	E	TOTAL:	1.3E+08	75000	56			
2040 AF 20400			CABLE INS	C	87000	8.9E+08				HEAT	WET PIPE
ELEVATION 117′-6″			LUBE OIL	E	1400	2.1E+08					SPRINKLERS
GENERAL FLOOR AREA			PLASTIC	D	6000	7.9E+07					HOSE STATION
			VOLATILES	E	55	7.5E+06					
			TRASH	B	1000	7.7E+06					
		42523	NET CAT.	E	TOTAL:	1.2E+09	28000	21			
2050 AF 20500			CABLE INS	C	87000	8.9E+08				HEAT	WET PIPE
ELEVATION 135′-3″			LUBE OIL	E	5400	8.2E+08					SPRINKLERS
GENERAL FLOOR AREA			PLASTIC	D	6000	7.9E+07					HOSE STATION
			VOLATILES	E	100	1.4E+07					
			HYDROGEN	E	50	7.6E+06					
			TRASH	B	50	3.9E+06					
		39462	NET CAT.	E	TOTAL:	1.8E+09	46000	34			
2050 AF 20502			CABLE INS	C	600	6.1E+06				SMOKE	WATER SPRAY
DEH SKID			LUBE OIL	E	250	3.8E+07					HOSE STATION
			PLASTIC	D	150	2.0E+06					
			TRASH	B	100	7.7E+05					
		149	NET CAT.	E	TOTAL:	4.7E+07	313000	235			
2052 AF 20504			CABLE INS	C	150	3.1E+06				SMOKE	HOSE STATION
HVAC EQUIPMENT			PAPER	C	250	3.9E+06					
AREA			PLASTIC	D	125	3.3E+06					
			RUBBER	D	13	3.1E+05					
			TRASH	B	13	2.0E+05					
		1231	NET CAT.	D	TOTAL:	1.1E+07	8700	7			

Table 9A-3 (Sheet 13 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2053 AF 20506			CABLE INS	C	250	2.6E+06				SMOKE	HOSE STATION
VFD POWER			PLASTIC	D	500	6.5E+06					
CONVERTER ROOM			TRASH	B	25	2.0E+05					
		3634	NET CAT.	D	TOTAL:	9.2E+06	15100	12			
2057 AF 20503			CABLE INS	C	2000	2.0E+07				HEAT	WATER SPRAY
GENERATOR SEAL			LUBE OIL	E	400	6.0E+07					HOSE STATION
OIL UNIT			PLASTIC	D	300	4.0E+06					
			VOLATILES	E	55	7.5E+06					
			TRASH	B	200	1.5E+06					
		144	NET CAT.	E	TOTAL:	9.4E+07	651000	488			
2060 AF 20600			CABLE INS	C	1000	1.0E+07				HEAT	WET PIPE
ELEVATION 161′-0″			LUBE OIL	E	250	3.8E+07					SPRINKLERS
GENERAL FLOOR AREA			PLASTIC	D	2500	3.3E+07					HOSE STATION
			VOLATILES	E	55	7.5E+06					
			TRASH	B	1000	7.7E+06					
		44042	NET CAT.	E	TOTAL:	9.6E+07	2200	2			
2063 AF 20601			CABLE INS	C	600	6.1E+06				SMOKE	HOSE STATION
TOOL ROOM/			PAPER	C	600	4.6E+06					
STORAGE AREA			PLASTIC	D	600	7.9E+06					
			RUBBER	D	100	1.2E+06					
			TRASH	B	50	3.9E+05					
		368	NET CAT.	D	TOTAL:	2.0E+07	55000	43			
2063 AF 20602			CABLE INS	C	250	2.6E+06				SMOKE	HOSE STATION
OFFICE AREA/			PAPER	C	1200	9.2E+06					
ENGINEERING			PLASTIC	D	600	7.9E+06					
WORKSTATION			RUBBER	D	100	1.2E+06					
			TRASH	B	50	3.9E+05					
		368	NET CAT.	D	TOTAL:	2.1E+07	58000	46			
FIRE AREA TOTAL:		176358	NET CAT.	E	TOTAL:	3.6E+09	21000	15			
2000 AF 02	NO								2	NONE	NONE
STAIRWELL S02			NEGLIGIBLE								
2003 AF 01	NO								3/0	HEAT	WET PIPE
											SPRINKLER
AUXILIARY BOILER			FUEL OIL	E	2000	2.9E+08					HOSE STATION
ROOM			CABLE INS	C	1600	1.6E+07					
			LUBE OIL	E	100	1.5E+07					
			PLASTIC	D	1000	1.3E+07					
			TRASH	B	1000	7.7E+06					
			VOLATILES	E	250	3.4E+07					
FIRE AREA TOTAL:		1940	NET CAT.	E	TOTAL:	3.7E+08	193000	145			
2009 AF 01	NO								2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE								

Table 9A-3 (Sheet 14 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2009 AF 02	NO								2	SMOKE	HOSE STATION
ELEVATOR			CABLE INS	C	300	3.1E+06					
			LUBRICANT	E	5	9.9E+04					
FIRE AREA TOTAL:		88	NET CAT.	E	TOTAL:	3.2E+06	36000	27			
2033 AF 02	NO								3/0	SMOKE	HOSE STATION
FPS MOTOR DRIVEN			CABLE INS	C	1000	1.0E+07					
PUMP ROOM			LUBE OIL	E	25	3.8E+06					
			PLASTIC	D	100	1.3E+06					
			TRASH	B	75	5.8E+05					
			VOLATILES	E	10	1.4E+06					
FIRE AREA TOTAL:		672	NET CAT.	E	TOTAL:	1.7E+07	26000	33			
2040 AF 01	NO								3	HEAT	WET PIPE SPRINKLER
CLEAN & DIRTY LUBE			CABLE INS	C	1000	1.0E+07					HOSE STATION
OIL STORAGE ROOM			LUBE OIL	E	29000	4.4E+09					
			TRASH	B	100	7.7E+05					
FIRE AREA TOTAL:		791	NET CAT.	E	TOTAL:	4.4E+09	5550000	4163			
2043 AF 01	NO								3/0	HEAT	WET PIPE SPRINKLER
SECONDARY SAMPLING			CABLE INS	C	500	5.1E+06					HOSE STATION
LABORATORY			LUBE OIL	E	110	1.7E+07					
			PLASTIC	D	1000	1.3E+07					
			TRASH	B	1000	7.7E+06					
			VOLATILES	E	250	3.4E+07					
FIRE AREA TOTAL:		1285	NET CAT.	E	TOTAL:	7.7E+07	60000	45			
2050 AF 01	NO								3	HEAT	WATER SPRAY
				HOSE STATION							
LUBE OIL			CABLE INS	C	500	5.1E+06					
RESERVOIR ROOM			LUBE OIL	E	17000	2.6E+09					
			PLASTIC	D	100	1.3E+06					
			TRASH	B	500	3.9E+06					
			VOLATILES	E	100	1.4E+07					
FIRE AREA TOTAL:		1169	NET CAT.	E	TOTAL:	2.6E+09	2216000	1662			
2052 AF 01	NO								2/0	SMOKE	HOSE STATION
TURBINE BUILDING			CABLE INS	C	11000	1.1E+08					
SWITCHGEAR			PLASTIC	D	600	7.9E+06					
ROOM #1			TRASH	B	100	7.7E+05					
			VOLATILES	E	5	6.8E+05					
FIRE AREA TOTAL:		1854	NET CAT.	C	TOTAL:	1.2E+08	66000	55			

Table 9A-3 (Sheet 15 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
2053 AF 01	NO								2/0	SMOKE	HOSE STATION
ELECTRICAL			CABLE INS	C	700	7.1E+06					
EQUIPMENT ROOM			LUBE OIL	E	10	1.5E+06					
			PLASTIC	D	1300	1.7E+07					
			TRASH	B	100	7.7E+05					
			VOLATILES	E	5	6.8E+05					
FIRE AREA TOTAL:		1722	NET CAT.	D	TOTAL:	2.7E+07	16000	11			
2053 AF 02	NO								2/0	SMOKE	HOSE STATION
TURBINE BUILDING			CABLE INS	C	11000	1.1E+08					
SWITCHGEAR			PLASTIC	D	600	7.9E+06					
ROOM #2			TRASH	B	100	7.7E+05					
			VOLATILES	E	5	6.8E+05					
FIRE AREA TOTAL:		2039	NET CAT.	C	TOTAL:	1.2E+08	60000	49			
4001 AF 01	NO								2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE								
4001 AF 02	NO								2	SMOKE	HOSE STATION
ELEVATOR			LUBRICANT	E	5	9.9E+04					
FIRE AREA TOTAL:		65	NET CAT.	E	TOTAL:	9.7E+04	1500	1			
4002 AF 01	NO								2	NONE	NONE
STAIRWELL S02			NEGLIGIBLE								
4002 AF 02	NO								2	NONE	NONE
STAIRWELL S04			NEGLIGIBLE								
4003 AF 01	NO								2/0	SMOKE	HOSE STATION
4003 AF 40340			CABLE INS	C	1530	1.6E+07					
DEMINERALIZED WATER			PAPER	C	100	7.7E+05					
DEOXYGENATING ROOM			WOOD	C	900	7.6E+06					
			PLASTIC	D	30	4.0E+05					
			TRASH	B	50	3.9E+05					
			LUBE OIL	E	7	1.1E+06					
			VOLATILES	E	10	1.4E+06					
		500	NET CAT.	D	TOTAL:	2.7E+07	54000	41			
4003 AF 40442			CABLE INS	C	180	1.8E+06					
BORIC ACID			PAPER	C	100	7.7E+05					
BATCHING ROOM			WOOD	C	600	5.0E+06					
			PLASTIC	D	50	6.6E+05					
			LUBRICANT	E	5	9.9E+04					
		730	NET CAT.	D	TOTAL:	8.4E+06	11500	8			

Table 9A-3 (Sheet 16 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[(1)]	Safety Area?[(2)]	Floor Area Sq Ft	Combust. Material[(3)]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[(4)] (Hours)	Detect. Cap.	Fixed Suppression Capability[(5)]
4003 AF 40503			CABLE INS	C	6200	6.3E+07					
LOWER SOUTH AIR			PAPER	C	10	7.7E+04					
HANDLING EQUIPMENT			RUBBER	D	100	1.2E+06					
ROOM			PLASTIC	D	300	4.0E+06					
			TRASH	B	5	3.9E+04					
			VOLATILES	E	10	1.4E+06					
		3070	NET CAT.	D	TOTAL:	7.0E+07	23000	17			
4003 AF 40601			CABLE INS	C	6200	6.3E+07					
UPPER SOUTH AIR			PAPER	C	10	7.7E+04					
HANDLING EQUIPMENT			RUBBER	D	100	1.2E+06					
ROOM			PLASTIC	D	300	4.0E+06					
			TRASH	B	5	3.9E+04					
			LUBE OIL	E	15	2.3E+06					
			VOLATILES	E	10	1.4E+06					
		3070	NET CAT.	D	TOTAL:	7.2E+07	24000	17			
FIRE AREA TOTAL:		7370	NET CAT.	D	TOTAL:	1.8E+08	24400	18			
4003 AF 02	NO								2	NONE	NONE
STAIRWELL S03			NEGLIGIBLE								
4031 AF 01	NO								2	SMOKE	HOSE STATION
4031 AF 40307			BATTERIES	A	120	2.4E+07					
BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM #1		770	NET CAT.	C	TOTAL:	3.4E+07	44000				
4031 AF 40308			CABLE INS	C	2000	2.0E+07					
BATTERY CHARGER			PAPER	C	200	1.5E+06					
ROOM #1			PLASTIC	D	500	6.6E+06					
		740	NET CAT.	C	TOTAL:	2.9E+07	39000				
FIRE AREA TOTAL:		1510	NET CAT.	D	TOTAL:	6.3E+07	42000	31			
4031 AF 02	NO								2	SMOKE	HOSE STATION
4031 AF 40309			BATTERIES	A	120	2.4E+07					
BATTERY			CABLE INS	C	1000	1.0E+07					
ROOM #2		740	NET CAT.	C	TOTAL:	3.4E+07	46000				
4031 AF 40310			CABLE INS	C	2000	2.0E+07					
BATTERY CHARGER				PAPER	C	200	1.5E+06				
ROOM #2			PLASTIC	D	500	6.6E+06					
		720	NET CAT.	C	TOTAL:	2.9E+07	40000				
4031 AF 40411			CABLE INS	C	1000	1.0E+07					
COMPUTER ROOM B,			PLASTIC	D	100	1.3E+06					
SHIFT TURNOVER ROOM			WOOD	C	250	2.1E+06					
			CLOTH	B	50	4.0E+05					
		1315	NET CAT.	C	TOTAL:	1.4E+07	11000	8			
FIRE AREA TOTAL:		2135	NET CAT.	D	TOTAL:	7.7E+07	36000	27			

Table 9A-3 (Sheet 17 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
4031 AF 05	NO								2/0	SMOKE	HOSE STATION
4031 AF 40300			CABLE INS	C	1000	1.0E+07					
ACCESS CORRIDOR,			PAPER	C	1200	9.2E+06					
ACCESS AREA,			PLASTIC	D	500	6.6E+06					
SECURITY ROOM #2			WOOD	C	500	4.2E+06					
			CLOTH	B	200	1.6E+06					
		1920	NET CAT.	D	TOTAL:	3.2E+07	17000	12			
4031 AF 40303			CABLE INS	C	2000	2.0E+07					
CORRIDOR AND			PAPER	C	1000	7.7E+06					
RESTROOM			PLASTIC	D	500	6.6E+06					
			WOOD	C	500	4.2E+06					
			CLOTH	B	500	4.0E+06					
		1600	NET CAT.	D	TOTAL:	4.3E+07	27000	20			
FIRE AREA TOTAL:		3520	NET CAT.	D	TOTAL:	7.5E+07	21000	16			
4031 AF 06	NO								2	SMOKE	HOSE STATION
CENTRAL ALARM			CABLE INS	C	1075	1.1E+07					
STATION & SECURITY			PAPER	C	200	1.5E+06					
ROOM #1			PLASTIC	D	175	2.3E+06					
			WOOD	C	500	4.2E+06					
			CLOTH	B	100	8.0E+05					
			TRASH	B	20	1.5E+05					
FIRE AREA TOTAL:		640	NET CAT.	D	TOTAL:	2.0E+07	31000	23			
4032 AF 01	NO								2/0	SMOKE	HOSE STATION
HEALTH PHYSICS			CABLE INS	C	4000	4.1E+07					
AREA			WOOD	C	3400	2.9E+07					
			PLASTIC	D	500	6.6E+06					
			RUBBER	D	50	6.1E+05					
			CLOTH	B	1000	8.0E+06					
			PAPER	C	4000	3.1E+07					
			TRASH	B	400	3.1E+06					
			VOLATILES	E	10	1.4E+06					
FIRE AREA TOTAL:		6280	NET CAT.	D	TOTAL:	1.2E+08	19000	14			
4032 AF 02	NO								2/0	SMOKE	HOSE STATION
CONTAINMENT			CABLE INS	C	4800	4.9E+07					WET PIPE
ACCESS CORRIDOR			PAPER	C	5000	3.9E+07					SPRINKLER
			PLASTIC	D	200	2.6E+06					
			FUEL OIL	E	100	1.4E+07					
			VOLATILES	E	50	6.8E+06					
FIRE AREA TOTAL:		2210	NET CAT.	D	TOTAL:	1.1E+08	50000	39			

Table 9A-3 (Sheet 18 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[(1)]	Safety Area?[(2)]	Floor Area Sq Ft	Combust. Material[(3)]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[(4)] (Hours)	Detect. Cap.	Fixed Suppression Capability[(5)]
4033 AF 01	NO								2/0	SMOKE	HOSE STATION
HOT MACHINE SHOP				ACETYLENE		E	150	3.2E+06			
			LUBE OIL	E	20	3.0E+06					
			WOOD	C	1500	1.3E+07					
			CABLE INS	C	3610	3.7E+07					
			LUBRICANT	E	30	5.9E+05					
			PLASTIC	D	150	2.0E+06					
			RUBBER	D	300	3.7E+06					
			CLOTH	B	100	8.0E+05					
			PAPER	C	50	3.9E+05					
			TRASH	B	50	3.9E+05					
			VOLATILES	E	20	2.7E+06					
FIRE AREA TOTAL:		2290	NET CAT.	E	TOTAL:	6.6E+07	29000	22			
4034 AF 01	NO								2/0	SMOKE	NONE
4034 AF 40311			CABLE INS	C	2000	2.0E+07					
CORRIDORS			CLOTH	B	500	4.0E+06					
			PAPER	C	1000	7.7E+06					
			PLASTIC	D	500	6.6E+06					
			WOOD	C	500	4.2E+06					
		1570	NET CAT.	C	TOTAL:	4.3E+07	27000	21			
4034 AF 40313			CABLE INS	C	200	2.0E+06					
OFFICES			CLOTH	B	200	1.6E+06					
			PAPER	C	7000	5.4E+07					
			PLASTIC	D	250	3.3E+06					
			WOOD	C	500	4.2E+06					
		1010	NET CAT.	C	TOTAL:	6.5E+07	64000	54			
4034 AF 40318			CABLE INS	C	1000	1.0E+07					
ALARA BRIEFING			CLOTH	B	500	4.0E+06					
ROOM & OFFICE			PAPER	C	4000	3.1E+07					
			PLASTIC	D	250	3.3E+06					
			WOOD	C	500	4.2E+06					
		1370	NET CAT.	C	TOTAL:	5.3E+07	38000	29			
4034 AF 40320			CABLE INS	C	1000	1.0E+07					
WOMEN'S CHANGE			CLOTH	B	760	6.1E+06					
ROOM			PAPER	C	560	4.3E+06					
			PLASTIC	D	280	3.7E+06					
			TRASH	B	50	3.9E+05					
			WOOD	C	2300	1.9E+07					
		1230	NET CAT.	C	TOTAL:	4.4E+07	36000	26			
4034 AF 40322			CABLE INS	C	1000	1.0E+07					
MEN'S CHANGE			CLOTH	B	1740	1.4E+07					
ROOM			PAPER	C	1440	1.1E+07					
			PLASTIC	D	720	9.5E+06					
			TRASH	B	100	7.7E+05					
			WOOD	C	5500	4.6E+07					
		2860	NET CAT.	C	TOTAL:	9.2E+07	32000	24			
FIRE AREA TOTAL:		8040	NET CAT.	C	TOTAL:	3.0E+08	37000	27			

Table 9A-3 (Sheet 19 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
4035 AF 01	NO		FUEL OIL	E	650	9.4E07			3/0	NONE	DRY PIPE
ANCILLARY DIESEL			LUBE OIL	E	16	2.4E06					SPRINKLERS
GENERATOR			CABLE INS	C	20	2.0E05					HOSE STATION
ROOM			PLASTIC	D	20	2.6E05					
			VOLATILES	E	10	1.4E06					
			CLOTH	B	10	8.0E04					
FIRE AREA TOTAL		230	NET CAT.	E	TOTAL	9.8E07	426,000	320			
4041 AF 01	NO								2/0	SMOKE	HOSE STATION
4041 AF 40403			CABLE INS	C	4000	4.1E+07					
TECHNICAL SUPPORT			PAPER	C	1500	1.2E+07					
CENTER			PLASTIC	D	200	2.6E+06					
			WOOD	C	1000	8.4E+06					
			CLOTH	B	50	4.0E+05					
			TRASH	B	20	1.5E+05					
		3660	NET CAT.	C	TOTAL:	6.4E+07	17000	13			
4041 AF 40410			CABLE INS	C	1000	1.0E+07					
COMPUTER ROOM A,			PLASTIC	D	100	1.3E+06					
CORRIDOR			WOOD	C	250	2.1E+06					
			CLOTH	B	50	4.0E+05					
		1315	NET CAT.	C	TOTAL:	1.4E+07	11000	8			
FIRE AREA TOTAL:		4975	NET CAT.	C	TOTAL:	7.8E+07	16000	12			
4041 AF 02	NO								2	SMOKE	HOSE STATION
CORRIDOR AND			CABLE INS	C	3000	3.1E+07					
RESTROOM			PLASTIC	D	20	2.6E+05					
			TRASH	B	20	1.5E+05					
FIRE AREA TOTAL:		1280	NET CAT.	C	TOTAL:	3.1E+07	24000	18			
4042 AF 01	NO								2/0	SMOKE	HOSE STATION
ELECTRICAL			CABLE INS	C	10000	1.0E+08					
SWITCHGEAR ROOM #1			PLASTIC	D	1100	1.5E+07					
FIRE AREA TOTAL:		3260	NET CAT.	D	TOTAL:	1.2E+08	36000	27			
4042 AF 02	NO								2/0	SMOKE	HOSE STATION
ELECTRICAL			CABLE INS	C	10000	1.0E+08					
SWITCHGEAR ROOM #2			PLASTIC	D	1300	1.7E+07					
FIRE AREA TOTAL:		3230	NET CAT.	D	TOTAL:	1.2E+08	37000	28			

Table 9A-3 (Sheet 20 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4051 AF 01	NO								2/0	SMOKE	HOSE STATION
NORTH AIR HANDLING			CABLE INS	C	12300	1.3E+08					
EQUIPMENT ROOM			PAPER	C	10	7.7E+04					
			LUBE OIL	E	20	3.0E+06					
			PLASTIC	D	350	4.6E+06					
			RUBBER	D	100	1.2E+06					
			TRASH	B	5	3.9E+04					
			VOLATILES	E	10	1.4E+06					
FIRE AREA TOTAL:		7310	NET CAT.	D	TOTAL:	1.4E+08	19000	14			
4052 AF 01	NO								2/0	SMOKE	HOSE STATION
4052 AF 40550			CABLE INS	C	10200	1.0E+08					
STAGING AND			PAPER	C	50	3.9E+05					
STORAGE AREAS			LUBE OIL	E	20	3.0E+06					
			LUBRICANT	E	10	2.0E+05					
			PLASTIC	D	160	2.1E+06					
			RUBBER	D	50	6.1E+05					
			ACETYLENE	E	50	1.1E+06					
			TRASH	B	50	3.9E+05					
			VOLATILES	E	10	1.4E+06					
		8380	NET CAT.	D	TOTAL:	1.1E+08	14000				
4052 AF 40551			CABLE INS	C	500	5.1E+06					
CONTAINMENT AIR			CHARCOAL	C	2500	3.7E+07					
FILTRATION EXHAUST		600	NET CAT.	D	TOTAL:	4.2E+07	69000				
ROOM A											
4052 AF 40552			CABLE INS	C	500	5.1E+06					
CONTAINMENT AIR			CHARCOAL	C	2500	3.7E+07					
FILTRATION EXHAUST		600	NET CAT.	D	TOTAL:	4.2E+07	69000				
ROOM B											
FIRE AREA TOTAL:		9580	NET CAT.	E	TOTAL:	2.0E+08	20500	15			
5031 AF 01	NO								0	SEE ZONE	SEE ZONE
5031 AF 50300			CABLE INS	C	2200	2.2E+07				HEAT	HOSE
ELECTRICAL/			PLASTIC	D	200	2.6E+06					STATION
MECHANICAL			LUBE OIL	E	2	3.0E+05					
EQUIPMENT ROOM			VOLATILES	E	10	1.4E+06					
		1031	NET CAT.	E	TOTAL:	2.5E+07	25000	18			
5031 AF 50350			LUBE OIL	E	70	1.1E+07				HEAT	PREACTION
MOBILE SYSTEMS			LUBRICANT	E	20	4.0E+05					SPRINKLERS
FACILITY			CABLE INS	C	4300	4.4E+07					HOSE STATION
			CLOTH	B	70	5.6E+05					
			PLASTIC	D	250	3.3E+06					
			BATTERIES	A	1	2.0E+05					
			GASOLINE	E	60	7.7E+06					
			WOOD	C	400	3.4E+06					
			RUBBER	D	1400	1.7E+07					
			VOLATILES	E	10	1.4E+06					
			ACETYLENE	E	30	6.5E+05					
		6300	NET CAT.	E	TOTAL:	8.9E+07	14000	11			

Table 9A-3 (Sheet 21 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone(1)	Safety Area?(2)	Floor Area Sq Ft	Combust. Material(3)	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.(4) (Hours)	Detect. Cap.	Fixed Suppression Capability(5)
5031 AF 50351			LUBE OIL	E	300	4.5E+07				HEAT	PREACTION
WASTE ACCUMULATION			CABLE INS	C	1500	1.5E+07					SPRINKLERS
ROOM			CLOTH	B	10000	8.0E+07					HOSE STATION
			PAPER	C	2500	1.9E+07					
			TRASH	B	31000	2.4E+08					
			PLASTIC	D	500	6.6E+06					
			WOOD	C	400	3.4E+06					
			RUBBER	D	500	6.1E+06					
			VOLATILES	E	10	1.4E+06					
		1500	NET CAT.	E	TOTAL:	4.2E+08	277000	208			
5031 AF 50352			CABLE INS	C	500	5.1E+06				HEAT	PREACTION
PACKAGED WASTE			PLASTIC	D	50	6.6E+05					SPRINKLERS
STORAGE ROOM			WOOD	C	400	3.4E+06					HOSE STATION
		810	NET CAT.	D	TOTAL:	9.1E+06	11000	8			
5031 AF 50353			CABLE INS	C	1100	1.1E+07				HEAT	HOSE STATION
HVAC EQUIPMENT			PLASTIC	D	20	2.6E+05					
ROOM			LUBE OIL	E	2	3.0E+05					
			VOLATILES	E	10	1.4E+06					
		840	NET CAT.	D	TOTAL:	1.3E+07	16000	11			
FIRE AREA TOTAL:		10481	NET CAT.	E	TOTAL:	5.5E+08	53000	40			
6030 AF 01	NO								3/0	SEE ZONE	SEE ZONE
6030 AF 60310			CABLE INS	C	1000	1.0E+07				NONE	DRY PIPE
DIESEL GENERATOR			FUEL OIL	E	100	1.4E+07					SPRINKLERS
ROOM A			LUBE OIL	E	500	7.6E+07					HOSE STATION
		1450	NET CAT.	E	TOTAL:	1.0E+08	69000	52			
6030 AF 60311			CABLE INS	C	2000	2.0E+07				SMOKE	HOSE STATION
SERVICE MODULE A			PAPER	C	100	7.7E+05					
		300	NET CAT.	C	TOTAL:	2.1E+07	71000	62			
6030 AF 60313			CABLE INS	C	500	5.1E+06				NONE	HOSE STATION
COMBUSTION AIR			PAPER	C	1000	7.7E+06					
CLEANER AREA A		290	NET CAT.	C	TOTAL:	1.3E+07	44000	33			
FIRE AREA TOTAL:		2040	NET CAT.	E	TOTAL:	1.3E+08	66000	49			
6030 AF 02	NO								3/0	SEE ZONE	SEE ZONE
6030 AF 60320			CABLE INS	C	1000	1.0E+07				NONE	DRY PIPE
DIESEL GENERATOR			FUEL OIL	E	100	1.4E+07					SPRINKLERS
ROOM B			LUBE OIL	E	500	7.6E+07					HOSE STATION
		1450	NET CAT.	E	TOTAL:	1.0E+08	69000	52			
6030 AF 60321			CABLE INS	C	2000	2.0E+07				SMOKE	HOSE STATION
SERVICE MODULE B			PAPER	C	100	7.7E+05					
		300	NET CAT.	C	TOTAL:	2.1E+07	71000	62			
6030 AF 60323			CABLE INS	C	500	5.1E+06				NONE	HOSE STATION
COMBUSTION AIR			PAPER	C	1000	7.7E+06					
CLEANER AREA B		290	NET CAT.	C	TOTAL:	1.3E+07	44000	33			
FIRE AREA TOTAL:		2040	NET CAT.	E	TOTAL:	1.3E+08	66000	49			

Table 9A-3 (Sheet 22 of 22)

FIRE PROTECTION SUMMARY

Fire Area/ Zone[(1)]	Safety Area?[(2)]	Floor Area Sq Ft	Combust. Material[(3)]	Fire Sev. Cat.	Amount	Heat Value (Btu)	Comb. Load, Btu/ Sq Ft	Equiv. Dur. (Min)	Boundary Fire Res.[(4)] (Hours)	Detect. Cap.	Fixed Suppression Capability[(5)]
6030 AF 03	NO								3	NONE	DRY PIPE SPRINKLERS HOSE STATION
DIESEL FUEL DAY TANK VAULT A			FUEL OIL	E	1500	2.2E+08					
FIRE AREA TOTAL:		100	NET CAT.	E	TOTAL:	2.2E+08	2160000	1620			
6030 AF 04	NO								3	NONE	DRY PIPE SPRINKLERS HOSE STATION
DIESEL FUEL DAY TANK VAULT B			FUEL OIL	E	1500	2.2E+08					
FIRE AREA TOTAL:		100	NET CAT.	E	TOTAL:	2.2E+08	2160000	1620			

Notes:

1. The first four digits of the fire area and fire zone numbers indicate the building, level and building area in which the fire area/zone is located. When the third or fourth digit is a zero, the fire area/zone spans more than one level or building area. The last two digits in a fire area number are a sequence number only. The last five digits in a fire zone number coincide with the room number of a prominent room in the fire zone.
2. A YES indication in the Safety Area column means that one or more safety-related components are located in the fire area.
3. Estimated quantities of combustible materials are shown. Where the presence of transient combustibles is anticipated, their presence is indicated by the listing of volatiles or trash. The units and heat of combustion values for the combustible materials are shown in Table 9A-1.
4. The boundary fire resistance for each fire area represents the minimum resistance, in hours, for the surrounding walls, floor, and ceiling, except that:
   - A non-rated barrier capable of qualifying as a three-hour barrier is considered to have a resistance of three hours, provided that penetrations are adequately sealed.
   - Stairwells, elevator shafts and the like, which are enclosed by two-hour (minimum) fire barrier walls, may comprise a portion of the boundary of a fire area having a three hour resistance.
   - Building exterior walls below grade (soil on the outside) are considered to have a fire resistance of at least three hours even though they are not fire-rated.

   A boundary fire resistance designation such as "3/0" indicates that part of the fire area boundary consists of nonrated building exterior walls/roof above grade, but that the minimum resistance of the fire barriers separating the fire area from adjacent fire areas is three hours. For detailed information about the fire resistance of fire area boundaries see Figures 9A-1 through 9A-6.
5. The fixed suppression capability is indicated for each fire area. Unless otherwise indicated, sprinkler and spray systems are automatic. Where a hose station is indicated, one or more hose streams are available. In addition to fixed suppression capability, portable extinguishers are provided throughout the plant.
6. Partial suppression coverage in this zone. See DCD 9A.3, Fire Protection Analysis Results, for details.

Table 9A-4

VENTILATION SYSTEMS SERVING FIRE AREAS CONTAINING CLASS 1E COMPONENTS

Fire Area	RCA	Class 1E Components	Ventilation System - Subsystem	Distribution Header
Ventilation Systems Serving Fire Areas Containing Class 1E Division A and C Components				
1202 AF 04	No	Division A batteries and equipment	VBS - A&C	AC-1
1242 AF 02	No	Division A equipment and penetrations	VBS - A&C	AC-1
1202 AF 03	No	Division C batteries, equipment & penetrations	VBS - A&C	AC-2
1230 AF 01	No	Division A & C cable only	VBS - B&D	BD-3
1240 AF 01	No	Division A & C cable only	VXS - Equip. room	Aux. building
1200 AF 01	Yes	Division A valves; division A & C cable	VAS - Aux/annex	Aux/annex
1200 AF 02	Yes	Division A & C cable only	VAS - Fuel handling	Fuel handling
Ventilation Systems Serving Fire Areas Containing Class 1E Division B and D Components				
Fire Area	**RCA**	**Class 1E Components**	**Ventilation System - Subsystem**	**Distribution Header**
1201 AF 02	No	Division B batteries, equipment & penetrations	VBS - B&D	BD-1
1201 AF 03	No	Division D batteries, equipment & penetrations	VBS - B&D	BD-2
1201 AF 04	No	Division D valves	VBS - B&D	BD-Common
1200 AF 03	No	Division B & D cable only	VBS - A&C	AC-3
1220 AF 01	No	Division B equipment; division B & D cable	VBS - A&C	AC-3
1201 AF 05	No	Division B & D valves & instrumentation	VXS	Self-contained
1201 AF 06	No	Division B & D valves & instrumentation	VXS	Self-contained
1230 AF 02	No	Division B & D cable only	VXS - Equip. Room	Aux. building
1220 AF 02	Yes	Division D valves	VAS - Aux/annex	Aux. building
Ventilation Systems Serving Principal Class 1E Fire Areas				
Fire Area	**RCA**	**Description**	**Ventilation System - Subsystem**	**Distribution Header**
1242 AF 01	No	Main control room	VBS - MCR/TSC	MCR
1232 AF 01	No	Remote shutdown room	VBS - B&D	BD-3
1210 AF 01	No	Spare battery fire area	VBS - A&C	AC-3
1243 AF 01	No	Reactor trip switchgear I	VXS - Equip. room	Aux. building
1243 AF 02	No	Reactor trip switchgear II	VXS - Equip. room	Aux. building
1000 AF 01	Yes	Containment/shield building	VFS	A and B

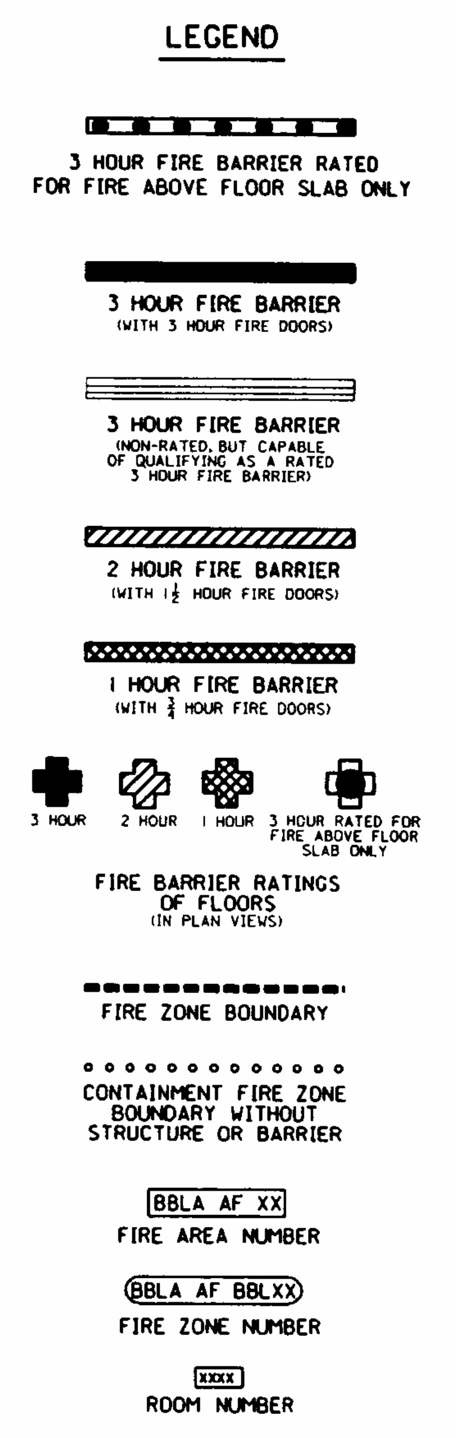

Figure 9A-1 (Sheet 1 of 16)

[*Fire Areas Legend*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 2 of 16)

[*Nuclear Island Fire Area Plan at Elevation 66′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 3 of 16)

[*Nuclear Island Fire Area Plan at Elevation 82′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 4 of 16)

[*Nuclear Island Fire Area Plan at Elevation 96′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 5 of 16)

[***Nuclear Island Fire Areas***
Plan at Elevation 100′-0″ & 107′-2″]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 6 of 16)

[*Nuclear Island Fire Area Plan at Elevation 117′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 7 of 16)

[*Nuclear Island Fire Area Plan at Elevation 135′-3″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 8 of 16)

[*Nuclear Island Fire Areas Plan at Elevation 153′-0″ & 160′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 9 of 16)

[*Nuclear Island Fire Areas*
Plan at Elevation 160′-6″ & 180′-0″]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 10 of 16)

[*Nuclear Island Fire Area Section A-A*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 11 of 16)

[*Nuclear Island Fire Area Section B-B*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 12 of 16)

[*Nuclear Island Fire Areas Section C-C & H-H*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 13 of 16)

[*Nuclear Island Fire Area Section G-G*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 14 of 16)

[*Nuclear Island Fire Area Section J-J*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 15 of 16)

[*Nuclear Island Fire Area Section K-K*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-1 (Sheet 16 of 16)

**[*Nuclear Island Fire Areas
Section I-I & R-R*]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-2 (Sheet 1 of 5)

[***Turbine Building Fire Area Plan at Elevation 100′-0″***]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-2 (Sheet 2 of 5)

[*Turbine Building Fire Area Plan at Elevation 117′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-2 (Sheet 3 of 5)

[***Turbine Building Fire Area Plan at Elevation 135′-3″***]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-2 (Sheet 4 of 5)

[*Turbine Building Fire Area Plan at Elevation 161′-0″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-2 (Sheet 5 of 5)

[***Turbine Building Fire Areas***
Plan at Elevation 194′-0″ & 224′-10″]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-3 (Sheet 1 of 3)

**[*Annex I & II Building Fire Areas
Plan at Elevation 100′-0″ & 107′-2″*]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-3 (Sheet 2 of 3)

[*Annex I & II Building Fire Area Plan at Elevation 117′-6″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-3 (Sheet 3 of 3)

[*Annex I & II Building Fire Area Plan at Elevation 135′-3″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-4

[*Radwaste Building Fire Area Plan at Elevation 100′-0″*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 9A-5

[*Diesel Generator Building Fire Area Plan at Elevation 100'-0"*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

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CHAPTER 10

STEAM AND POWER CONVERSION

10.1 Summary Description

The steam and power conversion system is designed to remove heat energy from the reactor coolant system via the two steam generators and to convert it to electrical power in the turbine-generator. The main condenser deaerates the condensate and transfers heat that is unusable in the cycle to the circulating water system. The regenerative turbine cycle heats the feedwater, and the main feedwater system returns it to the steam generators.

Table 10.1-1 gives the significant design and performance data for the major system components. Figure 10.1-1 shows the heat balance for the turbine cycle process.

10.1.1 General Description

The steam generated in the two steam generators is supplied to the high-pressure turbine by the main steam system. After expansion through the high-pressure turbine, the steam passes through the two moisture separator/reheaters (MSRs) and is then admitted to the three low-pressure turbines. A portion of the steam is extracted from the high- and low-pressure turbines for six stages of feedwater heating.

Exhaust steam from the low-pressure turbines is condensed and deaerated in the main condenser. The heat rejected in the main condenser is removed by the circulating water system (CWS). The condensate pumps take suction from the condenser hotwell and deliver the condensate through four stages of low-pressure closed feedwater heaters to the fifth stage, open deaerating heater. Condensate then flows to the suction of the steam generator feedwater booster pump and is discharged to the suction of the main feedwater pump. The steam generator feedwater pumps discharge the feedwater through one stage of high-pressure feedwater heating to the two steam generators.

The moisture separator drains are pumped to the deaerator. The reheater drains and high-pressure feedwater heater drains cascade into the deaerator. Drains from the low-pressure feedwater heaters are cascaded through successively lower pressure feedwater heaters to the main condenser.

The turbine-generator has an output of about 1,199,500 kW for the Westinghouse nuclear steam supply system (NSSS) thermal output of 3,415 MWt. The principal turbine-generator conditions for the turbine rating are listed in Table 10.1-1. The rated system conditions for the NSSS are listed in Table 10.1-1. The systems of the turbine cycle have been designed to meet the maximum expected turbine generator conditions.

Instrumentation systems are designed for the normal operating conditions of the steam and condensate systems. The systems are designed for safe and reliable control and incorporate requirements for performance calculations and periodic heat balances. Instrumentation for the secondary cycle is also provided to meet recommendations by the turbine supplier and ANSI/ASME TDP-2-1985, "Recommended Practices for the Prevention of Water Damage to

Steam Turbines Used for Electric Power Generation." Design features for prevention of water hammer in the steam generator are described in subsection 5.4.2.2. Continuous sampling instrumentation and grab sample points are provided so that water chemistry in the secondary cycle can be maintained within acceptable limits, as required by the nuclear steam system and turbine suppliers (see subsections 9.3.4 and 10.3.5). Condenser tube/tube sheet leakage can be identified and isolated by using condenser conductivity sampling provisions.

Criteria and bases for safety-related instrumentation for main steam isolation are discussed in Section 7.3.

10.1.2 Protective Features

Loss of External Electrical Load and/or Turbine Trip Protection

In the event of turbine trip, steam is bypassed to the condenser via the turbine bypass valves and, if required, to the atmosphere via the atmospheric relief valves. Steam relief permits energy removal from the reactor coolant system. Load rejection capability is discussed in subsections 10.3.2.3.1 and 15.2.2.

Overpressure Protection

Spring-loaded safety valves are provided on both main steam lines, in accordance with the ASME Code, Section III. The pressure relief capacity of the safety valves is such that the energy generated at the high-flux reactor trip setting can be dissipated through this system. The design capacity of the main steam safety valves equals or exceeds 105 percent of the NSSS design steam flow at an accumulation pressure not exceeding 110 percent of the main steam system design pressure. Overpressure protection for the main steam lines is a safety-related function. The main steam safety valves are described in subsection 10.3.2.

In addition, the shell sides of the feedwater heaters and the moisture separator/reheaters are provided with overpressure protection in accordance with ASME Code, Section VIII, Division 1, or equivalent standards.

Loss of Main Feedwater Flow Protection

The startup feedwater pumps provide feedwater to the steam generators for the removal of sensible and decay heat whenever main feedwater flow is interrupted, including loss of offsite electric power. This system is described in subsection 10.4.9.

Turbine Overspeed Protection

During normal operations, turbine overspeed protection is provided by the governing action of the electro-hydraulic control system. Additional protection is provided by an emergency trip system which continuously monitors critical turbine parameters on a multi-channel basis. Each of the channels is independently testable under load with overspeed protection during testing provided by the channels not being tested. If turbine speed exceeds 110 percent of rated speed, the electronic emergency trip system causes steam supply valves to close, tripping the unit. This system is described in subsection 10.2.2.5.

Turbine Missile Protection

Turbine disk integrity minimizes the probability of generating turbine missiles and is discussed in subsection 10.2.3. Turbine missiles are addressed in subsection 3.5.1.3. The favorable orientation of the turbine-generator directs potential missiles away from safety-related equipment and structures.

Radioactivity Protection

Under normal operating conditions, there are no significant radioactive contaminants present in the steam and power conversion system. However, it is possible for the system to become contaminated through steam generator tube leakage. In this event, radiological monitoring of the main condenser air removal system, the steam generator blowdown system, and the main steam lines will detect contamination and alarm high radioactivity concentrations. A discussion of the radiological aspects of primary-to-secondary system leakage and limiting conditions for operation is contained in Chapter 11. The steam generator blowdown system described in subsection 10.4.8 and the condensate polishing system described in subsection 10.4.6 serve to limit the radioactivity level in the secondary cycle.

Erosion-Corrosion Protection

Erosion-corrosion resistant materials are used in steam and power conversion systems for components exposed to single-phase or two-phase flow where significant erosion can occur. Factors considered in the evaluation of erosion-corrosion include system piping and component configuration and geometry, water chemistry, piping and component material, fluid temperature, and fluid velocity. Carbon steel with only carbon and manganese alloying agents is not used for applications subject to significant erosion-corrosion.

In addition to material selection, pipe size and layout may also be used to minimize the potential for erosion-corrosion in systems containing water or two-phase flow. The secondary side water chemistry (see subsection 10.3.5) uses a volatile pH adjustment chemical to maintain a noncorrosive environment. Steam and power conversion systems are designed to facilitate inspection and erosion-corrosion monitoring programs.

An industry-sponsored computer program developed for nuclear and fossil power plant applications is used to evaluate the rate of wall thinning for components and piping potentially susceptible to erosion-corrosion. The engineering models are the result of research and development in the fields of material science, water chemistry, fluid mechanics, and corrosion engineering. The program quantifies the benefits of piping material, system layout, and sizing considerations used to reduce corrosion rates.

10.1.3 Combined License Information on Erosion-Corrosion Monitoring

The Combined License holder will address preparation of an erosion-corrosion monitoring program for carbon steel portions of the steam and power conversion systems that contain water or wet steam. This monitoring program will address industry guidelines and the requirements included in Generic Letter 89-08.

Table 10.1-1

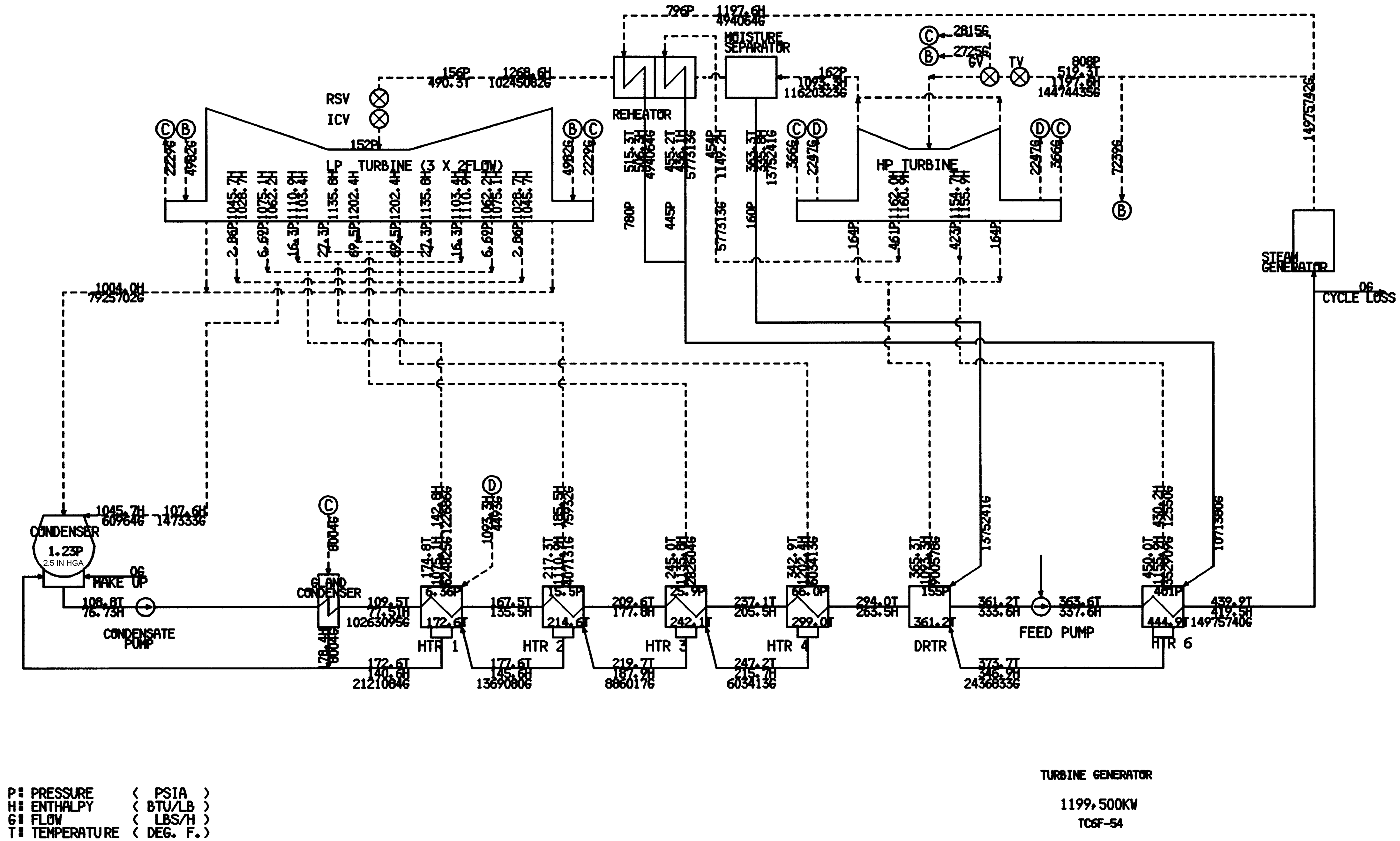
SIGNIFICANT DESIGN FEATURES AND PERFORMANCE CHARACTERISTICS FOR MAJOR STEAM AND POWER CONVERSION SYSTEM COMPONENTS

Nuclear Steam Supply System, Full Power Operation

Rated NSSS power (MWt)	3415
Steam generator outlet pressure (psig)	823
Steam generator inlet feedwater temperature (°F)	440
Maximum steam generator outlet steam moisture (%)	0.25
Steam generator outlet steam temperature (°F)	523
Quantity of steam generators	2
Flow rate per steam generator (lb/hr)	7.49×10^6

Turbine

Output (kW)	1,199,500 kW (heat balance value)
Turbine type	Tandem-compound, 6-flow, 54-in. last-stage blade
Turbine elements	1 high pressure 3 low pressure
Operating speed (rpm)	1800



$$\text{GROSS HEAT RATE} = \frac{14{,}975{,}742^{*}\ (1197.6 - 419.5)}{1199{,}500} = 9715\ \text{Btu/kW-Hr}$$

Figure 10.1-1

Heat Balance

10.2 Turbine-Generator

The function of the turbine-generator is to convert thermal energy into electric power.

10.2.1 Design Basis

10.2.1.1 Safety Design Basis

The turbine-generator serves no safety-related function and therefore has no nuclear safety design basis.

10.2.1.2 Power Generation Design Basis

The following is a list of the principal design features:

- The turbine-generator is designed for baseload operation and for load follow operation.
- The main turbine system (MTS) is designed for electric power production consistent with the capability of the reactor and the reactor coolant system.
- The turbine-generator is designed to trip automatically under abnormal conditions.
- The system is designed to provide proper drainage of related piping and components to prevent water induction into the main turbine.
- The main turbine system satisfies the recommendations of Nuclear Regulatory Commission Branch Technical Position ASB 3-1 as related to breaks in high-energy and moderate-energy piping systems outside containment. The main turbine system is considered a high-energy system.
- The system provides extraction steam for six stages of regenerative feedwater heating.

10.2.2 System Description

The turbine-generator is designated as a TC6F 54-inch last-stage blade unit consisting of turbines, a generator, external moisture separator/reheaters, exciter, controls, and auxiliary subsystems. (See Figure 10.2-1.) The major design parameters of the turbine-generator and auxiliaries are presented in Table 10.2-1. The piping and instrumentation diagram containing the stop, governing control, intercept, and reheat valves is shown in Figure 10.3.2-2.

The turbine-generator and associated piping, valves, and controls are located completely within the turbine building. There are no safety-related systems or components located within the turbine building. The probability of destructive overspeed condition and missile generation, assuming the recommended inspection and test frequencies, is less than 1×10^{-5} per year. In addition, orientation of the turbine-generator is such that a high-energy missile would be directed at a 90 degree angle away from safety-related structures, systems, or components. Failure of turbine-generator equipment does not preclude safe shutdown of the reactor. The

turbine-generator components and instrumentation associated with turbine-generator overspeed protection are accessible under operating conditions.

10.2.2.1 Turbine-Generator Description

The turbine is a 1800-rpm, tandem-compound, six-flow, reheat unit with 54-inch last-stage blades (TC6F 54-inch LRB). The high-pressure turbine element includes one double-flow, high-pressure turbine. The low-pressure turbine elements include three double-flow, low-pressure turbines and two external moisture separator/reheaters (MSRs) with two stages of reheating. The single direct-driven generator is water cooled and rated at 1375 MVA at 0.90 PF. Other related system components include a complete turbine-generator bearing lubrication oil system, a digital electrohydraulic (DEH) control system with supervisory instrumentation, a turbine steam sealing system (refer to subsection 10.4.3), overspeed protective devices, turning gear, a stator cooling water system, a generator hydrogen and seal oil system, a generator CO_2 system, an exciter cooler, a rectifier section, an exciter, and a voltage regulator.

The turbine-generator foundation is a spring-mounted support system. A spring-mounted turbine-generator provides a low-tuned, turbine-pedestal foundation. The springs dynamically isolate the turbine-generator deck from the remainder of the structure in the range of operating frequencies, thus allowing for an integrated structure below the turbine deck. The condenser is supported on springs and attached rigidly to the low-pressure turbine exhausts.

The foundation design consists of a reinforced concrete deck mounted on springs and supported on a structural steel frame that forms an integral part of the turbine building structural system. The lateral bracing under the turbine-generator deck also serves to brace the building frame. This "integrated" design reduces the bracing and number of columns required in the building. Additionally, the spring-mounted design allows for dynamic uncoupling of the turbine-generator foundation from the substructure. The spring mounted support system is much less site dependent than other turbine pedestal designs, since the soil structure is decoupled from turbine dynamic effects. The turbine-generator foundation consists of a concrete table top while the substructure consists of supporting beams and columns. The structure below the springs is designed independent of vibration considerations. The turbine-generator foundation and equipment anchorage are designed to the same seismic design requirement as the turbine building. See subsection 3.7.2.8 for additional information on seismic design requirements. See subsection 10.4.1.2 for a description of the support of the condenser.

10.2.2.2 Turbine-Generator Cycle Description

Steam from each of two steam generators enters the high-pressure turbine through four stop valves and four governing control valves; each stop valve is in series with one control valve. Crossties are provided upstream of the turbine stop valves to provide pressure equalization with one or more stop valves closed. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheater vessels. The external moisture separators reduce the moisture content of the high-pressure exhaust steam from approximately 10 to 13 percent at the rated load to approximately 0.17 percent moisture or less.

The AP1000 employs a 2 stage reheater, of which the first stage reheater uses the extraction steam from the high pressure turbine and the second reheater uses a portion of the main steam supply to reheat the steam to superheated conditions. The reheated steam flows through separate reheat stop and intercept valves in each of six reheat steam lines leading to the inlets of the three low-pressure turbines. Turbine steam extraction connections are provided for six stages of feedwater heating. Steam from the extraction point of the high-pressure turbine is supplied to high-pressure feedwater heater No. 6. The high-pressure turbine exhaust supplies steam to the deaerating feedwater heater. The low-pressure turbine third, fourth, fifth, and sixth extraction points supply steam to the low-pressure feedwater heaters No. 4, 3, 2, and 1, respectively.

Moisture is removed at a number of locations in the blade path. Drainage holes drilled through the blade rings provide moisture removal from blade rings located in high moisture zones. The effectiveness of moisture removal at these locations is enhanced by moisture nonreturn catchers which trap a large portion of the water from the blade path and direct it to the moisture removal system.

The external moisture separator/reheaters use multiple vane chevron banks (shell side) for moisture removal. The moisture removed by the external moisture separator/reheaters drain to a moisture separator drain tank and is pumped to the deaerator.

Condensed steam in the reheater (tube side) is drained to the reheater drain tank, flows into the shell side of the No. 6 feedwater heater, and cascades to the deaerator.

10.2.2.3 Exciter Description

The excitation system is a brushless exciter with a solid-state voltage regulator. Excitation power is obtained from the rotating shaft, which is directly connected to the main generator shaft. The brushless exciter consists of three parts: a permanent magnet pilot exciter, a main ac exciter, and a rectifier wheel. The exciter rectifiers are arranged in a full-wave bridge configuration and protected by a series-connected fuse. The turbine building closed cooling water system (TCS) provides cooling water to the exciter air-to-water heat exchangers.

10.2.2.4 Digital Electrohydraulic System Description

The turbine-generator is equipped with a digital electrohydraulic (DEH) system that combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, and automatic turbine control (ATC), which may be used, either for control or for supervisory purposes, at the option of the plant operator.

The DEH system employs three electric speed inputs whose signals are processed in redundant processors. Valve opening actuation is provided by a hydraulic system that is independent of the bearing lubrication system. Valve closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. The system is designed so that loss of fluid pressure, for any reason, leads to valve closing and consequent turbine trip.

Steam valves are provided in series pairs. A stop valve is tripped by the overspeed trip system; the control valve is modulated by the governing system and is actuated by the trip system.

10.2.2.4.1 Speed Control

The speed control function of the DEH provides speed control, acceleration, and overspeed protection functions. The speed control function produces a speed error signal, which is fed to the load control unit. The speed error signal is derived by comparing the desired speed with the actual speed of the turbine at steady-state conditions or by comparing the desired acceleration rate with the actual acceleration rate during startup.

The speed select algorithm receives three speed signals, performs a two-out-of-three comparison, compares the result to the speed reference signal, and transmits the error signal demanding the appropriate speed to the speed controller. A failure of one speed input generates an alarm. Failure of two or more speed inputs also generates an alarm and changes speed control to a manual mode of operation where automatic compensation for speed changes (except overspeed protection) will not occur.

The speed control function exists in two redundant channels, a primary and a backup. If the primary channel fails, the backup channel takes over automatically. If the backup channel fails, the primary channel will maintain control. In the event that both channels are lost, the turbine trips.

A trip signal is sent to a fast acting solenoid valve which actuates each control valve and intercept valve. Energizing these solenoid valves releases the hydraulic fluid pressure in the valve actuators, allowing springs to close each valve.

The speed control function is designed to slowly vary the rotor speed above and below critical frequencies when operating near critical speed. This will prevent the turbine from running at a constant speed near critical blade resonances.

10.2.2.4.2 Load Control

The load control function of the DEH develops signals that are used to regulate unit load. Signal outputs are based on a proper combination of the speed error, impulse pressure, and actual load (turbine megawatt) reference signals.

Steam flow is not controlled directly but rather by a characterization of turbine megawatt and valve position. Under normal conditions, the turbine requests a certain megawatt load target. Through a coordinated mode of control, the turbine valves adjust the steam flow from the steam generators supplied to the turbine.

10.2.2.4.3 Valve Control

The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. Each stop valve is controlled by an electrohydraulic actuator, so that the stop valve is either fully open or fully closed. The function of the stop valves is to shut off the steam flow to the turbine when required. The stop valves are closed by actuation of the emergency trip system devices. These devices are independent of the electronic flow control unit.

The turbine control valves are positioned by electrohydraulic servo actuators in response to signals from their respective flow control unit. The flow control unit signal positions the control valves for wide-range speed control through the normal turbine operating range, and for load control after the turbine-generator unit is synchronized.

The reheat stop and intercept valves, located in the hot reheat lines at the inlet to the low-pressure turbines, control steam flow to the low-pressure turbines. During normal operation of the turbine, the reheat stop and intercept valves are wide open. The intercept valve flow control unit positions the valve during startup and normal operations and closes the valve rapidly on loss of turbine load. The reheat stop valves close completely on turbine overspeed and turbine trip.

The control, stop, reheat stop, and intercept valves have dump valves connected to the hydraulic portion of their respective valve actuators. Opening a dump valve causes the connected control or stop valve to rapidly close. The dump valve actuators are connected to trip headers and open in response to loss of pressure in the connected trip header. The control and intercept dump valves are connected to the DEH overspeed protection control trip header and the stop and reheat stop dump valves are connected to the auto stop emergency trip header.

10.2.2.4.4 Power/Load Unbalance

A rate sensitive power/load unbalance circuit initiates fast closing intercept valve action under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed.

Valve action occurs when the power exceeds the load by 30 percent or more, and when the generator current is lost in a time span of 35 milliseconds or less. Cold reheat pressure is used as a measure of power. Generator current is used as a measure of load to provide discrimination between loss of load incidents and occurrences of electric system faults.

When the detection circuitry provides a signal indicating a power/load unbalance condition, the load reference signal is grounded, and the intercepter valve, which is a solenoid operated valve with quick response characteristics, is closed immediately. Should the condition disappear quickly, the power/load unbalance circuitry resets automatically, and the load reference signal is reestablished near its value prior to the loss of load.

10.2.2.4.5 Overspeed Protection

The DEH has two modes of operation to protect the turbine against overspeed. The first is the speed control that functions to maintain the desired speed as discussed in subsection 10.2.2.4.1. The second mode is the overspeed protection control which operates if the normal speed control should fail or upon a load rejection. The overspeed protection control opens a drain path for the hydraulic fluid in the overspeed protection control header if the turbine speed exceeds 103 percent of rated speed. The loss of fluid pressure in the header causes the control and intercept valves to close. If the speed falls below rated speed following an overspeed protection controller action, the header pressure is reestablished, the control and intercept valves are reopened, and the unit resumes speed control. Refer to Table 10.2-2 for a description of the sequence of events following a full-load rejection and the nominal trip setpoints. An emergency trip system is also provided to trip the turbine in the event that speeds in excess of the overspeed protection control trip points are reached. The emergency trip system is discussed in subsection 10.2.2.5.1.

Redundancy is built into the DEH overspeed protection control. The failure of a single valve will not disable the trip functions. The overspeed protection components are designed to fail in a safe position. Loss of the hydraulic pressure in the emergency trip system causes a turbine trip. Therefore, damage to the overspeed protection components, results in the closure of the valves and the interruption of steam flow to the turbine.

Quick closure of the steam valves prevents turbine overspeed. Valve closing times are given in Table 10.2-4.

10.2.2.4.6 Automatic Turbine Control

Automatic turbine control provides safe and proper startup and loading of the turbine generator. The applicable limits and precautions are monitored by the automatic turbine control programs even if the automatic turbine control mode has not been selected by the operator. When the operator selects automatic turbine control, the programs both monitor and control the turbine. The DEH controller takes advantage of the capability of the computer to scan, calculate, make decisions, and take positive action.

The automatic turbine control is capable of automatically:

- Changing speed
- Changing acceleration
- Generating speed holds
- Changing load rates
- Generating load holds

The thermal stresses in the rotor are calculated by the automatic turbine controls programs based on actual turbine steam and metal temperatures as measured by thermocouples or other temperature measuring devices. Once the thermal stress (or strain) is calculated, it is compared with the allowable value, and the difference is used as the index of the permissible first stage temperature variation. This permissible temperature variation is translated in the computer program as an allowable speed or load or rate of change of speed or load.

Values of some parameters are stored for use in the prediction of their future values or rates of change, which are used to initiate corrective measures before alarm or trip points are reached.

The rotor stress (or strain) calculations used in the program, and its decision-making counterpart are the main controlling sections. They allow the unit to roll with relatively high acceleration until the anticipated value of stress predicts that limiting values are about to be reached. Then a lower acceleration value is selected and, if the condition persists, a speed hold is generated. The same philosophy is used on load control in order to maintain positive control of the loading rates.

The automatic turbine controls programs are stored and executed in redundant distributed processing units, which contain the rotor stress programs and the majority of the automatic turbine controls logic programs. Once the turbine is latched, the automatic turbine controls programs are capable of rolling the turbine from turning gear to synchronous speed with supervision from a single operator.

Once the turbine-generator reaches synchronous speed, the startup or speed control phase of automatic turbine control is completed and no further action is taken by the programs. Upon closing the main generator breaker, the DEH automatically picks up approximately 5 percent of rated load to prevent motoring of the generator. At this time, the DEH is in load control.

The DEH unit is equipped with a remote control interface. Selection of the remote mode provides for control of the turbine-generator from an operator console. In the remote mode of control, the rate of this load change is controlled by the amount of this load change.

In the combined mode of both remote control and automatic turbine control, the automatic turbine control allows the remote control system control of load changes until an alarm condition occurs. If the operating parameters being monitored (including rotor stress) exceed their associated alarm limit, a load hold is generated in conjunction with the appropriate alarm message. The DEH generates the load hold by ignoring any further load increase or decrease until the alarm condition is cleared or until the operator overrides the alarm condition. At the same time that the DEH generates the load hold based on the automatic turbine control alarm condition, the DEH also informs the remote control system of its action. In the combined mode of control, both the load reference and the load rate are implicitly controlled by the remote control system while the automatic turbine control supervises the load changes with overriding control capability.

The operator may remove the turbine-generator from automatic turbine control. This action places the automatic turbine control in a supervisory capacity.

10.2.2.5 Turbine Protective Trips

Turbine protective trips, when initiated, cause tripping of the main stop, control, intercept, and reheat stop valves. The protective trips are:

- Low bearing oil pressure
- Low electrohydraulic fluid pressure
- High condenser back pressure
- Turbine overspeed
- Thrust bearing wear
- Remote trip that accepts external trips

A description of the trip system for turbine overspeed is provided below.

10.2.2.5.1 Emergency Trip System

The purpose of the emergency trip system is to detect undesirable operating conditions of the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the corrective actions. In addition, means are provided for testing emergency trip equipment and circuits.

The system utilizes a two channel configuration which permits on line testing with continuous protection afforded during the test sequence. A mechanical overspeed trip is also provided as described in 10.2.2.5.3.

The emergency trip system includes the emergency trip control block, trip solenoid valves, test panel, the mechanical overspeed trip device, speed sensors, and a test panel. These items and the function of the overspeed trips are describe in the following three subsystems.

10.2.2.5.2 Emergency Trip Control Block

The auto stop emergency trip header pressure is established when the auto stop trip solenoid valves are energized closed. The valves are arranged in two channels for testing purposes, the odd numbered pair correspond to channel 1, and the even numbered pair correspond to channel 2. This convention is carried throughout the emergency trip system in designating devices; e.g., channel 1 devices are odd-numbered, and channel 2 devices are even-numbered. Both valves in a channel will open to trip that channel. Both channels must trip before the auto stop trip header pressure collapses to close the turbine steam inlet valves. Each tripping function of the electrical emergency trip system can be individually tested from the operator/test panel without tripping the turbine by separately testing each channel of the appropriate trip function. The solenoid valves may be individually tested. Spool-type solenoid valves are not used in the emergency trip control block.

A trip of the emergency trip system opens a drain path for the hydraulic fluid in the auto stop emergency trip header. The loss of fluid pressure in the trip header causes the main stop and reheat stop valves to close. Also, check valves in the connection to the overspeed protection control header open to drop the pressure in the overspeed protection control header and cause the control and intercept valves to close. The control and intercept valves are redundant to the main stop and reheat stop valves respectively.

10.2.2.5.3 Overspeed Trip Functions and Mechanisms

The emergency overspeed trips for the AP1000 turbine consist of a mechanical and an electrical trip. The mechanical emergency overspeed trip trips before the electrical emergency trip. The emergency overspeed trip setpoints are identified in Table 10.2-2.

The mechanical overspeed trip device consists of a spring-loaded trip weight mounted in the rotor extension shaft. At normal operating speed, the weight is held in the inner position by the spring. When the turbine speed reaches the trip setpoint, the centrifugal force overcomes the compression force of the spring and throws the trip weight outward striking a trigger. As the trigger moves, it unseats a cup valve which drains the mechanical overspeed and manual trip header. The mechanical overspeed and manual trip header can be tripped manually via a trip handle mounted on the governor pedestal.

The electrical overspeed trip system has separate, redundant speed sensors and provides backup overspeed protection utilizing the trip solenoid valves in the emergency trip control block to drain the emergency trip header. The hydraulic fluid in the trip and overspeed protection control headers is independent of the bearing lubrication system to minimize the potential for contamination of the fluid.

The speed control and overspeed protection function of the DEH combined with the emergency trip system electrical and mechanical overspeed trips provide a level of redundancy and diversity at least equivalent to the recommendations for turbine overspeed protection found in III.2 of

Standard Review Plan (NUREG-0800) Section 10.2. Additionally, the issues and problems with overspeed protection systems identified in NUREG-1275 (Reference 3) have been addressed.

10.2.2.5.4 Test Blocks

Low bearing oil pressure, low electrohydraulic fluid pressure, and high condenser back pressure are each sensed by separate test block instrumentation. Each test block assembly consists of a steel test block, two pressure transmitters, two shutoff valves, two solenoid valves, and three needle valves. Each assembly is arranged into two channels. The assemblies, mounted on the governor pedestal, are connected to pressure sensors mounted in a nearby terminal box. The assemblies have an orifice on the system supply side and are connected to a drain or vent on the other side. An orifice is provided in each channel so that the measured parameter is not affected during testing. An isolation valve on the supply side allows the test block assembly to be serviced.

If the medium (pressure or vacuum) reaches a trip setpoint, then the pressure sensors cause the auto stop emergency trip header mechanism to operate. When functionally testing an individual trip device, the medium is reduced to the trip setpoint in one channel either locally through the hand test valves or remotely from the trip test panel via the test solenoid valves.

10.2.2.5.5 Thrust Bearing Trip Device

Two position pickups, which are part of the turbine supervisory instrument package, monitor movement of a disc mounted on the rotor near the thrust bearing collar. Axial movement of this collar is reflected in movement of the disc. Excessive movement of the disc is an indication of thrust bearing wear. Should excessive movement occur, relay contacts from the supervisory instrument modules close to initiate a turbine trip.

The thrust bearing trip function can be checked by a test device that simulates movement of the rotor to activate the trip outputs from the modules.

10.2.2.5.6 Remote Trip

The emergency trip system also has provisions to trip the turbine in response to a signal from the plant control system or plant safety and monitoring system.

10.2.2.6 Other Protective Systems

Additional protective features of the turbine and steam system are:

- Moisture separator reheater safety relief valves
- Rupture diaphragms located on each of the low-pressure turbine cylinder covers
- Turbine water induction protection systems on the extraction steam lines

10.2.2.7 Plant Loading and Load Following

The AP1000 turbine-generator control system and control strategy has the same loading and load following characteristics as the control system described in Section 7.7. In addition, the turbine-generator has the following capabilities:

- Daily load change between 100 and 30 percent of rated power
- Transition between baseload and load follow operation
- Extended weekend reduced power operation
- Rapid return to up to 90 percent of rated power

For the AP1000, this load following capability is maintained for most of cycle life.

10.2.2.8 Inspection and Testing Requirements

Major system components are readily accessible for inspection and are available for testing during normal plant operation. Turbine trip circuitry is tested prior to unit startup. To test governor valves with minimal disturbance, the load is reduced to that capable of being carried with one governor valve closed.

10.2.3 Turbine Rotor Integrity

Turbine rotor integrity is provided by the integrated combination of material selection, rotor design, fracture toughness requirements, tests, and inspections. This combination results in a very low probability of a condition that could result in a rotor failure.

10.2.3.1 Materials Selection

Fully integral turbine rotors are made from ladle refined, vacuum deoxidized, Ni-Cr-Mo-V alloy steel by processes which maximize steel cleanliness and provide high toughness. Residual elements are controlled to the lowest practical concentrations consistent with melting practices. The chemical property limits of ASTM A470, Classes 5, 6, and 7 are the basis for the material requirements for the turbine rotors. The specification for rotor steel used in the AP1000 has lower limitations than indicated in the ASTM standard for phosphorous, sulphur, aluminum, antimony, tin, argon, and copper. This material has the lowest fracture appearance transitions temperatures (FATT) and the highest Charpy V-notch energies obtainable on a consistent basis from water-quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Charpy tests and tensile tests in accordance with American Society of Testing and Materials (ASTM) specification A370 are required from the forging supplier.

The production of steel for the turbine rotors starts with the use of high-quality, low residual element scrap. An oxidizing electric furnace is used to melt and dephosphorize the steel. Ladle furnace refining is then used to remove oxygen, sulphur, and hydrogen from the rotor steel. The steel is then further degassed using a process whereby steel is poured into a mold under vacuum to produce an ingot with the desired material properties. This process minimizes the degree of chemical segregation since silicon is not used to deoxidize the steel.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Subsection 10.2.3.1 to produce a balance of material strength and toughness to provide safety while simultaneously providing high reliability, availability, and efficiency during operation. The restrictions on phosphorous, sulphur, aluminum, antimony, tin, argon, and copper in the

specification for the rotor steel provides for the appropriate balance of material strength and toughness. The impact energy and transition temperature requirements are more rigorous than those given in ASTM 470 Class 6 or 7.

Bore stress calculations include components due to centrifugal loads and thermal gradients where applicable. Fracture toughness will be at least $220\,\text{MPa} \bullet \sqrt{\text{m}} = 200\,\text{ksi} \bullet \sqrt{\text{in}}$ and the ratio of fracture toughness to the maximum applied stress intensity factor for rotors at speeds from normal to design overspeed will be at least 2. Material fracture toughness needed to maintain this ratio is verified by mechanical property tests on material taken from the rotor.

The rotor is evaluated for fracture toughness by criteria that include the design duty cycle stresses, number of cycles, ultrasonic examination capability and growth rate of potential flaws. Conservative factors of safety are included for the size uncertainty of potential or reported ultrasonic indications, rate of flaw growth (da/dN versus dK) and the duty cycle stresses and number.

Reported rotor forging indications are adjusted for size uncertainty and interaction. A rotor forging with a reported indication that would grow to critical size in the applicable duty cycles is not accepted. The combined rotation and maximum transient thermal stresses used in the applicable duty cycles are based on the brittle fracture and rotor fatigue analyses described below.

Maximum transient thermal stresses are determined from historical maximum loading rates for nuclear service rotors.

10.2.3.2.1 Brittle Fracture Analysis

A brittle fracture analysis is performed on the turbine rotor to provide confidence that small flaws in the rotor, especially near the centerline, do not grow to a critical size with unstable growth resulting in a rotor burst. The brittle fracture analysis process includes determining the stresses in the rotor resulting from rotation, steady-state thermal loads, and transient thermal loads from startup and load change. These stresses are combined to generate the maximum stresses and locations of maximum stress for the startup and load change transients. A fracture mechanics analysis is performed at the location(s) of maximum stress to verify that an initial flaw, equal to the minimum reportable size, will not grow to critical crack size over the life of the rotor under the cumulative effects of startup and load change transients.

A fracture mechanics analysis is done at the location(s) of maximum stress to determine the critical crack size and the initial flaw area that would just grow to the critical size when subjected to the number of startup and load change cycles determined to represent the lifetime of the rotor. This initial flaw area is divided by a factor of safety to generate an allowable initial flaw area. The minimum reportable flaw size is multiplied by a conservative factor to correct for the imperfect nature of a flaw as an ultrasonic reflector, as compared to the calibration reflector. The resulting area is the corrected flaw area. For an acceptable design, the allowable initial flaw area must be greater than or equal to the corrected flaw area.

A flaw is assumed to be an internal elliptical crack on the centerline for rotors without bores. For rotor contour or for flaws near the rotor bore (for bored rotors), a surface connected elliptical crack

is assumed. Flaw analysis is done assuming various flaw aspect ratios and the most conservative results are used. The flaw is assumed to be orientated normal to the maximum principle stress direction.

The beginning-of-life fracture appearance transition temperature for the high pressure and low pressure rotor is specified in the material specification for the specific material alloy selected. Both the high pressure and low pressure turbines operate at a temperature at which temperature embrittlement is insignificant. The beginning-of-life fracture appearance transition temperature is not expected to shift during the life of the rotor due to temperature embrittlement.

Minimum material toughness is provided in the turbine rotors by specification of maximum fracture appearance transition temperature and minimum upper shelf impact energy for the specific material alloy selected. There is not a separate material toughness (K_{IC}) requirement for AP1000 rotors.

10.2.3.2.2 Rotor Fatigue Analysis

A fatigue analysis is performed for the turbine rotors to show that the cumulative usage is acceptable for expected transient conditions including normal plant startups, load following cycling, and other load changes. The fatigue design curves are based on mean values of fatigue test data. Margin is provided by assuming a conservatively high number of turbine start and stop cycles. The Westinghouse/Mitsubishi-designed turbine rotors in operating nuclear power plants were designed using this methodology and have had no history of fatigue crack initiation due to duty cycles.

In addition to the low cycle fatigue analysis for transient events, an evaluation for high cycle fatigue is performed. This analysis considers loads due to gravity bending, bearing elevation misalignment, control stage partial arc admission bearing reactions, and steady-state unbalance stress. The local alternating stress is calculated at critical rotor locations considering the bending moments due to the loads described above. The maximum alternating stress is less than the smooth bar endurance strength modified by a size factor.

The AP1000 turbine generator is supported by a spring-mounted system to isolate the dynamic behavior of the turbine-generator equipment from the foundation structure. The support system includes a reinforced concrete deck on which the turbine generator is mounted. The deck is sized to maintain the gravity load and misalignment load bending stresses within allowable limits. The evaluation of the loads includes a dynamic analysis of the combined turbine-generator and foundation structure.

10.2.3.3 High Temperature Properties

The operating temperatures of the high-pressure rotors are below the creep rupture range. Creep rupture is, therefore, not considered to be a significant factor in providing rotor integrity over the lifetime of the turbine. Basic data are obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Rotor Design

The turbine assembly is designed to withstand normal conditions and anticipated transients, including those resulting in turbine trip, without loss of structural integrity. The design of the turbine assembly meets the more restrictive of the following criteria:

- The combined stresses of a low-pressure turbine disk at design overspeed due to centrifugal forces, interference fit, and thermal gradients do not exceed 0.75 of the minimum specified yield strength of the material; or,

- The tangential stresses will not cause a flaw, which is twice the corrected ultrasonic examination reportable size, to grow to critical size in the design life of the rotor. This will result in the ratio of fracture toughness to the maximum applied stress intensity factor for the rotor at speeds from normal to design overspeed being at least 2.

The high-pressure turbine has fully integral rotors forged from a single ingot of low alloy steel. This design is inherently less likely to have a failure resulting in a turbine missile than previous designs with shrunk-on discs. A major advantage of the fully integral rotor is the elimination of disc bores and keyways. In the fully integral rotor design, the location of peak stresses are in the lower stress blade fastening areas. This difference results in a substantial reduction of the rotor peak stresses, which in turn reduces the potential for crack initiation. The reduction in peak stress also permits selection of a material with improved ductility, toughness, and resistance to stress corrosion cracking.

The non-bored design of the high-pressure turbine element provides the necessary design margin by virtue of its inherently lower centerline stress. Metallurgical processes permit fabrication of the rotors without a center borehole. The use of solid rotor forgings was qualified by evaluation of the material removed from center-bored rotors for fossil power plants. This evaluation demonstrated that the material at the center of the rotors satisfied the rotor material specification requirements. Forgings for no-bore rotors are provided by suppliers who have been qualified based on bore material performance.

The low-pressure turbine element is a fully integral rotor fabricated from a single forging. There are no keyways, which can be potential locations for stress risers and corrosive contaminate concentration, exposed to a steam environment. The integral disc profiles are carefully designed to limit the surface stress in areas vulnerable to stress corrosion if a less than ideal steam environment exists to 50 percent of the yield strength to reduce the chances of stress corrosion as far as practicable.

10.2.3.5 Preservice Tests and Inspections

Preservice inspections for turbine rotors include the following:

- Rotor forgings are rough machined with a minimum stock allowance prior to heat treatment.

- Each rotor forging is subjected to a 100-percent volumetric (ultrasonic) examination. Each finish-machined rotor is subjected to a surface magnetic particle and visual examination.

Results of the above examination are evaluated by use of criteria that are more restrictive than those specified for Class 1 components in ASME Code, Section III and V. These criteria include the requirement that subsurface sonic indications are either removed or evaluated to verify that they do not grow to a size which compromises the integrity of the unit during the service life of the unit.

- Finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores (if present) or other highly stressed regions.

- Each fully bladed turbine rotor assembly is spin tested at 20 percent overspeed, the maximum speed following a load rejection from full load.

Rotor areas which require threaded holes are not subjected to a magnetic particle examination of the threaded hole. The number of threaded holes is minimized, and threaded holes are not located in high stress areas.

10.2.3.6 Maintenance and Inspection Program Plan

The maintenance and inspection program plan for the turbine assembly and valves is based on turbine missile probability calculations, operating experience of similar equipment, and inspection results. The methodology for analysis of the probability of generation of missiles for fully integral rotors was submitted in WCAP-15783 (Reference 1). The methodology used for analysis of the missile generation probability calculations used to determine turbine valve test frequency is described in WCAP-15785 (Reference 2). The maintenance and inspection program includes the activities outlined below:

- Disassembly of the turbine is conducted during plant shutdown. Inspection of parts that are normally inaccessible when the turbine is assembled for operation (couplings, coupling bolts, turbine rotors, and low-pressure turbine blades) is conducted.

  This inspection consists of visual, surface, and volumetric examinations as indicated below:

  – Each rotor and stationary and rotating blade path component is inspected visually and by magnetic particle testing on accessible surfaces. Ultrasonic inspection of the side entry blade grooves is conducted. These inspections are conducted at intervals of about 10 years for low-pressure turbines and about 8 years for high-pressure turbines.

  – A 100 percent surface examination of couplings and coupling bolts is performed.

  – Fluorescent penetrant examination is conducted on nonmagnetic components.

- At least one main steam stop valve, one main steam control valve, one reheat stop valve, and one intercept valve are dismantled approximately every 3 years during scheduled refueling or maintenance shutdowns. A visual and surface examination of valve internals is conducted. If unacceptable flaws or excessive corrosion are found in a valve, the other valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

- Main stop valves, control valves, reheat stop and intercept valves may be tested with the turbine online. The DEH control test panel is used to stroke or partially stroke the valves.

- Extraction nonreturn valves are tested prior to each startup.

- Turbine valve testing is performed at quarterly intervals. The quarterly testing frequency is based on nuclear industry experience that turbine-related tests are the most common cause of plant trips at power. Plant trips at power may lead to challenges of the safety-related systems. Evaluations show that the probability of turbine missile generation with a quarterly valve test is less than the evaluation criteria.

- Extraction nonreturn valves are tested locally by stroking the valve full open with air, then equalizing air pressure, allowing the spring closure mechanism to close the valve. Closure of each valve is verified by direct observation of the valve arm movement.

The valve inspection frequency of three years noted above is consistent with a 18-month fuel cycle for AP1000 and is based on evaluations performed to support this valve inspection interval at operating plants with 18-month fuel cycles. A monitoring program is in place at operating nuclear power plants to verify the success of longer valve inspection intervals. A Combined License holder recommendation for a valve inspection frequency longer than three years may be justified when a longer interval is supported by operating and inspection program experience and supported by the missile generation probability calculations.

10.2.4 Evaluation

Components of the turbine-generator are conventional and typical of those which have been extensively used in other nuclear power plants. Instruments, controls, and protective devices are provided to confirm reliable and safe operation. Redundant, fast actuating controls are installed to prevent damage resulting from overspeed and/or full-load rejection. The control system initiates a turbine trip upon reactor trip. Automatic low-pressure exhaust hood water sprays are provided to prevent excessive hood temperatures. Exhaust casing rupture diaphragms are provided to prevent low-pressure cylinder overpressure in the event of loss of condenser vacuum. The diaphragms are flange mounted and designed to maintain atmospheric pressure within the condenser and turbine exhaust housing while passing full flow.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine-generator and associated components. Radiological considerations do not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak due to a steam generator tube leak, it is possible for the steam to become contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in Chapters 11 and 12.

10.2.5 Instrumentation Applications

The turbine-generator is provided with turbine supervisory instrumentation including monitors for the following:

- Speed
- Stop valve position
- Control valve position
- Reheat intercept and stop valve positions
- Temperatures as required for controlled starting, including:
  - External valve chest inner surface
  - External valve chest outer surface
  - First-stage shell lower inner surface
  - Crossover pipe downstream of reheat stop valve No. 1
  - Crossover pipe downstream of reheat stop valve No. 2
  - Crossover pipe downstream of reheat stop valve No. 3
  - Crossover pipe downstream of reheat stop valve No. 4
  - Crossover pipe downstream of reheat stop valve No. 5
  - Crossover pipe downstream of reheat stop valve No. 6
- Casing and shaft differential expansion
- Vibration of each bearing
- Shaft eccentricity
- Bearing metal temperatures

Alarms are provided for the following abnormal conditions:

- High vibration
- Turbine supervisory instruments common alarm

In addition to the turbine protective trips listed in subsection 10.2.2.5, the following trips are provided:

- High exhaust hood temperature
- Low emergency trip system pressure
- Low shaft-driven lube oil pump discharge pressure
- High or low level in moisture separator drain tank

Indications of the following miscellaneous parameters are provided:

- Main steam throttle pressure
- Steam seal supply header pressure
- Steam seal condenser vacuum
- Bearing oil header pressure
- Bearing oil coolers coolant temperature

- DEH control fluid header pressure
- DEH control fluid temperature
- Crossover pressure
- Moisture separator drain tank level
- First-stage pressure
- High-pressure turbine exhaust pressure
- Extraction steam pressure, each extraction point
- Low-pressure turbine exhaust hood pressure
- Exhaust hood temperature for each exhaust

Generator supervisory instruments are provided, with sensors and/or transmitters mounted on the associated equipment. These indicate or record the following:

- Multiple generator stator winding temperatures; the detectors are built into the generator, protected from the cooling medium, and distributed around the circumference in positions having the highest expected temperature

- Stator coil cooling water temperature (one detector per coil)

- Hydrogen cooler inlet gas temperature (two detectors at each point)

- Hydrogen gas pressure

- Hydrogen gas purity

- Generator ampere, voltage, and power

Additional generator protective devices are listed in Table 10.2-3.

10.2.6 Combined License Information on Turbine Maintenance and Inspection

The Combined License holder will submit to the staff for review and approval within 3 years of obtaining a Combined License, and then implement a turbine maintenance and inspection program. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in subsection 10.2.3.6. The Combined License holder will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis.

10.2.7 References

1. WCAP-15783-P, Proprietary and WCAP-15783-NP, Nonproprietary, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines," Revision 2, August 2003.

2. WCAP-15785, Proprietary and WCAP-15786, Nonproprietary, "Probabilistic Evaluation of Turbine Valve Test Frequency," April 2002.

3. NUREG-1275, Vol. 11, Operating Experience Feedback Report - Turbine-Generator Overspeed Protection Systems, Commercial Power Reactors, H. L. Ornstein, Nuclear Regulatory Commission, April 1995.

Table 10.2-1

TURBINE-GENERATOR AND AUXILIARIES DESIGN PARAMETERS

Manufacturer Mitsubishi	
Turbine	
Type	TC6F 54-in. last row blades
No. of elements	1 high pressure; 3 low pressure
Last-stage blade length (in.)	54
Operating speed (rpm)	1800
Condensing pressure (in. HgA)	2.5
Turbine cycle heat rate (Btu/kWh)	9715
Generator	
Generator rated output (kW)	1,237,500 (nominal)
Power factor	0.90
Generator rating (kVA)	1,375,000 (nominal)
Hydrogen pressure (psig)	75
Moisture separator/reheater	
Moisture separator	Chevron vanes
Reheater	U-tube
Number	1 shell
Stages of reheating	2

Table 10.2-2

TURBINE OVERSPEED PROTECTION

Percent of Rated Speed (Approximate)	Event
100	Turbine is initially at valves wide open. Full load is lost. Speed begins to rise. When the breaker opens, the load drop anticipator immediately closes the control and intercept valves if the load at time of separation is greater than 30 percent.
101	Control and intercept valves begin to close.
103	The overspeed protection controller closes the control and intercept valves until the speed drops below 103 percent.
108	Peak transient speed with normally operating speed control system. If the power/load unbalance and speed control systems had failed prior to loss of load, then:
110	The mechanical overspeed trip device closes the turbine stop and reheat valves.
111	The electrical overspeed trip system closes the main stop and reheat stop valves based on a two-out-of-three trip logic system.

Note:
Following the above sequence of events, the turbine will approach but not exceed 120 percent of rated speed.

Table 10.2-3 (Sheet 1 of 2)

GENERATOR PROTECTIVE DEVICES FURNISHED WITH THE VOLTAGE REGULATOR PACKAGE

Device	Action	
• Generator Minimum Excitation Limiter	Limiter	- maintains generator reactive power output above certain level (normally steady-state stability limit level)
	Alarm	- when limiter is limiting
• Generator Maximum Excitation Limiter	Limiter	- maintains generator field voltage below certain voltage inverse time characteristics
	Alarm	- when limiter is timing
	Alarm	- when limiter is limiting
• Generator Overexcitation Protection	Alarm	- repositions the dc regulator adjuster to a preset position when overexcitation protection pickup level is exceeded
Inverse Timer	Alarm	- when timing commences
	ac regulator trip	- when timed out
Fixed Timer	Alarm	- when timing
	Unit trip	- when timed out
• Generator Volts/Hertz Limiter	Limiter	- maintains machine terminal volts/Hertz ratio below certain level
	Alarm	- when limiter is limiting
• Generator Dual Level Volts/Hertz Protection	Alarm	- when above either preset volts/Hertz level
	Unit trip	- if timed out at either alarm level
• Generator Automatic Field Ground Detection	Alarm	- brush failure (alarms about 20 seconds)
	Alarm	- ground
• Regulator Firing Circuit - Loss of Thyristor Firing Pulse Protection	Alarm	- loss of one firing circuit
	Unit Trip	- loss of both firing circuits
• Thyristor Blown Fuse Detection	Alarm	- When one or more thyristor fuses in power drawers open

Table 10.2-3 (Sheet 2 of 2)

GENERATOR PROTECTIVE DEVICES FURNISHED WITH THE VOLTAGE REGULATOR PACKAGE

Device	Action	
• Regulator Forcing Indication	Alarm	- online forcing
	Alarm	- offline forcing (blocks "Raise" controls of dc regulator and ac regulator adjusters)
• Regulator Loss of Power Supply (s) Protection	Alarm	- loss of one power supply
	Unit trip	- loss of both power supplies
• Regulator Loss of Sensing Protection	Alarm and AC regulator trip	- when regulator voltage transformer sensing is lost
• Excitation Supply Breaker	Alarm Excitation trip	
• Alternate Excitation Removal Equipment	Alarm	- For fast de-excitation, phase-back thyristor firing pulses for specified time, then trip excitation supply breaker
• Power System Stabilizer (PSS) Excessive Output Protection	Alarm Power System Stabilizer trip	- When PSS output exceeds specified level for specified time
• Power System Stabilizer Inservice Instrumentation Indication	Indicator	- lamps and contacts
• Exciter - Air Temperature Detection	Alarm	
• Exciter - Rotation Vibration Pick-up	Alarm Unit Trip	
• Exciter - Bearing Metal Detection	Alarm	
• Generator - Overvoltage Protection	Alarm	- Phase-back thyristor firing pulses if overvoltage condition persists for a specified time
• Exciter Diode Fuse Detection	Indicator	- Flag on rotating fuse raises when fuse opens; detected by periodic checks with strobe light.

Table 10.2-4

TURBINE-GENERATOR VALVE CLOSURE TIMES

Valve	Closing Time (seconds)
Main Stop Valves	0.3
Control Valves	0.3
Intercept Valves	0.3
Reheat Stop Valves	0.3
Extraction Nonreturn Valves	<1.0

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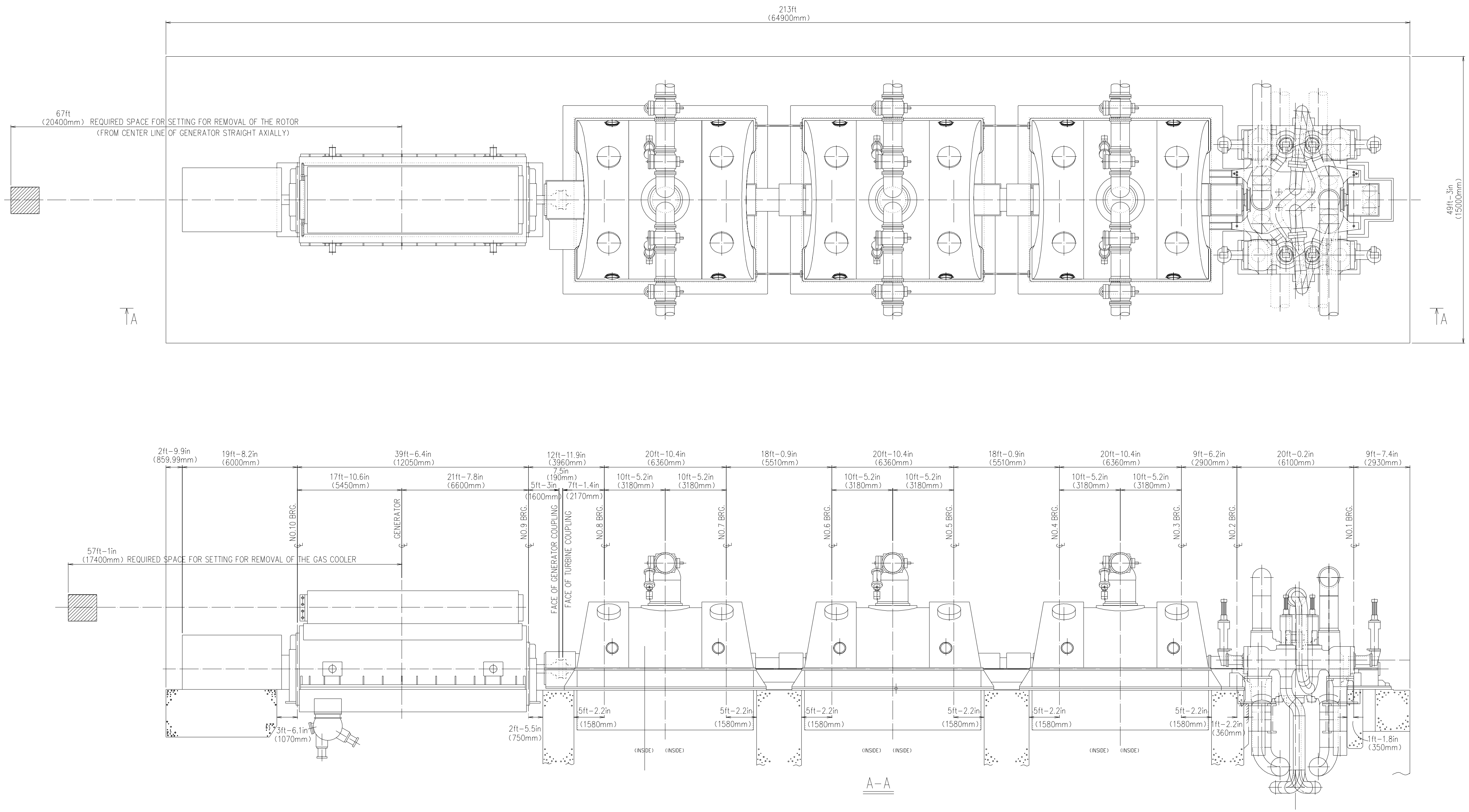

Figure 10.2-1 (Sheet 1 of 2)

Turbine Generator Outline Drawing

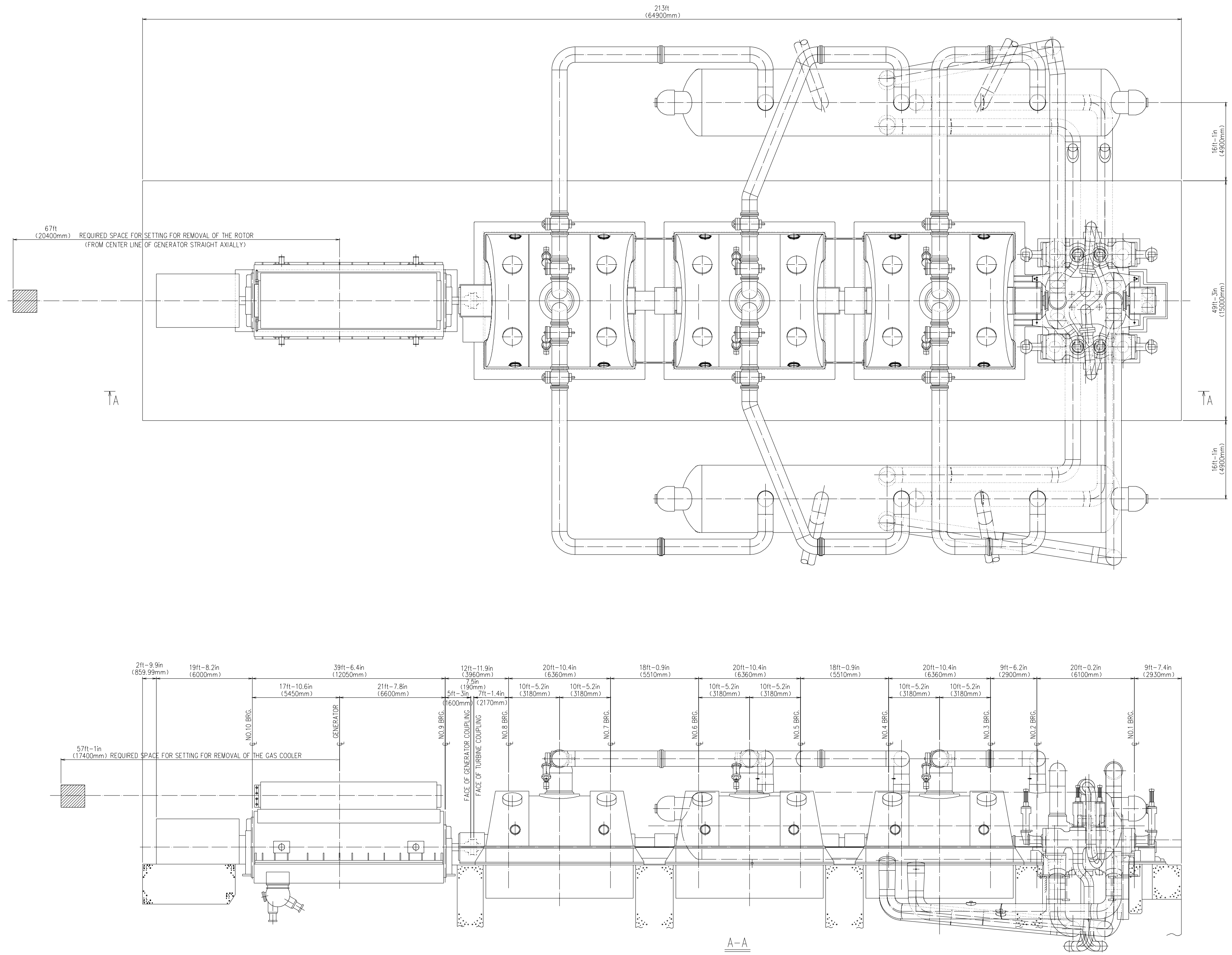

Figure 10.2-1 (Sheet 2 of 2)

Turbine Generator Outline Drawing

10.3 Main Steam Supply System

The main steam supply system as described in this section includes components of the AP1000 steam generator system (SGS), main steam system (MSS), and main turbine system (MTS).

The function of the main steam supply system is to supply steam from the steam generators to the high-pressure turbine over a range of flows and pressures covering the entire operating range from system warmup to maximum calculated turbine conditions.

The system provides steam to the moisture separator/reheaters and the gland seal system for the main turbine. The system dissipates heat generated by the nuclear steam supply system (NSSS) by means of steam dump valves to the condenser or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves when either the turbine-generator or condenser is unavailable.

10.3.1 Design Basis

10.3.1.1 Safety Design Basis

The main steam supply system safety design bases are as follows:

- The system is provided with a main steam isolation valve (MSIV) and associated MSIV bypass valve on each main steam line from its respective steam generator. These valves isolate the secondary side of each of the steam generators to prevent the uncontrolled blowdown of more than one steam generator and isolate nonsafety-related portions of the system.

- Codes and standards utilized in the design of the main steam supply system are identified in Section 3.2, according to the AP1000 equipment class of the component. The main steam supply system contains class B and class C safety-related components.

  Table 3.2-3 identifies the safety-related mechanical equipment in the main steam supply system, and lists the associated ASME code class. (Since all the safety-related components of the main steam supply system are in the AP1000 steam generator system [SGS], they appear in that table with a SGS prefix. For example, the main steam isolation valves [MSIVs] are listed there as SGS-PL-V040A and B).

  The following main steam supply system components are classified as equipment class B and are safety-related:

  – The main steam line piping from the steam generator up to, and including, the main steam isolation valves

  – The main steam isolation valve bypass piping up to, and including, the main steam isolation bypass valve

  – The inlet piping from the main steam line up to, and including, the main steam safety valves

- – The inlet piping from the main steam line up to, and including, the power operated relief valve block valve
- – The instrumentation tubing up to, and including, the main steam line pressure instrument root valves
- – The vent line on the main steam line up to, and including, the first isolation valve, and the nitrogen connection on the main steam line up to, and including, the first isolation valve
- – The main steam drain condensate pot located upstream of the main steam isolation valves, and the drain piping up to, and including, the first isolation valve

The following main steam supply system components are classified as equipment class C and are safety-related:

- – The main steam line piping from the main steam isolation valves outlet to the pipe restraint located on the wall between the auxiliary building and the turbine building
- – The main steam safety valve discharge piping and vent stacks
- – The piping from the outlet of the power operated relief block valve up to, and including, the power operated relief valve
- – The condensate drain piping from the outlet of the class B isolation valve to the restraint on the wall between the auxiliary building and the turbine building

(The remainder of the main steam supply system is nonsafety-related. Except for the power operated relief valve discharge piping from the power operated relief valve outlet to the power operated relief valve silencer, which is class D, the remainder of the main steam supply system is class E).

- The system provides suitable overpressure protection of the steam generator secondary side and class 2 main steam piping in accordance with ASME Code, Section III.
- The safety-related portion of the system is designed to withstand the effects of a safe shutdown earthquake and to perform its intended function following postulated events.
- The safety-related portions of the system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The safety-related portion of the system is designed so that a single, active failure in the main steam supply system will not result in:

  - A loss-of-coolant accident

  - Loss of integrity of other steam lines

  - Loss of the capability of the engineered safety features system to effect a safe reactor shutdown

  - Transmission of excessive loading to the containment pressure boundary

  Component or functional redundancy is provided so that safety functions can be performed assuming a single, active failure coincident with loss of offsite power. Consistent with NUREG 0138 and Standard Review Plan Section 10.3, the nonsafety-related valves downstream of the main steam isolation valves are assumed functional to effect this capability.

- The portion of the main steam supply system that is constructed in accordance with ASME Code, Section III, requirements is provided with access to welds and removable insulation, as required for in-service inspection in accordance with ASME Code, Section XI. (See subsection 10.3.4.4.)

- The main steam supply system is designed to function in the normal and accident environments identified in subsection 3.11.

- The main steam supply system is qualified to leak-before-break criteria as described in Section 3.6.

- The main steam supply system design complies with containment isolation criteria as discussed in subsection 6.2.3.

- The nonsafety-related turbine stop, turbine control, and moisture separator reheater stop valves are credited in a single failure analysis to mitigate the event for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event.

10.3.1.2 Power Generation Design Basis

The following is a list of the principal power generation design bases:

- The main steam supply system delivers steam from the steam generators to the turbine-generator for the range of flowrates, temperatures, and pressures existing from warmup to rated power conditions.

- Each main steam line is sized and routed to provide balanced steam pressures to the turbine stop valves.

- The main steam supply system provides the capacity to dump 40 percent of full plant load steam flow to the condenser during plant step-load reductions.

- The system provides the means of dissipating residual and sensible heat generated from the nuclear steam supply system during hot shutdown and cooldown even when the main condenser is not available. Power-operated atmospheric relief valves are provided to allow controlled cooldown of the steam generator and the reactor coolant system when the condenser is not available.

- Piping system components located downstream of the auxiliary building wall anchor assemblies are designed in accordance with the Power Piping Code, ANSI B31.1.

10.3.2 System Description

10.3.2.1 General Description

The main steam supply system shown in Figure 10.3.2-1 includes the following major components:

- Main steam piping from the steam generator outlet steam nozzles to the main turbine stop valves

- One main steam isolation valve and one main steam isolation valve bypass valve per main steam line

- Main steam safety valves

- Power-operated atmospheric relief valves and upstream isolation valves

Table 10.3.2-1 lists the design data for the major components of the main steam supply system. Table 10.3.2-2 lists the design data for the main steam safety valve.

10.3.2.2 Component Description

10.3.2.2.1 Main Steam Piping

A description of the main steam piping from the steam generators to the turbine stop valves is presented in Table 10.3.2-3.

The main steam lines deliver a steamflow from the secondary side of the two steam generators. A portion of the main steamflow is directed to the reheater and steam seals, with the turbine receiving the remaining steamflow. Table 10.3.2-1 lists the performance data for the main steam supply system. Each of the main steam lines from the steam generators is anchored at the auxiliary building wall and has sufficient flexibility to accommodate thermal expansion.

Design of seismic Category I piping and supports takes into consideration the loads discussed in subsection 3.9.3.

The main steam lines between the steam generator and the containment penetration are designed to meet the leak-before-break criteria. The portion of the main steam lines between the containment penetration and the anchor downstream of the main steam isolation valves is part of the break exclusion zone. Section 3.6 addresses the applicability of leak-before-break and break exclusion zone to the main steam line.

The layout of the steam piping provides for the collection and drainage of condensate to avoid water entrainment, by the proper sloping of lines and the use of condensate drain pots.

The sizing and layout of the main steam piping hydraulically balances the steam line pressure drops from the respective steam generator to the inlet of each turbine stop valve. Two main steam lines are cross-connected into a common header just before branching into each turbine stop valve. This arrangement equalizes flow and pressure to the inlet of the turbine stop valves. This also permits online testing of each turbine stop valve without exceeding the allowable limit on steam generator pressure differential. Each steam generator outlet nozzle contains an internal flow restrictor arrangement to limit flow in the event of a main steam line break. A further description of the flow restrictor is provided in subsection 5.4.4.

Sampling connections are installed in the nonsafety-related portion of each main steam line, downstream of the main steam isolation valves. These nozzles are used for the sampling of steam. The sampling is monitored and analyzed through the secondary sampling system (SSS). Refer to subsection 9.3.4 for further discussion of the secondary sampling system.

Containment penetrations are described in subsection 6.2.3.

Turbine bypass valves are provided between the main steam isolation valves and turbine-generator stop valves, as discussed under the turbine bypass system (refer to subsection 10.4.4).

Main steam piping is designed to consider the effects of erosion/corrosion. Piping containing dry, single phase steam is constructed of carbon steel. Piping exposed to wet, two-phase steam is constructed of erosion/corrosion resistant low alloy steel or carbon steel with a stainless steel inner liner. Velocities in the main steam piping to the high pressure turbine are limited to reduce the potential for pipe erosion. Low point drains are provided for collecting and draining moisture and to help reduce the potential for water carryover to the high and low pressure turbines. Pipe wall thickness inspections are performed to monitor wall erosion rates.

Branch connections are provided from the main steam system to perform various functions. Upstream of the main steam isolation valves, there are connections for the power-operated atmospheric relief valves, main steam safety valves, low point drains, high point vents, and nitrogen blanketing. Branch piping downstream of the main steam line isolation valves includes connections for the two stage reheaters, gland seal system, turbine bypass system, auxiliary steam system, and low point drains. Table 10.3.2-4 further describes branch piping, 2.5 inches and larger, that is downstream of the main steam isolation valves.

10.3.2.2.2 Main Steam Safety Valves

Main steam safety valves with sufficient rated capacity are provided to prevent the steam pressure from exceeding 110 percent of the main steam system design pressure:

- Following a turbine trip without a reactor trip and with main feedwater flow maintained
- Following a turbine trip with a delayed reactor trip and with the loss of main feedwater flow

A total main steam safety valve rated capacity as indicated in Table 10.3.2-2 meets this requirement. At the same time, the individual safety valves are limited to the maximum allowable steam relief valve capacity as indicated in Table 10.3.2-2 for a system pressure equal to main steam design pressure plus 10 percent overpressure. This value sufficiently limits potential uncontrolled blowdown flow and the ensuing reactor transient should a single safety valve inadvertently fail or stick in the open position.

Six safety valves are provided per main steam line for the plant. Table 10.3.2-2 lists the performance data and set pressures for the main steam safety valves.

The main steam supply system safety valves are located in the safety-related portion of the main steam piping upstream of the main steam isolation valves and outside the containment in the auxiliary building. Adequate provision is made in the steam piping for the installation and support of the valves. Consideration is given to the static and dynamic loads when operating or when subjected to seismic events.

The piping and valve arrangement minimizes the loads on the attachment, and analysis confirms the design by use of guidelines in ASME Section III, Nonmandatory Appendix O, "Rules for Design of Safety Valve Installations."

Each safety valve is connected to vent stacks by an open umbrella-type transition piece schematically depicted in detail A of Figure 10.3.2-1.

The vent stacks are designed to:

- Direct the relieved steam away from adjoining structures

- Prevent backflow of relieved steam through the umbrella-type transition section

- Draw a small quantity of ambient air through the umbrella-type transition section and mix with the total steam flow which leaves the vent stack outlet

- Minimize the backpressure on the valve outlet so that it does not restrict the valve's rated capacity

The vent stacks are not required for safety, but are structurally designed to withstand safe-shutdown earthquake loads in order to not jeopardize the performance of safety-related components.

10.3.2.2.3 Power-Operated Atmospheric Relief Valves

A power-operated atmospheric relief valve is installed on the outlet piping from each steam generator to provide for controlled removal of reactor decay heat during normal reactor cooldown when the main steam isolation valves are closed or the turbine bypass system is not available. The valves are sized to provide a flow as indicated in Table 10.3.2-1. The maximum capacity of the relief valve at design pressure is limited to reduce the magnitude of a reactor transient if one valve would inadvertently open and remain open.

Each power-operated relief valve is located outside the containment in the auxiliary building upstream of the main steam isolation valves, in the safety-related portion of the main steam line associated with each steam generator. This location permits valve operation following transient conditions, including those which could result in closure of the main steam isolation valves.

The operation of the power-operated relief valves is automatically controlled by steam line pressure during plant operations. The power-operated relief valves automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint. As steam line pressure decreases, the relief valves modulate closed, reseating at a pressure at least 10 psi below the opening pressure. The setpoint is selected between no-load steam pressure and the set pressure of the lowest set safety valves.

The steam generator power-operated atmospheric relief valves provide a nonsafety-related means for plant cooldown by discharging steam to the atmosphere when the turbine bypass system is not available. Under such circumstances, the relief valves (in conjunction with the startup feedwater system) allow the plant to be cooled down at a controlled cooldown rate from the pressure setpoint of the lowest set of safety valves down to the point where the normal residual heat removal (RNS) system can remove the reactor heat.

For their use during plant cooldown, the power-operated atmospheric relief valves are automatically controlled by steam line pressure, with remote manual adjustment of the pressure setpoint from the control room or the remote shutdown workstation. To effect a plant cooldown, the operator manually adjusts the pressure setpoint downward in a step-wise fashion. The maximum cooldown rate achievable is limited by the flow-passing capability of the relief valves, the number of steam generators (and hence the number of relief valves) in service, the available startup feedwater pumping capacity and by the desire to either maintain or recover steam generator water levels during the cooldown.

The power-operated atmospheric relief valves also help to avoid actuation of the safety valves during certain transients and, following safety valve actuation, act to assist the safety valves to positively reseat by automatically reducing and regulating steam pressure to a value below the safety valve reseating pressure. The operation of each power-operated atmospheric relief valve is controlled in response to measurements of steam line pressure provided by four separate pressure taps on the associated steam line.

The valve operator is an air-operated modulating type, providing throttling capability over a range of steam pressures.

The atmospheric relief valves are controlled by nonsafety-related control systems for the modulating steam relief function. The capability for remote manual valve operation is provided in the main control room and at the remote shutdown workstation. A safety-related solenoid is provided to vent the air from the valve operator to terminate a steam line depressurization transient.

An isolation valve with remote controls is provided upstream of each power operated relief valve providing isolation of a leaking or stuck-open valve. The upstream location allows for maintenance on the power-operated relief valve operator at power. The motor-operated isolation valve employs a safety-related operator and closes automatically on low steam line pressure to terminate steam line depressurization transients. The isolation valve is a containment isolation boundary and therefore is specified as safety-related, active, ASME Code, Section III, Safety Class 2.

10.3.2.2.4 Main Steam Isolation Valves

The function of the main steam isolation is to limit blowdown to one steam generator in the event of a steam line break to:

- Limit the effect upon the reactor core to within specified fuel design limits
- Limit containment pressure to a value less than design pressure

Main steam isolation consists of one quick-acting gate valve in each main steam line and one associated globe main steam isolation bypass valve with associated actuators and instrumentation. These valves are located outside the containment, downstream of the steam generator safety valves and the atmospheric relief valve, in the auxiliary building. The isolation valves provide positive shutoff with minimum leakage during postulated line severance conditions either upstream or downstream of the valves.

The main steam isolation valves close fully upon receipt of a manual or automatic signal and remain fully closed. Upon receipt of the closing signal, the main steam isolation valves complete the closing cycle despite loss of normally required utility services for actuator and/or instrumentation. On loss of actuating gas-hydraulic power, the valves fail to the closed position. Position indication and remote manual operation of the isolation valves are provided in the control room and remote shutdown workstation. Additionally, provisions are made for in-service inspection of the isolation valves.

Closure of the main steam isolation valves and main steam isolation bypass valves is initiated by the following:

- Low steam line pressure in one of two loops
- High containment pressure
- High negative steam pressure rate in one of two loops
- Low T_{cold} in either reactor coolant loop

- Manual actuation: There are four controls for main steam line actuation. Two of the controls provide system level actuation, that is, isolate both steam lines, and two of the controls, one per loop, provide isolation of a single steam line.

- Manual reset: In addition to the controls for manual isolation actuation, there are two controls for manual reset of the steam line isolation signal, one for each of the logic divisions associated with steam line controls, which can be used to manually reset that division's steam line isolation signal.

Each main steam isolation valve is a bidirectional wedge type gate valve composed of a valve body that is welded into the system pipeline. The main steam isolation gate valve is provided with a hydraulic/pneumatic actuator. The valve actuator is supported by the yoke, which is attached to the top of the body. The valve actuator consists of a hydraulic cylinder with a stored energy system to provide emergency closure of the isolation valve. The energy to operate the valve is stored in the form of compressed nitrogen contained in one end of the actuator cylinder. The main steam isolation valve is maintained in a normally open position by high-pressure hydraulic fluid. For emergency closure, redundant solenoids are energized resulting in the high-pressure hydraulic fluid being dumped to a fluid reservoir.

The main steam isolation bypass valves are used to permit warming of the main steam lines prior to startup when the main steam isolation valves are closed. The bypass valves are modulating, air-operated globe valves. For emergency closure, redundant 1E solenoids are provided. Each solenoid is energized from a separate safety-related division.

10.3.2.3 System Operation

10.3.2.3.1 Normal Operation

During normal power operation, the main steam supply system supplies steam to meet the demand of the main turbine system. The main steam supply system also supplies steam as required to the auxiliary steam system, and reheating steam to the moisture separator reheater. The main steam supply system also provides steam to the turbine gland seal system.

The main steam supply system is capable of accepting a ±10-percent step change in load followed by a ±5-percent/min ramp change without discharging steam to the atmosphere through the main steam safety valves or to the main condenser through the turbine bypass system. For large step change load reductions, steam is bypassed (up to 40 percent of full load flow) directly to the condenser via the turbine bypass system. As discussed in subsection 10.4.4, the main steam supply system, in conjunction with the turbine bypass system, is capable of accepting a 100-percent net load rejection without reactor trip (in conjunction with a reactor rapid power reduction) and without lifting safety valves. If the turbine bypass system is not available, steam is vented to the atmosphere via the power-operated atmospheric relief valves and the main steam safety valves, as required.

10.3.2.3.2 Emergency Operation

In the event that the plant must be shut down, the main steam isolation valves with associated main steam isolation bypass valves and other valves associated with the main steam lines can be closed. The power-operated atmospheric relief valves are then used to remove reactor decay and primary system sensible heat to cooldown to conditions at which the normal residual heat removal system can perform the remaining cooldown function. If the power-operated atmospheric relief valve for an individual main steam line is unavailable because of the loss of its control or power supply, the respective safety valves will provide overpressure protection. The remaining power-operated atmospheric relief valve is sufficient to cooldown the plant.

In the event that a design basis accident occurs, which results in a large steam line break, the main steam isolation valves with associated main steam isolation bypass valves automatically close. The closure of the main steam isolation valves and associated main steam isolation bypass valves result in no more than one steam generator supplying a postulated break.

The passive residual heat removal system (Section 6.3) provides safety-related decay heat removal capability should steam relief and feedwater be unavailable.

10.3.3 Safety Evaluation

- Each main steam line is provided with safety valves that limit the pressure in the line to limit over-pressurization and remove stored energy. Each line is provided with a power-operated atmospheric relief valve to permit reduction of the main steam line pressure and remove stored energy to achieve an orderly shutdown. The startup feedwater system, described in subsection 10.4.9, provides makeup to the steam generators consistent with the steaming rate.

- Redundant power supplies and power divisions operate the main steam isolation valves and main steam isolation bypass valves to isolate safety and nonsafety-related portions of the system. Branch lines upstream of the main steam isolation valves contain normally closed, power-operated atmospheric relief valves which modulate open and closed on steam line pressure. In the event the atmospheric relief valves fail closed, the safety valves provide overpressure protection.

  Releases of radioactivity from the main steam system are minimized because there are no significant amounts of radioactivity in the system under normal operating conditions. Additionally, the main steam isolation system provides controls for reducing releases, as described in Chapter 15, following a steam generator tube rupture.

  Detection of radioactive leakage into the system, which is characteristic of a steam generator tube leak or rupture, is facilitated by inline radiation monitors on each steam line, the radiation monitor in the turbine vent and drain system which monitors condenser air removal, and the steam generator blowdown line radiation monitor.

- Section 3.2 provides the quality group classification, the required design and fabrication codes, and seismic category applicable to the safety-related portion of this system and

supporting systems. The power supplies and controls necessary for safety-related functions of the main steam supply system are safety-related, as described in Chapters 7 and 8.

- The safety-related portion of the main steam supply system is located in the containment and auxiliary building. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other appropriate natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 describe the bases of the structural design of these buildings.

  The safety-related portion of the main steam supply system is designed to remain functional after a safe shutdown earthquake. Sections 3.7 and 3.9 provide the design loading conditions that were considered. Sections 3.5, 3.6, and 9.5 describe the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- As indicated by the failure mode and effects analysis in Table 10.3.3-1, no single failure coincident with loss of offsite power compromises the system safety functions.

- The main steam supply system is initially tested with the program given in Chapter 14. Periodic in-service functional testing is done in accordance with subsection 10.3.4.

  Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the safety-related portions of the main steam supply system.

- The safety-related components of the main steam supply system are qualified to function in normal, test, and accident environmental conditions. The environmental qualification program is described in Section 3.11.

- A discussion of high energy pipe break locations and evaluation of effects are provided in subsections 3.6.1 and 3.6.2.

- A discussion of the leak-before-break application and criteria is presented in subsection 3.6.3.

10.3.4 Inspection and Testing Requirements

10.3.4.1 Preoperational Testing

10.3.4.1.1 Valve Testing and Inspection

The operability and relief setpoints of the main steam safety valves will be verified at operating temperature using steam as the pressurization fluid. The advantage of this approach is that the testing at temperature will reduce the probability of having to adjust the valve setpoints during hot functional testing heatup. The valves may be either bench tested or in-situ tested. The valves will be adjusted to lift at their set pressure defined in Table 10.3.2-2 and a pressure less than 1250 psig.

The sum of the rated capacities of the valves shall exceed the capacity specified in Table 10.3.2-1. The relieving capacity of the valve is certified in accordance with the ASME Code, Section III NC-7000.

The lift-point of each power-operated atmospheric relief valve is checked against pressure gauges mounted in the main steam piping.

The power operated relief valves will be verified to have a relief capacity of at least 300,000 lbs/hour at 1106 psia in order to satisfy their non-safety related function of decay heat removal.

The main steam isolation valves are tested to verify the closing time prior to initial startup.

10.3.4.1.2 System Testing

The main steam supply system is designed to allow testing of system operation for both normal and emergency operating modes. This includes operation of applicable portions of the protection system.

The safety-related components of the system are designed and located to permit pre-service and in-service inspections.

10.3.4.1.3 Pipe Testing

The main steam lines within the containment and the auxiliary building are visually and volumetrically inspected at installation as required by ASME Code, Section XI pre-service inspection requirements.

10.3.4.2 In-service Testing

The performance and structural leaktight integrity of system components are demonstrated by operation.

Additional description of in-service inspection and in-service testing of ASME Code, Section III, Class 2 and 3 components is contained in Section 6.6 and subsection 3.9.6. The nonsafety-related turbine stop, turbine control, and moisture separator reheater stop valves are included in the inservice test program discussed in subsection 3.9.6.

10.3.5 Water Chemistry

The objectives of the secondary side water chemistry program are as follows:

- Minimizing general corrosion in the steam generators, turbine, and feedwater system by maintaining proper pH control and by minimizing oxygen ingress (coupled with oxygen scavenging)

- Minimizing localized corrosion in the steam generators, turbine, and feedwater system by minimizing chemical contaminant ingress and by controlling contaminant levels through condensate polishing and steam generator blowdown.

10.3.5.1 Chemistry Control Basis

Steam Generator Owner's Group recommendations are considered in the secondary side water chemistry program.

Secondary side water chemistry control basis for AP1000 is shown below:

System Design

- Selection of secondary side materials to minimize corrosive species such as copper oxides
- Capability of deaeration in the demineralized water supply path, condenser, and deaerator
- Capability of continuous blowdown of the steam generator bulk water
- Capability of post-construction cleaning of the feedwater system followed by wet layup of the feedwater system and steam generators

Operation Phase

- Early identification of contaminant ingress (salts, corrosion products, and oxygen)
- Capability to filter and demineralize condensate by passage of part of the condensate flow through a condensate polisher system prior to and during plant startup and shutdown and during power operation with abnormal secondary cycle chemistry.
- Chemical addition to establish and maintain an environment that minimizes system corrosion
- Identification of action levels based on chemistry conditions, as determined by high sensitivity continuous monitoring or by grab sampling

10.3.5.2 Contaminant Ingress

Contaminants may be introduced into the secondary side water system through three major mechanisms: makeup water; condenser tube leaks; atmospheric leaks at the condenser or pump seals. The following methods are used to detect the ingress of contaminants in the secondary water system:

- Demineralized water is continuously monitored as it is being produced in the water treatment plant.
- Ionic contaminants are detected by monitoring (either continuous process monitors or sample analysis) the condensate pump discharge, feedwater downstream of addition of heater and moisture separator drains, and steam generator bulk flow as blowdown.
- Atmospheric ingress is detected by monitoring the condensate pump discharge for excessive dissolved oxygen and by monitoring condenser air removal rate.

10.3.5.3 Condensate Polishing

A condensate polishing system with a capacity of one third design condensate flow is provided to remove corrosion products and ionic contaminants. This polishing system will not normally be employed during all phases of plant operation.

The secondary side water system has provisions for recirculating feedwater to the condenser prior to and during startup. The polisher may be used during this phase to remove corrosion products from the feedwater and thus prevent their ingress into the steam generators. Full flow or near full flow condensate polishing is possible at the lower condensate flows that exist during startup and low-power operation. See subsection 10.4.6 for additional information.

10.3.5.4 Chemical Addition

AP1000 employs an all-volatile treatment (AVT) method to minimize general corrosion in the feedwater system, steam generators, and main steam piping. A pH adjustment chemical and an oxygen scavenger are the two chemicals to be injected into the condensate pump discharge header, downstream of the condensate polishers.

To reduce the general corrosion rate of ferrous alloys, a volatile pH adjustment chemical is injected to maintain a noncorrosive environment. Although the pH adjustment chemical is volatile and will not concentrate in the steam generator, it will reach an equilibrium level which will help establish noncorrosive conditions.

An oxygen scavenger is added to maintain the dissolved oxygen content in the feedwater within specified limits for each mode of operation. The oxygen scavenger also promotes the formation of a protective magnetite layer on ferrous surfaces and keeps this layer in a reduced state, further inhibiting general corrosion.

10.3.5.5 Action Levels for Abnormal Conditions

Appropriate responses to abnormal chemistry conditions provide for the long-term integrity of secondary cycle components. Action taken when chemistry parameters are outside normal operating ranges will, in general, be consistent with action levels described in Reference 1.

Secondary side water chemistry guidelines are provided in Table 10.3.5-1.

10.3.5.6 Layup and Heatup

AP1000 anticipates no long-term steam generator layup under dry conditions. When maintenance or inspection is required on the secondary side of the steam generators, the steam generators are drained hot under nitrogen atmosphere. After cooling, the nitrogen purge is lifted and the maintenance/inspection begun.

Wet layup conditions are established for corrosion protection during outages. Guidelines are given in Table 10.3.5-2.

Before heatup to full power, the bulk water in the steam generators is normally brought into power operation specifications by draining and refilling or by feeding and bleeding. Guidelines for heatup are provided in Table 10.3.5-3.

10.3.5.7 Chemical Analysis Basis

Guidelines for chemical control and diagnostic parameters are listed in Table 10.3.5-1. Each parameter will be addressed as indicated below.

Oxygen in the presence of moisture rapidly corrodes carbon steel. These corrosion products may be carried through the feedwater system and form sludge in the steam generator. This sludge forms an environment for localized corrosion mechanisms on steam generator tubes. Thus, concentrations of oxygen are kept as low as practical in the feedwater system, and dissolved oxygen is controlled at the condenser and deaerator to prevent oxygen transport to the feedwater system.

Residual concentration of the oxygen scavenger is also measured in the feedwater sample and is used as input for injection of the oxygen scavenger.

In the absence of significant impurities, the pH is controlled by the concentration of the volatile pH adjustment chemical and the oxygen scavenger. Maintaining the pH within the recommended band results in minimal corrosion rates of ferrous materials.

Conductivity is also a measure of the presence of ionic contamination and provision is made for monitoring conductivity in samples of condensate, feedwater, and steam generator blowdown. Provision is also made for specific ions, such as sodium and chloride, which could be indicative of aggressive chemistry conditions.

10.3.5.8 Sampling

In addition to the sampling locations listed in Table 10.3.5-1, other sampling points are provided in the secondary side water system. These sampling points are identified in Table 9.3.4-1 (continuous sample points) and Table 9.3.4-2 (grab sample points).

10.3.5.9 Condenser Inspection

The secondary side water chemistry program includes an inspection program of the condenser to verify condenser integrity. This program includes a visual inspection of the condenser during outages and component inspection for air leaks during plant operation.

10.3.5.10 Conformance to Branch Technical Position MTEB 5-3

AP1000 conformance to Branch Technical Position MTEB 5-3 is discussed in Section 1.9.

10.3.6 Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

The material specifications for pressure-retaining materials in safety-related portions of the main steam and feedwater systems meet the fracture toughness requirements of ASME Code, Section III, Articles NC-2300 and ND-2300 for Quality Group B and Quality Group C components.

10.3.6.2 Material Selection and Fabrication

Pipe, flanges, fittings, valves, and other piping material conform to the referenced ASME, ASTM, ANSI, or Manufacturer Standardization Society-Standard Practice code.

No copper or copper-bearing materials are used in the steam and feedwater systems.

The following requirements apply to the nonsafety-related portion of the main steam system.

Component	Alloy/Carbon Steel
Pipe	ANSI/ASME B36.10M
Fittings	ANSI/ASME B16.9, B16.11
Flanges	ANSI/ASME B16.5

Material selection and fabrication requirements for ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with the requirements for ASME Class 2 and 3 systems and components outlined in subsections 6.1.1.1 and 6.1.1.2. Material specifications for the main steam and feedwater systems are listed in Table 10.3.2-3.

Conformance with the applicable regulatory guides is described in subsection 1.9.1.

Nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems is addressed in subsection 6.6.5.

10.3.7 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

10.3.8 References

1. "PWR Secondary Water Chemistry Guidelines," EPRI TR-102134-R5, March 2000.

Table 10.3.2-1

MAIN STEAM SUPPLY SYSTEM
DESIGN DATA

Steam Flow (lb/hr)	**Maximum Calculated**
Per steam generator	7,488,000
Total	14,976,000

Design Conditions

Design pressure (psia)	1200
Design temperature (°F)	600°F

Operating Conditions

Full plant load pressure (psia)	838
Full plant load temperature (°F)	523
No load (hot standby) pressure (psia)	1106
No load (hot standby) temperature (°F)	557

Main Steam Piping: See Table 10.3.2-3.

Steam Generator Flow Restrictor

Number per steam generator outlet nozzle	7
Throat size (ft^2)	0.2
Total area (ft^2)	1.4

Power-Operated Relief Valve

Number per main steam line		1
Normal set pressure		1150 psig
Design capacity	Minimum:	70,000 lb/hr at 100 psia inlet pressure
	Maximum:	1,020,000 lb/hr at 1200 psia inlet pressure
Code		ASME Code, Section III, Class 3, seismic Category I
Actuator		Air-operated modulating

Table 10.3.2-2

DESIGN DATA FOR MAIN STEAM SAFETY VALVES

Number per main steam line	6
Total number of valves required per steam line	6
Relieving capacity per valve at 110% of design pressure	1,390,000 lb/hr
Relieving capacity per steam line at 110% of design pressure	8,340,000 lb/hr
Total relieving capacity, 2 lines at 110% of design pressure	16,680,000 lb/hr
Valve size	8 x 2(10)
Design code	ASME Code, Section III, Class 2, seismic Category I

Valve Number	Set Pressure (psig)	Relieving Capacity[(a)] (lb/hr)
SGS PL V030A(B)	1185	1,248,000
SGS PL V031A(B)	1191	1,254,000
SGS PL V032A(B)	1198	1,262,000
SGS PL V033A(B)	1204	1,268,000
SGS PL V034A(B)	1211	1,275,000
SGS PL V035A(B)	1217	1,282,000
Total capacity, 2 lines		15,178,000

Note:

a. Based on system accumulation pressure of 3%, per Subsection NC-7512 of ASME Code, Section III, Division 1, 1989 Edition, Subsection NC, Class 2 components.

Table 10.3.2-3

DESCRIPTION OF MAIN STEAM AND MAIN FEEDWATER PIPING

Segment	Material Specification
Main Steam Line	
Steam generator outlet to containment penetration	SA-333 Gr. 6 seamless pipe
Containment penetration to MSIV	SA-333 Gr. 6 seamless pipe
MSIV to auxiliary/turbine building wall	SA-333 Gr. 6 seamless pipe
Auxiliary/turbine building wall to equalization header[a]	ASTM A-106 Gr. B
Branch lines to turbine stop valves[a]	ASTM A-106 Gr. B
Main Feedwater Line	
Feedwater pump outlet to individual steam generator feedwater lines[a]	ASTM A-106 Gr. B
Feedwater heater bypass line[a]	ASTM A-106 Gr. B
Start of individual steam generator feedwater lines to auxiliary/turbine building wall[a]	ASTM SA335 Gr. P-11
Auxiliary/turbine building wall to MFIV	SA-335 Gr. P-11
MFIV to containment penetration	SA-335 Gr. P-11
Containment penetration to steam generator nozzle	SA-335 Gr. P-11

Note:

a. Piping is beyond the ASME Section III piping boundary.

Table 10.3.2-4

MAIN STEAM BRANCH PIPING (2.5-INCH AND LARGER) DOWNSTREAM OF MSIV

Description	Maximum Steam Flow	Shutoff Valve	Valve Closure Time	Actuator	Comments
Turbine bypass lines to condenser; 6 lines total	998,000 lb/hr each line	12-in. globe (turbine bypass valve)	5 sec or less[(a)] when tripped closed	Air operator, fail close	Bypass valve is tripped closed on main steam isolation signal
Reheating steam to moisture separator reheater, 4 lines total	247,000 lb/hr, each MSR	12-in. globe (reheat steam supply control valve 2 each) and 8-in. (reheat steam supply bypass valve, 2 each)	5 sec or less[(a)]	Air operators; fail close	Main steam flow to reheater ceases (thermodynamically) following turbine trip flow ceases following valve closure on a main steam isolation signal
Main steam supply to auxiliary steam system	123,000 lb/hr	6-in. globe (isolation valve)	10 sec or less	Air operator; fail close	Main steam flow to auxiliary steam system terminates following isolation valve closure on a main steam isolation signal
High pressure turbine steam supply lines; 4 lines total	3,744,000 lb/hr each line	27.5-in. stop valve in each line	5 sec or less[(a)]	Hydraulically operated from electro-hydraulic turbine control system	Main steam flow to high pressure turbine ceases following stop valve closure on a turbine trip
Main steam supply to turbine glands	37,000 lb/hr	6-in. gate (isolation valve)	60 sec or less	Motor operator; manually operated	Main steam flow to turbine seals continues following a turbine trip; however, this steam flow is relatively small and has been considered in the steam line break analysis (Section 3.6)

(a) Specified closure times are for safety analysis purposes; other system performance requirements may dictate more rapid closure.

Table 10.3.3-1 (Sheet 1 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
1	MSIVs V040A(B) normally open, fail closed with self contained hydraulic operator	Isolates SG A(B) in the event of a MSLB to prevent blowdown of more than one SG; Isolates containment in conjunction with SG and main steam line inside containment	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room & remote shutdown work-station	a. None; Plant goes to or remains in a safe shutdown condition	One MSIV is provided for each steam line. Each MSIV redundantly activated from separate safety-related power divisions. Redundant backup provided by downstream isolation valves. Redundant containment isolation provided by SG and main steam line inside containment.
			b. DBA Except SGTR	b. Fails to close upon ESF isolation signal	b. Position indica-tion on main control room & remote shutdown workstation	b. None; closure of either MSIV or downstream valves prevent blowdown of more than one SG; containment integrity is maintained by MSIV and either SG and steam line integrity inside containment or downstream valves.	
			c. DBA-SGTR	c. Fails to close on ESF isolation signal	c. Same as 1b	c. None; limiting failure is PORV failed open discharging to atmo-sphere. Termination of break flow occurs on automatic block valve closure plus PRHR actuation. Continued break flow past MSIV precluded by redundant downstream isolation valves.	Redundant isolation provided by downstream isolation valves

Table 10.3.3-1 (Sheet 2 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
2	Main steam power operated relief valve V233A(B) normally closed fail closed, air-operated control valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown from more than one SG in conjunction with block valve	a. All but DBA	a1. Fails to open upon open signal	a1. Position indication on main control room & remote shutdown workstation; steam line high pressure	a1. None; heat removal available via steam dump or PRHR; safety valves provide over-pressure protection	Redundant isolation provided by PORV and block valve via separate safety-related power divisions.
				a2. Fails open or fails to close on command including spurious operation	a2. Position indication on main control room & remote shutdown workstation; low SG level or SG pressure	a2. None; maximum flow less than DBA limit; shutdown effected with 1 PORV, PRHR, or steam dump	
			b. DBA except SGTR	b. Fails to close	b. Position indication on main control room & remote shutdown workstation; steam line low pressure alarm	b. None, redundant isolation provided by PORV block valve	Dose analysis based on failed open PORV with subsequent block valve closure
			c. DBA - SGTR	c. Fail to close	c. Position indication on main control room & remote shutdown workstation; streamline low pressure alarm	c. None; automatic redundant isolation provided by PORV block valve. Releases based on signal generation and closure time delay	

Table 10.3.3-1 (Sheet 3 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
3	Main steam line PORV block valve V027A(B), normally open fail as is motor-operated gate valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown from more than 1 SG in conjunction with PORV and provides containment integrity in conjunction with SG and main steam line inside containment	a. All but DBA	a1. Same as 2.a1 a2. Same as 2.a2	a1. Same as 2.a1 a2. Same as 2.a2	a1. Same as 2.a1 a2. Same as 2.a2	Redundant steam line isolation provided by PORV and block valve via separate safety-related power divisions. Redundant containment isolation provided by SG and main steam line inside containment.
			b. DBA except SGTR	b. Same as 2b	b. Position indication on main control room & remote shutdown workstation	b. Same as 2b; containment integrity is maintained by SG and main steam line inside containment	
			c. DBA SGTR	c. Same as 2b	c. Position indication on main control room & remote shutdown workstation	c. None, automatic redundant isolation of the PORV on low steam line pressure	Dose analysis based on failed open PORV isolated by block valve. Releases equivalent.

Table 10.3.3-1 (Sheet 4 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
4	Main steam isolation bypass valve V240A(B) normally closed, fail closed air-operated valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown of more than one SG; isolates containment in conjunction with SG and main steam line inside containment	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room and remote shutdown workstation	a. Plant continues operation or goes to or remains at a safe shutdown condition	One MSIV bypass is provided for each steam line. Each bypass valve redundantly activated from separate 1E power divisions. Redundant backup provided by downstream isolation valves. Redundant containment isolation provided by SG and main steam line inside containment.

Table 10.3.3-1 (Sheet 5 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECT ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			b. DBA except SGTR	b. Fails to close upon ESF isolation signal	b. Position indication on main control room & remote shutdown workstation	b. None, closure of either bypass valve or down-stream isolation valves prevents blowdown of more than 1 SG; containment integrity maintained by either MSIV bypass valve or SG/steam line integrity inside containment	
			c. DBA-SGTR	c. Fails to close on ESF isolation signal	c. Position indication on main control room & remote shutdown workstation	c. None, limiting failure is PORV failed open discharging to atmosphere. Termination of break flow occurs on automatic block valve closure plus passive RHR actuation. Continued break flow past MSIV bypass precluded by redundant downstream isolation valves	Redundant isolation provided by downstream isolation valves

Table 10.3.3-1 (Sheet 6 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
5	Main steam line drain isolation valve V036A(B), normally open fail closed, air-operated valve	Isolates containment in conjunction with SG and main steam line inside containment. Isolates SG No. 1(2) in the event of a MSLB to prevent blowdown from more than one SG.	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room & high level alarm in condensate drain pot	a. None; local drains provided to limit moisture carry to turbine	
			b. DBA including SGTR	b. Fails to close upon ESF isolation signal	b. Position indication on main control room	b. None; closure of either series isolation valves provides steam line isolation; containment integrity is maintained by either condensate isolation or SG and main steam line inside containment	

Table 10.3.3-1 (Sheet 7 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
6	Main steam line drain control valve V086A(B) normally closed, fail closed, air-operated valve	Isolates SG A(B) in the event of a main steam line break to prevent blowdown to more than one SG	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room and high level alarm in condensate drain pot	a. None; local drains provided to limit moisture carryover to turbine	
			b. DBA including SGTR	b. Fails to close upon ESF isolation signal	b. Position indication provided on main control room	b. None, closure of either series isolation valves provides steam line isolation	

Table 10.3.3-1 (Sheet 8 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
7	Main steam safety valves V030A, V031A, V032A, V033A, V034A, V035A (V030B, V031B, V032B, V033B, V034B, V035B), normally closed	Protect SG A(B) and associated steam line up to MSIV from overpressurization	All	a. Fails to open when required	a. Higher pressure and/or water level in SG A(B)	a. None, 5 out of 6 safety valves for SG A(B) still available with PORV available to supplement relief capacity; also, plant trip occurs on high steam generator level	
				b. Spurious opening or failure to reset after opening	b. Low steam line pressure	b. None, maximum flow from one safety valve less than DBA analysis assumptions, Shutdown effected by other SG or PRHR	

Table 10.3.3-1 (Sheet 9 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
8	Steam Generator blowdown isolation V074A(B), normally open, fail closed air-operated valve	Isolates blowdown from SG A(B) upon PRHR actuation; isolates containment in conjunction with SG and main steam line inside containment	All	a. Fails closed or fails to open upon command	a. Position indication on the main control room and zero flow measured in blowdown system	a. None, blowdown is terminated but has no safety impact	
				b. Fails open or fails to close on command	b. Position indication on main control room	b. None, redundant isolation of blowdown via series isolation valve V075A(B), Containment integrity is maintained by blowdown isolation or SG and blowdown line inside containment	Redundant isolation is provided for SG volume for PRHR operation via series valves; containment isolation via blowdown isolation or SG and blowdown line inside containment

Table 10.3.3-1 (Sheet 10 of 10)

MAIN STEAM SUPPLY SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
9	Steam Generator blowdown isolation V075A(B), normally open, fail closed air-operated valve	Isolates blowdown from SG A(B) upon PRHR actuation	All	a. Fails closed or fails to open upon command	a. Position indication on main control room and zero flow in blowdown system	a. None, blowdown is terminated but has no safety impact	
				b. Fails open or fails to close on command	b. Position indication on main control room	b. None, redundant isolation of blowdown via series isolation valve V074A(B)	Redundant isolation is provided for SG volume for PRHR operation via series valves

Table 10.3.5-1 (Sheet 1 of 3)

GUIDELINES FOR SECONDARY SIDE WATER CHEMISTRY DURING POWER OPERATION

CONDENSATE

Parameters	Normal Value
Control	
Cation conductivity due to strong acid anions at 25°C, μS/cm	≤ 0.15
Total cation conductivity at 25°C, μS/cm	≤ 0.3
Dissolved oxygen, ppb[(a)]	≤ 10
Diagnostic	
Total organic carbon, ppb	≤ 100
Sodium, ppb	< 1
pH at 25°C	> 9.0
Specific conductivity at 25°C, μS/cm	2 - 6
Volatile pH adjustment chemical, ppb	(b)

Notes:

a. Air leakage should be reduced until total air ejected flow rate is less than 6 scfm.

b. pH, volatile pH adjustment chemical concentration and specific conductivity should correlate.

Table 10.3.5-1 (Sheet 2 of 3)

GUIDELINES FOR SECONDARY SIDE WATER CHEMISTRY DURING POWER OPERATION

FEEDWATER

Parameters	Normal Value
Control	
pH at 25°C[(a)]	> 9.5
Hydrazine, ppb[(c)]	≥ 100
Total iron, ppb	≤ 20
Diagnostic	
Dissolved oxygen, ppb	≤ 2
Cation conductivity due to strong acid anions at 25°C, μS/cm	≤ 0.2
Specific conductivity at 25°C, μS/cm	4.0 - 12.0
Volatile pH adjustment chemical, ppb	(a)

Notes:

a. pH, volatile pH adjustment chemical concentration and specific conductivity should correlate.
b. When operating with condensate polishers, the pH of an all-ferrous system can be controlled to a lower value of 9.2, with action required when pH < 9.2.
c. Values apply if hydrazine is used for oxygen scavenging. An alternate oxygen scavenger may be used with appropriate concentration limits.

Table 10.3.5-1 (Sheet 3 of 3)

GUIDELINES FOR SECONDARY SIDE WATER CHEMISTRY DURING POWER OPERATION

STEAM GENERATOR BLOWDOWN

Parameters	Normal Value
Control	
pH at 25°C[a]	9.0 - 9.5[b]
Total cation conductivity	≤ 0.8[c]
Sodium, ppb	≤ 20
Chloride, ppb	≤ 20
Sulfate, ppb	≤ 20
Silica, ppb	≤ 300
Diagnostic	
Cation conductivity due to strong acid anions at 25°C, μS/cm	≤ 0.5
Suspended solids, ppb	< 1000
Specific conductivity at 25°C, μS/cm	< 3.0
Volatile pH adjustment chemical, ppb	(a)

Notes:

a. pH, volatile pH adjustment chemical concentration and specific conductivity should correlate.
b. When operating with condensate polishers, the pH of an all-ferrous system can be controlled to a value of > 8.8.
c. Based on concentrations of total anionic species present, any inconsistencies between theoretical and measured values should be investigated.

Table 10.3.5-2

GUIDELINES FOR STEAM GENERATOR WATER DURING COLD SHUTDOWN/WET LAYUP

Parameters	Normal Value	Prior to Heatup (≤ 200°F)
Control		
pH at 25°C	9.8 - 10.5	≥ 9.3[a]
Hydrazine, ppm[b]	75 - 200	
Sodium, ppb	≤ 1000	≤ 100
Chloride, ppb	≤ 1000	≤ 100
Sulfate, ppb	≤ 1000	≤ 100
Diagnostic		
Volatile pH adjustment chemical - as required to achieve pH range		
Total organic carbon, ppb	≤ 100	

Notes:

a. Conformance with pH guideline may be waived prior to achieving no load temperature and passing steam forward to turbine.

b. Values apply if hydrazine is used for oxygen scavenging. An alternate oxygen scavenger may be used with appropriate concentration limits.

Table 10.3.5-3

GUIDELINES FOR STEAM GENERATOR BLOWDOWN DURING HEATUP (> 200°F TO < 5% POWER)

Parameters	Normal Value	Value Prior to Power Escalation Above 5%	Value Power Escalation Prior to Above 30%[b]
Control			
pH at 25°C[a]	≥ 9.0	--	≥ 9.0
Total cation conductivity at 25°C, μS/cm	≤ 2.0	≤ 2.0	≤ 0.8
Dissolved oxygen, ppb	≤ 5	≤ 5	≤ 5
Sodium, ppb	≤ 100	≤ 100	≤ 20
Chloride, ppb	≤ 100	≤ 100	≤ 20
Sulfate, ppb	≤ 100	≤ 100	≤ 20
Silica, ppb	--	--	≤ 300
Diagnostic			
Specific conductivity at 25°C, μS/cm[a]	≥ 10		
Volatile pH adjustment chemical[a]	(a)		
Silica, ppb	≤ 1000		

Notes:
a. pH, volatile pH adjustment chemical concentration and specific conductivity should correlate.
b. This column is presented here for startup chemistry continuity with Table 10.3.5-1 since > 5% power denotes power operation. If escalation > 5% power is accomplished prior to meeting the values in this column, Action Level 1 requirements take effect.

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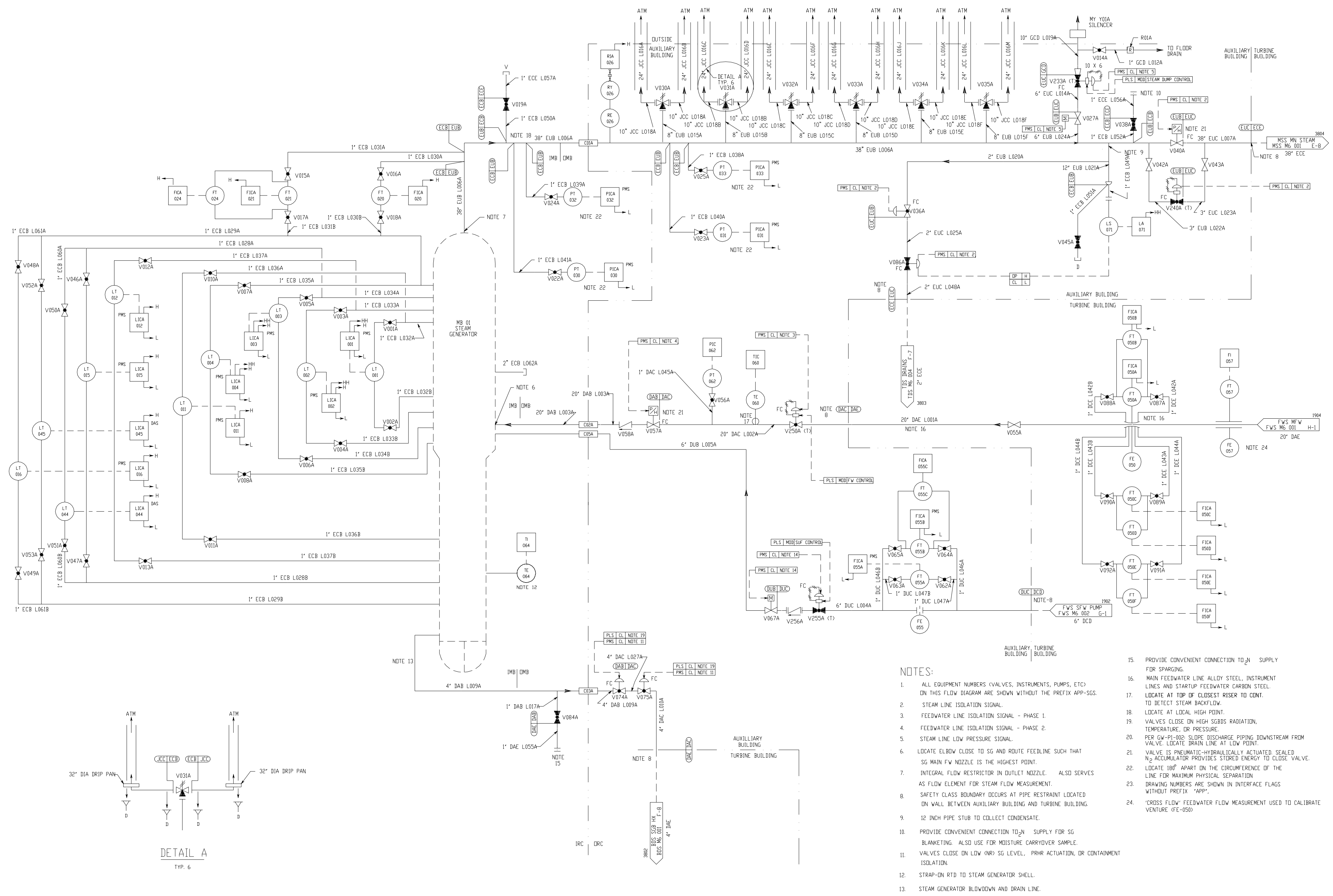


Figure 10.3.2-1 (Sheet 1 of 2)

Main Steam Piping and Instrumentation Diagram (Safety Related System) (REF) SGS 001

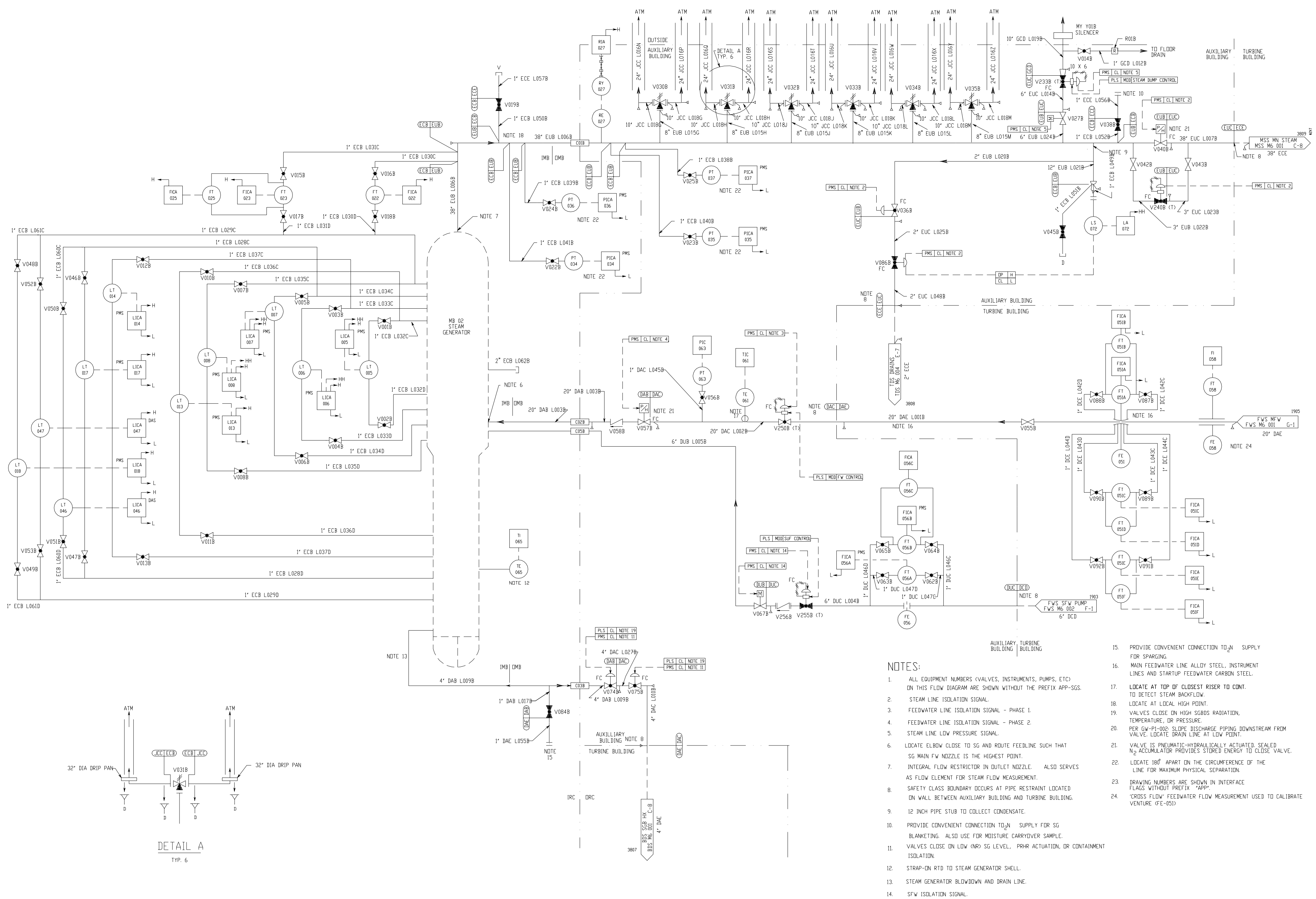
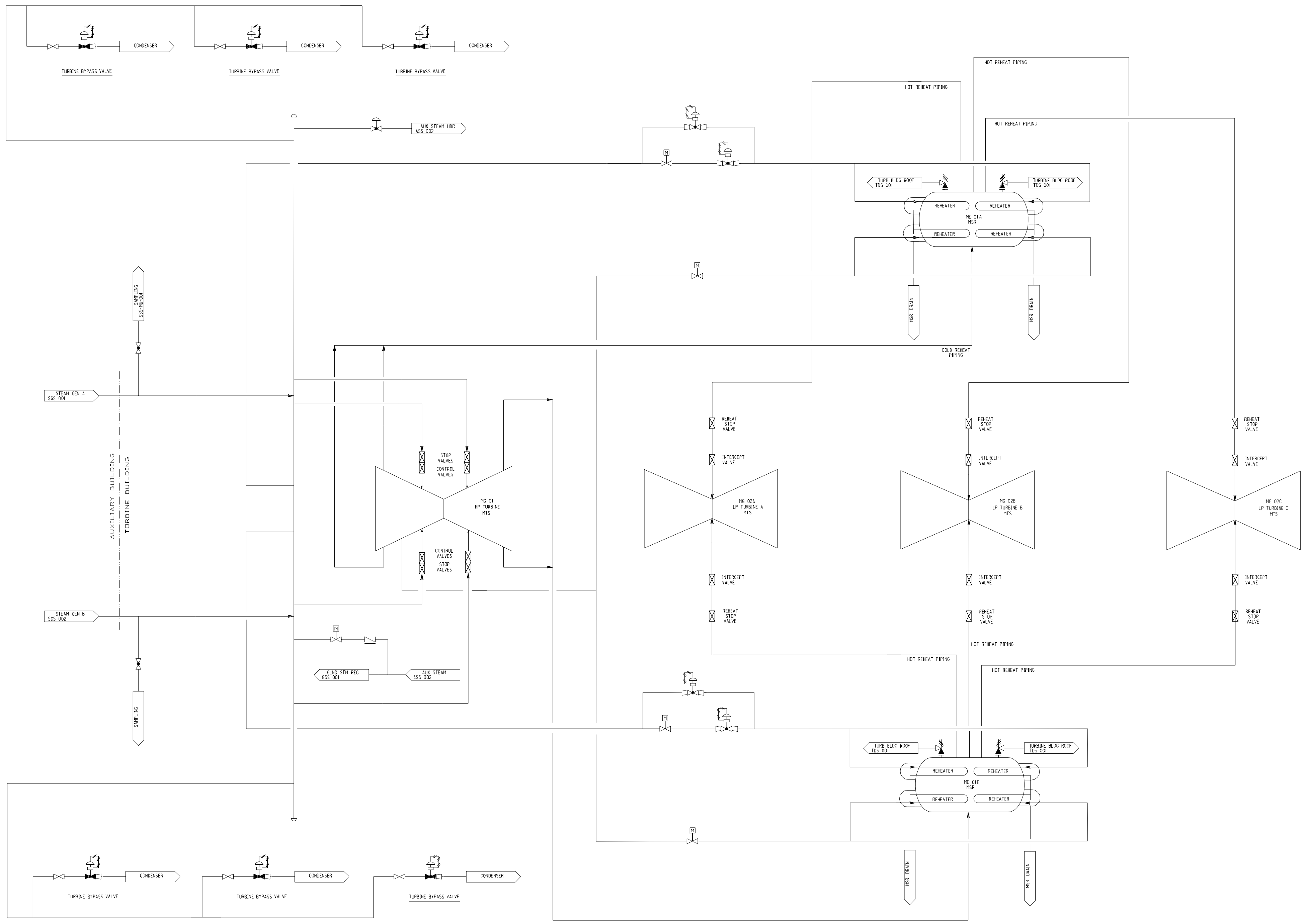


Figure 10.3.2-1 (Sheet 2 of 2)

Main Steam Piping and Instrumentation Diagram (Safety Related System) (REF) SGS 002



Inside Turbine Building

Figure 10.3.2-2

Main Steam System Diagram
(REF)MSS 001

10.4 Other Features of Steam and Power Conversion System

This section provides descriptions of each of the principal design features of the steam and power conversion system not in Sections 10.2 and 10.3.

10.4.1 Main Condensers

The main condenser functions as the steam cycle heat sink, receiving and condensing exhaust steam from the main turbine, and the turbine bypass system.

10.4.1.1 Design Basis

10.4.1.1.1 Safety Design Basis

The main condenser serves no safety-related function and therefore has no nuclear safety design basis.

10.4.1.1.2 Power Generation Design Basis

The main condenser is designed to receive and condense the full-load main steamflow exhausted from the main turbine and serves as a collection point for vents and drains from various components of the steam cycle system.

The main condenser is designed to receive and condense steam bypass flows up to 40 percent of plant full load steam flow while condensing the remaining low-pressure turbine steam flow. This condensing action is accomplished without exceeding the maximum allowable condenser backpressure for main turbine operation.

The condenser hotwell is designed to store at the normal operating water level an amount of condensate equivalent to at least three minutes of full load condensate system operating flow.

The main condenser is designed to deaerate the condensate so that the dissolved oxygen content of the condensate remains under 10 ppb during normal full power operation.

10.4.1.2 System Description

The main condenser is part of the AP1000 condensate system (CDS). The condensate system is described in subsection 10.4.7 and shown in Figure 10.4.7-1. Classification of equipment and components is given in Section 3.2. Table 10.4.1-1 provides main condenser design data.

The main condenser is a three-shell, single-pass, multipressure, spring-supported unit. Each shell is located beneath its respective low-pressure turbine. The condenser is equipped with titanium tubes. The titanium material provides good corrosion and erosion resisting properties.

In a multipressure condenser, the condenser shells operate at slightly different pressures and temperatures. Condensate that is condensed in the low pressure condenser shell drains through internal piping to the high pressure (hottest) shell where it is slightly heated and mixed with

condensate of the high pressure shell. Condensate then flows through a single outlet to the suction of the condensate pumps.

The condenser shells are located below the turbine building operating floor and are supported on a spring-mounted foundation from the turbine building basemat. A rigid connection is provided between each low-pressure turbine exhaust opening and the steam inlet connections of the condenser. Two low-pressure feedwater heaters are located in the neck area of each condenser shell. Piping is installed for hotwell level control and condensate sampling.

10.4.1.2.1 System Operation

During normal power operation, exhaust steam from the low-pressure turbines is directed into the main condenser shells. The condenser also receives auxiliary system flows, such as feedwater heater vents and drains and gland sealing steam spillover and drains.

The hotwell level controller provides automatic makeup or rejection of condensate to maintain a normal level in the condenser hotwells. On low level, the makeup control valves open and admit condensate by vacuum draw to the hotwell from the condensate storage tank. On high-water level the condensate reject control valves open to divert water from the condensate pump discharge to the condensate storage tank. This rejection automatically stops when the hotwell level falls to within normal operating range. Rejection to the storage tank can be manually overridden upon an indication of high-hotwell conductivity to prevent transfer of contaminants into the condensate storage tank in the event of a condenser tube failure.

Air inleakage and noncondensable gases contained in the turbine exhaust steam are collected in the condenser and removed by the main condenser air removal system. The condenser air removal system is discussed further in subsection 10.4.2.

To protect the condenser shells and turbine exhaust hoods from overpressurization, steam relief blowout diaphragms are provided in the low-pressure turbine exhaust hoods.

The main condenser is capable of accepting up to 40 percent of full load main steam flow from the turbine bypass system. Operation of the turbine bypass system is discussed in subsection 10.4.4. In the event of high condenser pressure or trip of the circulating water pumps, the turbine bypass valves are prohibited from opening.

Distribution headers are incorporated to protect the condenser tubes, feedwater heaters located in the condenser neck, and other condenser components from turbine bypass or high-temperature drains entering the condenser shell.

The main condenser interfaces with secondary sampling system (SSS) to permit sampling of the condensate in the condenser hotwell. Also, grab sampling capability is provided for each condenser tubesheet. Should circulating water in-leakage occur, these provisions permit determination of which tube bundle has sustained the leakage. Steps may be taken to repair or plug the leaking tubes. This is performed by isolating the circulating water system from the affected water box. Plant power is reduced as necessary. This will temporarily reduce condenser capacity by approximately 50 percent. The water box is then drained and the affected tubes are

either repaired or plugged. Refer to subsection 10.3.5.5 for a discussion regarding action levels for abnormal secondary cycle chemistry conditions.

A condenser tube cleaning system performs mechanical cleaning of the circulating water side of the titanium tubes. This cleaning, along with chemical treatment of the circulating water, reduces fouling and helps to maintain the thermal performance of the condenser.

10.4.1.3 Safety Evaluation

The main condenser has no safety-related function and therefore requires no nuclear safety evaluation.

During normal operation and shutdown, the main condenser has no significant inventory of radioactive contaminants. Radioactive contaminants may enter through a steam generator tube leak. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentrations of radioactive contaminants, is included in Chapter 11. No hydrogen buildup in the main condenser is anticipated. The failure of the main condenser and any resultant flooding will not preclude operation of any essential system since no safety-related equipment is located in the turbine building and the water cannot reach safety-related equipment located in Category I plant structures.

10.4.1.4 Tests and Inspections

The condenser water boxes are hydrostatically tested after erection. Condenser shells are tested by completely filling them with water and then testing by the fluorescent tracer method in accordance with Reference 1. Tube joints are leak tested during construction.

10.4.1.5 Instrumentation Applications

The main condenser hotwell is equipped with level control devices for control of automatic makeup and rejection of condensate. Condensate level in the condenser hotwell is indicated in the main control room and alarms on high or low level.

Condenser pressure for each condenser shell is indicated in the main control room and alarms on high level. Also, pressure instrumentation is provided to alarm prior to reaching the maximum turbine operating backpressure limit. Pressure devices are provided to trip the main turbine on high turbine exhaust pressure.

Temperature indication for monitoring condenser performance is provided.

10.4.2 Main Condenser Evacuation System

Main condenser evacuation is performed by the condenser air removal system (CMS). The system removes noncondensable gases and air from the main condenser during plant startup, cooldown, and normal operation. This action is provided by liquid ring vacuum pumps.

10.4.2.1 Design Basis

10.4.2.1.1 Safety Design Basis

The condenser air removal system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.2.1.2 Power Generation Design Basis

- The condenser air removal system removes air and noncondensable gases from the condenser during plant startup, cooldown, and normal operation from the steam side of the three main condenser shells and exhausts them into the atmosphere.

- The system establishes and maintains a vacuum in the condenser during startup and normal operation by the use of liquid ring vacuum pumps.

10.4.2.2 System Description

10.4.2.2.1 General Description

Classification of equipment and components is given in Section 3.2.

The air removal system consists of four liquid ring vacuum pumps that remove air and noncondensable gases from the three condenser shells during normal operation and provide condenser hogging during startup. One vacuum pump is provided for each condenser shell, and one pump is provided as a standby. The noncondensable gases, together with a quantity of vapor, are drawn through the air cooler sections of condenser shells to the suction of the vacuum pumps. These noncondensables consist mainly of air, nitrogen, and ammonia. No hydrogen buildup is anticipated in the system (see subsection 10.4.1.3). Dissolved oxygen is present in the condensate and condenser hotwell inventory. Only trace amounts of this oxygen are released in the condenser, and the amounts are negligible compared to the amount of gas and vapor being evacuated by the system. Therefore, the potential for explosive mixtures within the condenser air removal system does not exist.

The circulating water system (CWS) provides the cooling water for the vacuum pump seal water heat exchangers. The seal water is kept cooler than the saturation temperature in the condenser to maintain satisfactory vacuum pump performance.

The noncondensable gases and vapor mixture discharged to the atmosphere are not normally radioactive. However, it is possible for the mixture to become contaminated in the event of primary-to-secondary system leakage. Air inleakage and noncondensable gases removed from the condenser and discharged by the vacuum pumps are routed to the turbine island vents, drains, and relief system (TDS) and monitored for radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated release from the system, is included in Chapter 11.

The discharge from the condenser air removal system has a connection for taking local grab samples. Connections also allow the installation of portable, continuous sampling equipment.

Should the condenser air removal system become inoperable, a gradual increase in condenser back pressure would result from the buildup of noncondensable gases. This increase in backpressure would cause a decrease in the turbine cycle efficiency. If the condenser air removal system remains inoperable, condenser backpressure increases to the turbine trip setpoint, and a turbine trip is initiated. Loss of the main condenser vacuum causes a turbine trip but does not close the main steam isolation valves. A loss of condenser vacuum incident is described in subsection 15.2.5.

10.4.2.2.2 Component Description

The liquid ring vacuum pumps are supplied as packaged units. Major components in each package include a vacuum pump, seal water heat exchanger, seal water pump, air/water separator, and exhaust silencer. Seal water is supplied to seal the clearances in the pump and also to condense vapor at the inlet to the pump. Seal water flows through the shell side of the seal water heat exchanger and circulating water flows through the tube side. Seal water make up is provided by the condensate system (CDS).

Piping and valves are carbon steel. The piping is designed to ANSI B31.1.

10.4.2.2.3 System Operation

During startup operation, air is removed from the condenser by operating three liquid ring vacuum pumps. The fourth pump is on standby.

During normal plant operation, noncondensable gases are removed from the condenser by three vacuum pumps. If one pump trips, the condition is alarmed in the main control room, and the standby pump is started.

10.4.2.3 Safety Evaluation

The condenser air removal system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.2.4 Tests and Inspections

Testing and inspection of the system is performed prior to plant operation. A performance test is conducted on each pump in accordance with Reference 2. In addition, the pumps are hydrostatically tested.

10.4.2.5 Instrumentation Applications

The effectiveness of the air removal system is indicated by monitoring condenser pressure, using instrumentation described in subsection 10.4.1.5. Vacuum pump status (on/off) is indicated in the main control room, and pump trips are alarmed.

Volumetric flow indication is provided to monitor the quantity of exhausted noncondensable gases.

A radiation detector monitors the discharge of the condenser vacuum pumps through the turbine island vents, drains, and relief system (TDS). The radiation detector is indicated and alarmed. For process and effluent radiological monitoring and sampling systems, refer to Section 11.5.

10.4.3 Gland Seal System

10.4.3.1 Design Basis

10.4.3.1.1 Safety Design Basis

The gland seal system (GSS) serves no safety-related function and therefore has no nuclear safety design basis.

10.4.3.1.2 Power Generation Design Basis

- The gland seal system prevents air leakage into and steam leakage out of the casings of the turbine-generator.

- The system returns condensed steam to the condenser and exhausts noncondensable gases into the atmosphere via the turbine island vents, drains, and relief system.

- The presence of radioactive contamination in the noncondensable gas exhausted from the gland seal condenser, is detected by a radiation monitor in the turbine island vents, drains, and relief system.

10.4.3.2 System Description

10.4.3.2.1 General Description

The gland seal system consists of the following items and assemblies:

- Steam supply header
- Steam drains/noncondensable gas exhaust header
- Two motor driven gland seal condenser exhaust blowers
- Associated piping, valves, and controls
- Gland seal condenser
- Vent and drain lines

The quality group standards for the gland seal system are provided in Section 3.2. The gland seal system is shown in Figure 10.4.3-1.

10.4.3.2.2 System Operation

The annular space through which the turbine shaft penetrates the turbine casing is sealed by steam supplied to the rotor glands. Where the packing seals against positive pressure, the sealing steam connection acts as a leakoff. Where the packing seals against vacuum, the sealing steam either is drawn into the casing or leaks outward to a vent annulus maintained at a slight vacuum. The vent annulus receives air leakage from the outside. The air-steam mixture is drawn to the gland seal condenser.

Sealing steam is distributed to the turbine shaft seals through the steam-seal header. This sealing steam is supplied from either the auxiliary steam system (ASS), or from main steam (MSS), extracted ahead of the high-pressure turbine throttle valves. Steam flow to the header is controlled by the steam-seal feed valve which responds to maintain the steam-seal supply header pressure. The low and high pressure turbine sealing systems each have a separate steam pressure regulating valve which provides sealing steam. Excess steam is returned to the No. 1 feedwater heaters via the spillover control valve which automatically opens to bypass excess steam from the GSS.

During the initial startup phase of turbine-generator operation, steam is supplied to the gland seal system from the auxiliary steam header which is supplied from the auxiliary boiler. At times other than initial startup, turbine-generator sealing steam is supplied from either the auxiliary steam system or from main steam.

At the outer ends of the glands, collection piping routes the mixture of air and excess seal steam to the gland seal condenser. The gland seal condenser is a shell and tube type heat exchanger where the steam-air mixture from the turbine seals is discharged into the shell side and condensate flows through the tube side as a cooling medium. The gland seal condenser is maintained at a slight vacuum by a motor-operated blower. There are two 100-percent blowers mounted in parallel. Condensate from the steam-air mixture drains to the main condenser while noncondensables are exhausted to the turbine island vents, drains, and relief system through a common discharge line shared by the vapor extractor blowers.

The mixture of noncondensable gases discharged from the gland seal condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to be radioactively contaminated. The headered discharge line vents to the turbine vents, drains, and relief system which contains a radiation monitor for detection of radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. A description of the radiological aspects of primary-to-secondary system leakage is included in Chapter 11.

Failure of the gland seal system normally results in no release of radioactivity to the atmosphere.

10.4.3.3 Safety Evaluation

The gland seal system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.3.4 Tests and Inspections

The system is tested in accordance with written procedures during the initial testing and operation program. Since the gland seal system is in use and essential parameters are monitored during normal plant operation, the satisfactory operation of the system components demonstrate system operability.

10.4.3.5 Instrumentation Applications

A pressure controller is provided to maintain the steam-seal supply header pressure by providing signals to the steam-seal feed valve. Pressure control valves are used to provide appropriate pressures to operate both the low and high pressure turbine steam seals. Excess steam flow is handled by the gland spillover control valve which discharges to the No. 1 feedwater heaters.

The gland seal condenser is monitored for shell side pressure and internal liquid level.

Pressure indication with appropriate alarm is provided for monitoring the operation of the system. A radiation detector with an alarm is provided in the turbine island vents, drains, and relief system to detect radiation associated with primary-to-secondary side leakage in the steam generators.

10.4.4 Turbine Bypass System

The turbine bypass system provides the capability to bypass main steam from the steam generators to the main condenser in a controlled manner to dissipate heat and to minimize transient effects on the reactor coolant system during startup, hot shutdown, cooldown, and step-load reductions in generator load. The turbine bypass system is also called the steam dump system, and is part of the main steam system (MSS).

10.4.4.1 Design Basis

10.4.4.1.1 Safety Design Basis

The turbine bypass system serves no safety-related function and therefore has no nuclear safety design basis. The nonsafety-related turbine bypass valves are credited in a single failure analysis to mitigate the event for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event.

10.4.4.1.2 Power Generation Design Basis

The turbine bypass system has the capacity to bypass 40 percent of the full load main steam flow to the main condenser.

The turbine bypass system bypasses steam to the main condenser during plant startup and permits a manually controlled cooldown of the reactor coolant system to the point where the normal residual heat removal system can be placed in service.

The turbine bypass system total flow capacity, in combination with bypass valve response time, reactor coolant system design, and reactor control system response, is sufficient to reduce

challenges to the main steam power-operated relief valves, main steam safety valves, and pressurizer safety valves during: reactor trip from 100-percent power; and 100-percent load rejection or turbine trip from 100-percent power without reactor trip.

10.4.4.2 System Description

10.4.4.2.1 General Description

The turbine bypass system is part of the main steam system and is shown on Figure 10.3.2-2. The system consists of a manifold connected to the main steam lines upstream of the turbine stop valves and of lines from the manifold with regulating valves to each condenser shell.

The capacity of the system, along with the NSSS control systems, provides the capability to meet the design requirement bases specified in subsection 10.4.4.1.2. For power changes less than or equal to a 10 percent change in electrical load, the turbine bypass system is not actuated; the total power change is handled by the reactor power control, pressurizer level control, pressurizer pressure control, and the steam generator level control systems described in Section 7.7. For load rejections greater than 10 percent but less than 50 percent, or a turbine trip from 50 percent power or less, the turbine bypass system operates in conjunction with the same control systems used for the 10 percent or less load change to meet the design basis requirements specified in subsection 10.4.4.1.2. For load rejections greater than 50 percent power, the rapid power reduction system (described in Section 7.7) operates in conjunction with the previously mentioned control systems to meet the design basis requirements. The rapid power reduction system is designed to rapidly reduce the nuclear power to a value that can be handled by the turbine bypass system. Certain transient conditions or system degradations beyond those of subsection 10.4.4.1.2 may result in a reactor trip and may result in the operation of the main steam power operated relief and safety valves.

10.4.4.2.2 Component Description

The turbine bypass valves are globe valves and are electropneumatically operated. The valves fail to a closed position upon loss of air or electric signal. A modulating positioner responds to the electric signal from the control system and provides an appropriate air pressure to the valve actuator for modulating the valve open.

Solenoid valves located in the air line to each bypass valve actuator serve as protective interlocks for bypass valve actuation and for tripping the valve open or closed. One of the solenoid valves is energized, when required, to bypass the modulating positioner and provide full air pressure to the actuator diaphragm to quickly trip open the bypass valve. Other solenoid valves, when deenergized, block the air supply to the actuator and vent the actuator diaphragm; this action blocks the bypass valve from opening, or closes the valve if opened.

Two of the blocking solenoid valves for each turbine bypass valve are redundant and block bypass valve actuation upon low reactor coolant system T_{avg}. This minimizes the possibility of excessive reactor coolant system cooldown. However, the low T_{avg} block can be manually bypassed for one of the bypass valves to allow operation during plant cooldown.

Another blocking solenoid valve prevents actuation of the bypass valve when the condenser is not available. This solenoid valve also prevents unblocking the steam dump valve when the condenser is available unless one of the following signals exist:

- High negative rate of change of turbine pressure
- Reactor trip
- Control system in the steam header pressure control mode (see subsection 10.4.4.3)

10.4.4.3 System Operation

The turbine bypass system has two modes of operation:

- T_{avg} control mode
- Pressure control mode

The T_{avg} control mode is the normal at-power control mode. The turbine bypass system is regulated by the difference between the measured reactor coolant system average coolant temperature (T_{avg}) and a T_{avg} setpoint derived from turbine first-stage impulse pressure. Two operational modes of the T_{avg} control mode are possible. The first mode is the load rejection steam dump controller, which prevents a large increase in reactor coolant temperature following a large, sudden load decrease. Turbine bypass valve control in conjunction with reactor power control results in a match between reactor power and turbine load. The second mode is the plant trip steam dump controller, which automatically defeats the load rejection steam dump controller following a reactor trip and provides a controlled rate of removal of decay heat, which in turn decreases reactor coolant system T_{avg}.

The pressure control mode is manually selected and is used to remove decay heat during plant startup and cooldown. The difference between steam header pressure and a pressure setpoint is used to control the turbine bypass flow. The pressure setpoint is manually adjustable and is based on the desired reactor coolant system temperature. The turbine bypass system is operated in the pressure control mode when the plant is at no-load and there is no turbine load reference. There are three pressure control operational modes as follows:

- Header pressure – control derived from the difference between header pressure and pressure setpoint

- Cooldown – control derived from the manually selected desired reactor coolant system cooldown rate and the target reactor coolant system temperature

- Manual – control derived from direct use of valve loading signals.

The bypass valves are divided into two banks. The banks are opened sequentially; the second bank starts to open only after a demand signal that is greater than the full-open demand of the first bank is generated.

The turbine bypass valves have two stroke control modes, modulate and trip open/close. If the demand signal is greater than the full open demand for the particular bank of valves, a trip open

demand signal is generated. When the demand signal decreases below the full-open demand, the trip open demand clears and the valves return to the modulating mode. Additional description of steam dump logic is given in Section 7.7.

Chapter 15 addresses credible single failures of the turbine bypass system. If the bypass valves fail-open, additional heat load is placed on the condenser. If this load is great enough, the turbine is tripped on high condenser pressure. Ultimate overpressure protection for the condenser is provided by turbine rupture discs. If the bypass valves fail-closed, the power operated relief valves (reference subsection 10.3.2.2.3) permit controlled cooldown of the reactor.

10.4.4.4 Safety Evaluation

There is no safety-related equipment in the vicinity of the turbine bypass system. The high-energy lines of the turbine bypass system are located in the turbine building.

The failure of a turbine bypass high-energy line will not disable the turbine speed control system. The turbine speed control system is designed in such a manner that its failure will cause a turbine trip. Additional information concerning speed control can be found in subsection 10.2.2.3.

10.4.4.5 Inspection and Testing Requirements

Before the system is placed in service, turbine bypass valves are tested to verify they function properly. The steam lines are hydrostatically tested to confirm leaktightness. System piping and valves are accessible for inspection. No inservice inspection and testing is required except for the turbine bypass valves which are included in the inservice program as discussed in subsection 3.9.6.

10.4.4.6 Instrumentation Applications

Turbine bypass controls are described in Section 7.7. Controls in the main control room are provided for selection of the system operating mode. Pressure indication and valve position indication are also provided in the main control room.

10.4.5 Circulating Water System

10.4.5.1 Design Basis

10.4.5.1.1 Safety Design Basis

The circulating water system (CWS) serves no safety-related function and therefore has no nuclear safety design basis.

10.4.5.1.2 Power Generation Design Basis

The circulating water system supplies cooling water to remove heat from the main condensers, the turbine building closed cooling water system (TCS) heat exchangers, and the condenser vacuum pump seal water heat exchangers under varying conditions of power plant loading and design weather conditions.

10.4.5.2 System Description

10.4.5.2.1 General Description

Classification of components and equipment in the circulating water system is given in Section 3.2. The circulating water system and cooling tower are subject to site specific modification or optimization. The system described here is applicable to a broad range of sites. The Combined License applicant will determine the final system configuration. Table 10.4.5-1 provides circulating water system design data based on a conceptual design.

[[The circulating water system consists of three 33-1/3-percent-capacity circulating water pumps, one hyperbolic natural draft cooling tower, and associated piping, valves, and instrumentation.]]

Makeup water to the CWS is provided by the raw water system (RWS). In addition, water chemistry is controlled by the turbine island chemical feed system (CFS).

10.4.5.2.2 Component Description

Circulating Water Pumps

[[The three circulating water pumps are vertical, wet pit, single-stage, mixed-flow pumps driven by electric motors. The pumps are mounted in an intake structure, which is connected to the cooling tower by a canal. The three pump discharge lines connect to a]] common header which connects to the two inlet water boxes of the condenser as well as supplies cooling water to the TCS and condenser vacuum pump seal water heat exchangers. [[Each pump discharge line has a motor-operated butterfly valve located between the pump discharge and the main header. This permits isolation of one pump for maintenance and allows two-pump operation.]]

[[Cooling Tower]]

[[The cooling tower is site specific with this description provided as a reference design using a hyperbolic natural draft structure. Operation of the cooling tower during conditions that are more restrictive than design conditions may result in higher condenser back pressure.]]

[[The cooling tower has a basin which serves as storage for the circulating water inventory and allows bypassing of the cooling tower during cold weather operations. This basin is connected to the intake of the circulating water pumps by a canal.]]

[[Cooling Tower Makeup and Blowdown]]

The circulating water system makeup is provided by the raw water system. [[Makeup to and blowdown from the circulating water system is controlled by the makeup and blowdown control valves. These valves, along with the turbine island chemical feed system provide chemistry control in the circulating water in order to maintain a noncorrosive, nonscale-forming condition and limit biological growth in circulating water system components.]]

Piping and Valves

[[The underground portions of the circulating water system piping are constructed of concrete pressure piping. The remainder is carbon steel, with an internal coating of a corrosion- resistant compound.]] Motor-operated butterfly valves are provided in each of the circulating water lines at their inlet to and exit from the condenser shell to allow isolation of portions of the condenser. [[Control valves provide regulation of cooling tower blowdown and makeup.]]

The circulating water system is designed to withstand the maximum operating discharge pressure of the circulating water pumps. [[Piping includes the expansion joints, butterfly valves, condenser water boxes, and tube bundles. The piping design pressure is site specific and therefore will be provided by the Combined License applicant (subsection 10.4.12.1).]]

A TCS heat exchanger can be taken out of service by closing the inlet isolation valve. Water chemistry in the isolated heat exchanger train is maintained by a continuous flow of circulating water through a small bypass valve around the inlet isolation valve.

Backwashable strainers are provided upstream of each TCS heat exchanger. They are actuated by a timer and have a backup starting sequence initiated by a high differential pressure across each individual strainer. The backwash can be manually activated.

Circulating Water Chemical Injection

Circulating water chemistry is maintained by the turbine island chemical feed system. Turbine island chemical equipment injects the required chemicals into the circulating water [[downstream of the CWS pumps.]] This maintains a noncorrosive, nonscale-forming condition and limits the biological film formation that reduces the heat transfer rate in the condenser and the heat exchangers supplied by the circulating water system.

The specific chemicals used within the system are determined by the site water conditions and therefore will be provided by the Combined License applicant (subsection 10.4.12). The chemicals can be divided into six categories based upon function: biocide, algaecide, pH adjuster, corrosion inhibitor, scale inhibitor, and a silt dispersant. The pH adjuster, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. The biocide application frequency may vary with seasons. [[The algaecide is applied, as necessary, to control algae formation on the cooling tower.]]

Addition of biocide and water treatment chemicals is performed by turbine island chemical feed injection metering pumps and is adjusted as required. [[Chemical concentrations are measured through analysis of grab samples from the CWS.]] Residual chlorine is measured to monitor the effectiveness of the biocide treatment.

[[Chemical injections are interlocked with each circulating water pump to prevent chemical injection when the circulating water pumps are not running.]]

10.4.5.2.3 System Operation

[[The three circulating water pumps take suction from the circulating water intake structure and circulate the water through the TCS, the condenser vacuum pump seal water heat exchangers, and the tube side of the main condenser and back through the piping discharge network to the cooling tower. The natural draft cooling tower cools the circulating water by discharging the water over a network of baffles in the tower. The water then falls through fill material to the basin beneath the tower and, in the process, rejects heat to the atmosphere. Provision is made during cold weather to direct a portion of the circulating water flow into freeze-prevention spray headers on the periphery of the cooling tower. Air flowing through the peripheral spray is thus heated and allows deicing in the central cooling tower spray baffles.]]

[[The flow to the cooling tower can be diverted directly to the basin, bypassing the cooling tower internals. This is accomplished by opening the bypass valve while operating one of the circulating water pumps. The bypass is normally used only during plant startup in cold weather or to maintain circulating water system temperature above 40°F while operating at partial load during periods of cold weather.]]

The raw water system supplies makeup water [[to the cooling tower basin to replace water losses due to evaporation, wind drift, and blowdown. A separate connection is provided between the RWS and CWS to initially fill the CWS piping. This line connects to the CWS downstream of the CWS pump isolation valves.]]

A condenser tube cleaning system is installed to clean the circulating water side of the main condenser tubes. [[Blowdown from the circulating water system is taken from the discharge of the circulating water system pumps and is discharged to the plant outfall.]]

The circulating water system is used to supply cooling water to the main condenser to condense the steam exhausted from the main turbine. If the [[circulating water pumps, the cooling tower, or the circulating water piping malfunctions such that]] condenser backpressure rises above the maximum allowable value, the main condenser will no longer be able to adequately support unit operation. Cooldown of the reactor may be accomplished by using the power-operated atmospheric steam relief valves or safety valves rather than the turbine bypass system when the condenser is not available.

Passage of condensate from the main condenser into the circulating water system through a condenser tube leak is not possible during power generation operation, since the circulating water system operates at a greater pressure than the condenser.

Turbine building closed cooling water in the TCS heat exchangers is maintained at a higher pressure than the circulating water to prevent leakage of the circulating water into the closed cooling water system.

Cooling water to the condenser vacuum pump seal water heat exchangers is supplied from the circulating water system. Cooling water flow from the circulating water system is normally maintained through all four heat exchangers to facilitate placing the spare condenser vacuum pump in service. Isolation valves are provided for the condenser vacuum pump seal water heat exchanger cooling water supply lines to facilitate maintenance.

Small circulating water system leaks in the turbine building will drain into the waste water system. Large circulating water system leaks due to pipe failures will be indicated in the control room by a loss of vacuum in the condenser shell. The effects of flooding due to a circulating water system failure, such as the rupture of an expansion joint, will not result in detrimental effects on safety-related equipment since there is no safety-related equipment in the turbine building and the base slab of the turbine building is located at grade elevation. Water from a system rupture will run out of the building through a relief panel in the turbine building west wall before the level could rise high enough to cause damage. Site grading will carry the water away from safety-related buildings.

[[The cooling tower is located so that collapse of the tower has no potential to damage equipment, components, or structures required for safe shutdown of the plant.]]

10.4.5.3 Safety Evaluation

The circulating water system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.5.4 Tests and Inspections

Components of the circulating water system are accessible as required for inspection during plant power generation. [[The circulating water pumps are tested in accordance with standards of the Hydraulic Institute.]] Performance, hydrostatic, and leakage tests associated with preinstallation and preoperational testing are performed on the circulating water system. The system performance and structural and leaktight integrity of system components are demonstrated by continuous operation.

10.4.5.5 Instrumentation Applications

[[Instrumentation provided indicates the open and closed positions of motor-operated butterfly valves in the circulating water piping. The motor-operated valve at each pump discharge is interlocked with the pump so that the pump trips if the discharge valve fails to reach the full-open position shortly after starting the pump.]]

[[Local grab samples are used to periodically test the circulating water quality to limit harmful effects to the system piping and valves due to improper water chemistry.]]

[[Pressure indication is provided on the circulating water pump discharge lines.]] A differential pressure transmitter is provided between one inlet and outlet branch to the condenser. This differential pressure transmitter is used to determine the frequency of operating the condenser tube cleaning system (CES).

Temperature indication is supplied on the common CWS inlet header to the TCS heat exchanger trains. This temperature is also representative of the inlet cooling water temperature to the main condenser.

A flow element is provided on the common discharge line from the TCS heat exchangers to allow monitoring of the total flow through the TCS heat exchangers. Flow measurement for the raw water makeup [[to the cooling tower and for the cooling tower blowdown]] is also provided.

[[Level instrumentation provided in the circulating water pump intake structure activates makeup flow from the RWS to the cooling tower basin when required. Level instrumentation also annunciates a low-water level in the pump structure and a high-water level in the cooling tower basin.]]

The circulating water chemistry is controlled [[by cooling tower blowdown and chemical addition,]] to maintain the circulating water with an acceptable Langelier Index range or an acceptable Stability Index range as provided by the Combined License applicant (subsection 10.4.12.1). [[The system accomplishes this by regulating the blowdown valve. This regulation causes the tower basin water level to fluctuate. The fluctuation is sensed by a level controller which operates the makeup valve to cooling tower makeup.]]

The control approach is to allow the makeup water to concentrate naturally to its upper limit. Provisions are made to add chemicals for pH control.

The cycles of concentration [[at which the cooling tower is operated]] is dependent on the quality of the cooling tower makeup water. [[Cooling tower blowdown is discharged to the waste water system.]]

Monitoring of the circulating water system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. See Chapter 7.

10.4.6 Condensate Polishing System

The condensate polishing system (CPS) can be used to remove corrosion products and ionic impurities from the condensate system during plant startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown operations.

10.4.6.1 Design Basis

10.4.6.1.1 Safety Design Basis

The condensate polishing system serves no safety-related function and therefore has no nuclear safety-related design basis.

10.4.6.1.2 Power Generation Design Basis

The power generation design bases are to:

- Remove corrosion products, dissolved solids and other impurities from the condensate system and maintain a noncorrosive environment within the condensate, feedwater and steam generator systems

- Provide polishing capacity for processing one-third of the maximum condensate flow in a sidestream arrangement

- Provide polishing capability during normal startup and shutdown operations of the plant

- Provide for plant operation with a "continuous" condenser tube leak of .001 gpm or a "faulted" leak of 0.1 gpm until repairs can be completed or until an orderly shutdown is achieved

10.4.6.2 System Description

The condensate polishing system is used during operating modes of startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown. Classification of components in the CPS is identified in Section 3.2. The major components for the condensate polishing system are described below. The condensate polishing system is shown in Figure 10.4.6-1.

Deep Bed Mixed Resin Polisher

The polisher vessel is constructed of carbon steel with a protective rubber lining on the inside of the vessel. Leachable sulphur of the rubber lining is less than 20 ppb. Level indication is provided.

Resin Trap

The resin trap is located in the effluent piping of the vessel. Differential pressure across the trap is monitored.

Spent Resin Tank

The spent resin tank is constructed of carbon steel with an interior protective rubber lining. It is used for storage of exhausted or spent resin prior to shipping offsite for regeneration or disposal.

Resin Addition Hopper and Eductor

The resin addition hopper stores regenerated or new resin and the eductor is used to inject resin into the polisher vessel. The hopper is constructed of carbon steel. The eductor uses demineralized water to transfer the resin to the vessel.

10.4.6.3 System Operation

The condensate polishing system cleans up the condensate during startup to meet condensate and feedwater system water chemistry specifications as described in subsection 10.3.5. The condensate system is recirculated to the hotwell during startup until the desired water quality is attained. Condensate system startup operation is described in subsection 10.4.7. Utilization of the condensate polishing system during startup assists in minimizing the startup duration of the plant.

During power operation, the condensate polishers are used only when abnormal secondary cycle conditions exist. This allows for continued operation of the plant with a "continuous" condenser

tube leak of 0.001 gpm or a "faulted" leak of 0.1 gpm until repairs can be made or until an orderly shutdown is achieved. The condensate polisher flow is controlled by the condensate polisher bypass valve.

Exhausted or spent resin is removed from the vessel and replaced with new or regenerated resin. Resin replacement requires the polisher vessel to be out of service. Spent resin is transferred directly from the polisher vessel to a truck or to the spent resin tank until it can be removed offsite. Spent condensate polishing resin will normally be nonradioactive and not require any special packaging prior to disposal. In the event of radioactive contamination of the resin in a vessel, temporary shielding is installed (if required). Radioactive resin is transferred directly from the condensate polishing vessel or from the spent resin tank to a temporary processing unit. Radiation monitors associated with the steam generator blowdown system, the steam generator system (main steam), and the turbine island vents, drains and relief system provide the means to determine if the secondary side is radioactively contaminated. Subsection 11.4.2 describes waste management of radioactively contaminated resin. A spill containment barrier is provided to contain spent resin tank or condensate polisher vessel contents in the event of a tank failure. The spill containment barrier is a curb surrounding the area containing the spent resin tank and condensate polisher vessel with sufficient height to contain the contents of a full tank or vessel.

The procedures for radiation protection and the handling and processing of radwaste are addressed in Chapters 11 and 12. Shielding design is described in Section 12.3.

Upon removal of the exhausted resin from the polisher vessel, the vessel is rinsed and the new resin is placed in the vessel using the resin addition hopper and eductor. After the new cation and anion resins are placed in the vessel, demineralized water is added until the water level is just above the resin bed. Compressed air from the plant service air system is injected up through the resin bed to fluidize and thoroughly mix the resins. Prior to plant startup, a new resin bed is rinsed and resin performance is verified, with flow through the vessel discharged to the condenser. The polisher vessel is then placed in operation or on standby.

10.4.6.4 Safety Evaluations

The condensate polishing system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.6.5 Tests and Inspections

The condensate polishing system is operationally checked prior to plant startup to verify proper functioning of the polisher vessels and associated instrumentation and controls.

10.4.6.6 Instrument Applications

When the condensate polishing system is in service, polishing system differential pressure instrumentation provides a control signal to the condensate bypass valve which maintains sufficient flow through the polisher vessel for optimum performance. The polisher is removed from service when: 1) a high differential pressure exists across the polisher vessel, 2) the ion exchange resin capacity becomes exhausted as evidenced by a high effluent conductivity, or 3) at

the completion of a pre-determined volume through-put. The resin trap is monitored for high differential pressure and an alarm indicates the need to backwash the trap.

10.4.7 Condensate and Feedwater System

The condensate and feedwater system provides feedwater at the required temperature, pressure, and flow rate to the steam generators. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the low-pressure feedwater heaters to the feedwater pumps, and is then pumped through the high-pressure feedwater heaters to the steam generators.

The condensate and feedwater system is composed of components from the condensate system (CDS), main and startup feedwater system (FWS), and steam generator system (SGS). The startup feedwater system is described in subsection 10.4.9.

10.4.7.1 Design Basis

10.4.7.1.1 Safety Design Basis

The safety-related portion of the system is required to function following a design basis accident (DBA) to provide containment and feedwater isolation, as discussed below, for the main lines routed into containment.

The portion of the feedwater system from the steam generator inlets outward through the containment up to and including the main feedwater isolation valves (MFIVs) is constructed in accordance with the requirements of ASME Code, Section III for Class 2 components and is designed to seismic Category I requirements. The portion of the feedwater system from the main feedwater isolation valve (MFIV) inlets to the piping restraints at the interface between the auxiliary building and the turbine building is constructed in accordance with the requirements of ASME Code, Section III for Class 3 components and is designed to seismic Category I requirements.

The system provides redundant isolation valves, as described below, for the main feedwater lines routed into containment. The isolation valves close after receipt of an isolation signal in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Chapter 6.

- The safety-related portions of the feedwater system are designed to remain functional after a safe shutdown earthquake (SSE) and to perform their intended function of isolating feedwater flow following postulated events.

- The safety-related portions of the feedwater system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The portion of the feedwater system to be constructed in accordance with ASME Code, Section III, Class 2 requirements is provided with access to welds and removable insulation for inservice inspection, in accordance with ASME Code, Section XI. The portion of the feedwater system to be constructed in accordance with ASME Code, Section III, Class 3 requirements is also designed and configured to accommodate inservice inspection in accordance with ASME Code, Section XI.

- The condensate and feedwater system classification is described in Section 3.2. The control functions and power supplies are described in Chapters 7 and 8.

- For a main feedwater or main steam line break (MSLB) inside the containment, the condensate and feedwater system is designed to limit high energy fluid to the broken loop. High energy line break for piping not qualified for leak before break (LBB) criteria is discussed in subsection 3.6.3.

- Double valve main feedwater isolation is provided via the main feedwater control valve (MFCV) and main feedwater isolation valve (MFIV). Valves fail closed on loss of actuating fluid. Both valves are designed to close automatically on main feedwater isolation signals, an appropriate engineered safety features (ESF) isolation signal, within the time established within the Technical Specification, Section 16.1.

- The MFCVs provide backup isolation to their respective containment isolation valves in order to terminate feedwater flow. The MFCVs are located in the auxiliary building in piping designed to ASME Code, Section III, Class 3 seismic Category I requirements. These valves are components of the steam generator system (SGS).

- For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater system (MFIV and MFCV) with ESF isolation signals generated by the protection and safety monitoring system.

10.4.7.1.2 Power Generation Design Basis

- The condensate and feedwater system provides a continuous feedwater supply to the two steam generators at the required pressures and temperatures for steady-state and anticipated transient conditions.

- Plant operation is possible at 100-percent power with one condensate pump out of service, and approximately 70-percent power with one booster/main feedwater pump assembly out of service.

- Plant operation is possible at greater than 70-percent power with one feedwater heater string out of service.

- The feedwater and condensate pumps and pump control system are designed so that loss of one booster/main feedwater pump assembly or one condensate pump does not result in trip of the turbine-generator or reactor.

- The pumps and other system components are designed so that the condensate, feedwater booster and feedwater pumps are protected from running with very low net positive suction heads without tripping on short transient low levels in a hotwell or deaerator tank.

- The condenser hotwell is designed to store, at the normal operating water level, an amount of condensate equivalent to at least three minutes of full-load condensate system operating flow.

- The system is able to accommodate ten-percent step or five-percent per minute ramp load changes without significant deviation from the programmed water levels in the steam generators or major effect on the feedwater system.

- The system has the capability of accommodating the necessary changes in feedwater flow to the steam generators with the steam pressure increase resulting from a 100-percent load rejection.

- The booster/main feedwater pumps are tripped simultaneously with the feedwater isolation signal to close the main feedwater isolation valves. In addition, the same isolation signal closes the isolation valve in the cross connect line between the main feedwater pump discharge header and the startup feedwater pump discharge header.

- A check valve, which acts on reverse pressure differential, is provided in the main feedwater line to each steam generator between the MFIV and the containment penetration. The check valve is designed to withstand the forces encountered when closing after a main feedwater line rupture. The valves perform no safety-related function but will serve to prevent blowdown from more than one steam generator during feedline break while the appropriate engineered safety features signal is generated to isolate using the MFIV and MFCV. During normal or upset conditions, the function of these check valves is to prevent reverse flow from the steam generators whenever the feedwater system is not in operation.

10.4.7.2 System Description

10.4.7.2.1 General Description

The condensate and feedwater system is shown schematically in Figure 10.4.7-1, and in Figure 10.3.2-1. Classification of equipment and components is given in Section 3.2.

The condensate and feedwater system supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The condensate and feedwater system is composed of the condensate system, the main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps condensate forward to the deaerator. The feedwater system takes suction from the deaerator and pumps feedwater forward to the steam generator system utilizing high-pressure main feedwater pumps. The steam generator system contains the safety-related piping and valves that deliver feedwater to the steam generators. The condensate and feedwater systems are located within the turbine building, and the steam generator system is located within the auxiliary building and containment.

The main portion of the feedwater flow originates from condensate pumped from the main condenser hotwell by the condensate pumps. The main condenser hotwell receives makeup from the condensate storage tank. (Refer to subsection 9.2.4 for a description of the condensate storage system.) The condensate passes in sequence through: the condensate polishing system or condensate polishing bypass (described in subsection 10.4.6); the gland steam condenser; three strings of low-pressure heaters, each string consisting of a No. 1 and No. 2 low-pressure heater; two strings of low-pressure heaters No. 3 and No. 4; the No. 5 open low pressure heater (deaerator); the three parallel booster/main feedwater pumps; and two strings of high-pressure heaters, No. 6. Feedwater is pumped to the plant's two steam generators through each generator's respective flow element, control valve, feedwater isolation valve, and check valve. The balance of the plant's feedwater flow is provided by drains from the main steam system moisture separator reheater, drains from the No. 6 feedwater heaters, and steam condensed in the deaerator. These flows are collected in the deaerator and pumped forward in the feedwater cycle. A portion of the condensate flow downstream of the condensate polishers is diverted to provide cooling to the steam generator blowdown system heat exchangers before returning to the main condensate flow at the deaerator.

During plant startup, three recirculation paths facilitate system cleanup and adjustment of water quality prior to initiating feed to the steam generators. These cleanup loops are designed for approximately 33 percent of design condensate flow and include a hotwell recirculation loop, a deaerator recirculation loop, and a third recirculation loop from downstream of the No. 6 feedwater heaters. Steam is provided to the deaerating feedwater heater from the auxiliary steam supply system to preheat the feedwater to over 200°F during the initial cleanup and startup recirculation operations. This preheating action, along with chemical addition, minimizes formation of iron oxides in the condensate system.

The condensate polishing system is described in subsection 10.4.6 and may be in service or bypassed. Each of the two main feedwater lines to the two steam generators contains a feedwater flow element, a main feedwater control valve, a main feedwater isolation valve, and a check valve.

The turbine island chemical feed system (CFS) described in subsection 10.4.11 is provided to inject an oxygen scavenging agent and a pH control agent into the condensate pump discharge downstream of the condensate polishers and an oxygen scavenging agent and pH control agent into the feedwater booster pump suction piping. Injection points are shown in Figure 10.4.7-1. During normal power operation, the addition of an oxygen scavenging agent and pH control agent to the condensate system downstream of the condensate demineralizers is in automatic control, with manual control available. The added chemicals control pH according to the condensate and feedwater system chemistry requirements and establish an oxygen scavenging agent residual in the feedwater system. The oxygen scavenger agent and pH control agent will be selected by the Combined License applicant.

A cross connection from the main feedwater pump discharge header to the startup feedwater header allows any booster/main feedwater pump to supply feedwater to the startup feedwater control valves. The startup feedwater system is described in subsection 10.4.9. Thus, feedwater from the deaerator storage tank can be supplied by the booster/main feedwater pumps through the startup feedwater connections to the steam generators during hot standby, plant startup and low power operation. A check valve in the cross connection piping prevents the startup feedwater

pumps from supplying the main feedwater header, and a nonsafety-related isolation valve in the cross connection piping automatically closes upon the feedwater isolation signal that trips the main feedwater pumps.

A condensate and feedwater failure analysis for safety-related components is presented in Table 10.4.7-1. Occurrences which produce an increase in feedwater flow or decrease in feedwater temperature result in increased heat removal from the reactor coolant system which is compensated for by control system action, as described in subsection 10.4.7.5. Events which produce the opposite effect (i.e., decreased feedwater flow or increased feedwater temperature) result in reduced heat transfer in the steam generators. Normally, automatic control system action is available to adjust feedwater flow to prevent excess energy accumulation in the reactor coolant system, and the increasing reactor coolant temperature provides a negative reactivity feedback, reducing reactor power. In the absence of normal control action, either the high-outlet temperature or the high-pressure trips of the reactor protection system are available to provide reactor safety. Loss of all feedwater is examined in Section 15.3.

Refer to subsection 5.4.2.2 for a description of steam generator design features to prevent fluid flow water hammer. The main feedwater connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV. The feedwater lines contain no high-point pockets that could trap steam and lead to water hammer. The horizontal pipe length from the main nozzle to the downward turning elbow of each steam generator is minimized.

10.4.7.2.2 Component Description

The feedwater system is constructed in accordance with the requirements of ASME Code, Section III for Class 2 components and seismic Category I requirements from the steam generator out through the MFIVs. From upstream of the MFIV to the restraint at the interface between the auxiliary building and turbine building, the system is constructed in accordance with ASME Code, Section III for Class 3 components and seismic Category I requirements. The remaining piping of the condensate and feedwater system meets ANSI B31.1 requirements. Safety-related feedwater piping materials are described in subsection 10.3.6.

Feedwater Piping

Feedwater is supplied to each of the two steam generators by a main feedwater line during normal operation. Each of the lines is anchored at the auxiliary building/turbine building interface, and has sufficient flexibility to provide for relative movement of the steam generators resulting from thermal expansion.

The feedwater system and steam generator design minimize the potential for waterhammer and subsequent effects. Details are provided in Subsection 5.4.2.2. Feedwater piping analysis considers the following factors and events in the evaluation:

- Steam generators with top feed ring design (BTP ASB 10-2)
- Main feedwater check valves due to line breaks (BTP MEB 3-1)
- Spurious isolation or feedwater control valve trips
- Pump trips

- Deaerator regulating flow control valve trip
- Local feedwater piping, anchors, supports, and snubbers, as applicable

Feedwater Isolation Valves

One MFIV is installed in each of the two main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from the steam generators in the event of a feedwater pipe rupture. The main feedwater check valve provides backup isolation. In the event of a secondary side pipe rupture inside the containment, the MFIVs limit the quantity of high energy fluid that enters the containment through the broken loop and limit cooldown. The MFCV provides backup isolation to limit cooldown and high energy fluid addition.

Each MFIV is a bidirectional wedge type gate valve composed of a valve body that is welded into the system pipeline. The MFIV gate valve is provided with a hydraulic/pneumatic actuator. The valve actuator is supported by the yoke, which is attached to the top of the body. The valve actuator consists of a hydraulic cylinder with a stored energy system to provide emergency closure of the isolation valve. The energy to operate the valve is stored in the form of compressed nitrogen contained in one end of the actuator cylinder. The MFIV is maintained in a normally open position by high-pressure hydraulic fluid. For emergency closure, redundant solenoids are energized resulting in the high-pressure hydraulic fluid being dumped to a fluid reservoir.

The feedwater isolation functional diagram is shown in Figure 7.2-1. To provide safety function actuation, the redundant actuation solenoid valves are powered from separate Class 1E power divisions. Redundant control and indication channels are provided for each of the isolation valves. Provisions are made for inservice inspection of the isolation valves.

Feedwater Control Valves

The MFCVs are air-operated control valves with the dual purpose of controlling feedwater flow rate as well as providing backup isolation of the feedwater system. The valve body is a globe design. Seats and trim are of an erosion resistant material. The design allows for removal and replacement of seats and other wearing parts.

The feedwater control valves (MFCVs) automatically maintain the water level in the steam generators during operational modes. Positioning of the main feedwater control valve during normal operation is the function of an automatic feedwater level control system using a refinement of a standard three element control scheme. The three-element control system maintains feedwater flow equal to the steam flow, and steam generator water level is used as an input to trim feedwater flow and maintain programmed water level. Refinements on the standard control are made by varying the flow demand of the valve based on the actual stem position.

In the event of a secondary side pipe rupture inside the containment, the main feedwater control valves provide a redundant isolation to the MFIVs to limit the quantity of high energy fluid that enters the containment through the broken loop. For emergency closure of the MFCV, a solenoid is deenergized to close the valve in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Chapter 6.

Feedwater Check Valves

Each main feedwater line includes a check valve installed outside containment. During normal and upset conditions, the check valve prevents reverse flow from the steam generator whenever the feedwater pumps are tripped. In addition, the closure of the valves prevents more than one steam generator from blowing down in the event of feedwater pipe rupture. The check valve is designed to limit blowdown from the steam generator and to prevent slam resulting in potentially severe pressure surges due to water hammer. The valves are designed to withstand the closure forces encountered during the normal, upset and faulted conditions. Rapid closure associated with a feedline rupture does not impose unacceptable loads on the steam generator or the steam generator system. The closure of the valves provides for isolation of the steam generators in the event of a feedwater line break to prevent blowdown from both steam generators. The valves are seismic Category I, ASME Code, Section III, Class 2 valves.

Plant Main Condenser

For a description of main condenser, refer to subsection 10.4.1.

Condensate Pumps

The three 50-percent, vertical, multistage, centrifugal condensate pumps are motor-driven and operate in parallel. Valving allows individual pumps to be removed from service. Pump capacity meets normal, full-power requirements with two of the three pumps in operation.

Condensate Regulating Valves

The main condensate flow to the deaerator is regulated by two parallel, split-ranged, pneumatically operated control valves. Condensate is regulated to maintain the level in the deaerator storage tank. During startup and low loads, the smaller valve modulates to control flow while the larger valve remains closed. As load increases, the larger valve modulates to control flow.

Low-Pressure Feedwater Heaters

These heaters are shell and tube heat exchangers with the heated condensate flowing through the tube side and the extraction steam condensing on the shell side. Parallel strings of low-pressure feedwater heaters No. 1 and 2 are located in each of three condenser necks. Feedwater heaters No. 3 and 4 are also parallel strings of heaters. Except for the No. 1 feedwater heaters, the closed low-pressure feedwater heaters have integral drain coolers, and their shell side drains cascade to the next lower stage feedwater heater. The drains from the No. 1 heaters are dumped to their respective condenser shell.

A drain line from each heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The low-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

Deaerator

The deaerator is a tray type, horizontal shell, direct contact heater located on top of a horizontal storage tank. Internal components include a tray stack, spray valves, and a vent condensing assembly. Condensate enters the deaerator from the top and is sprayed through the spray valves into a spray chamber. Heating steam flows from the bottom up through the trays and into the spray chamber. The heating steam is condensed and raises the temperature of the condensate to near saturation, liberating dissolved gases from the condensate. Condensate then cascades through the tray section, exposing a large surface area of condensate to the scrubbing action of the countercurrent rising steam. Condensate drains from the deaerator through downcomers into the storage tank. Noncondensables are vented from the top of the deaerator and flow through an orifice and valve assembly to the main condenser.

Auxiliary steam from the auxiliary steam supply system (see subsection 10.4.10) is supplied to the deaerator during recirculation conditions and maintains the pressure in the tank above atmospheric. The steam heats the condensate during cleanup and recirculation for liberation of noncondensables. Auxiliary steam is also automatically supplied to the deaerator following turbine trip to assist in maintaining deaerator pressure above atmospheric.

The shells of the deaerator and the deaerator storage tank are carbon steel. Most of the internals of the deaerator, including the tray assemblies, vent condenser, and spray valves, are stainless steel.

A high level dump line and control valve provide overflow protection to the deaerator storage tank. During high level conditions, water from the deaerator storage tank is drained to the main condenser.

High-Pressure Feedwater Heater

The main feedwater pumps discharge into a parallel string of No. 6 high-pressure feedwater heaters. These heaters are shell and tube heat exchangers with integral drain coolers. Heated feedwater flows through the tubes and extraction steam condenses in the shell. The No. 6 heaters drain into low-pressure heater No. 5 (deaerator).

A drain line from each heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The high-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

Feedwater Booster Pumps

The feedwater booster pumps are horizontal, centrifugal pumps located upstream of the main feedwater pumps. Each feedwater booster pump takes suction from the deaerator storage tank and pumps forward to its associated main feedwater pump. An electric motor drives both the booster pump and the main feedwater pump. The booster pump is driven by one end of the motor shaft and the main pump is driven by the other end through a mechanical speed increaser. The booster pump, operating at a lower speed than the main feedwater pump, boosts the pressure of feedwater from the deaerator to meet the net positive suction head requirements of the main feedwater pump.

Main Feedwater Pumps

The three main feedwater pumps operate in parallel and take suction from the associated feedwater booster pumps. The combined discharge from the main feedwater pumps is supplied to the No. 6 high-pressure feedwater heater and then to the steam generator system. Each main feedwater pump is a horizontal, centrifugal pump driven, through a mechanical speed increaser, by the motor that drives the associated feedwater booster pump.

Isolation valves allow each of the booster/main feedwater pumps to be individually removed from service while continuing power operations at reduced capacity.

Pump Recirculation Systems

Minimum flow control systems automatically protect the pumps in the condensate and feedwater system from pumping below the minimum flow rate to prevent pump damage. The condensate pumps recirculate to the main condenser. The booster/main feedwater pumps recirculate to the deaerator storage tank.

10.4.7.2.3 System Operation

10.4.7.2.3.1 Plant Startup

During plant startup, the condensate and feedwater system operates in several different configurations. These are described in subsections 10.4.7.2.3.1.1 through 10.4.7.2.3.1.4.

10.4.7.2.3.1.1 Hotwell Recirculation

The hotwell recirculation flow path is used to recirculate flow from downstream of the gland steam condenser to the main condenser to facilitate cleanup of the condensate inventory in the main condenser hotwell. This flow path also provides a minimum flow for operation of the gland steam condenser and the condensate pumps. With a condensate pump operating, the setpoint of the recirculation valve is manually adjusted to achieve the desired flow rate for cleanup of condensate. Condensate polishing equipment is aligned and placed in service to attain the required water quality.

The hotwell recirculation valve is placed in automatic operation when minimum flow is required only for operation of the gland steam condenser and one or two condensate pumps. The recirculation valve automatically maintains the minimum flow and closes when system flow to the deaerator exceeds the required minimum. The recirculation valve remains on standby and opens, as necessary, if system flow drops below minimum.

Once the hotwell recirculation loop is placed in service and cooling is available to the gland steam condenser, sealing steam may be applied to the turbine glands. Condenser vacuum can then be drawn using condenser air removal equipment.

10.4.7.2.3.1.2 Deaerator Recirculation

The deaerator recirculation flow path is used to recirculate condensate from downstream of the deaerator storage tank to the main condenser to facilitate cleanup of condensate. Deaerator recirculation is initiated by adjusting the recirculation flow control valve from the main control room to achieve the desired flow rate. Condensate is recirculated for cleanup of water quality using the condensate polishing equipment. Auxiliary steam can be admitted to the deaerator to heat the condensate for liberation of noncondensable gases.

10.4.7.2.3.1.3 Third Stage Recirculation

The third stage of condensate/feedwater recirculation during the plant heatup cycle can begin when condensate and feedwater has been sufficiently cleaned and deaerated at the feedpump suction. Flow is initiated by adjusting the recirculation flow control valve from the main control room to achieve the desired flow rate. Feedwater is recirculated from downstream of the No. 6 feedwater heaters to the main condenser for cleanup and deaeration of the condensate and feedwater inventory.

10.4.7.2.3.1.4 Plant Heatup

The condenser hotwell makeup and overflow valves are enabled and function automatically during the plant heatup cycle to maintain condensate inventory. Condensate is returned to the condensate storage tank as volume expansion occurs, and makeup occurs as needed for system losses.

During heatup, the main condenser is available to accept turbine bypass steam from the main steam system, as well as various drains, vents, and condensate/feedwater recirculation flow. Noncondensable gases are removed in the air removal sections of the main condenser and through the deaerator vents. Control and monitoring of water quality and chemistry are accomplished by operation of the condensate polishing equipment, chemical feed system, and secondary sampling equipment as required.

The steam generators are filled, as required, either by the startup feedwater pumps using water from the condensate storage tank, or alternatively by a booster/main feedwater pump using water from the deaerator storage tank and supplied through cross connect piping to the startup feedwater control valves. The steam generators are drained, as required, through the steam generator blowdown system.

During the initial stages of plant heatup, one condensate pump operates as necessary to maintain level in the deaerator storage tank. Either one or both startup feedwater pumps, or one booster/main feedwater pump, is in operation when feeding water to the steam generators. The feedwater pumps in use operate on minimum flow recirculation as necessary while maintaining the water level of the steam generators.

Feedwater is controlled by the startup feedwater control valves (SFCVs) which are operated either manually from the control room or automatically in accordance with steam generator level demand. Condensate flow to the steam generator blowdown heat exchangers is controlled during plant heatup to obtain the necessary cooling to the blowdown stream. Any excess level in the

deaerator storage tank is automatically drained to the main condenser through the deaerator high level dump flow path.

10.4.7.2.3.2 Power Operation

One operating condensate pump supplies sufficient condensate flow to the deaerator during initial power operation and at low-power levels. As power escalates, a second condensate pump is started prior to exceeding approximately 50-percent, full-load condensate flow. The third condensate pump is in standby.

The condensate regulating valves to the deaerator automatically maintain the level of the deaerator storage tank. If condensate flow to the deaerator drops below the minimum required flow for operation of the gland steam condenser or the condensate pumps, the hotwell recirculation valve to the condenser opens to provide the minimum flow.

Noncondensables are removed by the deaerating section of the main condenser and by the deaerator. Condensate polishing, chemical feed and condensate sampling are performed, as needed, to maintain water quality.

For normal operating conditions between 0- and 100-percent load, system operation is primarily automatic. Automatic level control systems control the water levels in the feedwater heaters and the condenser hotwell. Feedwater heater water levels are controlled by modulating flow control valves. Level control valves in the makeup line to the condenser from the condensate storage tank and in the return line to the condensate storage tank control the level in the condenser hotwell.

During reactor startup and at very low power levels, feedwater is supplied to the steam generators through the startup feedwater control valves using either the startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. Refer to subsection 10.4.9 for a description of the startup feedwater system. If the startup feedwater pumps are initially in use, transfer is made to a booster/main feedwater pump prior to exceeding the capacity limit of the startup pumps. As power increases, startup feedwater continues to be supplied through the startup feedwater control valves until control of feedwater is automatically transferred from the startup feedwater control valves to the main feedwater control valves. The startup feedwater control valves close, and the main feedwater control valves open to supply main feedwater to the steam generators and maintain steam generator level. Position indication is available in the main control room for the main and startup feedwater control valves. As power escalates, booster/main feedwater pump minimum flow recirculation automatically decreases as the forward flow to the steam generators increases. The second and third booster/main feedwater pumps are brought into operation as required.

Condensate flow to the steam generator blowdown heat exchangers is normally automatically controlled. In the automatic mode, condensate flow is regulated to control the steam generator blowdown outlet temperature from the blowdown heat exchangers.

Ten-percent step load and 5-percent/minute ramp changes are accommodated without major effect to the condensate and feedwater system. The system is capable of providing the necessary feedwater flow to the steam generators with the steam pressure increase resulting from a 100-percent load rejection.

10.4.7.2.3.3 Plant Shutdown

Operation during power descent is largely the reverse of power ascent. As power is decreased, one of the two operating condensate pumps may be stopped; one or two booster/main feedwater pumps may be stopped as well. At low feedwater flow, control of feedwater is automatically transferred from the main feedwater control valves to the startup feedwater control valves.

Following reactor trip or other reactor shutdown, feedwater is supplied through the startup feedwater control valves to maintain steam generator inventories. Decay heat and sensible heat are removed by steam release via the steam dump system to the condenser to cool the plant and bring it to cold shutdown. During this time, startup feedwater is supplied either by an operating booster/main feedwater pump drawing from the deaerator storage tank, or by the startup feedwater pumps drawing from the condensate storage tank.

10.4.7.2.3.4 Emergency Operation

In the event of a design basis event (with or without normal ac power supplies available), feedwater isolation signals are generated as required. The MFIVs and MFCVs automatically close on receipt of the isolation signals. The condensate and feedwater system is not required to supply feedwater under accident conditions to effect plant shutdown or to mitigate the consequences of an accident. However, the startup feedwater system is expected to be available as a nonsafety-related system to provide a source of feedwater for the steam generators. Also, the condenser may be available to accept turbine bypass steam for secondary side heat removal. Coordinated operation of the startup feedwater system (Refer to subsection 10.4.9), if available, and the main steam supply system (Refer to Section 10.3) removes the primary loop sensible heat and reactor decay heat.

10.4.7.3 Safety Evaluation

- The safety-related portions of the main feedwater system are located in the containment and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of these buildings.

- The safety-related portions of the main feedwater system are designed to remain functional after a design basis earthquake. Subsection 3.7.2 and Section 3.9 provide the design loading conditions that are considered. Sections 3.5, 3.6, and subsection 9.5.1 describe the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- The main feedwater system safety-related functions are accomplished by redundant means. A single, active component failure of the safety-related portion of the system does not compromise the safety function of the system. Table 10.4.7-1 provides a failure analysis of the safety-related active components of the feedwater system. Power is supplied from onsite power systems, as described in Chapter 8.

- Preoperational testing of the safety-related portion of the condensate and feedwater system is performed as described in Chapter 14. Periodic inservice functional testing is done in accordance with subsection 10.4.7.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the feedwater system.

- Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. The controls and power supplies necessary for the safety-related functions of the condensate and feedwater system are Class 1E, and are described in Chapters 7 and 8.

- For a main feedwater line break inside the containment or a main steam line break, the MFIVs and the main feedwater control valves automatically close upon receipt of a feedwater isolation signal. The signals that produce a main feedwater isolation signal are identified and discussed in subsection 7.3.1.2.6.

- The MFIVs are provided with solenoids supplied by redundant power divisions. Failure of either of the power divisions or solenoids does not prevent closure of the MFIV. Releases of radioactivity from the condensate and feedwater system, resulting from the main feedwater line break, are minimal because of the negligible amount of radioactivity in the system under normal operating conditions. Following a steam generator tube rupture, the main steam isolation system and the passive residual heat removal heat exchanger reduce accidental releases, as discussed in Section 10.3 and Chapter 15. Detection of radioactive leakage into and out of the system is facilitated by area radiation monitoring (described in subsection 12.3.4), process radiation monitoring (described in Section 11.5), and steam generator blowdown sampling (described in subsection 10.4.8).

- For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater (MFIV and MFCV) with isolation signals generated by the protection and safety monitoring system (PMS). Refer to subsection 7.3.1.2.6.

- Prevention and mitigation of feedline-related water hammer is accomplished through operation of the feedwater delivery system as described in subsection 5.4.2.2. The feedwater piping at the steam generators is sloped so that it does not drain into the steam generators. These features help avoid the formation of a steam pocket in the feedwater piping which, when collapsed, could create a hydraulic instability.

10.4.7.4 Tests and Inspections

10.4.7.4.1 Preoperational Valve Testing

The MFIVs and feedwater control valves are checked for closing time prior to initial startup.

10.4.7.4.2 Preoperational Pipe Testing

The main feedwater lines from the steam generator to the anchor at the interface between the turbine building and the auxiliary building are classified as ASME Code, Section III, Class 2 and 3 and seismic Category I piping. The Class 2 portions of the main feedwater system piping

are tested and inspected to the requirements of ASME Code, Section III, Class 2 piping. The portion of the piping between the containment penetration and the anchor, which is considered as the break exclusion zone described in subsection 3.6.2, is subjected to 100-percent volumetric inspection at installation.

10.4.7.4.3 Preoperational System Testing

Preoperational testing of the condensate and feedwater system is performed as described in Chapter 14. Tests described in subsection 14.2.9.1.7, under item c) of General Test Method and Acceptance Criteria satisfy BTP (AS) 10-2. Additional testing of the feedwater system is conducted during startup testing as described in subsection 14.2.10.4.18.

10.4.7.4.4 Inservice Inspections

The performance, and structural and leaktight integrity of the condensate and feedwater system components are demonstrated by continuous operation.

Additional description of inservice testing and inspection for the MFIV and MFCV is presented in subsection 3.9.6 and Section 6.6.

10.4.7.5 Instrumentation Applications

The condensate and feedwater instrumentation, is designed to facilitate automatic operation, remote control, and indication of system parameters.

Positioning of the main feedwater control valve during normal operation is the function of an automatic feedwater level control system using a refinement of a standard three element control scheme. For each steam generator, the three-element control system maintains feedwater flow equal to the steam flow, and steam generator water level is used as an input to trim feedwater flow and maintain programmed water level. Refinements on the standard control are made by varying the valve flow demand based on actual stem position (accounting for varying C_v versus lift) dynamic line losses and feedwater temperature. A flow venturi is located in each feedwater line to provide signals for the three element feedwater control system. Feedwater control is further described in subsection 7.7.1.8.

The main feedwater pumps are tripped by manual actuation or feedwater isolation described in Section 7.3. A flow element in the discharge piping from each main feedwater pump provides a flow signal for control of the associated minimum flow recirculation valve.

Level transmitters, located at the deaerator storage tank, control deaerator level. Condensate flow to the deaerator is regulated by two split ranged control valves upstream of the deaerator. During normal power generation, the valves are regulated by a three element control system; total feedwater flow is used as a feed forward demand signal, and the control is trimmed by measured feedback of total condensate flow and deaerator storage tank level.

In the event a feedwater heater experiences a sizable tube leak or a feedwater heater water level control valve fails closed, the main turbine is protected from failure resulting from flooding on the shell side of a feedwater heater and subsequent water induction into the moving turbine

blades. This is accomplished by automatic closure of the isolation valve in the steam extraction line to that heater and opening the high-level dump control valve that dumps the heater excess drains to the condenser. For heaters that do not have extraction line isolation valves, condensate isolation valves are automatically closed to isolate condensate flow to the heater tubes.

The total water volume in the condensate and feedwater system is maintained through automatic makeup and rejection of condensate to the condensate storage tank. The system makeup and rejection are controlled by the condenser hotwell level controller. Level transmitters are provided at the condenser hotwell for use by the hotwell level controller. The system water quality requirements are automatically maintained through the injection of an oxygen scavenging agent and a pH control agent into the condensate system. The pH control agent and oxygen scavenging agent injection is controlled by pH and the level of oxygen scavenging agent residual in the system which are continuously monitored by the secondary sampling system.

Instrumentation, including pressure indication, flow indication, and temperature indication, required for monitoring the system, is provided in the control room.

10.4.8 Steam Generator Blowdown System

The steam generator blowdown system (BDS) assists in maintaining acceptable secondary coolant water chemistry during normal operation and during anticipated operational occurrences of main condenser inleakage or primary to secondary steam generator tube leakage. It does this by removing impurities which are concentrated in the steam generator. The steam generator blowdown system accepts water from each steam generator and processes the water as required.

10.4.8.1 Design Basis

10.4.8.1.1 Safety-Related Design Basis

The safety-related portion of each blowdown line is part of the steam generator system (SGS). Effects of a blowdown system line break are discussed in Section 3.6. The safety-related design bases are as follows:

- The system is provided with two isolation valves on each steam generator. These valves isolate the secondary side of the steam generators to preserve the steam generator inventory. This action provides a heat sink for a safe shutdown or design basis accident mitigation. It also provides isolation of nonsafety-related portions of the system.

- The steam generator blowdown system safety-related functions can be performed assuming a single, active component failure coincident with the loss-of-offsite or onsite power.

- Piping and valves from the steam generator up to and including the containment isolation valve, the first valve on the outboard side of the containment, are designed to ASME Code, Section III, Class 2, and seismic Category I requirements. The blowdown system piping and valves from the outlet of the containment isolation valve up to and including pipe anchors located at the auxiliary building wall are designed in accordance with ASME Code, Section III, Class 3, and seismic Category I requirements.

- The safety-related portion of the system is designed to withstand the effects of a safe shutdown earthquake. The safety-related portion of the system is protected from the effects of natural phenomena and is capable of performing its intended function following postulated events such as fire, internal missile, and pipe break.

- The safety-related portion of the system is designed so that a single, active failure in the blowdown system will not result in:

  – Loss-of-coolant accident
  – Loss of integrity of steam lines
  – Loss of the capability to effect a safe reactor shutdown
  – Transmission of excessive loading to the containment pressure boundary.

- The portion of the steam generator system that is constructed in accordance with ASME Code, Section III, Class 2 and 3, requirements is provided with access to welds and removable insulation, as required for inservice inspection in accordance with ASME Code, Section XI. (See subsection 10.4.8.4.)

- The safety-related portion of the blowdown system is designed to function in the normal and accident environments identified in subsection 3.11.1.

- The safety-related portion of the blowdown system is designed as described in Section 3.6 with regard to high-energy pipe break location and evaluation.

10.4.8.1.2 Power Generation Design Basis

The steam generator blowdown system draws secondary water from each steam generator via the blowdown or drain line and processes this water as required to:

- Assist in controlling steam generator secondary side water chemistry during normal plant operation

- Cool down the steam generator for inspection and maintenance purposes

- Establish and maintain steam generator wet layup conditions during plant shutdown periods

- Drain the secondary side of the steam generators for maintenance

10.4.8.2 System Description

10.4.8.2.1 General Description

Figures 10.4.8-1 and 10.3.2-1 illustrate the steam generator blowdown system piping and instrumentation design. Classification of equipment and components for the steam generator blowdown system is given in Section 3.2. The system consists of two blowdown trains, one for each steam generator. A crosstie is provided to process blowdown from both steam generators through both heat exchangers during high capacity blowdown from one steam generator.

The blowdown water is extracted from each steam generator from a location just above the tube sheet. The blowdown from each steam generator is cooled by a regenerative heat exchanger, and flow is controlled and pressure reduced by a blowdown flow control valve. To recover the thermal energy, the condensate system provides cooling for the heat exchangers. To recover the blowdown fluid, each blowdown train has an electrodeionization (EDI) demineralizing unit which removes impurities from the blowdown flow. Downstream of the electrodeionization units, both trains combine into a common header that contains a relief valve for providing overpressure protection for the low-pressure portion of the system. A back-pressure control valve maintains pressure in the system between the flow control valve and the back-pressure control valve.

A pump is provided to drain the secondary side of the steam generator. The pump is also used for recirculation during low-pressure steam generator wet layup and cooling operations.

System isolation from the steam generator under normal operating and transient conditions is accomplished by the two isolation valves located in the auxiliary building. The valves close on actuation of the passive residual heat removal system, containment isolation, or high blowdown system radiation, temperature, or pressure.

10.4.8.2.2 System Operation

The various modes of operation are described in the following subsections.

10.4.8.2.2.1 Plant Startup

While low-pressure conditions exist in the steam generator, the blowdown flow control valves are bypassed, and the steam generator recirculation/drain pump is used to discharge the blowdown flow to the condensate system (CDS) for processing and recovery.

As the steam generator pressure increases, the blowdown rate is limited to about 200 gpm or less by first tripping and then isolating the recirculation pump. When the steam generator pressure reaches approximately 125 psig, the blowdown flow control valves are throttled to control the blowdown rate. When the desired operational blowdown rate is achieved, the valves are placed in automatic operation. The condensate control valves, which control the supply of cooling water to the heat exchangers, are adjusted during startup. When the condensate outlet temperature increases to a preset level, the condensate control valves are placed in automatic operation. The cooling water flow to the heat exchangers controls blowdown water to a temperature that is acceptable to the blowdown system electrodeionization units.

10.4.8.2.2.2 Normal Operation

The effectiveness of the blowdown system in controlling water chemistry depends upon the blowdown rate. The normal blowdown flowrate varies from a minimum of about 0.06 percent to a maximum of about 0.6 percent of maximum steaming rate. During normal operation, when the impurities are low, the expected blowdown rate is approximately 0.1 percent of maximum steaming rate (about 30 gpm total, or 15 gpm per steam generator), which maximizes the detection sensitivity for condenser tube leakage. The blowdown flow is cooled by the heat exchanger, and the pressure is reduced by the flow control valves. The blowdown fluid is processed through the electrodeionization units and discharged to the condensate system (condenser hotwell) for reuse.

In the event of main condenser tube leakage, when the concentration of impurities is high, the blowdown rate is increased to a maximum of approximately 0.6 percent of the maximum steaming rate (about 170 gpm total, or 85 gpm per steam generator). Normal operation is to recover the blowdown flow through the condensate system. However, blowdown with high levels of impurities can be discharged to the waste water system.

The back-pressure control valve is preset to a pressure which prevents flashing of the blowdown fluid in the electrodeionization units.

The blowdown flow and the electrodeionization waste stream (brine) flow are both continuously monitored for radioactivity from steam generator primary to secondary tube leakage. If such radioactivity is detected, the liquid radwaste system (WLS) is aligned to process the blowdown and electrodeionization waste effluent. If radioactivity reaches a preset high level, the blowdown flow control valves and the isolation valves automatically close.

The system operates normally under automatic control, except for flow control adjustments or flow path changes.

10.4.8.2.2.3 Steam Generator Cooling

The blowdown system can be operated to cool the steam generator for inspection and maintenance when the steam generator pressure is less than 125 psig. The blowdown is recirculated to the steam generators by the steam generator recirculation/drain pump, bypassing the blowdown flow control valves, and the electrodeionization units. The steam generator recirculation/drain pump is aligned by opening manual valves upstream and downstream of the pump. The pump recirculates the steam generator water through the heat exchangers at a total flowrate of approximately 200 gpm (100 gpm per steam generator). The condensate control valves are manually controlled to provide the cooling for the heat exchangers.

10.4.8.2.2.4 Steam Generator Wet Layup

The system can be operated to establish and maintain wet layup conditions in the steam generators during plant shutdown periods. During wet layup operation, water is circulated through the steam generators in the same manner as for steam generator cooling, except that the heat exchangers are not required. To maintain the correct pH and oxygen concentration in the secondary water, chemicals are added to the recirculation flow via the turbine island chemical feed system (CFS). (See subsection 10.4.11 for chemical feed system details.)

10.4.8.2.2.5 Steam Generator Drain

The steam generator blowdown system can be operated to drain the steam generator using the recirculation/drain pump and bypassing the flow control valves and the electrodeionization units. Total drain flowrate is approximately 200 gpm. During this mode of operation, the blowdown discharge maybe sent to the waste water system, the liquid radwaste system or the condensate system.

10.4.8.2.2.6 Steam Generator Tube Sheet Flush

The system can be operated for a short time at a total flowrate of approximately 1.7 percent of the maximum steaming rate (about 260 gpm) from one steam generator. To accommodate the high flow, the blowdown from one steam generator is isolated and the flow from the other steam generator is routed through both heat exchanger trains at a rate of approximately 130 gpm per train. The blowdown flow control valves and the blowdown electrodeionization units are bypassed during this operation. The blowdown flow is controlled by throttling the flow control valve bypass isolation valves which are in series with a flow restricting orifice. The blowdown is discharged to the waste water system (WWS).

10.4.8.2.2.7 Emergency Operation

Blowdown system isolation is actuated on low steam generator water levels. The isolation of steam generator blowdown provides for a continued availability of the steam generator as a heat sink for decay heat removal in conjunction with operation of the passive residual heat removal system and the startup feedwater system.

10.4.8.2.3 Component Description

A description of the major steam generator blowdown system components is provided in this subsection.

10.4.8.2.3.1 Blowdown Regenerative Heat Exchangers

Two regenerative heat exchangers are provided, one for each steam generator blowdown train. The heat exchangers are located in the turbine building at the base slab elevation.

10.4.8.2.3.2 Blowdown Flow Control Valves

Two blowdown flow control valves are provided, one for each steam generator blowdown train. The control valves are capable of controlling the flow and pressure over the range of normal operating conditions.

10.4.8.2.3.3 Recirculation/Drain Pump

One centrifugal pump is provided for use during operating modes when steam generator pressure is low.

10.4.8.2.3.4 Pressure Control Valve

A backpressure control valve is provided to maintain appropriate system backpressure, within the operating range of blowdown flows, and prevent flashing within the low pressure section of the system when the blowdown is discharged to the condenser hotwell.

10.4.8.2.3.5 Blowdown Isolation Valves

Two valves in series, located outside containment in the auxiliary building, are provided to automatically isolate the blowdown system in the event of abnormal conditions within the blowdown system, the reactor coolant system, or the main steam system. The valves are air-operated globe valves that fail close on loss of air or actuating power. See Section 7.3 for a description of the automatic control functions on the valves.

The first isolation valve provides a containment isolation function in addition to redundant isolation of the blowdown system. The valves close on an engineered safeguards actuation signal and provide containment integrity in conjunction with the steam generator and main steam line inside containment. The valves are active, ASME Code, Section III, Safety Class 2, seismic Category I.

The isolation valves provide for redundant isolation of the blowdown system upon actuation of the passive residual heat removal system, low (narrow range) steam generator level, or abnormal conditions in the blowdown system. Each isolation valve receives an actuation signal from the protection and safety monitoring system (PMS) upon passive residual heat removal actuation to preserve steam generator inventory. The valves also close upon receiving a low (narrow range) water level signal to preserve steam generator inventory. Additionally, the valves receive a high radiation signal, high temperature signal, and high pressure signal, indicating abnormal conditions in the blowdown system and actuating automatic isolation of the system. The second isolation valves are active, ASME Code, Section III, Safety Class 3, seismic Category I.

The valves are located outside containment within the auxiliary building and are attached to seismic Category I piping.

10.4.8.2.3.6 Electrodeionization Unit

Two trains of electrodeionization demineralizing units are provided for the steam generator blowdown system electrodeionization. The electrodeionization unit in each train is configured in a stack arrangement. The stack normally contains numerous pairs of stacked membranes. One cell pair consists of an ion-diluting flow (product) channel located between a cation and an anion membrane with an ion concentrating (brine) flow channel located alternately between the cell pairs. A dc potential is maintained across the electrode plates which are located on opposite ends of the stacked membranes. Ion exchange resin is contained within the product flow channel, acting as an ion selective media in the electrodeionization process. Isolation valves are provided for each stack to allow for maintenance of a stack.

A filter, upstream of the electrodeionization stack in each train, removes suspended solids and particulate matter from electrodeionization influent. Electrodeionization effluent flows through a resin trap which collects resin fines and small particulates which pass through the unit.

Each electrodeionization unit includes one centrifugal brine pump which maintains a constant flow in the closed loop brine system and flushes ionic impurities from the brine channels in the stack. A small percentage of blowdown in the brine process is used to control impurity concentration. This electrodeionization brine blowdown waste stream is directed to the waste water system (WWS) or the liquid radwaste system (WLS).

The electrodeionization stacks are located in the turbine building and in a shielded area. The area has no drain. Anionic and cationic resins are contained within the electrodeionization stacks. These resins are not consumed or exhausted in the electrodeionization process. Radiation monitors associated with the steam generator blowdown system, steam generator system (main steam), and the condenser air removal system provides the means to determine if the secondary side is radioactively contaminated.

The electrodeionization units are self-cleaning. Even after processing radioactive blowdown they will not contaminate succeeding treatment of nonradioactive blowdown.

After prolonged use, the electrodeionization units will be replaced. If they are not radioactively contaminated, they require no special packaging and may be disposed as clean solid waste. If they are radioactively contaminated, they will be dewatered, the nozzles blocked and packaged for transport according to DOT regulations. Packaged electrodeionization units may be stored in the Radwaste Building.

10.4.8.2.4 Instrumentation Applications

Flow, pressure, temperature, and radioactivity indicators with alarms monitor system operation. If pressure, temperature, or radioactivity reach a high level setpoint, an alarm is annunciated and the blowdown flow control valves and upstream isolation valves are automatically closed.

Flow elements and transmitters measure and control blowdown flow from the steam generators. The flow elements are located downstream of the blowdown flow control valves.

Temperature instrumentation monitors the temperature of blowdown fluid upstream and downstream of each heat exchanger. The heat exchanger outlet temperature controls heat exchanger cooling water flow as well as the blowdown flow to limit high temperature blowdown fluid to the electrodeionization unit.

Radioactivity detection instrumentation detects and monitors the presence of radioactivity in the combined blowdown stream from both trains. A radiation element is located in the common header upstream of the recovered blowdown three-way valve. This three-way valve normally directs the recovered blowdown flow to the condenser. When recovery of the blowdown fluid is not possible, the flow is diverted to the waste water system. Upon detection of significant levels of radioactivity via a radiation transmitter alarm, the steam generator blowdown flow is diverted to the liquid radwaste system for processing. A second radioactive detection instrument is located on the waste stream of the electrodeionization blowdown. Similarly, a three-way valve normally directs this electrodeionization brine blowdown to the waste water system. With detection of significant levels of radioactivity, the brine blowdown is diverted to the liquid radwaste system.

10.4.8.3 Safety Evaluation

- Each blowdown line is provided with redundant safety-related valves that isolate the secondary side of the steam generator to preserve the steam generator inventory. The inventory is maintained as a heat sink for sensible and decay heat removal from the reactor coolant system.

- The steam generator blowdown system safety-related functions are accomplished by redundant means. A single, active component failure within the safety-related portion of the system does not compromise the safety-related function of the system. Power is supplied by the Class 1E dc power system as described in Chapter 8.

- Section 3.2 delineates the quality group classification. The controls and power supplies necessary for safety-related functions of the steam generator blowdown system are Class 1E, and are described in Chapters 7 and 8.

- The safety-related portion of the steam generator blowdown system are located in the containment and auxiliary buildings. These buildings and areas are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of these buildings and areas. The safety-related portions of the steam generator blowdown system are designed to remain functional after a safe shutdown earthquake. Sections 3.7 and 3.9 provide the design loading conditions that are considered.

- No single failure coincident with loss of offsite power compromises the safety-related functions of the system or will result in:

  – Loss-of-coolant accident
  – Loss of integrity of steam lines
  – Loss of the capability to effect a safe reactor shutdown
  – Transmission of excessive loading to the containment pressure boundary.

  Component or functional redundancy is provided so that safety-related functions can be performed, assuming a single, active failure coincident with loss of ac power.

- The steam generator blowdown system is initially tested in accordance with the program described in Chapter 14. Periodic inservice functional testing is done in accordance with subsection 10.4.8.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the safety-related portions of the steam generator blowdown system.

- The safety-related components of the steam generator blowdown system are qualified to function in normal, test, and accident environmental conditions. The environmental qualification program is provided in Section 3.11.

- Discussions of high energy pipe break locations and evaluation of effects are provided in subsections 3.6.1 and 3.6.2.

- Subsection 6.2.3 delineates the criteria and compliance with applicable requirements and the criteria for the containment isolation provisions.

- The failure modes and effects analysis for the steam generator blowdown system is provided in Table 10.3.3-1.

10.4.8.4 Inspection and Testing Requirements

10.4.8.4.1 Preservice Testing/Inspection

The blowdown system components are tested and inspected during plant startup as a part of the preservice test program as discussed in Chapter 14. The steam generator blowdown system's safety-related functions are designed to include the capability for testing. This includes operation of applicable portions of the protection system. The safety-related components of the system (valves and piping,) are designed and located to permit preservice and inservice inspections to the extent practical.

The steam generator blowdown lines within the containment and the auxiliary building are visually and volumetrically inspected at installation as required by ASME Code, Section XI preservice inspection requirements.

10.4.8.4.2 Inservice Testing/Inspection

The performance and structural leaktight integrity of system components are demonstrated by normal operation.

Additional discussion of inservice inspection of the blowdown containment isolation valves is contained in Section 6.6 and subsection 3.9.6.

Instruments and controls are calibrated during startup and recalibrated, as necessary, to maintain system operation within its design specifications.

10.4.9 Startup Feedwater System

The startup feedwater system supplies feedwater to the steam generators during plant startup, hot standby and shutdown conditions, and during transients in the event of main feedwater system unavailability. The startup feedwater system is composed of components from the AP1000 main and startup feedwater system (FWS) and steam generator system (SGS).

10.4.9.1 Design Basis

10.4.9.1.1 Safety Design Basis

The safety functions of the startup feedwater system are to provide for containment isolation, steam generator isolation and feedwater isolation following design basis events requiring these actions. Containment isolation is provided to limit radioactive releases to the environment following design basis events that result in the releases of radioactivity to the containment. Steam generator isolation is provided to limit rapid blowdown to a single steam generator following a feedwater or steamline break. Feedwater isolation limits excessive feedwater flow to the steam generators to limit mass and energy releases to containment to limit excessive RCS cooldown and to limit steam generator overfill.

The portion of the startup feedwater system from the steam generator inlets outward through the containment up to and including the startup feedwater isolation valves (SFIVs) is constructed in

accordance with the requirements of ASME Code, Section III for Class 2 components and is designed to seismic Category I requirements. The portion of the startup feedwater system from the startup feedwater isolation valve inlets to the piping restraints at the interface between the auxiliary building and the turbine building is constructed in accordance with the requirements of ASME Code, Section III for Class 3 components and is designed to seismic Category I requirements.

The startup feedwater system provides redundant isolation valves, as described below, for the startup feedwater lines routed into containment. The isolation valves close after receipt of an isolation signal in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Section 6.2.

- The safety-related portions of the startup feedwater system are designed to remain functional after a safe shutdown earthquake (SSE) and to perform their intended function of isolating startup feedwater flow following postulated events.

- The safety-related portions of the startup feedwater system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The portion of the startup feedwater system to be constructed in accordance with ASME Code, Section III, Class 2 requirements is provided with access to welds and removable insulation for inservice inspection, in accordance with ASME Code, Section XI. The portion of the startup feedwater system to be constructed in accordance with ASME Code, Section III, Class 3 requirements is also designed and configured to accommodate inservice inspection in accordance with ASME Code, Section XI. The startup feedwater system is designed so that the active components are capable of limited testing during plant operation.

- The startup feedwater system quality group classification codes are identified in Section 3.2. The control functions and power supply are described in Chapters 7 and 8.

- Double valve startup feedwater isolation is provided by the startup feedwater control valve and the startup feedwater isolation valve. Both valves are designed to close on a startup feedwater isolation signal, an appropriate engineered safeguards features (ESF) signal as indicated on Figure 7.2-1. The startup feedwater control valve also serves as a containment isolation valve. The startup feedwater control valve fails closed on loss of air. See Section 7.3. Backflow in the startup feedwater line results in closure of the startup feedwater check valve.

- For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation signal and startup feedwater control valve), with isolation signals generated by the protection and safety monitoring system.

10.4.9.1.2 Power Generation Design Basis

- During normal plant startup, shutdown or hot standby, feedwater can be supplied through the startup feedwater control valves to the steam generators using either a booster/main feedwater pump drawing water from the deaerator storage tank (refer to subsection 10.4.7), or using the startup feedwater pumps drawing water from the condensate storage tank.

- In the event of loss of the main feedwater system, the startup feedwater pumps automatically supply feedwater to the steam generators for heat removal from the reactor coolant system. The heat removal function of the startup feedwater system is nonsafety-related. The startup feedwater system avoids the need for actuation of the safety-related passive core cooling system. Following the transient, the system refills the steam generators and supports reactor coolant system cooldown.

- One operating startup feedwater pump delivers sufficient flow to the steam generators to avoid actuation of the passive core cooling system following a reactor trip. The maximum flow available from two operating startup feedwater pumps does not result in overcooling the reactor coolant system, overfilling the steam generators, or inputting excessive mass/energy to containment following a main steam line break.

- The startup feedwater pumps use the condensate storage tank as a water supply source. A sufficient volume of feedwater is available from the condensate storage tank (refer to subsection 9.2.4) to achieve cold shutdown, based on 8 hours of operation at hot standby conditions and subsequent cooldown of the reactor coolant system within 6 hours to conditions which permit operation of the normal residual heat removal system.

- The startup feedwater pumps are headered at the pump discharge, and a separate line runs from the header to each steam generator.

- For a main feedwater or main steam line break (MSLB) inside the containment, the startup feedwater lines provide a nonsafety-related path for the addition of feedwater to the remaining intact loop if ac power is available.

- For a main feedwater line break upstream of the main feedwater isolation valve (outside of the containment), the startup feedwater lines provide a nonsafety-related path for the addition of feedwater to maintain steam generator level if ac power is available.

- Two startup feedwater pumps are provided with a single pump capable of satisfying the startup feedwater system flow demand for decay heat removal. These pumps automatically start and maintain steam generator water level when the main feedwater system is unavailable.

- In the event of loss of normal ac power, the startup feedwater pumps and associated motor operated isolation valves are powered by the onsite standby ac power supply (diesels). Each of the two startup feedwater pumps is powered by its respective standby diesel.

- During normal plant startup, feedwater is supplied through the startup feedwater control valves to the steam generators until transition is made to the main feedwater control valves of the main feedwater system. During normal plant shutdown, feedwater is supplied through the startup feedwater control valves after transition is made from the main feedwater control valves, and until the normal residual heat removal system is placed in service.

10.4.9.2 System Description

10.4.9.2.1 General Description

The startup feedwater system is shown schematically in Figure 10.4.7-1 as part of the condensate and feedwater system piping and instrument diagram and in Figure 10.3.2-1 as part of the main steam system piping and instrument diagram. Classification of equipment and components is given in Section 3.2.

Startup feedwater is defined to be feedwater that passes through the startup feedwater control valves, and can be supplied from either of two sources. Startup feedwater can be supplied by a booster/main feedwater pump drawing from the deaerator storage tank and delivering through cross connect piping to the startup feedwater header; or, startup feedwater can be supplied by one or both startup feedwater pumps drawing from the condensate storage tank and delivering to the startup feedwater header. The startup feedwater header is defined to be the common segment of startup feedwater piping downstream of the startup feedwater pumps. The booster/main feedwater pumps are part of the condensate and feedwater system and are described in subsection 10.4.7. As described in subsection 10.4.7.2.1, the cross connection piping between the main feedwater pump discharge header and the startup feedwater header contains a check valve and a nonsafety-related, air-operated isolation valve. The check valve prevents the startup feedwater pumps from supplying the main feedwater header, and the isolation valve automatically closes upon a main feedwater isolation signal to isolate the main feedwater system from the startup feedwater system.

Two parallel startup feedwater pumps are provided and take suction from the condensate storage tank. Each startup feedwater pump discharges to the startup feedwater header through a venturi flow element, an automatic recirculation valve, and a remotely-operated isolation valve. The venturi flow element provides a flow measurement signal at normal flow rates, and cavitates at a flow rate near pump runout to choke the flow and avoid further flow increase. The automatic recirculation valve functions as a check valve to prevent reverse flow through the pump, and also functions as a minimum flow control valve for pump protection; during conditions of low forward flow to the system, sufficient flow from the pump is automatically recirculated back to the condensate storage tank to meet pump minimum flow requirements. The discharge isolation valve is closed when the associated pump is not operating; when in standby operation, the valve automatically opens when the associated pump starts.

The startup feedwater header branches into individual lines to the two steam generators. Each individual line contains a startup feedwater control valve, a check valve, and a startup feedwater isolation valve. Startup feedwater flow in each line is controlled by the associated startup feedwater control valve to maintain level in the associated steam generator.

A startup feedwater system failure analysis for safety-related components is presented in Table 10.4.9-1.

10.4.9.2.2 Component Description

From the connections at the steam generators out through the startup feedwater isolation valves, the startup feedwater system is designed in accordance with the requirements of ASME Code, Section III for Class 2 components and seismic Category I requirements. From upstream of the startup feedwater isolation valve to the restraints at the interface between the auxiliary building and turbine building, the system is designed in accordance with ASME Code, Section III for Class 3 components and seismic Category I requirements. The remaining portion of the startup feedwater system is nonsafety-related.

Startup Feedwater Pump

Each startup feedwater pump is a multistage, centrifugal pump driven by an ac motor. Each pump can supply 100 percent of the required flow to the two steam generators to meet the decay heat removal requirements specified in subsection 10.4.9.1.2. The pumps automatically start as described in subsection 10.4.9.2.3.4. Isolation valves at the pump suction and discharge allow each startup feedwater pump to be individually serviced. The discharge isolation valve for each pump is powered by the same train of the onsite standby ac power supply as the associated pump.

Startup Feedwater Control Valve

The startup feedwater control valves are air-operated, modulating control valves with the dual purpose of controlling startup feedwater flow rate, as well as providing isolation of the startup feedwater system. The valve body is a globe design that provides the required range of startup feed control, as well as positive isolation. The startup feedwater control valves operator is equipped with an auxiliary air accumulator to provide independent operation of the startup feedwater control valves upon loss of normal instrument air supply.

The startup feedwater control valves automatically maintain water level in the steam generators during operation of the startup feedwater system, in response to signals generated by the plant control system.

In the event of a secondary side pipe rupture inside the containment, the startup feedwater control valve provides a secondary backup to the startup feedwater isolation valve limiting the quantity of high-energy fluid that enters the containment through the broken pipe. For emergency closure of the valve, a solenoid is deenergized, resulting in valve closure in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Section 6.2. The electrical solenoid is energized from a Class 1E source.

Startup Feedwater Isolation Valve

One startup feedwater isolation valve is installed in each startup feedwater line outside containment and downstream of a startup feedwater control valve and a startup feedwater check valve. The following primary functions are performed by the valve:

- The startup feedwater isolation valve is provided to prevent the uncontrolled blowdown from more than one steam generator in the event of startup feedwater line rupture. The startup feedwater isolation valve provides backup isolation.

- The startup feedwater isolation valve and the startup feedwater control valve provide isolation of the nonsafety-related portions of the system from the safety-related portions.

- In the event of a secondary pipe rupture inside containment, the startup feedwater isolation valve and startup feedwater control valve provide isolation to limit the quantity of high energy fluid that enters the containment.

- In the event of a steam generator tube rupture, the startup feedwater isolation valve and startup feedwater control valve limit overfill of the steam generator by terminating startup feed flow.

The startup feedwater isolation valve is a remotely-operated gate valve designed in accordance with ASME Code, Section III Class 2 requirements. The valve operator is designed to stroke against steam generator pressure or startup feedwater pump shutoff head.

The startup feedwater isolation valve and startup feedwater control valve functional diagrams are shown in Figure 7.2-1. To provide the safety function actuation (closure) as well as reliable alignment, and redundant and independent actuation, the startup feedwater isolation valve and startup feedwater control valve are powered from separate Class 1E power sources.

10.4.9.2.3 System Operation

The startup feedwater system supplies the steam generators with feedwater during conditions of plant startup, hot standby and shutdown, and during transients in the event of main feedwater system unavailability. The startup feedwater system also supplies feedwater during low power operation under conditions when the startup feedwater control valves regulate the feedwater flow to the steam generators.

10.4.9.2.3.1 Startup

During reactor startup and at low power levels, feedwater is supplied to the steam generators through the startup feedwater control valves using either the startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. Refer to subsection 10.4.7 for a description of the operation of the condensate and feedwater system and the booster/main feedwater pumps. The feedwater pumps in use operate on minimum flow recirculation as necessary while maintaining the water level of the steam generators. Feedwater is controlled by the startup feedwater control valves, which are operated either manually from the control room or automatically in accordance with steam generator level

demand. If the startup feedwater pumps are initially in use, transfer is made to a booster/main feedwater pump prior to exceeding the capacity limit of the startup pumps. As power increases, feedwater continues to be supplied through the startup feedwater control valves until control of feedwater is automatically transferred from the startup feedwater control valves to the main feedwater control valves. As the main feedwater control valves open and assume responsibility for maintaining steam generator water level, the startup feedwater control valves close. Position indication is available in the main control room for the main and startup feedwater control valves.

10.4.9.2.3.2 Hot Standby

During hot standby conditions, feedwater is supplied to the steam generators through the startup feedwater control valves using either one or both startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. The startup feedwater control valves operate to maintain the steam generator levels, and minimum flow recirculation is automatically utilized as required to protect the feedwater pumps that are in use.

10.4.9.2.3.3 Shutdown

Operation during power descent and shutdown is generally the reverse of operation during startup and power ascent. At low feedwater flows, control of feedwater is automatically transferred from the main feedwater control valves to the startup feedwater control valves. Feedwater is supplied by an operating booster/main feedwater pump drawing from the deaerator storage tank. Feedwater can continue to be supplied by a booster/main feedwater pump during the shutdown process; alternatively, feedwater supply can be transferred to the startup feedwater pumps when flow demand has decreased to within their capacity. Feedwater continues to be supplied until the normal residual heat removal system is placed in service.

10.4.9.2.3.4 Automatic Starts

The startup feedwater pumps automatically start upon conditions resulting from insufficient main feedwater flow to the steam generators. An automatic pump start signal is generated by the plant control system (PLS). The signal is generated on low main feedwater flow coincident with low steam generator level. As a backup to this logic, it is also initiated on steam generator level alone, at a setpoint below the low steam generator level setpoint.

The amount of startup feedwater flow delivered to each steam generator is determined by the associated startup feedwater control circuit, which sends a signal to modulate the startup feedwater control valve (Figure 10.3.2-1) in response to steam generator water level control signals. The control valve is modulated as required to maintain the programmed steam generator water level setpoint.

Following a reactor trip that is not the result of a main feedwater system malfunction and in which the main feedwater system remains available, the startup feedwater pumps do not automatically start. In this case, the startup feedwater control valves take control and open to supply the steam generators using feedwater delivered from a booster/main feedwater pump through cross-connect piping. The startup feedwater pumps remain on standby for backup protection, and can be manually started if desired by the plant operator.

10.4.9.2.3.5 Emergency Operation

The startup feedwater system is not required to supply feedwater under accident conditions. However, the startup feedwater system is expected to be available as a nonsafety-related, first line of defense to provide a source of feedwater for the steam generators. Coordinated operation of the startup feedwater system (which starts automatically, as discussed in subsection 10.4.9.2.3.4), if available, and the main steam supply system (refer to Section 10.3) are employed to remove the primary loop sensible heat and reactor decay heat. A minimum condensate storage tank volume of 325,000 gallons is required for defense-in-depth purposes. The condensate storage tank size is shown in subsection 9.2.4.2.2.

10.4.9.3 Safety Evaluation

- The safety-related portions of the startup feedwater system are located in the containment and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of these buildings.

- The safety-related portions of the startup feedwater system are designed to remain functional after a design basis earthquake. Subsection 3.7.2 and Section 3.9 provide the design loading conditions that are considered. Sections 3.5, 3.6, and subsection 9.5.1 provide the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- The startup feedwater system safety-related functions are accomplished by redundant means. A single, active component failure of the safety-related portion of the system does not compromise the safety function of the system. Table 10.4.9-1 provides a failure analysis of the safety-related active components of the startup feedwater system. Power is supplied from onsite power systems, as described in Chapter 8.

- Preoperational testing of the safety-related portion of the condensate and feedwater system is performed as described in Chapter 14. Periodic inservice functional testing is done in accordance with subsection 10.4.9.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the startup feedwater system.

- Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. The controls and power supplies necessary for the safety-related functions of the startup feedwater system are Class 1E, as described in Chapters 7 and 8.

- The startup feedwater isolation valves and the startup feedwater control valves automatically close upon receipt of a feedwater isolation signal, which occurs on a steam generator high-high water level and other appropriate engineered safeguards signals as shown on the diagrams titled “Feedwater Isolation” and “Steamline Isolation” in Figure 7.2-1.

- For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation valve and startup feedwater control valve) to prevent steam generator overfill, with engineered safeguards isolation signals generated by the protection and safety monitoring system (PMS).

10.4.9.4 Tests and Inspections

10.4.9.4.1 Preoperational Valve Testing

The startup feedwater isolation valves and startup feedwater control valves are checked for closing time prior to initial startup.

10.4.9.4.2 Preoperational Pipe Testing

The Class 2 portion of the startup feedwater system piping is tested and inspected to the requirements of ASME Code, Section III, Class 2 piping. In addition, the portion of the piping between the containment penetration and the anchor, which is traditionally considered as the break exclusion zone described in subsection 3.6.2, is subjected to 100-percent volumetric inspection at installation (that is, 100-percent volumetric examination of shop and field longitudinal and circumferential welds).

10.4.9.4.3 Preoperational System Testing

Preoperational testing of the startup feedwater system is performed as described in Chapter 14. Tests described in subsection 14.2.9.1.7, under item c) of General Test Method and Acceptance Criteria satisfy BTP (AS) 10-2. Additional testing of the startup feedwater system is conducted during startup testing as described in subsection 14.2.10.4.18.

10.4.9.4.4 Inservice Inspections

The performance and structural and leaktight integrity of the startup feedwater system components are demonstrated by normal operation.

The inservice inspection program for ASME Section III Class 2 and 3 components is described in Section 6.6. The inservice testing program, including testing for the startup feedwater isolation valve and startup feedwater control valve, is described in subsection 3.9.6.

10.4.9.5 Instrumentation Applications

The startup feedwater system instrumentation is designed to facilitate automatic operation, remote control, and continuous indication of system parameters.

The startup feedwater flow is controlled by a steam generator level demand signal modulating the startup feedwater control valve. The control valve may either be in manual or automatic control. Refer to Section 7.7. The startup feedwater flow transmitters also provide redundant indication of startup feedwater and automatic safeguards actuation input on low flow coincident with low, narrow range steam generator level. See Section 7.3.

10.4.10 Auxiliary Steam System

The auxiliary steam system (ASS) provides the steam required for plant use during startup, shutdown, and normal operation. Steam is supplied from either the auxiliary boiler or the main steam system.

10.4.10.1 Design Basis

10.4.10.1.1 Safety Design Basis

The auxiliary steam system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.10.1.2 Power Generation Design Basis

The auxiliary steam system supplies steam required by the unit for a cold start of the main steam system and turbine-generator. Additionally, the auxiliary steam system provides steam for hot water heating. Main steam supplies the auxiliary steam header during normal operation. The auxiliary boiler provides steam to the header during plant shutdown.

10.4.10.2 System Description

10.4.10.2.1 General Description

The auxiliary boiler is located in the turbine building. The system consists of steam generation equipment and distribution headers.

Condensate from the condensate storage tank is chemically treated and pumped to the auxiliary boiler deaerator where oxygen and non-condensables are removed using auxiliary steam. The auxiliary boiler feedwater pumps deliver condensate from the auxiliary boiler deaerator to the auxiliary boiler. A feedwater control valve, located in the feedwater piping, regulates water level in the auxiliary boiler. Feedwater flow is proportional to auxiliary boiler steaming rate. Steam generated by the auxiliary boiler is supplied to the plant auxiliary steam distribution piping.

Boiler water quality is maintained by controlling boiler blowdown flow to an atmospheric blowdown tank and by feeding oxygen scavenging and pH control chemicals to the boiler makeup water system.

Water level in the auxiliary boiler deaerator is maintained by an automatic control valve in the condensate supply and deaerator overflow piping. Makeup water is supplied from the demineralized water transfer and storage system.

10.4.10.2.2 Component Description

Auxiliary steam system component classification is as described in Section 3.2.

Auxiliary Steam System and Boiler

The auxiliary steam boiler is an oil-fired package boiler with a nominal net output capacity of at least 110,000 pounds per hour of saturated steam at 195 psig. The system is protected from overpressure by safety valves located on the boiler, boiler deaerator, and auxiliary steam header.

Pumps

Two 100-percent capacity auxiliary boiler feedwater pumps are provided to feed the auxiliary steam boiler.

Two 100-percent capacity auxiliary boiler makeup pumps maintain level in the boiler deaerator.

Auxiliary Boiler Deaerator

The auxiliary boiler deaerator is a 100-percent-capacity deaerator which uses steam supplied by the auxiliary steam header. The auxiliary boiler deaerator steam blanket is controlled for preheating and deaerating boiler makeup water. The auxiliary boiler deaerator removes oxygen and non-condensables from auxiliary boiler feedwater.

Chemical Treatment Components

The auxiliary boiler makeup water is treated with pH control and oxygen scavenging chemicals. Chemical injections maintain proper water chemistry during operational conditions. Batch chemicals for cleaning and layup are injected into the auxiliary boiler and auxiliary boiler deaerator when they are not in operation. Chemical feed equipment for the auxiliary steam system is part of the turbine island chemical feed system (CFS) and is described in Section 10.4.11.

Auxiliary Boiler Fuel Oil Components

Two 100-percent capacity positive displacement fuel oil pumps supply fuel oil to the auxiliary steam boiler. These pumps are part of the standby diesel and auxiliary boiler fuel oil system (DOS). As described in DCD subsection 9.5.4, these pumps supply fuel oil to the auxiliary boiler from the fuel oil storage tanks which are also part of the standby diesel and auxiliary boiler fuel oil system.

10.4.10.2.3 System Operation

When in operation, the auxiliary steam system provides the following services:

- Steam to the plant hot water heating system heat exchangers where water is heated and pumped to the heating system ventilation coils.
- Steam for the condensate system deaerator when condensate heating occurs during preoperational cleanup of the condensate and feedwater system
- Sealing steam to the glands of the main turbine prior to the availability of main steam

- Steam for maintaining pressure in the condensate system deaerator after a turbine trip when extraction steam is lost.
- Steam for blanketing of the MSR and feedwater heaters when main steam is not available.

Operational safety features are provided within the system for the protection of plant personnel and equipment. The auxiliary steam system does not interface directly with nuclear process systems.

10.4.10.3 Safety Evaluation

The auxiliary steam system has no safety-related function and therefore requires no nuclear safety evaluation. High energy pipe rupture analysis is not required for the auxiliary steam system since none of the lines pass through areas where safety related equipment is located.

10.4.10.4 Tests and Inspections

Testing of the auxiliary steam system is performed prior to initial plant operation.

Components of the system are monitored during operation to verify satisfactory performance.

10.4.10.5 Instrumentation Applications

A boiler control system is provided with the auxiliary boiler package for automatic control of the auxiliary boiler. Features of the control system include automatic shutdown of the auxiliary boiler and auxiliary boiler fuel oil pumps on an abnormal condition.

The auxiliary steam system is provided with the necessary controls and indicators for local or remote monitoring of the operation of the system.

10.4.11 Turbine Island Chemical Feed

The turbine island chemical feed system (CFS) injects required chemicals into the condensate (CDS), feedwater (FWS), auxiliary steam (ASS), circulating water (CWS), service water (SWS), demineralized water treatment (DTS) and potable water (PWS) systems. CFS components are located in the turbine building.

10.4.11.1 Design Basis

10.4.11.1.1 Safety Design Basis

The turbine island chemical feed system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.11.1.2 Power Generation Design Basis

A noncorrosive condition is maintained within the systems serviced by the turbine island chemical feed system.

The secondary sampling system (SSS), as described in subsection 9.3.4, contains sampling requirements in accordance with water chemistry specifications that are provided in Table 10.3.5-1.

10.4.11.2 System Description

Classification of equipment and components is given in Section 3.2.

10.4.11.2.1 Component Description

Condensate, Feedwater and Auxiliary Steam

An all-volatile chemical feed system (AVT) is used for condensate, feedwater and auxiliary steam water chemistry control. An oxygen scavenger is injected into the condensate system downstream of the condensate polishers to control the dissolved oxygen level. Feedwater chemistry is controlled by maintaining a residual level of oxygen scavenger. The injection point for the feedwater oxygen scavenger is located on the feedwater booster pump suction piping. A pH adjuster is also injected into the condensate system downstream of the condensate polisher for pH control. Injection for pH control of the feedwater is located on the feedwater booster pump suction. Chemical feed pumps and tanks are used to store and inject the chemicals into the piping system. Subsection 10.4.10.2.2 describes chemical feed for the auxiliary steam system.

Circulating Water and Service Water

A biocide, pH adjuster and dispersant/corrosion/scale inhibitor are injected into the circulating water and service water systems as required. An algicide can be fed to the circulating water and service water cooling tower basins or to the canals. Subsections 9.2.1.2.2 and 10.4.5.2.2 describe chemical feed for the service water and circulating water systems, respectively.

Demineralized Water Treatment

A pH adjuster and scale inhibitor are injected into the demineralized water treatment system. Subsection 9.2.3.2.3 describes chemical feed for the demineralized water treatment system.

Potable Water

A biocide is injected into the potable water system. Subsection 9.2.5.3 describes chemical feed for the potable water system.

10.4.11.2.2 System Operation

Condensate, Feedwater and Auxiliary Steam System Chemistry Control

An oxygen scavenger is injected into the feedwater booster pump suction to maintain a residual level of oxygen scavenger and a dissolved oxygen level of not more than 5 ppb at the inlet to the steam generator.

A pH adjuster is also injected into the feedwater booster pump suction to maintain the pH at the steam generator inlet within the control program for pH.

An oxygen scavenger is injected into the condensate system downstream of the condensate polisher to maintain a dissolved oxygen level of not more than 10 ppb at the inlet of the deaerator.

A pH adjuster is injected into the condensate system downstream of the condensate polisher to maintain the pH above 9.0 at the deaerator inlet within the control program for pH.

The chemical feed system may be used to place the steam generators in wet layup. This layup process is accomplished using the chemical feed system in conjunction with the steam generator blowdown system. Refer to subsection 10.4.8.2 for details of this process.

An oxygen scavenger and pH adjuster are injected into the auxiliary steam system downstream of the boiler makeup pumps to maintain the dissolved oxygen level and pH within the auxiliary boiler program levels. The chemical feed rates are manually adjusted.

Circulating Water and Service Water System Chemistry Control

A biocide, pH adjuster and dispersant/corrosion/scale inhibitor are injected downstream of the circulating water and service water pumps as required. Chemical feed rates for the biocide and dispersant/corrosion/scale inhibitor are manually adjusted to maintain proper concentrations. The pH adjuster chemical feed rate is controlled electronically from instrumentation that measures pH.

An algicide is provided to control algae formation on the circulating water cooling tower and service water cooling tower. The algicide is fed using a flexible hose and the feed rate is manually adjusted.

Demineralized Water Treatment System Chemistry Control

A pH adjuster and scale inhibitor are injected into the raw water supply to the demineralized water treatment system upstream of the cartridge filters. The scale inhibitor feed rate is manually adjusted and the pH adjuster chemical feed rate is controlled electronically from instrumentation that measures pH.

Potable Water System Chemistry Control

A biocide is injected into the raw water supply to the potable water system upstream of the potable water storage tank. The biocide feed rate is manually adjusted.

10.4.11.3 Safety Evaluation

The turbine island chemical feed system has no safety-related function and therefore requires no nuclear safety evaluation.

Toxic gases, such as chlorine, are not used in the turbine island chemical feed system. The impact of toxic material on main control room habitability is addressed in Section 6.4.

10.4.11.4 Tests and Inspections

The turbine island chemical feed system is operationally checked before initial plant startup to verify proper functioning of the feed systems and chemical sensors.

10.4.11.5 Instrumentation Applications

The secondary sampling system (SSS), as described in subsection 9.3.4, provides instrumentation which measures dissolved oxygen, oxygen scavenger residual, and pH for the condensate, feedwater, and steam generator systems. These analyzers provide an indication of water quality and inputs for either manual or automatic control of the condensate and feedwater systems oxygen scavenging and pH control chemical feed pumps. Grab samples are analyzed to provide input for manual adjustment of feed rates for the auxiliary steam system oxygen scavenging and pH control chemical feed pumps. Wet layup operations are manually performed based on the results of the grab sample analysis.

Grab samples are analyzed to provide input for manual adjustment of feed rates for biocide, pH adjustment and/or dispersant/corrosion/scale inhibitor chemicals for the circulating water, service water, demineralized water treatment and potable water systems.

10.4.12 Combined License Information

10.4.12.1 Circulating Water System

The Combined License applicant will address the final configuration of the plant circulating water system including piping design pressure, the cooling tower or other site-specific heat sink.

As applicable, the Combined License applicant will address the acceptable Langelier or Stability Index range, the specific chemical selected for use in the CWS water chemistry control, pH adjuster, corrosion inhibiter, scale inhibiter, dispersant, algicide and biocide applications reflecting potential variations in site water chemistry and in micro macro biological lifeforms. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4.

10.4.12.2 Condensate, Feedwater and Auxiliary Steam System Chemistry Control

The Combined License applicant will address the oxygen scavenging agent and pH adjuster selection for the turbine island chemical feed system.

10.4.12.3 Potable Water

The Combined License applicant will address the specific biocide. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4.

10.4.13 References

1. ASME Performance Test Code 19.11, 1970.

2. Heat Exchange Institute Performance Standard for Liquid Ring Vacuum Pumps.

3. American Water Works Association, Code 504-80, Rubber Seated Butterfly Valves.

Table 10.4.1-1

MAIN CONDENSER DESIGN DATA

Condenser Data	
Condenser type	Multipressure, Single pass
Hotwell storage capacity	3 min
Heat transfer	7,540 x 10^6 Btu/hr
Design operating pressure (average of all shells)	2.7 in.-Hg
Shell pressure (design)	0 in.-Hg absolute to 15 psig
Circulating water flow	600,000 gpm
Water box pressure (design)	60 psig
Tube-side inlet temperature	87°F
Approximate Tube-side temperature rise	25.2°F
Condenser outlet temperature	116.8°F
Waterbox material	Carbon Steel
Condenser Tube Data	
Tube material (main section)	Titanium
Tube size	1-3/8″ O.D. – .5 mm
Tube material (periphery)	Titanium
Tube size	1-3/8″ O.D. – .7 mm
Tube sheet material	Titanium or Titanium Clad Carbon Steel
Support plates	Modular Design/Carbon Steel

Table 10.4.5-1

[[DESIGN PARAMETERS FOR MAJOR CIRCULATING WATER SYSTEM COMPONENTS]]

(Conceptual Design)

Circulating Water Pump	
Quantity	Three per unit
Flow rate (gal/min)	200,000
Natural Draft Cooling Tower	
Quantity	One per unit
Approach temperature (°F)	10
Inlet temperature (°F)	112.2
Outlet temperature (°F)	87
Approximate Temperature range (°F)	25.2
Flow rate (gal/min)	600,000
Heat transfer (Btu/hr)	7,540 x 10^6
Wind velocity design (mph) Seismic design criteria per Uniform Building Code	110
Predicted performance during limiting site conditions: Outlet temp @ wet bulb temp of 80°F (1% exceedance)	90°F

Table 10.4.7-1 (Sheet 1 of 2)

CONDENSATE AND FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
1. SGS PL V057A (MFIV)	1a. Valve fails closed or fails to open on command. Train "A" is not available for FW flow to SG "A."	FW Train "B" available. SFW Train "A" available.	None. Decay heat removal is maintained via PRHR actuation on ESF signal. SFW available to provide flow to SG "A."
	1b. Valve fails open or fails to close on command. Trains "A" and "B" are available for FW flow. Isolation function of V057A is not available. Redundant power division closure of MFIV provided for reliability; backup isolation provided by V058A and V250A.	Valve V250A (MFCV) provides backup isolation to terminate feedwater flow. Check valve V058A provides redundant feedwater blowdown isolation from SG "A;" redundant containment isolation provided by SG and feedwater line inside containment.	None. RCS integrity is maintained by valve V058A/V250A available to prevent SG "A" blowdown. Decay heat removal available via PRHR and SFW actuated by ESF signal. SG overfill protection provided by backup isolation of V250A.
2. SGS PL V057B (MFIV)	2a. Same as except for SG "B."	FW Train "A" available. SFW Train "B" available.	Same as 1a except for SG "B."
	2b. Same as 1B except isolation function of V057B is not available.	Same as 1b except for "B" train valves and SG "B."	Same as 1b except for "B" train valves and SG "B."
3. SGS PL V250A (MFCV)	3a. Valve fails closed or fails to open on command. Train "A" is not available for FW flow to SG "A."	FW Train "B" available. SFW Train "A" available.	None. Decay heat removal is maintained via PRHR actuation on ESF signal. SFW available to provide flow to SG "A."
	3b. Valve fails open or fails to close on command. Trains "A" and "B" are available for FW flow without flow control to SG "A." Backup isolation provided by V058A and V057A.	Valve V057A (MFIV) provides backup isolation to terminate feedwater flow. Check valve V058A and V057A provide redundant feedwater blowdown isolation from SG "A." SFW train "A" and "B" available for decay heat removal.	None. RCS integrity is maintained by valve V057A and V058A closure to limit SG blowdown. Decay heat removal available via PRHR and SFW actuated by ESF signal. SG overfill protection provided by redundant isolation of V057A.

Table 10.4.7-1 (Sheet 2 of 2)

CONDENSATE AND FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
4. SGS PL V250B (MFCV)	4a. Same as 3a, except for train “B” and SG “B.”	Same as 3a except train “B.”	Same as 3a except for SG “B.”
	4b. Same as 3b, except for SG “B” and valves V057B and V058B.	Same as 3b except valves V057B and V058B and SG “B.”	Same as 3b except for V057B and V058B.

Table 10.4.9-1 (Sheet 1 of 2)

STARTUP FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
1. SGS PL V255A (SFCV)	1a. Valve fails closed or fails to open on command. SFW Flow is not available to SG A.	System is not available for SFW supply to SG "A."	None. Decay heat removal is maintained via PRHR actuation on ESF signal.
	1b. Valve fails open or fails to close on command. SFW flow is uncontrolled.	Downstream isolation valve V067A trips closed on high SG level; system pumps are tripped on high SG level.	None. RCS integrity is maintained by V067A closure and main feedwater isolation. SG overfill terminated by ESF closure of V067A.
2. SGS PL V225B (SFCV)	2a. Same as 1a except flow is not available to SG B.	System is not available for SFW supply to SG "B."	None. Same as 1a.
	2b. Same as 1b.	Same as 1b except valve V067B trips closed on high SG level.	Same as 1b except RCS integrity is maintained by V067B and main feedwater isolation, and overfill terminated by closure of V067B.
3. SGS PL V067A (SFIV)	3a. Valve fails closed. SFW flow is not available to SG A.	System is not available for SFW supply to SG "A."	None. Same as 1a.
	3b. Valve fails open. Valve is a stop check and failure of operator does not preclude check valve function.	None. Valve V255A is automatically closed and SFW pumps tripped on an ESF signal. SG overfill protection provided by automatic isolation of V255A.	None. RCS integrity is maintained by V255A closure to limit cooldown; PRHR available for decay heat removal and SG overfill protection provided by redundant isolation of V255A.

Table 10.4.9-1 (Sheet 2 of 2)

STARTUP FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
4. SGS PL V067B (SFIV)	4a. Same as 3a except flow not available to SG "B."	Same as 3a except SFW supply not available to SG "B."	Same as 1a.
	4b. Same as 3b.	Same as 3b except reference valve is V255B.	Same as 3b except reference valve is V255B.

Table 10.4.9-2

NOMINAL COMPONENT DESIGN DATA – STARTUP FEEDWATER SYSTEM

Startup Feedwater Pump	
Type	Multi-stage, centrifugal
Driver	Electric Motor
Quantity	2
Capacity	520 gpm @ 80°F
Head	3250 ft
Motor hp	800

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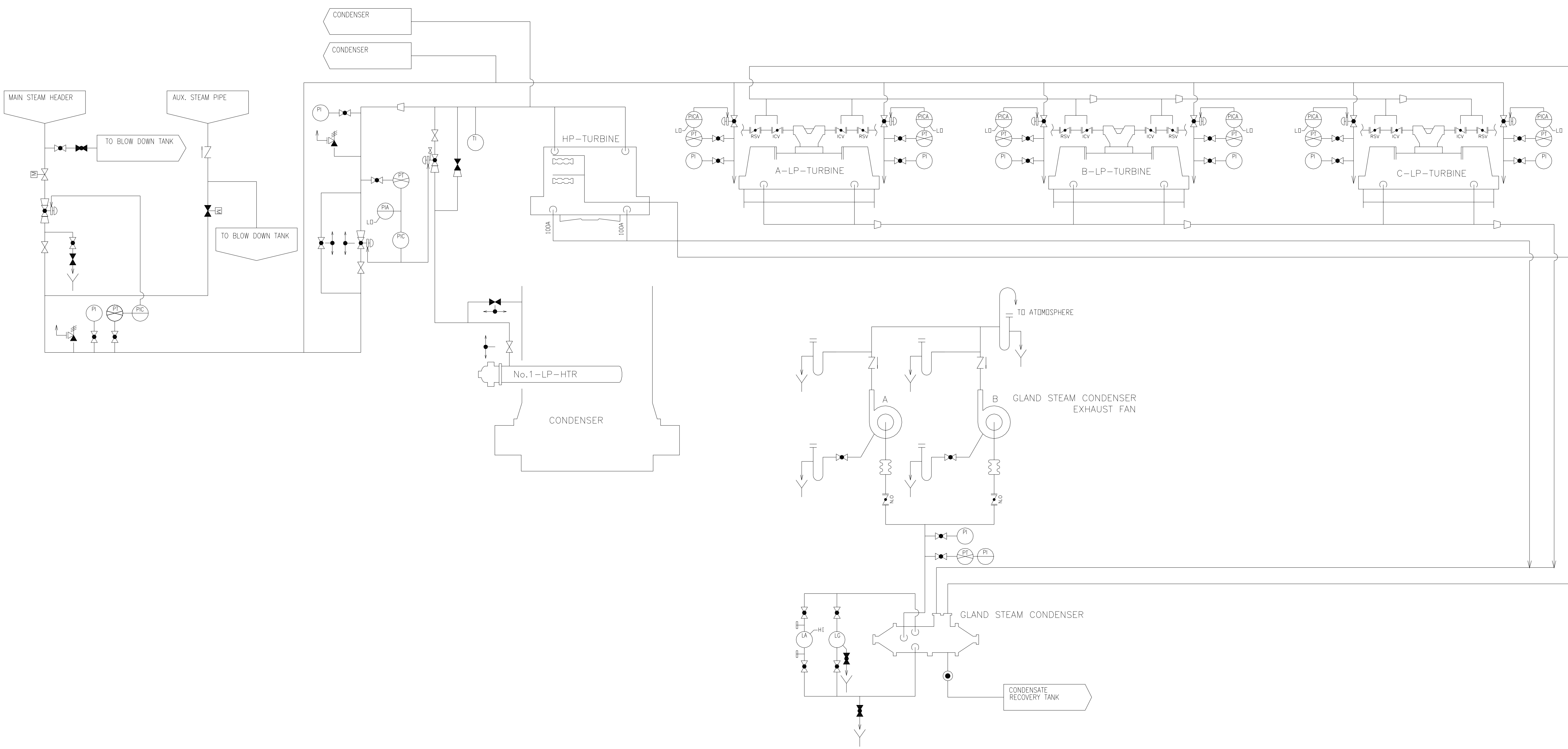
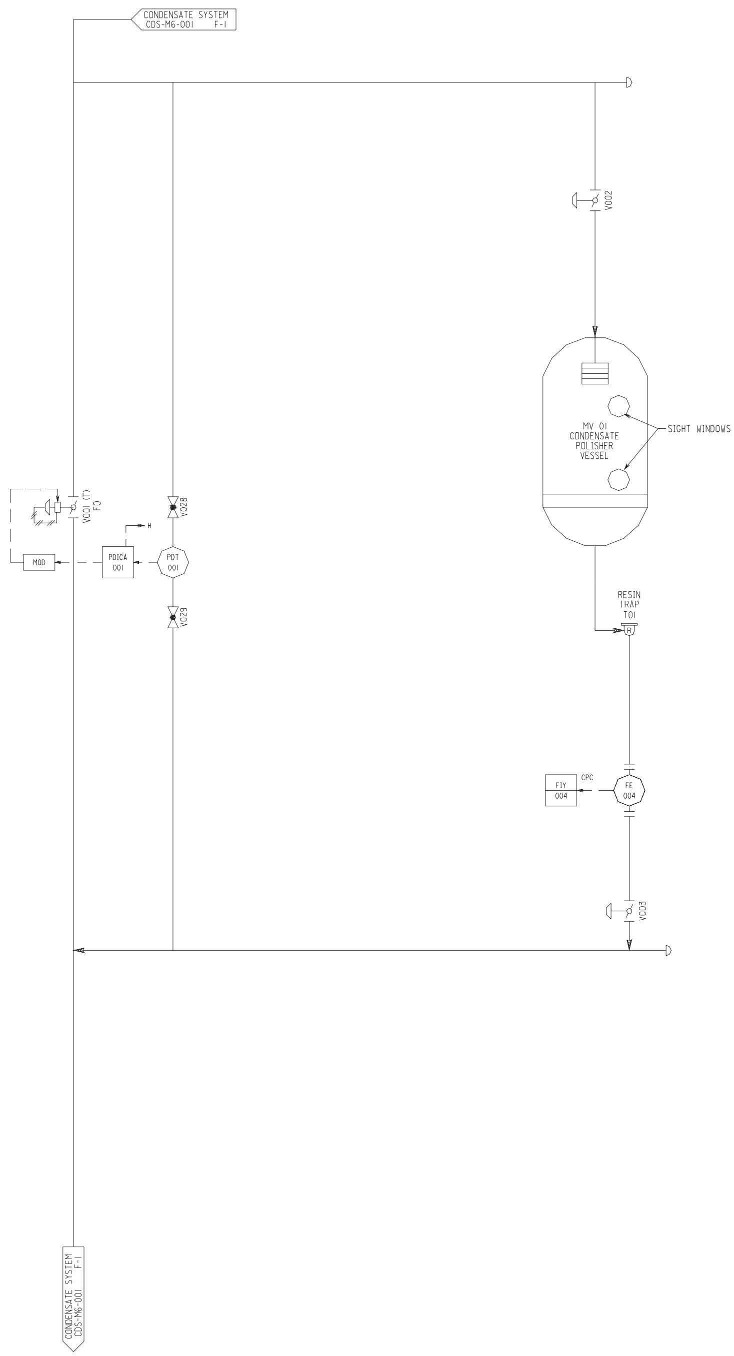


Figure 10.4.3-1

Gland Seal System
Piping and Instrumental Diagram



Inside Turbine Building

Figure 10.4.6-1

Condensate Polishing System
Piping and Instrumentation Diagram

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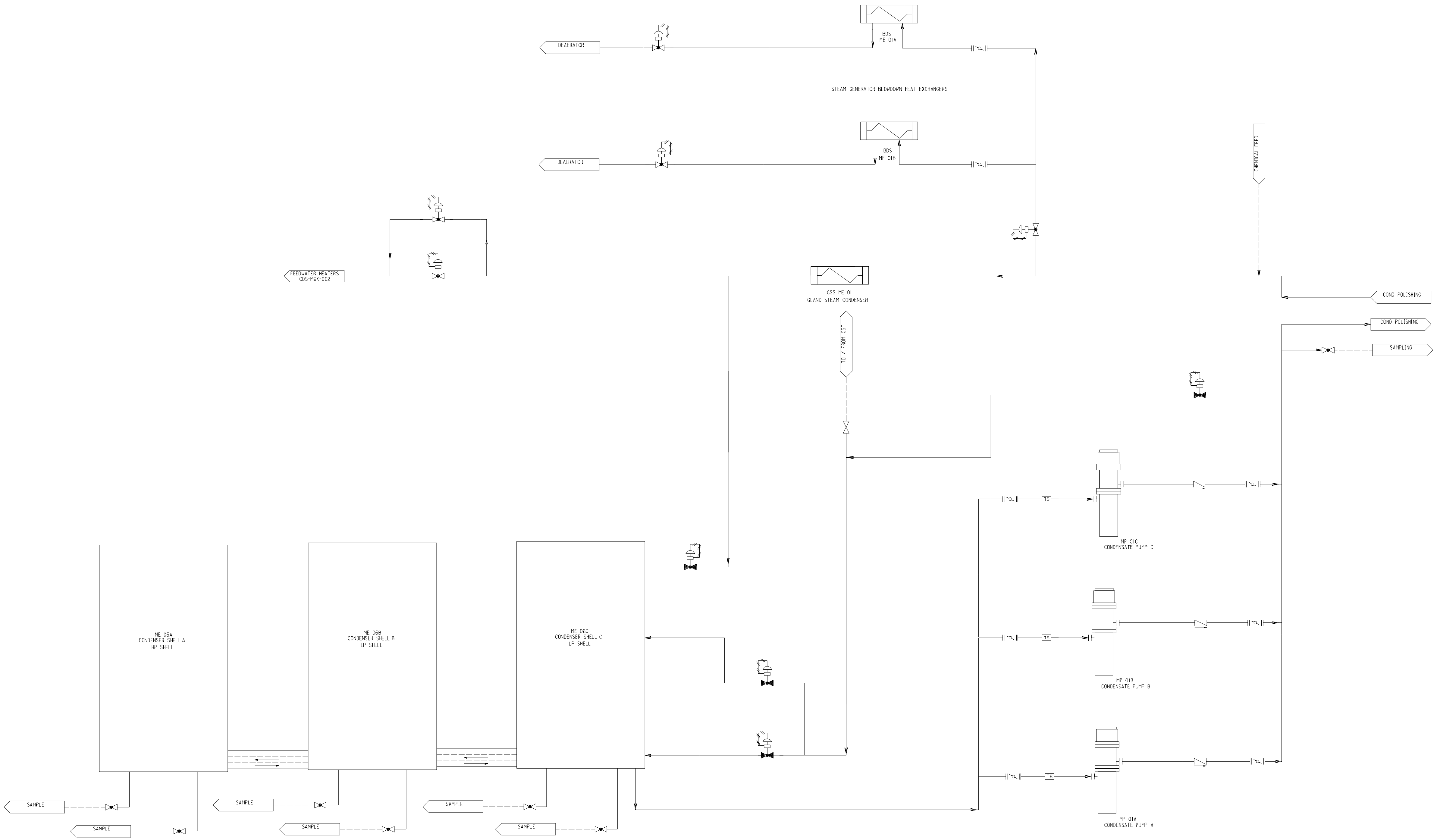


Figure 10.4.7-1 (Sheet 1 of 4)

Condensate and Feedwater System
Piping and Instrumental Diagram

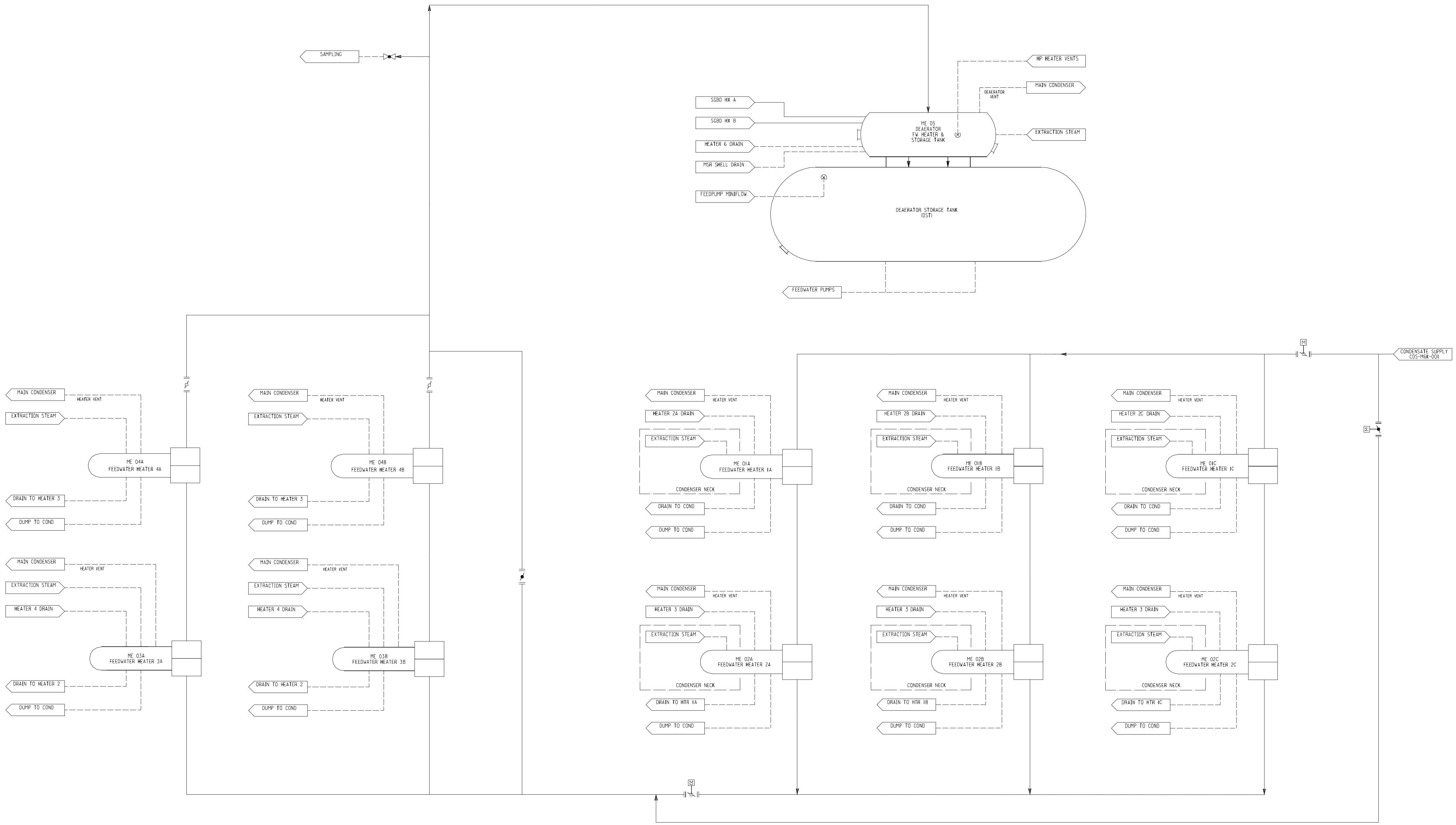


Figure 10.4.7-1 (Sheet 2 of 4)

Condensate and Feedwater System Piping and Instrumental Diagram

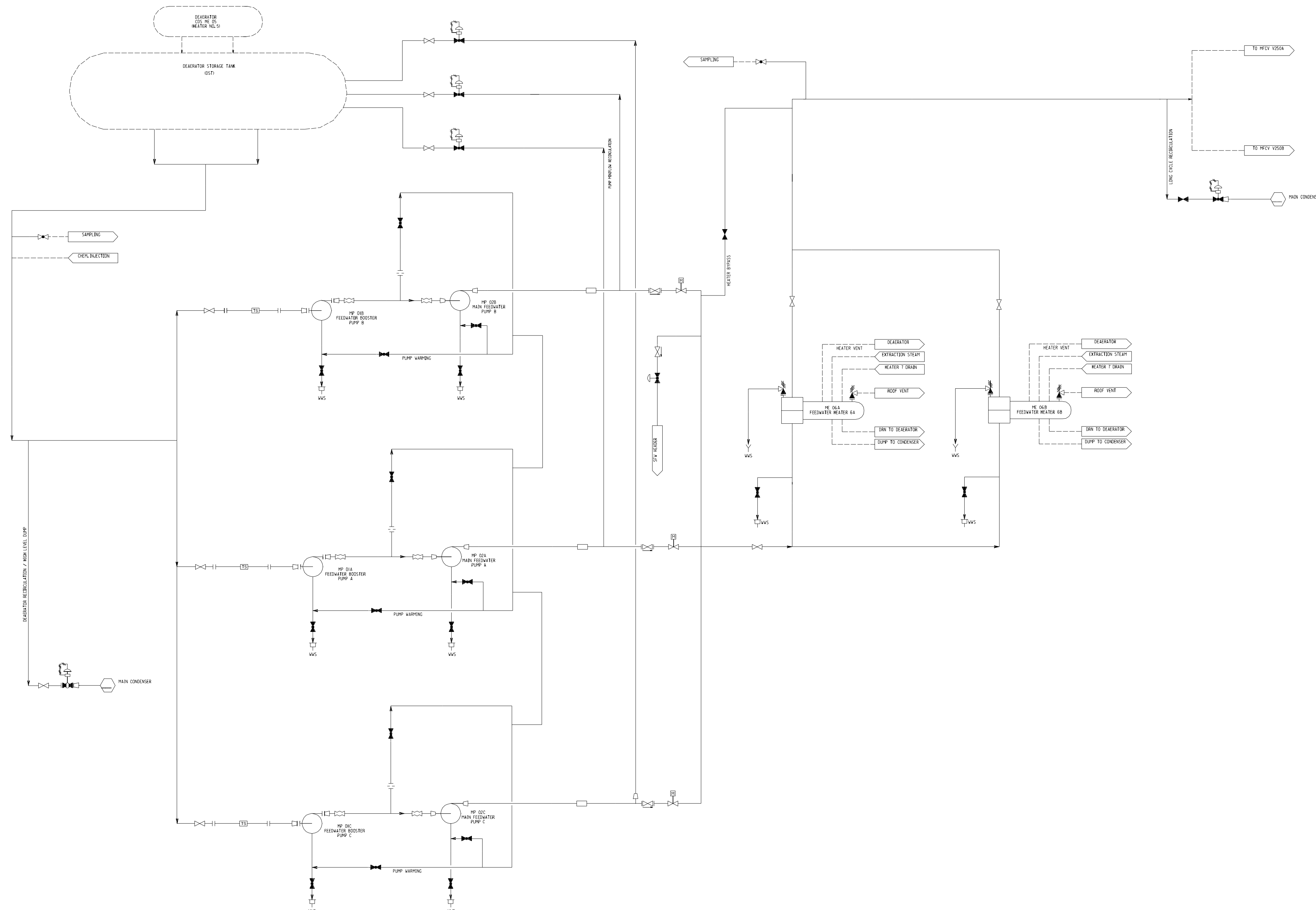


Figure 10.4.7-1 (Sheet 3 of 4)

Condensate and Feedwater System
Piping and Instrumental Diagram

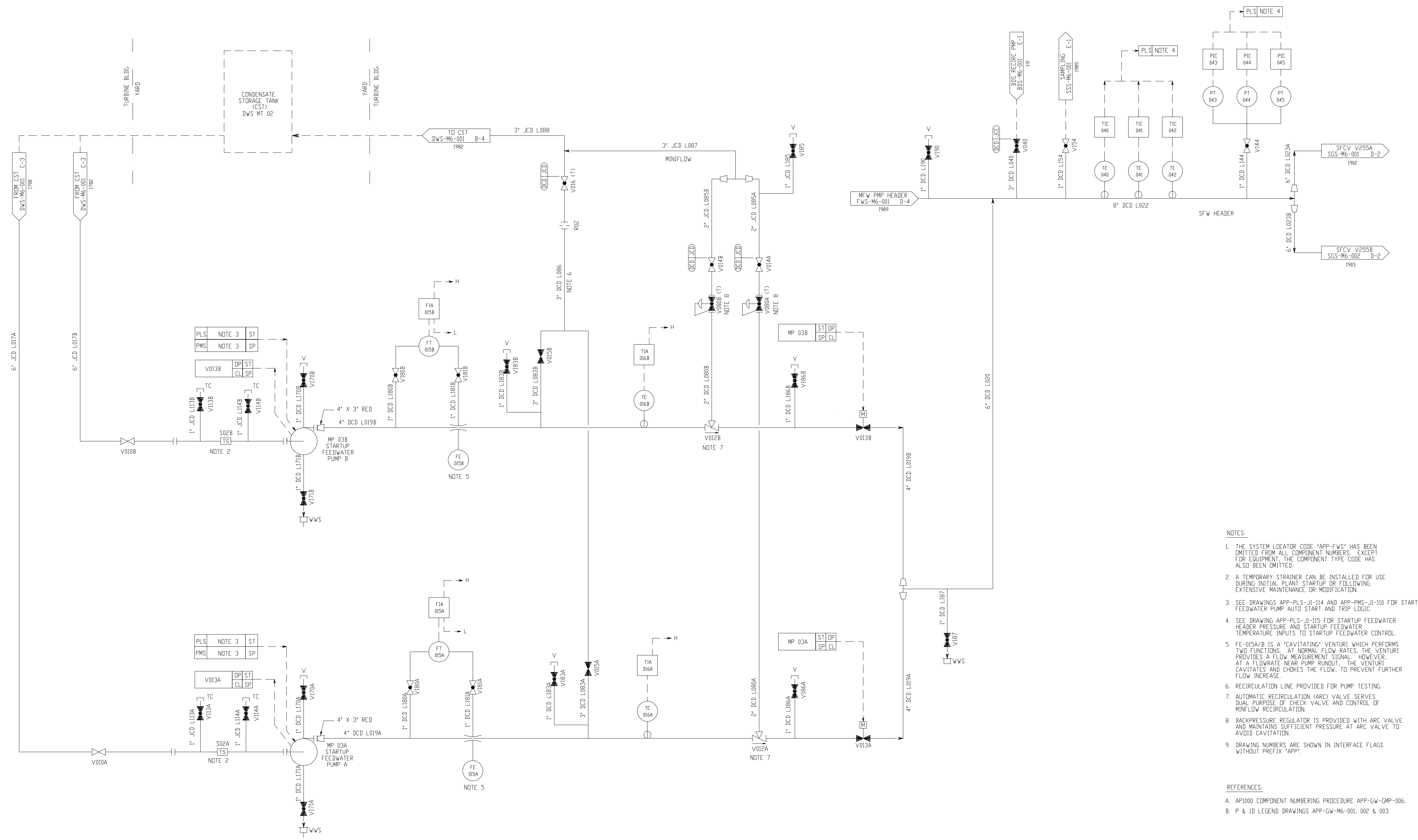
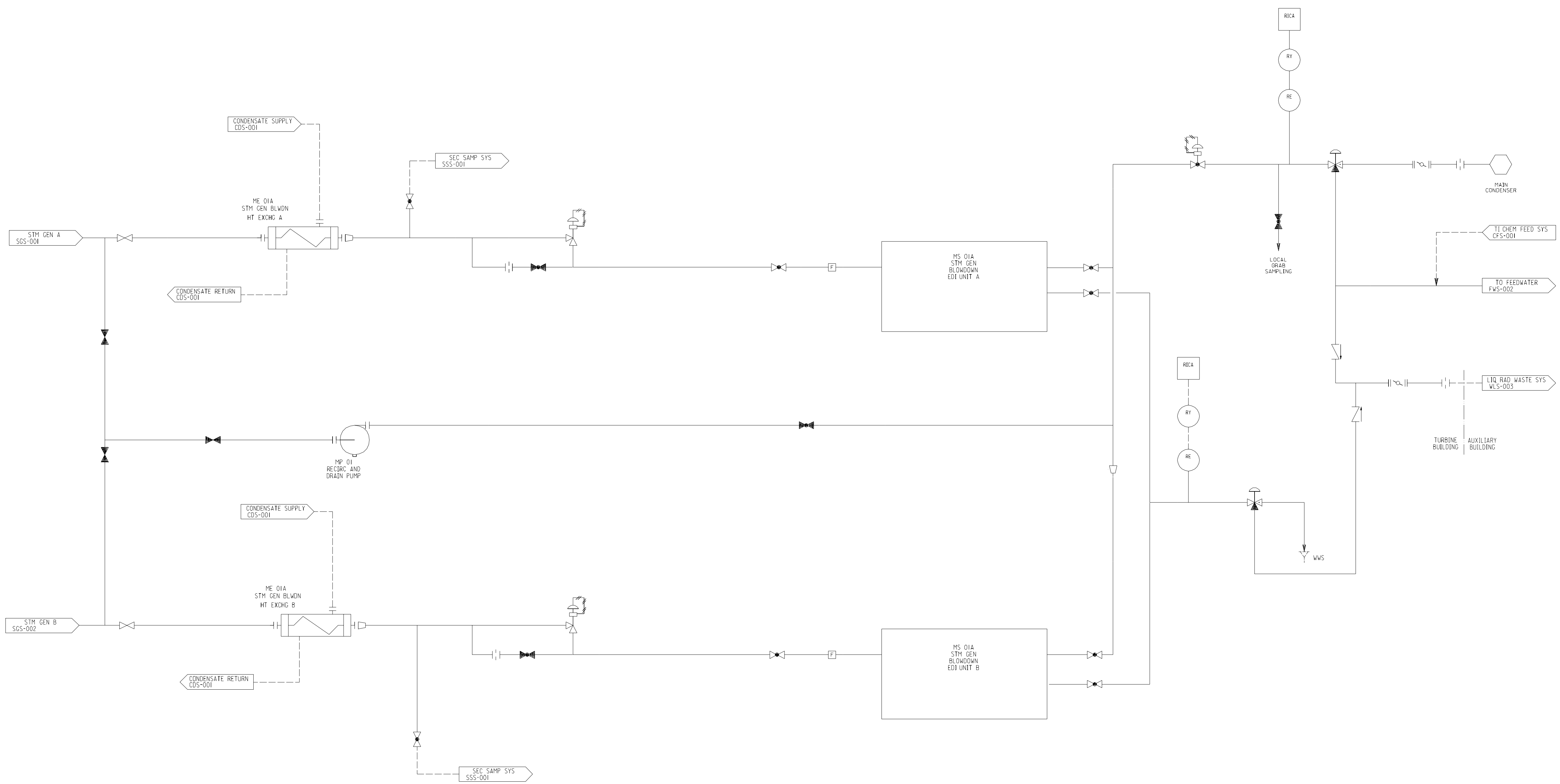


Figure 10.4.7-1 (Sheet 4 of 4)

Condensate and Feedwater System Piping and Instrumental Diagram



Inside Turbine Building

Figure 10.4.8-1

Steam Generator Blowdown System Piping and Instrumentation Diagram

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CHAPTER 11

RADIOACTIVE WASTE MANAGEMENT

11.1 Source Terms

This section addresses the sources of radioactivity that are treated by the liquid and gaseous radwaste systems. Radioactive materials are generated within the core (fission products) and have the potential of leaking to the reactor coolant system by way of defects in the fuel cladding. The core radiation field also results in activation of the coolant to form N-16 from oxygen and the activation of corrosion products in the reactor coolant system.

Two source terms are presented for the primary and the secondary coolant. The first is a conservative, or design basis, source term that assumes the design basis fuel defect level. This source term serves as a basis for system design and shielding requirements.

The second source term is a realistic model. This source term represents the expected average concentrations of radionuclides in the primary and the secondary coolant. These values are determined using the model in the PWR-GALE code (Reference 1) and which provides the bases for estimating typical concentrations of the principal radionuclides that are expected to occur. This source term model reflects the industry experience at a large number of operating PWR plants.

11.1.1 Design Basis Reactor Coolant Activity

11.1.1.1 Fission Products

For the design basis source term it is assumed that there is a significant fuel defect level, well above that anticipated during normal operation. It is assumed that small cladding defects are present in fuel rods producing 0.25 percent of the core power output (also stated as 0.25 percent fuel defects). The defects are assumed to be uniformly distributed throughout the core.

The parameters used in the calculation of the reactor coolant fission product concentrations, including pertinent information concerning the fission product escape rate coefficients, coolant cleanup rate, and demineralizer effectiveness, are listed in Table 11.1-1. Since the fuel defects are assumed to be uniformly distributed in the core, the fission product escape rate coefficients are based on average fuel temperature.

The determination of reactor coolant activity is based on time-dependent fission product core inventories that are calculated by the ORIGEN code (Reference 2).

The fission product activity in the reactor coolant is calculated using the following differential equations.

For parent nuclides in the coolant:

$$\frac{dN_{cp}}{dt} = \frac{FR_p\, N_{Fp}}{M_c}$$

$$-\left[\lambda_p + D_p + \frac{Q_L}{M_c}\left(\frac{DF_p - 1}{DF_p}\right)\right] N_{cp}$$

For daughter nuclides in the coolant:

$$\frac{dN_{cd}}{dt} = \frac{FR_d\, N_{Fd}}{M_c} + f_p\, \lambda_p\, N_{c_p}\ -$$

$$\left[\lambda_d + D_d + \frac{Q_L}{M_c}\left(\frac{DF_d - 1}{DF_d}\right)\right] N_{cd}$$

where:

N_c	=	Concentration of nuclide in the reactor coolant (atoms/gram)
N_F	=	Population of nuclide in the fuel (atoms)
t	=	Operating time (seconds)
R	=	Nuclide release coefficient (1/sec)
F	=	Fraction of fuel rods with defective cladding
M_c	=	Mass of reactor coolant (grams)
λ	=	Nuclide decay constant (1/sec)
D	=	Dilution coefficient by feed and bleed (1/sec) $= \frac{\beta}{B_O - \beta t} \times \frac{1}{DF}$
B_o	=	Initial boron concentration (ppm)
β	=	Boron concentration reduction rate (ppm/sec)
DF	=	Nuclide demineralizer decontamination factor
Q_L	=	Purification or letdown mass flow rate (grams/sec)
f	=	Fraction of parent nuclide decay events that result in the formation of the daughter nuclide

Subscript p refers to the parent nuclide.

Subscript d refers to the daughter nuclide.

Table 11.1-2 lists the resulting reactor coolant radionuclide concentrations. The values presented are the maximum values calculated to occur during the fuel cycle from startup through the equilibrium cycle. Thus, the source term does not represent any particular time in the fuel cycle but is a conservative composite.

The design basis source term based on 0.25 percent fuel defects is used to ensure a consistent set of design values for interfaces among the radioactive waste processing systems. The Technical Specifications in Chapter 16, which are related to fuel failure are also based upon 0.25 percent fuel defects. In addition, the liquid and gaseous radioactive waste processing systems have the capability to process wastes based upon 1.0 percent fuel defects.

11.1.1.2 Corrosion Products

The reactor coolant corrosion product activities are based on operating plant data and are independent of fuel defect level. The concentrations of corrosion products are included in Table 11.1-2.

11.1.1.3 Tritium

A number of tritium production processes add tritium to the reactor coolant:

- Fission product formation in the fuel (ternary fission) forms tritium which can diffuse through the fuel clad or leak through fuel clad defects
- Neutron reactions with soluble boron in the reactor coolant
- Burnable neutron absorber
- Neutron reactions with soluble lithium in the reactor coolant
- Neutron reactions with deuterium in the reactor coolant

The first two processes are the principal contributors to tritium in the reactor coolant. Table 11.1-3 lists the tritium introduced to the reactor coolant from each of the processes.

Tritium exists in the reactor coolant primarily combined with hydrogen (that is, a tritium atom replaces a hydrogen atom in a water molecule) and thus cannot be readily separated from the coolant by normal processing methods. The maximum concentration of tritium in the reactor coolant is less than 3.5 microcuries per gram as a result of losses due to leakage and the controlled release of tritiated water to the environment.

11.1.1.4 Nitrogen-16

Activation of oxygen in the coolant results in the formation of N-16 which is a strong gamma emitter. Because of its short half-life of 7.11 seconds, N-16 is not of concern outside the containment. Table 12.2-3 provides N-16 concentrations at various points in the reactor coolant system. After shutdown, N-16 is not a source of radiation inside of containment.

11.1.2 Design Basis Secondary Coolant Activity

Steam generator tube defects cause the introduction of reactor coolant into the secondary cooling system. The resulting radionuclide concentrations in the secondary coolant depend upon the primary-to-secondary leak rate, the nuclide decay constant, and the steam generator blowdown rate.

The reactor coolant leakage into the secondary system is assumed to have radionuclide concentrations as defined in Table 11.1-2. The parameters used in the calculation of the secondary side activities are provided in Table 11.1-4 and the resulting radionuclide concentrations in the steam generator secondary side water and steam are presented in Tables 11.1-5 and 11.1-6.

11.1.3 Realistic Reactor Coolant and Secondary Coolant Activity

The realistic source terms for both the reactor coolant and the secondary coolant are determined using the modeling in ANSI-18.1 (Reference 3). This modeling is also incorporated in the PWR-GALE code. The reference plant values provided in ANSI-18.1 were adjusted to be consistent with the AP1000 parameters listed in Table 11.1-7. The adjustment factors are applied to the fission products. The realistic source terms are listed in Table 11.1-8.

11.1.4 Core Source Term

The core fission product inventories used to establish source terms for accident radiological consequence analyses are provided in Appendix 15A.

11.1.5 Process Leakage Sources

The systems containing radioactive liquids are potential sources for the release of radioactive material to plant buildings and then to the environment. The leakage sources and the resulting airborne concentrations are discussed in Section 12.2.

Release pathways for radioactive materials are discussed in Sections 11.2 and 11.3.

11.1.6 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

11.1.7 References

1. “Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code),” NUREG-0017, Revision 1, March 1985.

2. RSIC Computer Code Collection CCC-371, ORIGEN 2.1 Isotope Generation and Depletion Code - Matrix Exponential Method, August 1, 1991.

3. ANSI/ANS-18.1-1984, “Radioactive Source Term for Normal Operation of Light Water Reactors.”

Table 11.1-1 (Sheet 1 of 2)

PARAMETERS USED IN THE CALCULATION OF DESIGN BASIS FISSION PRODUCT ACTIVITIES

Core thermal power (MWt)	3,400
Reactor coolant liquid volume (ft^3)[(a)]	9,575
Reactor coolant full-power average temperature (°F)	578.1
Purification flow rate (gal/min)[(b)]	
Maximum	100
Normal	91.3
Effective cation demineralizer flow, annual average (gal/min)[(b)]	9.1
Nuclide release coefficients (the product of the failed fuel fraction and the fission product escape rate coefficient)	
Equivalent fraction of core power produced by fuel rods containing small cladding defects (failed fuel fraction)	0.0025
Fission product escape rate coefficients during full-power operation (s^{-1}):	
Kr and Xe isotopes	6.5×10^{-8}
Br, Rb, I, and Cs isotopes	1.3×10^{-8}
Mo, Tc, and Ag isotopes	2.0×10^{-9}
Te isotopes	1.0×10^{-9}
Sr and Ba isotopes	1.0×10^{-11}
Y, Zr, Nb, Ru, Rh, La, Ce, and Pr isotopes	1.6×10^{-12}
Chemical and volume control system mixed bed demineralizers	
Resin volume (ft^3)	50
Demineralizer isotopic decontamination factors:	
Kr and Xe isotopes	1
Br and I isotopes	10
Sr and Ba isotopes	10
Other isotopes	1

Table 11.1-1 (Sheet 2 of 2)

PARAMETERS USED IN THE CALCULATION OF DESIGN BASIS FISSION PRODUCT ACTIVITIES

Chemical and volume control system cation bed demineralizer	
Resin volume (ft^3)	50
Demineralizer isotopic decontamination factors:	
Kr and Xe isotopes	1
Sr and Ba isotopes	1
Rb-86, Cs-134, and Cs-137	10
Rb-88, Rb-89, Cs-136, and Cs-138	1
Other isotopes	1
Other isotopic removal mechanisms	See Note c
Initial boron concentration (ppm)	1,400
Operation time (effective full-power hours)	12,492

Notes:

a. Reactor coolant mass used in defining fission product activities is based on above stated conditions before thermal expansion (conservative).

b. Flow calculated at 2250 psia and 250°F.

c. For all isotopes, except the isotopes of Kr, Xe, Br, I, Rb, Cs, Sr, and Ba, a removal decontamination factor of 10 is assumed to account for removal mechanisms other than ion exchange, such as plateout or filtration. This decontamination factor is applied to the normal purification letdown flow.

Table 11.1-2

DESIGN BASIS REACTOR COOLANT ACTIVITY

Nuclide	**Activity (µCi/g)**	**Nuclide**	**Activity (µCi/g)**
Kr-83m	1.8×10^{-1}	Rb-88	1.5
Kr-85m	8.4×10^{-1}	Rb-89	6.9×10^{-2}
Kr-85	3.0	Sr-89	1.1×10^{-3}
Kr-87	4.7×10^{-1}	Sr-90	4.9×10^{-5}
Kr-88	1.5	Sr-91	1.7×10^{-3}
Kr-89	3.5×10^{-2}	Sr-92	4.1×10^{-4}
Xe-131m	1.3	Y-90	1.3×10^{-5}
Xe-133m	1.7	Y-91m	9.2×10^{-4}
Xe-133	1.2×10^{2}	Y-91	1.4×10^{-4}
Xe-135m	1.7×10^{-1}	Y-92	3.4×10^{-4}
Xe-135	3.5	Y-93	1.1×10^{-4}
Xe-137	6.7×10^{-2}	Zr-95	1.6×10^{-4}
Xe-138	2.5×10^{-1}	Nb-95	1.6×10^{-4}
Br-83	3.2×10^{-2}	Mo-99	2.1×10^{-1}
Br-84	1.7×10^{-2}	Tc-99m	2.0×10^{-1}
Br-85	2.0×10^{-3}	Ru-103	1.4×10^{-4}
I-129	1.5×10^{-8}	Rh-103m	1.4×10^{-4}
I-130	1.1×10^{-2}	Rh-106	4.5×10^{-5}
I-131	7.1×10^{-1}	Ag-110m	4.0×10^{-4}
I-132	9.4×10^{-1}	Te-127m	7.6×10^{-4}
I-133	1.3	Te-129m	2.6×10^{-3}
I-134	2.2×10^{-1}	Te-129	3.8×10^{-3}
I-135	7.8×10^{-1}	Te-131m	6.7×10^{-3}
Cs-134	6.9×10^{-1}	Te-131	4.3×10^{-3}
Cs-136	1.0	Te-132	7.9×10^{-2}
Cs-137	5.0×10^{-1}	Te-134	1.1×10^{-2}
Cs-138	3.7×10^{-1}	Ba-137m	4.7×10^{-1}
Cr-51	1.3×10^{-3}	Ba-140	1.0×10^{-3}
Mn-54	6.7×10^{-4}	La-140	3.1×10^{-4}
Mn-56	1.7×10^{-1}	Ce-141	1.6×10^{-4}
Fe-55	5.0×10^{-4}	Ce-143	1.4×10^{-4}
Fe-59	1.3×10^{-4}	Pr-143	1.5×10^{-4}
Co-58	1.9×10^{-3}	Ce-144	1.2×10^{-4}
Co-60	2.2×10^{-4}	Pr-144	1.2×10^{-4}

Note:
These activities are used for shielding and radwaste system interface design. For 1 percent fuel defect calculations (maximum release and liquid and gaseous radwaste system capability) multiply the activities above by 4 except for corrosion products (Cr-51, Mn-54, Mn-56, Fe-55, Fe-59, Co-58 and Co-60).

Table 11.1-3

TRITIUM SOURCES

	Release to the Coolant (curies/cycle[1])	
Tritium Source	**Design Basis**	**Best Estimate**
Produced in the core	1770	354
Ternary fission	279	56
Burnable absorbers		
Produced in the coolant	734	734
Soluble boron	168	168
Soluble lithium	4	4
Deuterium		
TOTAL	2955	1316

1 Cycle length of 18 months. Design basis case reflects the historical assumption that 10% of the tritium produced in the core is released to the coolant. Best estimate case is based on a release of only 2% of the tritium.

Table 11.1-4

PARAMETERS USED TO CALCULATE SECONDARY COOLANT ACTIVITY

Total secondary side water mass (lb/steam generator)	1.76×10^5
Steam generator steam fraction	0.055
Total steam flow rate (lb/hr)	1.5×10^7
Moisture carryover (percent)	0.1
Total makeup water feed rate (lb/hr)	732
Total blowdown rate (gpm)	186
Total primary-to-secondary leak rate (gpd)	500
Iodine partition factor (mass basis)	100

Table 11.1-5

DESIGN BASIS STEAM GENERATOR SECONDARY SIDE LIQUID ACTIVITY

Nuclide	Activity (μCi/g)	Nuclide	Activity (μCi/g)
Br-83	2.3×10^{-5}	Y-93	1.5×10^{-7}
Br-84	4.0×10^{-6}	Zr-95	2.7×10^{-7}
Br-85	4.9×10^{-8}	Nb-95	2.7×10^{-7}
I-129	2.4×10^{-11}	Mo-99	3.4×10^{-4}
I-130	1.4×10^{-5}	Tc-99m	3.2×10^{-4}
I-131	1.1×10^{-3}	Ru-103	2.3×10^{-7}
I-132	7.3×10^{-4}	Rh-103m	2.3×10^{-7}
I-133	1.8×10^{-3}	Rh-106	2.0×10^{-10}
I-134	8.1×10^{-5}	Ag-110m	6.7×10^{-7}
I-135	8.7×10^{-4}	Te-127m	1.3×10^{-6}
Rb-88	2.3×10^{-4}	Te-127	3.2×10^{-7}
Rb-89	8.9×10^{-6}	Te-129m	4.4×10^{-6}
Cs-134	2.1×10^{-3}	Te-129	3.8×10^{-6}
Cs-136	3.0×10^{-3}	Te-131m	1.0×10^{-5}
Cs-137	1.5×10^{-3}	Te-131	2.8×10^{-6}
Cs-138	9.5×10^{-5}	Te-132	1.3×10^{-4}
H-3	1.0	Te-134	3.2×10^{-6}
Cr-51	2.2×10^{-6}	Ba-137m	1.4×10^{-3}
Mn-54	1.1×10^{-6}	Ba-140	1.7×10^{-6}
Mn-56	1.3×10^{-4}	La-140	6.0×10^{-7}
Fe-55	8.4×10^{-7}	Ce-141	2.6×10^{-7}
Fe-59	2.2×10^{-7}	Ce-143	2.2×10^{-7}
Co-58	3.2×10^{-6}	Ce-144	1.9×10^{-7}
Co-60	3.7×10^{-7}	Pr-143	2.5×10^{-7}
Sr-89	3.3×10^{-6}	Pr-144	1.9×10^{-7}
Sr-90	1.5×10^{-7}		
Sr-91	3.3×10^{-6}		
Sr-92	4.0×10^{-7}		
Y-90	2.7×10^{-8}		
Y-91m	1.8×10^{-6}		
Y-91	2.3×10^{-7}		
Y-92	4.9×10^{-7}		

Table 11.1-6

DESIGN BASIS STEAM GENERATOR SECONDARY SIDE STEAM ACTIVITY

Nuclide	Activity (μCi/g)
Kr-83m	1.8×10^{-6}
Kr-85m	7.2×10^{-6}
Kr-85	2.5×10^{-5}
Kr-87	4.1×10^{-6}
Kr-88	1.3×10^{-5}
Kr-89	3.0×10^{-7}
Xe-131m	1.2×10^{-5}
Xe-133m	1.4×10^{-5}
Xe-133	1.1×10^{-3}
Xe-135m	1.0×10^{-5}
Xe-135	3.1×10^{-5}
Xe-137	5.7×10^{-7}
Xe-138	2.1×10^{-6}
I-129	2.7×10^{-13}
I-130	1.5×10^{-7}
I-131	1.3×10^{-5}
I-132	8.0×10^{-6}
I-133	2.0×10^{-5}
I-134	8.9×10^{-7}
I-135	9.5×10^{-6}
H-3	1.0

Table 11.1-7

PARAMETERS USED TO DESCRIBE REALISTIC SOURCES

Parameter	Symbol	Units	AP1000 Value	Nominal Value
Thermal power	P	MWt	3400	3400
Steam flow rate	FS	lb/hr	1.5×10^7	1.5×10^7
Weight of water in reactor coolant system	WP	lb	4.3×10^5	5.5×10^5
Weight of water in all steam generators	WS	lb	3.5×10^5	4.5×10^5
Reactor coolant purification flow	FD	lb/hr	4.3×10^4	3.7×10^4
Reactor coolant letdown flow (yearly average for boron control)	FB	lb/hr	1.5×10^2	5.0×10^2
Steam generator blowdown flow (total)	FBD	lb/hr	7.5×10^4	7.5×10^4
Fraction of radioactivity in blowdown stream which is not returned to the secondary coolant system	NBD	-	0.0	1.0
Flow through the purification system cation demineralizer	FA	lb/hr	4.3×10^3	3.7×10^3
Ratio of condensate demineralizer flow rate to the total steam flow rate	NC	-	0.33	0.0
Fraction of the noble gas activity in the letdown stream which is not returned to the reactor coolant system	Y		0.0	0.0
Primary-to-secondary leakage	FL	lb/day	75	75

Table 11.1-8 (Sheet 1 of 4)

REALISTIC SOURCE TERMS

Noble Gases

Nuclide	Reactor Coolant Activity (µCi/g)	Steam Generator Steam Activity (µCi/g)
Kr-85m	0.21	4.4×10^{-8}
Kr-85	1.4	2.9×10^{-7}
Kr-87	0.19	3.9×10^{-8}
Kr-88	0.36	7.7×10^{-8}
Xe-131m	1.1	2.3×10^{-7}
Xe-133m	0.093	2.0×10^{-8}
Xe-133	3.6	7.6×10^{-7}
Xe-135m	0.17	3.5×10^{-8}
Xe-135	1.1	2.3×10^{-7}
Xe-137	0.044	9.2×10^{-9}
Xe-138	0.15	3.2×10^{-8}

Halogens

Nuclide	Reactor Coolant Activity (µCi/g)	Steam Generator Liquid Activity (µCi/g)	Steam Generator Steam Activity (µCi/g)
Br-84	0.02	1.2×10^{-7}	1.2×10^{-9}
I-131	0.04	2.7×10^{-6}	2.7×10^{-8}
I-132	0.25	5.1×10^{-6}	5.1×10^{-8}
I-133	0.14	7.4×10^{-6}	7.4×10^{-8}
I-134	0.42	3.9×10^{-6}	3.9×10^{-8}
I-135	0.28	1.1×10^{-5}	1.1×10^{-7}

Table 11.1-8 (Sheet 2 of 4)

REALISTIC SOURCE TERMS

Rubidium, Cesium

Nuclide	Reactor Coolant Activity (μCi/g)	Steam Generator Liquid Activity (μCi/g)	Steam Generator Steam Activity (μCi/g)
Rb-88	0.24	8.9×10^{-7}	4.4×10^{-9}
Cs-134	5.9×10^{-3}	1.5×10^{-6}	7.6×10^{-9}
Cs-136	7.4×10^{-4}	1.7×10^{-7}	8.7×10^{-10}
Cs-137	7.9×10^{-3}	2.0×10^{-6}	9.9×10^{-9}

Tritium

Nuclide	Reactor Coolant Activity (μCi/g)	Steam Generator Liquid Activity (μCi/g)	Steam Generator Steam Activity (μCi/g)
H-3	1	1.0×10^{-3}	1.0×10^{-3}

Table 11.1-8 (Sheet 3 of 4)

REALISTIC SOURCE TERMS

Miscellaneous Nuclides

Nuclide	Reactor Coolant Activity (µCi/g)	Steam Generator Liquid Activity (µCi/g)	Steam Generator Steam Activity (µCi/g)
Na-24	4.6×10^{-2}	3.6×10^{-6}	1.8×10^{-8}
Cr-51	2.6×10^{-3}	3.6×10^{-7}	1.8×10^{-9}
Mn-54	1.3×10^{-3}	1.8×10^{-7}	9.2×10^{-10}
Fe-55	1.0×10^{-3}	1.4×10^{-7}	7.0×10^{-10}
Fe-59	2.5×10^{-4}	3.3×10^{-8}	1.7×10^{-10}
Co-58	3.9×10^{-3}	5.3×10^{-7}	2.6×10^{-9}
Co-60	4.4×10^{-4}	6.1×10^{-8}	3.1×10^{-10}
Zn-65	4.3×10^{-4}	5.9×10^{-8}	2.8×10^{-10}
Sr-89	1.2×10^{-4}	1.6×10^{-8}	8.1×10^{-11}
Sr-90	1.0×10^{-5}	1.4×10^{-9}	7.0×10^{-12}
Sr-91	9.8×10^{-4}	6.4×10^{-8}	3.2×10^{-10}
Y-90	1.2×10^{-6}	1.6×10^{-10}	8.0×10^{-13}
Y-91m	5.7×10^{-4}	5.6×10^{-9}	2.8×10^{-11}
Y-91	4.4×10^{-6}	5.9×10^{-10}	3.1×10^{-12}
Y-93	4.3×10^{-3}	2.8×10^{-7}	1.4×10^{-9}
Zr-95	3.3×10^{-4}	4.5×10^{-8}	2.2×10^{-10}
Nb-95	2.4×10^{-4}	3.1×10^{-8}	1.6×10^{-10}
Mo-99	5.6×10^{-3}	6.7×10^{-7}	3.2×10^{-9}
Tc-99m	5.1×10^{-3}	2.4×10^{-7}	1.2×10^{-9}
Ru-103	6.3×10^{-3}	8.6×10^{-7}	4.5×10^{-9}
Ru-106	7.5×10^{-2}	1.0×10^{-5}	5.0×10^{-8}
Rh-103m	6.3×10^{-3}	8.6×10^{-7}	4.5×10^{-9}
Rh-106	7.5×10^{-2}	1.0×10^{-5}	5.0×10^{-8}
Ag-110m	1.1×10^{-3}	1.5×10^{-7}	7.5×10^{-10}
Te-129m	1.6×10^{-4}	2.2×10^{-8}	1.1×10^{-10}

Table 11.1-8 (Sheet 4 of 4)

REALISTIC SOURCE TERMS

Miscellaneous Nuclides

Nuclide	Reactor Coolant Activity (µCi/g)	Steam Generator Liquid Activity (µCi/g)	Steam Generator Steam Activity (µCi/g)
Te-129	2.9×10^{-2}	3.9×10^{-7}	2.0×10^{-9}
Te-131m	1.4×10^{-3}	1.4×10^{-7}	7.0×10^{-10}
Te-131	9.7×10^{-3}	4.9×10^{-8}	2.5×10^{-10}
Te-132	1.5×10^{-3}	1.8×10^{-7}	8.9×10^{-10}
Ba-137m	7.4×10^{-3}	1.9×10^{-6}	9.3×10^{-9}
Ba-140	1.1×10^{-2}	1.4×10^{-6}	7.2×10^{-9}
La-140	2.3×10^{-2}	2.4×10^{-6}	1.2×10^{-8}
Ce-141	1.3×10^{-4}	1.7×10^{-8}	8.6×10^{-11}
Ce-143	2.6×10^{-3}	2.6×10^{-7}	1.3×10^{-9}
Ce-144	3.4×10^{-3}	4.5×10^{-7}	2.3×10^{-9}
Pr-143	3.0×10^{-3}	3.3×10^{-7}	1.8×10^{-9}
Pr-144	3.4×10^{-3}	4.5×10^{-7}	2.3×10^{-9}
W-187	2.3×10^{-3}	2.2×10^{-7}	1.1×10^{-9}
Np-239	2.0×10^{-3}	2.2×10^{-7}	1.1×10^{-9}

11.2 Liquid Waste Management Systems

The liquid waste management systems include the systems that may be used to process and dispose of liquids containing radioactive material. These include the following:

- Steam generator blowdown processing system (subsection 10.4.8);
- Radioactive waste drain system (subsection 9.3.5);
- Liquid radwaste system (WLS) (Section 11.2).

This section primarily addresses the liquid radwaste system. The other systems are also addressed in subsection 11.2.3, which discusses the expected releases from the liquid waste management systems.

The liquid radwaste system is designed to control, collect, process, handle, store, and dispose of liquid radioactive waste generated as the result of normal operation, including anticipated operational occurrences.

11.2.1 Design Basis

Subsection 1.9.1 discusses the conformance of the liquid radwaste system design with the criteria of Regulatory Guide 1.143.

11.2.1.1 Safety Design Basis

The liquid radwaste system serves no safety-related functions except for:

- Containment isolation; see subsection 6.2.3.

- Draining the passive core cooling system compartments to the containment sump to prevent flooding of these compartments and possible immersion of safety-related components.

- Back flow prevention check valves in the drain lines from the chemical and volume control system compartment and the passive core cooling system compartments to the containment sump, which prevent cross flooding of these compartments. Each drain line has two check valves in series so that a single failure does not compromise the back flow prevention safety function. See subsection 6.3.3.3.2 for a discussion of containment flooding.

11.2.1.2 Power Generation Design Basis

11.2.1.2.1 Capacity

The liquid radwaste system provides holdup capacity as shown in Table 11.2-2, and permanently installed processing capacity of 75 gpm through the ion exchange/filtration train. This is adequate capacity to meet the anticipated processing requirements of the plant. The projected flows of various liquid waste streams to the liquid radwaste system under normal conditions are identified in Table 11.2-1.

The liquid radwaste system design can accept equipment malfunctions without affecting the capability of the system to handle both anticipated liquid waste flows and possible surge load due to excessive leakage. Table 11.2-4 contains information on the surge capacity of individual tanks.

Portions of the liquid radwaste system may become unavailable as a result of the malfunctions listed in subsection 11.2.1.2.2.

Ample surge capacity of the system, provisions for using mobile processing equipment and the low load factor of the processing equipment permits the system to accommodate waste until failures can be repaired and normal plant operation resumed. In addition, the liquid radwaste system is designed to accommodate the anticipated operational occurrences described in subsection 11.2.1.2.3.

11.2.1.2.2 Failure Tolerance

11.2.1.2.2.1 Pump Failure

Where operation is not essential and surge capacity is available, a single pump is provided. This applies to most applications in the liquid radwaste system. Two reactor coolant drain tank pumps and two containment sump pumps are provided because the relative inaccessibility of the containment during power operation would hinder maintenance. The containment sump pumps are submersible pumps with permanently lubricated bearings and mechanical seals. To protect them from damage due to loss of suction, each pump is interlocked to stop on a low level condition in the sump. The reactor coolant drain tank pumps are vertical sump type pumps with motors above the reactor coolant drain tank shaft coupled to pumps submersed in the liquid within the reactor coolant drain tank. This arrangement minimizes contamination of the motors and permits removal and maintenance of the motors outside of the radiation area.

Process pumps located outside containment are air-operated, double diaphragm type. These pumps are capable of significant suction lifts, and can thus be located on or near the top of the associated waste tank, with internal suction piping. They can pump slurries with high solids fractions, run deadheaded, and run dry without damage. In addition, they can operate over a wide range of hydraulic conditions by varying the driving air input. This makes it possible to fulfill many different applications with a single pump model, thereby facilitating maintenance and reducing the inventory of spare parts.

11.2.1.2.2.2 Filter or Ion Exchanger Plugging

Instrumentation is provided to give indication of the pressure drop across filters and ion exchangers. Periodic checks of the pressure drops provide indication of equipment fouling, thus permitting corrective action to be taken before an excessive pressure drop is reached. Change of filter cartridges and ion exchange beds is expected to occur based upon radiation survey.

11.2.1.2.3 Anticipated Operational Occurrences

11.2.1.2.3.1 High Primary Coolant System Leakage Rate

The system is designed to handle an abnormal primary coolant system leak in addition to the expected leakage during normal operation. Operation of the system is the same as for normal operation, except that the load on the system is increased.

11.2.1.2.3.2 High Use of Decontamination Water

If large quantities of water are used to decontaminate areas or equipment, the load on the liquid radwaste system is increased. However, the liquid radwaste system is designed to handle a large, continuous input to the waste holdup tanks. If the water can be discharged without processing based on sampling which shows acceptably low activity, the overall liquid radwaste system capacity is increased.

To accommodate the possible use of special decontamination fluids or very large volumes of decontamination fluids, mobile equipment is used as discussed in subsection 11.2.1.2.5.2.

11.2.1.2.3.3 Steam Generator Tube Leakage

During normal operations, steam generator blowdown is returned to the condensate system, as described in subsection 10.4.8. However, if excessive radioactivity is detected, the blowdown is diverted to the liquid radwaste system for processing and disposal.

The blowdown fluid is brought into the waste holdup tanks, which provide some surge capacity to hold the fluid during processing. It is then processed in the same fashion as, and combined with, other inputs.

In the event of a steam generator tube rupture, the condensate storage tank may also become contaminated. In this event, the tank is cleaned by the use of temporary equipment brought to the site for the purpose, as described in subsection 11.2.1.2.5.2.

11.2.1.2.3.4 Refueling

The load on the liquid radwaste system is expected to increase during refueling because of the increased level of maintenance activities in the plant, but operation is the same as for normal plant operation. There is no significant effect on the performance capability of the liquid radwaste system.

11.2.1.2.4 Controlled Release of Radioactivity

The liquid radwaste system provides the capability to reduce the amounts of radioactive nuclides released in the liquid wastes through the use of demineralization and time delay for decay of short-lived nuclides.

The assumed equipment decontamination factors appear in Table 11.2-5. Estimates of the radioactive source terms and annual average flow rate that will be processed in the liquid radwaste system or discharged to the environment during normal operation appear in Table 11.2-1.

Before radioactive liquid waste is discharged, it is pumped to a monitor tank. A sample of the monitor tank contents is analyzed, and the results are recorded. In this way, a record is kept of planned releases of radioactive liquid waste.

The liquid waste is discharged from the monitor tank in a batch operation, and the discharge flow rate is restricted as necessary to maintain an acceptable concentration when diluted by the circulating water discharge flow. These provisions preclude uncontrolled releases of radioactivity.

In addition, the discharge line contains a radiation monitor with diverse methods of stopping the discharge. The first method closes an isolation valve in the discharge line, which prevents any further discharge from the liquid radwaste system. The valve automatically closes and an alarm is actuated if the activity in the discharge stream reaches the monitor setpoint. The second method stops the monitor tank pumps.

To minimize leakage from the liquid radwaste system, the system is of welded construction except where flanged connections are required to facilitate component maintenance or to allow connection of temporary or mobile equipment. Air-operated diaphragm pumps or pumps having mechanical seals are used. These pumps minimize system leakage thereby minimizing the release of radioactive gas that might be entrained in the leaking fluid to the building atmosphere.

Provisions are made to control spills of radioactive liquids due to tank overflows. Table 11.2-3 lists the provisions for tank level indication, alarms, and overflow disposition for liquid radwaste system tanks outside containment.

The liquid radwaste system is designed so that the annual average concentration limits established by 10 CFR 20 (Appendix B, table 2, column 2) (Reference 1) for liquid releases are not exceeded during plant operation. Subsection 11.2.3 describes the calculated releases of radioactive materials from the liquid radwaste system and other portions of the liquid waste management systems resulting from normal operation.

11.2.1.2.4.2 Abnormal Operation

Subsections 11.2.1.2.2 and 11.2.1.2.3 describe the capability of the liquid radwaste system to accommodate abnormal conditions for various equipment and other anticipated operational occurrences. During these anticipated occurrences, the effectiveness of the liquid radwaste system in controlling releases of radioactivity remains unaffected, so releases are limited as during normal operation.

Subsection 11.2.3 discusses the calculated releases of radioactive materials from the liquid radwaste system for abnormal situations.

11.2.1.2.5 Equipment Design

11.2.1.2.5.1 Permanently Installed Equipment

The liquid radwaste system equipment design parameters are provided in Table 11.2-2.

The seismic design classification and safety classification for the liquid radwaste system components and structures are listed in Section 3.2. The components listed are located in the Seismic Category I Nuclear Island.

11.2.1.2.5.2 Use of Mobile and Temporary Equipment

The liquid radwaste system is designed to handle most liquid effluents and other anticipated events using installed equipment. However, for events occurring at a very low frequency or producing effluents not compatible with the installed equipment, temporary equipment may be brought into the radwaste building mobile treatment facility truck bays.

Connections are provided to and from various locations in the liquid radwaste system to these mobile equipment connections. This allows the mobile equipment to be used in series with installed equipment, as an alternate to it with the treated liquids returned to the liquid radwaste system, or as an ultimate disposal point for liquids that are to be removed from the plant site for disposal elsewhere.

The use of temporary equipment is common practice in operating plants. The radwaste building truck bays and laydown space for mobile equipment, in addition to the flexibility of numerous piping connections to the liquid radwaste system, allow the plant operator to incorporate mobile equipment in an integrated fashion.

Temporary equipment is also used to clean up the condensate storage tank if it becomes contaminated following steam generator tube leakage. This use of temporary equipment is similar to that just described, except that the equipment is used in the yard rather than in the radwaste building truck bays.

11.2.2 System Description

The liquid radwaste system, shown in Figure 11.2-1, includes tanks, pumps, ion exchangers, and filters. The liquid radwaste system is designed to process, or store for processing by mobile equipment, radioactively contaminated wastes in four major categories:

- Borated, reactor-grade, waste water -- this input is collected from the reactor coolant system (RCS) effluents received through the chemical and volume control system (CVS), primary sampling system sink drains and equipment leakoffs and drains.

- Floor drains and other wastes with a potentially high suspended solids content -- this input is collected from various building floor drains and sumps.

- Detergent wastes -- this input comes from the plant hot sinks and showers, and some cleanup and decontamination processes. It generally has low concentrations of radioactivity.

- Chemical waste -- this input comes from the laboratory and other relatively small volume sources. It may be mixed hazardous and radioactive wastes or other radioactive wastes with a high dissolved-solids content.

Nonradioactive secondary-system waste is not processed by the liquid radwaste system. Secondary-system effluent is normally handled by the steam generator blowdown processing system, as described in subsection 10.4.8, and by the turbine building drain system.

Radioactivity can enter the secondary systems from steam generator tube leakage. If significant radioactivity is detected in secondary-side systems, blowdown is diverted to the liquid radwaste system for processing and disposal.

11.2.2.1 Waste Input Streams

11.2.2.1.1 Reactor Coolant System Effluents

The effluent subsystem receives borated and hydrogen-bearing liquid from two sources: the reactor coolant drain tank and the chemical and volume control system. The reactor coolant drain tank collects leakage and drainage from various primary systems and components inside containment. Effluent from the chemical and volume control system is produced mainly as a result of reactor coolant system heatup, boron concentration changes and RCS level reduction for refueling.

Input collected by the effluent subsystem normally contains hydrogen and dissolved radiogases. Therefore, it is routed through the liquid radwaste system vacuum degasifier before being stored in the effluent holdup tanks.

The liquid radwaste system degasifier can also be used to degas the reactor coolant system before shutdown by operating the chemical and volume control system in an open loop configuration. This is done by taking one of the effluent holdup tanks out of normal waste service and draining. Then normal chemical and volume control system letdown is directed through the degasifier to the dedicated effluent holdup tank. From there, it is pumped back to the suction of the chemical and volume control system makeup pumps with the effluent holdup tank pump. The makeup pumps return the fluid to the reactor coolant system in the normal fashion. This process is continued as necessary for degassing the reactor coolant system as described in subsection 9.3.6.

The input to the reactor coolant drain tank is potentially at high temperature. Therefore, provisions are made for recirculation through a heat exchanger for cooling. The tank is inerted with nitrogen and is vented to the gaseous radwaste system. Transfer of water from the reactor coolant drain tank is controlled to maintain an essentially fixed tank level to minimize tank pressure variation.

Reactor coolant system effluents from the chemical and volume control system letdown line or the reactor coolant drain subsystem pass through the vacuum degasifier, where dissolved hydrogen and fission gases are removed. These gaseous components are sent via a water separator to the gaseous radwaste system. A degasifier discharge pump then transfers the liquid to the currently selected effluent holdup tank. If flows from the letdown line and the reactor coolant drain tank are routed to the degasifier concurrently, the letdown flow has priority and the drain tank input is automatically suspended.

In the event of abnormally high degasifier water level, inputs are automatically stopped by closing the letdown control and containment isolation valves.

The effluent holdup tanks vent to the radiologically controlled area ventilation system and, in abnormal conditions, may be purged with air to maintain a low hydrogen gas concentration in the tanks' atmosphere. Hydrogen monitors are included in the tanks vent lines to alert the operator of elevated hydrogen levels.

The contents of the effluent holdup tanks may be recirculated and sampled, recycled through the degasifier for further gas stripping, returned to the reactor coolant system via the chemical and volume control system makeup pumps, discharged to the mobile treatment facility, processed through the ion exchangers, or directed to the monitor tanks for discharge without treatment.

Processing through the ion exchangers is the normal mode.

The AP1000 liquid radwaste system processes waste with an upstream filter followed by four ion exchange resin vessels in series. Any of these vessels can be manually bypassed and the order of the last two can be interchanged, so as to provide complete usage of the ion exchange resin.

The top of the first vessel is normally charged with activated carbon, to act as a deep-bed filter and remove oil from floor drain wastes. Moderate amounts of other wastes can also be routed through this vessel. It can be bypassed for processing of relatively clean waste streams. This vessel is somewhat larger than the other three, with an extra sluice connection to allow the top bed of activated carbon to be removed. This feature is associated with the deep bed filter function of the vessel; the top layer of activated carbon collects particulates, and the ability to remove it without disturbing the underlying zeolite bed minimizes solid-waste production.

The second, third and fourth beds are in identical ion exchange vessels, which are selectively loaded with resin, depending on prevailing plant conditions.

After deionization, the water passes through an after-filter where radioactive particulates and resin fines are removed. The processed water then enters one of three monitor tanks. When one of the monitor tanks is full, the system is automatically realigned to route processed water to another tank.

The contents of the monitor tank are recirculated and sampled. In the unlikely event of high radioactivity, the tank contents are returned to a waste holdup tank for additional processing.

Normally, however, the radioactivity will be well below the discharge limits, and the dilute boric acid is discharged for dilution to the circulating water blowdown. The discharge flow rate is set to limit the boric acid concentration in the circulating water blowdown stream to an acceptable concentration for local requirements. Detection of high radiation in the discharge stream stops the discharge flow and operator action is required to re-establish discharge. The raw water system which provides makeup for the circulating water system is used as a backup source for dilution water when cooling tower blowdown is not available for the discharge path.

11.2.2.1.2 Floor Drains and Other Wastes with Potentially High Suspended Solid Contents

Potentially contaminated floor drain sumps and other sources that tend to be high in particulate loading are collected in the waste holdup tank. Additives may be introduced to the tank to improve filtration and ion exchange processes. Tank contents may be recirculated for mixing and sampling. The tanks have sufficient holdup capability to allow time for realignment and maintenance of the process equipment.

The waste water is processed through the waste pre-filter to remove the bulk of the particulate loading. Next it passes through the ion exchangers and the waste after-filter before entering a monitor tank. The monitor tank contents are sampled and, if necessary, returned to a waste holdup tank or recirculated directly through the filters and ion exchangers.

Waste water meeting the discharge limits is discharged to the circulating water blowdown through a radiation detector that stops the discharge if high radiation is detected.

11.2.2.1.3 Detergent Wastes

The detergent wastes from the plant hot sinks and showers contain soaps and detergents. These wastes are generally not compatible with the ion exchange resins described in subsections 11.2.2.1.1 and 11.2.2.1.2. The detergent wastes are not processed and are collected in the chemical waste tank. If the detergent wastes activity is low enough, the wastes can be discharged without processing.

When sufficient detergent wastes are produced and processing is necessary, mobile processing equipment is brought into one of the radwaste building mobile systems facility truck bays provided for this purpose.

11.2.2.1.4 Chemical Wastes

Inputs to the chemical waste tank normally are generated at a low rate. These wastes are only collected; no internal processing is provided. Chemicals can be added to the tank for pH or other adjustment. Since the volume of these wastes is low, they can be treated by the use of mobile equipment or by shipment offsite.

11.2.2.1.5 Steam Generator Blowdown

Steam generator blowdown is normally accommodated within the steam generator blowdown system, which is described in subsection 10.4.8.

If steam generator tube leakage results in significant levels of radioactivity in the steam generator blowdown stream, this stream is redirected to the liquid radwaste system for treatment before release. In this event, one of the waste holdup tanks is drained to prepare it for blowdown processing. The blowdown stream is brought into that holdup tank, and continuously or in batches pumped through the waste ion exchangers. The number of ion exchangers in service is determined by the operator to provide adequate purification without excessive resin usage. The blowdown is then collected in a monitor tank, sampled, and discharged in a monitored fashion.

11.2.2.2 Other Operations

11.2.2.2.1 Sampling

Grab sampling taps are provided where required to monitor influent boron and radioactivity concentrations; to monitor performance of various components; to determine tank water characteristics before transfer, processing or discharge; to verify performance of the on-line analyzers; and to collect samples of discharges to the environs for analysis and documentation. Samples are taken in low radiation areas.

11.2.2.2.2 Tank Cleaning

Extraordinary measures for tank cleaning are not normally required because the pumps take suction from the low point of the tank, and the tank bottoms are sloped so that the tank can be fully drained. Recirculation connections are provided to allow the tanks to be effectively mixed. Also, the air-operated double-diaphragm pumps used can pump air, water or slurries without damage, and can run dry to clear the bottoms of the tanks.

Provisions are made for tank cleaning using a portable tank cleaning rig. Suction is taken from the tank bottom via a temporary hose. The pump discharge passes through a filter and the hose to a tank cleaning lance, which is manually inserted through a manway on the tank. The operator can direct the high-velocity water throughout the inside of the tank.

11.2.2.3 Component Description

The general descriptions and summaries of the design basis requirements for the liquid radwaste system components follow. Table 11.2-2 contains the operating parameters for the liquid radwaste system components.

Additional information regarding the applicable codes and classifications is also available in Section 3.2.

11.2.2.3.1 Liquid Radwaste System Pumps

Reactor Coolant Drain Tank Pumps

Two full-capacity, stainless steel, reactor coolant drain tank pumps recirculate the reactor coolant drain tank contents for cooling and to discharge the reactor coolant drain tank contents to the degasifier or to an effluent holdup tank. These vertical sump pumps have permanently lubricated bearings and mechanical seals. The pumps start and stop on high and low level.

Containment Sump Pumps

Two full-capacity containment sump pumps are provided. These pumps discharge the containment sump contents to the waste holdup tank. These submersible sump pumps have permanently lubricated bearings and mechanical seals. The pumps start and stop on high and low level.

Degasifier Vacuum Pumps

Two stainless steel, full-capacity, liquid ring type, degasifier vacuum pumps maintain the degasifier at a low pressure for efficient gas stripping.

These liquid ring pumps use water as the compressant. The water is recycled to minimize consumption. Excess water from vapor condensation is discharged to an effluent holdup tank.

Degasifier Separator Pump

Two full capacity centrifugal pumps are provided to discharge recovered compressor water from the degasifier separator back to the degasifier vacuum pumps. The pump also serves to discharge any excess compressor water accumulation in the separator to an effluent holdup tank. The pumps start and stop to share the duty. The pump is constructed of stainless steel and has a mechanical seal.

Other Pumps

The following air-operated double-diaphragm pumps are mounted near the associated tanks with internal suction piping. Construction is of stainless steel, with elastomeric diaphragms.

- Degasifier discharge pumps (2)
- Effluent holdup tank pumps (2)
- Waste holdup tank pumps (2)
- Monitor tank pumps (3)
- Chemical waste tank pump (1)

11.2.2.3.2 Liquid Radwaste System Heat Exchangers

Reactor Coolant Drain Tank Heat Exchanger

One horizontal U-tube heat exchanger is provided. The heat exchanger has a flanged tubesheet that permits removal of the tube bundle for inspection and cleaning.

The heat exchanger is designed to prevent the reactor coolant drain tank contents from boiling with hot leakage influent as shown in Table 11.2-4.

The reactor coolant drain tank contents flow through the tubes which are stainless steel component cooling water flows through the carbon steel shell.

Vapor Condenser

One horizontal U-tube heat exchanger assists in drying the gases drawn out of the liquid waste by the vacuum pump, before they are sent to the gaseous radwaste system. As the gas bearing water cascades down through the packing in the degasifier vessel, it boils in the low pressure. To minimize the size of the vacuum pumps, a vapor condenser is provided between the degasifer vessel and the vacuum pumps. In the vapor condenser, most of the water vapor is condensed out of the gas stream before it enters the vacuum pump. The vapor condenser is cooled by chilled

water. Chilled water flows through the tubes, which are stainless steel. Water vapor condenses on the tubes and drains through a subcooling section in the stainless steel shell. The non-condensible gases and condensate are recombined in a common pipe leading to the suction of the liquid ring type vacuum pumps.

11.2.2.3.3 Liquid Radwaste System Tanks

Reactor Coolant Drain Tank

One reactor coolant drain tank is provided. The tank is sized to accommodate two vertical sump type pumps and to have a volume above the normal operating water level sufficient to accept the influent rate shown in Table 11.2-4.

The reactor coolant drain tank is a stainless steel, horizontal, cylindrical tank with dished heads. It is provided with a vacuum breaker to prevent excess external pressure during containment leak testing. It is protected from excess internal pressure by a relief valve which vents to the containment sump.

Containment Sump

The containment sump is a stainless steel, rectangular sump tank designed for embedment in concrete. The containment sump is sized as shown in Table 11.2-4.

Degasifier Column

A one-stage, stainless steel degasifier column is provided. The degasifier column is designed to meet the performance parameters shown in Table 11.2-5.

Agitation and surface exposure are accomplished by spraying the influent onto the top of a column of packing which breaks up the flow and spreads it into thin films as it cascades downward. The low pressure causes the inlet water to boil. The flashed vapor accompanies the gas bearing water downward through the packing. Exposure to low pressure draws out the non-condensible gases consistent with Henry's Law and they pass out the vacuum connection. The vacuum connection is located near the last point of contact with the degassed water where the vacuum is greatest and conditions are least conducive to reabsorption. A stainless steel mesh demister is provided at the vessel vacuum connection to remove water droplets which are entrained in the gas/vapor mixture as it is exiting to the vapor condenser.

Degasifier Separator

One stainless steel separator is provided. It is designed to remove compressor water from the vacuum pump discharge flow for reuse. It also serves as a silencer.

Effluent Holdup Tanks

These stainless steel tanks contain effluent waste prior to processing. They are horizontal cylinders with internal pump suction piping at the low point of the tank, and with side manways for maintenance.

Waste Holdup Tanks

These stainless steel tanks contain floor and equipment drain waste before processing. They are vertical cylinders with internal pump suction piping at the low points of the tanks and with side manways for maintenance.

Monitor Tanks

These stainless steel tanks contain processed waste before discharge. They are vertical cylinders with internal pump suction piping at the low points of the tanks and with side manways for maintenance.

Chemical Waste Tank

This stainless steel tank contains chemical waste and hot sinks and shower drains before processing via mobile equipment. The configuration is a vertical cylinder with internal pump suction piping at the low point of the tank and with a side manway for maintenance.

11.2.2.3.4 Liquid Radwaste System Ion Exchangers

Four ion exchange vessels are provided, with resin volumes as shown in Table 11.2-2. The media will be selected by the Combined License holder to optimize system performance. They are stainless steel, vertical, cylindrical pressure vessels with inlet and outlet process nozzles plus connections for resin addition, sluicing, and draining. The process outlet and flush water outlet connections are equipped with resin retention screens designed to minimize pressure drop.

11.2.2.3.5 Liquid Radwaste System Filters

Waste Pre-Filter

This filter is provided to collect particulate matter in the process stream before ion exchange. The unit is constructed of stainless steel and has disposable filter bags.

Waste After-Filter

This filter is provided downstream of the ion exchangers to collect particulate matter, such as resin fines. The unit is constructed of stainless steel and has disposable filter cartridges.

11.2.2.4 Instrumentation Design

Instrumentation readout is available in the main control room and on portable display and control panels.

Alarms are provided to the data display system including a radwaste system annunciator in the main control room.

Pressure indicators provide pressure drops across demineralizers, filters, and strainers.

Releases to the environment are monitored for radioactivity. Section 11.5 describes this instrumentation.

Each tank is provided with level instrumentation that actuates an alarm on high liquid level in the tank, thus warning of potential tank overflow. High level in redundant tank pairs also diverts the flow to the standby tank. Table 11.2-3 provides a summary of the tank level alarms.

11.2.2.5 System Operation and Performance

11.2.2.5.1 Reactor Coolant System Effluent Processing

11.2.2.5.1.1 Reactor Coolant Systems Effluent: Letdown Line

Chemical and volume control system letdown is directed to the degasifier. This letdown flow automatically takes priority by causing isolation of influent to the degasifier from the reactor coolant drain tank pumps to prevent the design capacity of the degasifier from being exceeded.

When the degasifier and waste gas system are placed in operation one of the degasifier vacuum pumps operates to maintain a vacuum in the degasifier column. The degasifier separator pump operates to return compressor water to the vacuum pump. The degasifier separator vents to the gaseous radwaste system. Its level is automatically controlled by discharging excess water (due to condensation of vapor carryover from the degasifier column) to an effluent holdup tank. In the event of abnormally high level, chemical and volume control system letdown flow is automatically stopped.

Two effluent holdup tanks are provided. One is aligned to receive inputs. When it fills to the appropriate level, an alarm alerts the operator that the tank is full and ready for processing. The inlet diversion valve automatically realigns the system to route input to the other tank upon high-high alarm.

11.2.2.5.1.2 Reactor Coolant System Effluent: Reactor Coolant Drain Tank

The reactor coolant drain tank receives input from the reactor coolant system and other drains inside containment that have the potential to contain radioactive gas or hydrogen.

Initially and after servicing, the reactor coolant drain tank is filled with demineralized water and then purged with nitrogen to dilute and displace oxygen. The tank vent to the gaseous radwaste system normally remains closed. One of the reactor coolant drain tank pumps and the discharge valve are automatically controlled to maintain reactor coolant drain tank water level within a narrow band to minimize tank pressure variation. An alarm alerts the operator if the reactor coolant drain tank reaches a temperature consistent with the design leak of saturated RCS coolant. The system automatically realigns valves and recirculates the tank contents through the reactor coolant drain tank heat exchanger.

The cumulative quantity discharged from the reactor coolant drain tank is totalized and indicated for use in reactor coolant leakage evaluations.

The discharge may have a relatively high dissolved hydrogen concentration and is therefore aligned to the degasifier. However, during reactor coolant system loop drain operations the hydrogen and radioactive gas concentrations should be low and discharge may be directly aligned to an effluent holdup tank.

11.2.2.5.1.3 Processing of the Reactor Coolant System Effluents

Each effluent holdup tank vent includes a hydrogen detector to monitor the hydrogen concentration in the tank atmosphere. In the event of high alarm, the operator initiates air purge through the tank to dilute the hydrogen gas and maintain it below the flammable limits. The tanks vent to the radiologically controlled area ventilation system.

An effluent holdup tank high level alarm alerts the operator that the tank is full and ready for processing. The inlet diversion valve automatically directs the influent to the other tank upon high-high alarm.

To process the contents of the filled tank, the effluent holdup tank pump is started to recirculate and sample the tank contents. If additional gas stripping is required, the tank contents may be recirculated through the degasifier. The degasifier functions automatically as described in subsection 11.2.2.5.1.1.

The discharge of either effluent holdup tank pump can be aligned to the suction of the chemical and volume control system makeup pumps. This mode of operation is used during reactor coolant system degassing operations. Reactor coolant from the chemical and volume control system letdown is degassed in the degasifier, collected in one of the effluent holdup tanks, and continuously pumped back to the chemical and volume control system makeup pumps. The pump returns the degassed water to the reactor coolant system.

Reactor coolant collected in an effluent holdup tank during reactor coolant system loop drain operations may also be pumped to the chemical and volume control system makeup pumps for refill of the reactor coolant system. Before beginning this process, the operator fully drains the effluent holdup tank receiving the reactor coolant so that the boron concentration of the reactor coolant system is not significantly affected.

The effluent may be transferred to the mobile treatment facility for concentration or solidification. This disposal method is used only during unusual conditions that restrict the normal processed waste discharge mode described in the following paragraphs.

The normal mode of operation is to process the effluent by ion exchange and filtration to remove the radioactive materials. The ion exchangers operate in series as described in subsection 11.2.2.1.1.

The last bed provides a polishing function and also prevents radioactivity breakthrough to the monitor tank when the upstream unit becomes exhausted. This allows the full capacity of the upstream resin beds to be used, reducing the amount of spent resin that is generated.

When the analysis of samples taken periodically downstream of the ion exchange processing indicates an increase in radioactivity above prescribed limits, the operator isolates the expended

unit(s) for resin replacement. Flow continues through the other units until a fresh resin bed is ready. When one of the last two ion exchangers has been replenished, the fresh unit is then brought online as the downstream unit.

The after-filter removes resin fines and other particulate matter that may pass through the ion exchangers. A high differential pressure alarm alerts the operator to the need for filter element replacement. Normally, filter element replacement is initiated on high radioactivity determined by periodic survey.

Process discharge is normally aligned to one of the three monitor tanks. When one of the tanks is full, an alarm alerts the operator that the tank is full and ready to be discharged. The inlet diversion valve automatically realigns the system to route processed waste to another tank upon high-high level.

The operator then starts the monitor tank pump to recirculate the tank contents and samples the processed waste. Since the ion exchangers operate in the borated saturated mode, the water contains boric acid. The radioactivity and chemistry of the processed waste is determined by sample analysis. In the unlikely event that radioactivity exceeds discharge limitations, the tank contents are returned to a waste holdup tank for reprocessing.

Once it is confirmed that the waste water is within radioactivity discharge limitations, the operator prepares the system for discharge. The operator initiates discharge by starting the monitor tank pump and opening the remotely operated discharge valve. During controlled discharge, grab samples are taken for laboratory analysis and documentation of discharge.

If the radiation monitor in the discharge line detects high radiation, the valve automatically closes. The operator is alerted to this condition by a high radiation alarm, and is required to take corrective action. A manual drain valve is opened to flush the radiation monitor and confirm low radiation before re-establishing discharge to the circulating water blowdown. Low monitor tank level automatically stops the monitor tank pump.

11.2.2.5.2 Floor Drain and Equipment Drain Waste Processing

Miscellaneous liquid wastes normally include influent from the radioactive floor drains, equipment drains and auxiliary building sump and excess water from the solid radwaste system. These wastes collect in one of two waste holdup tanks.

A high level alarm in the tank alerts the operator that the tank is full and ready to be processed. The inlet diversion valve automatically directs influents to the second waste holdup tank upon high-high level. The waste holdup tank pump is started to recirculate and sample the tank contents. Additives may be introduced to the waste holdup tank to optimize filtration and ion exchange processes.

Floor drain wastes are also brought into the waste holdup tanks from the containment sump. High sump level automatically opens the containment isolation valves and starts a pump to transfer the sump contents. Low level automatically stops the pump and closes the isolation valves. An alarm is provided to alert the operator to abnormally high containment sump level and the standby pump

is automatically started. Cumulative flow is totalized and indicated to support reactor coolant leakage analysis.

The normal mode of operation is to process the waste water through the pre-filter, ion exchangers, and after-filter to the monitoring tank as described for the reactor coolant system effluent processing. Under abnormal conditions, the waste may also be transferred directly to a mobile treatment facility.

11.2.2.5.3 Detergent Waste Processing

The detergent wastes from the plant hot sinks and showers are routed to the chemical waste tank. Normally, these wastes are sampled and confirmed suitable for discharge without processing. If processing prior to discharge is necessary, three courses of action are available. The waste water may be transferred to a waste holdup tank and processed in the same manner as other radioactively contaminated waste water. If the onsite processing capabilities are not suitable for the composition of the detergent waste, processing can be performed using mobile equipment brought into one of the truck bays of the radwaste building or the waste water can be shipped offsite for processing. After processing by mobile equipment the water may be transferred to a waste holdup tank for further processing by the onsite equipment or transferred to a monitor tank for sampling and discharge.

11.2.2.5.4 Chemical Waste Processing

Radioactively contaminated chemical wastes are collected in the chemical waste tank. Chemicals may be added to the tank for pH or other adjustment. The volume of these wastes is expected to be low. The design includes alternatives for processing or discharge of chemical wastes. They may be processed onsite without being combined with other wastes using mobile equipment. When combined with detergent wastes, they may be suitable for discharge without treatment or for processing by onsite equipment before discharge. When not suitable for onsite processing, they can be treated using mobile equipment or shipped offsite for processing. After processing by mobile equipment the water may be transferred to a waste holdup tank for further processing by the onsite equipment or transferred to a monitor tank for sampling and discharge.

11.2.2.5.5 Steam Generator Blowdown Processing

Normal steam generator blowdown processing is accommodated by the steam generator blowdown system, which is described in subsection 10.4.8.

If steam generator tube leakage results in levels of radioactivity in the blowdown stream above what can be accommodated by the secondary-side systems, this stream is directed to the liquid radwaste system. For this function, the operator aligns the steam generator blowdown system to the inlet of the waste holdup tank. The blowdown waste is then processed in the same way as other wastes.

11.2.2.5.6 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media are spent and ready to be transferred to the solid

radwaste system, the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidize in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system (WSS). Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

11.2.3 Radioactive Releases

Liquid waste is produced both on the primary side (primarily from adjustment of reactor coolant boron concentration and from reactor coolant leakage) and the secondary side (primarily from steam generator blowdown processing and from secondary side leakage). Primary and secondary coolant activity levels are provided in Section 11.1 for both the design case and the anticipated case, which is based on operating plant experience.

Except for reactor coolant system degasification in anticipation of shutdown, the AP1000 does not recycle primary side effluents for reuse. Primary effluents are discharged to the environment after processing. Fluid recycling is provided for the steam generator blowdown fluid which is normally returned to the condensate system.

11.2.3.1 Discharge Requirements

The release of radioactive liquid effluents from the plant may not exceed the concentration limits specified in Reference 1 nor may the releases result in the annual offsite dose limits specified in 10 CFR 50, Appendix I (Reference 2) being exceeded.

11.2.3.2 Estimated Annual Releases

The annual average release of radionuclides from the plant is determined using the PWR-GALE code (Reference 3). The PWR-GALE code models releases which use source terms derived from data obtained from the experience of operating PWRs. The code input parameters used in the analysis to model the AP1000 plant are listed in Table 11.2-6. The annual releases for a single-unit site are presented in Table 11.2-7.

In agreement with Reference 3, the total releases include an adjustment factor of 0.16 curies per year to account for anticipated operational occurrences. The adjustment uses the same distribution of nuclides as the calculated releases.

11.2.3.3 Dilution Factor

The dilution factor provided for the activity released is site dependent and is provided by the Combined License applicant. If the available dilution is low, the discharge rate can be reduced to maintain acceptable concentrations.

The required dilution flow is dependent on the liquid waste discharge rate and, while the monitor tank pumps have a design flow rate of 100 gpm, the discharge flow is controlled to be compatible with the available dilution flow. With a typical liquid waste release of 1925 gallons per day, the nominal circulating water blowdown flow of 6000 gpm provides sufficient dilution flow to

maintain the annual average discharge concentrations well below the effluent concentration limits. Actual plant operation is dependent on the waste liquid activity level and the available dilution flow.

11.2.3.4 Release Concentrations

The annual release data provided in Table 11.2-7 represent expected releases from the plant. To demonstrate compliance with the Reference 1 effluent concentration limits, the discharge concentrations have been evaluated for the release of a typical daily liquid waste volume of 1925 gallons per day and using the nominal circulating water blowdown flow of 6000 gpm. Table 11.2-8 lists the annual average nuclide release concentrations and the fraction of the effluent concentration limits using base GALE code assumptions. As shown in Table 11.2-8, the overall fraction of the effluent concentration limit is 0.11, which is well below the allowable value of 1.0.

The annual releases from the plant have also been evaluated based on operation with the maximum defined fuel defect level. The maximum defined fuel defect level corresponds to the Technical Specification limit on coolant activity which is based on 0.25 percent fuel defects. Table 11.2-9 lists the annual average nuclide release concentrations and the fractions of the effluent concentration limits for the maximum defined fuel defects. As shown in Table 11.2-9, the overall fraction of the effluent concentration limit for the maximum defined fuel defect level is 0.53, which is well below the allowable value of 1.0.

11.2.3.5 Estimated Doses

Estimated doses are site specific and are the responsibility of the Combined License applicant.

11.2.3.6 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the liquid radwaste system is in accordance with the overall quality assurance program described in Chapter 17.

11.2.4 Preoperational Testing

11.2.4.1 Sump Level Instrument Testing

One of the diverse methods of detecting small reactor coolant pressure boundary leaks is monitoring the containment sump level. (See subsection 5.2.5 for a full discussion.) A sump capacity calibration test is performed so the containment sump level instruments can provide a display that is correlated to the contained volume of water in the sump.

In addition to a normal level accuracy calibration of the containment sump level instruments, WLS-LT-034 and WLS-LT-035, their displays will be correlated to the volume of water during preoperational testing. A known volume of water will be added to the containment sump. The change in sump level will be measured by marking the sump wall before and after the addition of water. The change in the display of the sump level instruments will be compared to the level change measured on the sump wall. A sump level change corresponding to a volume of water

which is smaller than that released in an hour by 0.5 gpm reactor coolant system leak can be detected.

11.2.4.2 Discharge Control/Isolation Valve Testing

The AP1000 effluent discharge line includes a radiation monitor, WLS-RE-229, as described in subsection 11.5.2.3.3. A concentration of radioactivity in the effluent, which exceeds the radiation monitor setpoint, causes a high radiation signal to automatically close the discharge control/isolation valve.

A test will be performed on the liquid radwaste system discharge control/isolation valve, WLS-PL-V233, during preoperational testing. A simulated WLS-RE-229 high radiation signal will be sent to the plant control system and the discharge control/isolation valve will be observed to close.

11.2.5 Combined License Information

11.2.5.1 Liquid Radwaste Processing by Mobile Equipment

The Combined License applicant will discuss how any mobile or temporary equipment used for storing or processing liquid radwaste conforms to Regulatory Guide 1.143. For example, this includes discussion of equipment containing radioactive liquid radwaste in the nonseismic Radwaste Building.

11.2.5.2 Cost Benefit Analysis of Population Doses

The analysis performed to determine offsite dose due to liquid effluents is based upon the AP1000 generic site parameters included in Chapter 1 and Tables 11.2-5 and 11.2-6. The Combined License applicant will provide a site specific cost-benefit analysis to address the requirements of 10 CFR 50, Appendix I, regarding population doses due to liquid effluents.

11.2.5.3 Identification of Ion Exchange and Adsorbent Media

The Combined License applicant will identify the types of liquid waste ion exchange and adsorbent media to be used in the liquid radwaste system (WLS). This determination will be based on developments in ion exchange technology and specific characteristics of the liquid radwaste to be processed.

11.2.5.4 Dilution and Control of Boric Acid Discharge

The Combined License applicant will determine the rate of discharge and the required dilution to maintain acceptable concentrations. Refer to Section 11.5 for a discussion of the program to control releases.

The Combined License applicant will discuss the planned discharge flow rate for borated wastes and controls for limiting the boric acid concentration in the circulating water system blowdown.

11.2.6 References

1. "Annual Limits on Intake (ALIs) and Derived Air Concentrations (DACs) of Radionuclides for Occupational Exposure; Effluent Concentrations; Concentrations for Release to Sewerage," 10 CFR Part 20, Appendix B, Issued by 58 FR 67657, April 28, 1995.

2. "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low As Is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," 10 CFR Part 50, Appendix I.

3. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," NUREG-0017, Revision 1, March 1985.

4. ANSI/ANS-55.6-1993, "Liquid Radioactive Waste Processing Systems for Light Water Reactor Plants."

Table 11.2-1 (Sheet 1 of 2)

LIQUID INPUTS AND DISPOSITION

Collection Tank and Sources	Expected Input Rate	Activity	Basis	Disposition
1. Effluent holdup tanks				Filtered, demineralized, and discharged
Chemical and volume control system letdown	159,000 gpy	100% of reactor coolant	AP1000-specific calculations[b]	
Leakage inside containment (to reactor coolant drain tank)	10 gpd	167% of reactor coolant	ANSI/ANS-55.6	
Leakage outside containment (to effluent holdup tanks)	80 gpd	100% of reactor coolant	ANSI/ANS-55.6	
Sampling drains	200 gpd	100% of reactor coolant	ANSI/ ANS-55.6[a]	
2. Waste holdup tank				Filtered, demineralized and discharged
Reactor containment cooling	500 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Spent fuel pool liner leakage	25 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Misc. drains	675 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	

Table 11.2-1 (Sheet 2 of 2)

LIQUID INPUTS AND DISPOSITION

Collection Tank and Sources	Expected Input Rate	Activity	Basis	Disposition
3. Detergent waste				Filtered, monitored, and discharged. If necessary, processed with mobile equipment.
Hot shower	0 gpd	10^{-7} μCi/g	ANSI/ANS-55.6	
Hand wash	200 gpd	10^{-7} μCi/g	ANSI/ANS-55.6	
Equipment and area decontamination	40 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Laundry			Offsite laundry	
4. Chemical wastes	2 gpd	≤ reactor coolant	Estimate	Processed with mobile equipment

Notes:

a. ANSI/ANS-55.6 identifies sampling drains activity of 5 percent of reactor coolant; 100 percent is used as a conservative input for GALE Code analysis.

b. Average letdown for all normal reactor fuel cycle operations; initial heatup, dilutions and borations.

Table 11.2-2 (Sheet 1 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Pumps	
Containment sump pumps	
Number	2
Type	Submersible centrifugal
Design pressure (psig)	15 external
Design temperature (°F)	250
Design flow (gpm)	100
Material	Stainless steel
Reactor coolant drain tank pumps	
Number	2
Type	Vertical sump type, centrifugal
Design pressure (psig)	15 external
Design temperature (°F)	250
Design flow (gpm)	100
Material	Stainless steel
Degasifier separator pump (part of vacuum degasifier)	
Number	2
Type	Centrifugal
Design pressure (psig)	125
Design temperature (°F)	200
Design flow (gpm)	7
Material	Stainless steel

Table 11.2-2 (Sheet 2 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Pumps	
Standard waste processing pump Standard waste processing pump used for: Number — Application 2 — Degasifier discharge pumps 2 — Effluent holdup tank pumps 2 — Waste holdup tank pumps 3 — Monitor tank pumps 1 — Chemical waste tank pump	
Type	Air-operated, double-diaphragm
Design pressure (psig)	125
Design temperature (°F)	200
Design flow (gpm)	100 (can be varied by varying air supply flow)
Material	Stainless steel body, Elastomeric diaphragm
Degasifer vacuum pumps (part of vacuum degasifier package)	
Number	2
Type	Liquid ring
Design pressure (psig)	125
Design temperature (°F)	200
Design flow (scfm)	0.5 steady, 150 hogging
Material	Stainless steel

Table 11.2-2 (Sheet 3 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Filters	
Waste pre-filter	
Number	1
Type	Disposable bag
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Particle size (micron, 98% retention)	25
Materials	
Housing	Stainless steel
Filter	Polypropylene/pleated paper
Waste after-filter	
Number	1
Type	Disposable bag or cartridge
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Particle size (micron, 98% retention)	0.5
Materials	
Housing	Stainless steel
Filter medium	Polypropylene/pleated paper

Table 11.2-2 (Sheet 4 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Heat Exchangers	
Reactor Coolant drain tank heat exchanger	
Number	1
Type	Horizontal U-tube
Design pressure (psig)	150
Design temperature (°F)	250 tubeside, 200 shellside
Design flow (lb/hr)	48,700 tubeside, 62,200 shellside
Heat Transfer Design Case	
Temperature inlet (°F)	175 tubeside, 95 shellside
Temperature outlet (°F)	143 tubeside, 120 shellside
Material	SS tubeside, CS shellside
Vapor condenser	
Number	1
Type	Horizontal U-tube
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (lb/hr)	100,000 tubeside, 1700 shellside
Heat Transfer Design Case	
Temperature inlet (°F)	45 tubeside, 84 shellside
Temperature outlet (°F)	63 tubeside, 60 shellside
Material	SS

Table 11.2-2 (Sheet 5 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Ion Exchangers	
Deep bed filter	
Number	1
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Nominal resin volume (ft^3)	50
Material	Stainless steel
Resin type	Layered: Activated charcoal on zeolite resin (Adjustable for plant conditions)
Process decontamination factors	See Table 11.2-5
Waste ion exchangers	
Number	3
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (lb/hr)	75
Nominal resin volume (ft^3)	30
Materials	Stainless steel
Resin type	One cation, Two mixed (Adjustable for plant conditions)
Process decontamination factors	See Table 11.2-5

Table 11.2-2 (Sheet 6 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Tanks	
Reactor coolant drain tank	
Number	1
Nominal volume (gal)	900
Type	Horizontal
Design pressure (psig)	10 internal, 15 external
Material	Stainless steel
Containment sump	
Number	1
Nominal volume (gal)	220
Type	Rectangular
Design pressure (psig)	Atmospheric
Design temperature (°F)	200
Material	Stainless steel
Effluent holdup tanks	
Number	2
Nominal volume (gal)	28,000
Type	Horizontal
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Waste holdup tanks	
Number	2
Nominal volume (gal)	15,000
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel

Table 11.2-2 (Sheet 7 of 7)

COMPONENT DATA – LIQUID RADWASTE SYSTEM

Monitor tanks	
Number	3
Nominal volume (gal)	15,000
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Chemical waste tank	
Number	1
Nominal volume (gal)	8,900
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Degasifier separator (part of vacuum degasifier package)	
Number	1
Nominal volume (gal)	45
Type	Vertical
Design pressure (psig)	75
Design temperature (°F)	200
Material	Stainless steel
Degasifier column (part of vacuum degasifier package)	
Number	1
Nominal volume (gal)	900
Type	Vertical
Design pressure (psig)	75 internal 15 external
Design temperature (°F)	150
Material	Stainless steel

Table 11.2-3

SUMMARY OF TANK LEVEL INDICATION, LEVEL ANNUNCIATORS, AND OVERFLOWS

Tank	Level Indication Location (Note 3)	Alarm Location	Alarm	Overflow To
Effluent holdup	MCR	MCR	High	Room drains to auxiliary building sump which is pumped to waste holdup tank (Note 2)
Waste holdup	MCR	MCR	High	Room (Note 2)
Chemical waste	MCR	MCR	High	Room (Note 2)
Monitor	MCR	MCR	High	Room (Note 2)

Notes:
1. MCR = main control room
2. Room is within auxiliary building (seismic Category 1) and water-tight with curbs or walls of sufficient height to contain the entire contents of the contained tank.
3. Monitoring of the liquid radwaste system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication and control are available on portable displays which may be connected to the data display and processing system. See Chapter 7.

Table 11.2-4

TANK SURGE CAPACITY

Reactor Coolant Drain Tank

- Sized to accept 10 gpm of saturated reactor coolant for 1 hour without discharge or overflow.
- Reactor coolant drain tank heat exchanger designed to limit the temperature to less than 175°F with this input assumed to be at 580°F.

Containment Sump

- Sized to allow collection of 160 gallons of water between pumping cycles.

Effluent Holdup Tanks

- Sized to allow (together) a back-to-back plant shutdown and restart without delay at any time during the first 85 percent of core life. This operation requires nominal processing of the effluent monitor tanks and normal discharge with temporary storage of waste fluid in the cask loading pit.
- Sized to allow (together) a single plant shutdown and restart without delay at any time during the first 80 percent of core life. This operation requires nominal processing to the monitor tanks, but no discharge from the plant.

Other Tanks

- Sized based on accommodating maximum input without operator intervention for reasonable lengths of time.

Table 11.2-5

DECONTAMINATION FACTORS

Decontamination factors assumed per NUREG-0017, Revision 1 (PWR-GALE code input) to be as follows:

Resin Type/Component	Iodine	Cs/Rb	Other
Zeolite/deep bed filter (Note 1)	1	100	1
Cation/waste ion exchanger 1	1	10	10
Mixed/waste ion exchanger 2	100	2 (Note 2)	100
Mixed/waste ion exchanger 3	10	10 (Note 2)	10 (Note 2)

Other components not directly involved in discharge from the plant:

Degasifier Column

Reduce hydrogen by a factor of 40

Assuming inlet flow of 100 gpm at 130°F.

Notes:
1. This component is not included in NUREG-0017. DFs based upon "Reduction of Cesium and Cobalt Activity in Liquid Radwaste Processing Using Clinoptilolite Zeolite at Duke Power Company," by O.E. Ekechokwu, et al., Proc. Waste Management '92, Tucson, Arizona, March 1992, University of Arizona, Tucson.
2. Credit for this decontamination factor not taken in determination of anticipated annual releases.

Table 11.2-6 (Sheet 1 of 3)

INPUT PARAMETERS FOR THE GALE COMPUTER CODE

Thermal power level (MWt)	3400
Mass of primary coolant (lb)	4.35×10^5
Primary system letdown rate (gpm)	100
Letdown cation demineralizer flow rate, annual average (gpm)	10
Number of steam generators	2
Total steam flow (lb/hr)	14.97×10^6
Mass of liquid in each steam generator (lb)	1.75×10^5
Total blowdown rate (lb/hr)	4.2×10^4
Blowdown treatment method	0[(1)]
Condensate demineralizer regeneration time	N/A
Condensate demineralizer flow fraction	0.33
Primary coolant bleed for boron control	
Bleed flow rate (gpd)	435
Decontamination factor for I	10^3
Decontamination factor for Cs and Rb	10^3
Decontamination factor for others	10^3
Collection time (day)	30
Process and discharge time (day)	0
Fraction discharged	1.0
Equipment Drains and Clean Waste	
Equipment drains flow rate (gpd)	290
Fraction of reactor coolant activity	1.023
Decontamination factor for I	10^3
Decontamination factor for Cs and Rb	10^3
Decontamination factor for others	10^3
Collection time (day)	30
Process and discharge time (day)	0
Fraction discharged	1.0

Table 11.2-6 (Sheet 2 of 3)

INPUT PARAMETERS FOR THE GALE COMPUTER CODE

Dirty Waste	
Dirty waste input flow rate (gpd)	1200
Fraction of reactor coolant activity	0.001
Decontamination factor for I	10^3
Decontamination factor for Cs and Rb	10^3
Decontamination factor for others	10^3
Collection time (day)	10
Process and discharge time (day)	0
Fraction discharged	1.0
Blowdown Waste	
Blowdown fraction processed	1
Decontamination factor for I	100
Decontamination factor for Cs and Rb	10
Decontamination factor for others	100
Collection time	N/A
Process and discharge time	N/A
Fraction discharged	0
Regenerant Waste	N/A

Table 11.2-6 (Sheet 3 of 3)

INPUT PARAMETERS FOR THE GALE COMPUTER CODE

Gaseous Waste System	
Continuous gas stripping of full letdown purification flow	None
Holdup time for xenon, (days)	38
Holdup time for krypton, (days)	2
Fill time of decay tanks for gas stripper	N/A
Gas waste system: HEPA filter	None
Auxiliary building: Charcoal filter	None
Auxiliary building: HEPA filter	None
Containment volume (ft^3)	2.1×10^6
Containment atmosphere internal cleanup rate (ft^3/min)	N/A
Containment high volume purge:	
Number of purges per year (in addition to two shutdown purges)	0
Charcoal filter efficiency (%)	90
HEPA filter efficiency (%)	99
Containment normal continuous purge rate (ft^3/min) (based on 20 hrs/week at 4000 ft^3/min)	500
Charcoal filter efficiency (%)	90
HEPA filter efficiency (%)	99
Fraction of iodine released from blowdown tank vent	N/A
Fraction of iodine removed from main condenser air ejector release	0.0
Detergent Waste Decontamination Factor	0.0(2)

Notes:

1. A "0" is input to indicate that the blowdown is recycled to the condensate system after treatment in the blowdown system.
2. A "0.0" is input to indicate that the plant does not have an onsite laundry.

Table 11.2-7 (Sheet 1 of 2)

RELEASES TO DISCHARGE CANAL (Ci/Yr) CALCULATED BY GALE CODE

Nuclide	Shim Bleed	Misc. Wastes	Turbine Building	Combined Releases	Total Releases(1)
Corrosion and Activation Products					
Na-24	0.00053	0.0(2)	0.00008	0.00061	0.00163
Cr-51	0.00068	0.0	0.0	0.00070	0.00185
Mn-54	0.00048	0.0	0.0	0.00049	0.00130
Fe-55	0.00037	0.0	0.0	0.00037	0.00100
Fe-59	0.00008	0.0	0.0	0.00008	0.00020
Co-58	0.00125	0.0	0.00001	0.00126	0.00336
Co-60	0.00016	0.0	0.0	0.00017	0.00044
Zn-65	0.00015	0.0	0.0	0.00015	0.00041
W-187	0.00004	0.0	0.0	0.00005	0.00013
Np-239	0.00008	0.0	0.0	0.00009	0.00024
Fission Products					
Br-84	0.00001	0.0	0.0	0.00001	0.00002
Rb-88	0.00010	0.0	0.0	0.00010	0.00027
Sr-89	0.00004	0.0	0.0	0.00004	0.00010
Sr-90	0.0	0.0	0.0	0.0	0.00001
Sr-91	0.00001	0.0	0.0	0.00001	0.00002
Y-91m	0.0	0.0	0.0	0.00001	0.00001
Y-93	0.00003	0.0	0.0	0.00002	0.00009
Zr-95	0.00010	0.0	0.0	0.00005	0.00023
Nb-95	0.00009	0.0	0.0	0.00005	0.00021
Mo-99	0.00028	0.0	0.00001	0.00013	0.00057
Tc-99m	0.00027	0.0	0.00001	0.00013	0.00055
Ru-103	0.00183	0.00001	0.00002	0.00185	0.00493
Rh-103m	0.00183	0.00001	0.00002	0.00185	0.00493
Ru-106	0.02729	0.00011	0.00021	0.02761	0.07352
Rh-106	0.02729	0.00011	0.00021	0.02761	0.07352
Ag-110m	0.00039	0.0	0.0	0.00039	0.00105
Ag-110	0.00005	0.0	0.0	0.00005	0.00014
Te-129m	0.00004	0.0	0.0	0.00005	0.00012
Te-129	0.00006	0.0	0.0	0.00006	0.00015

Table 11.2-7 (Sheet 2 of 2)

RELEASES TO DISCHARGE CANAL (Ci/Yr) CALCULATED BY GALE CODE

Nuclide	Shim Bleed	Misc. Wastes	Turbine Building	Combined Releases	Total Releases(1)
Te-131m	0.00003	0.0	0.0	0.00003	0.00009
Te-131	0.00001	0.0	0.0	0.00001	0.00003
I-131	0.00512	0.00004	0.00015	0.00531	0.01413
Te-132	0.00009	0.0	0.0	0.00009	0.00024
I-132	0.00054	0.00001	0.00007	0.00062	0.00164
I-133	0.00211	0.00003	0.00038	0.00252	0.00670
I-134	0.00030	0.0	0.0	0.00031	0.00081
Cs-134	0.00370	0.00001	0.00002	0.00373	0.00993
I-135	0.00144	0.00002	0.00041	0.00187	0.00497
Cs-136	0.00023	0.0	0.0	0.00024	0.00063
Cs-137	0.00496	0.00001	0.00003	0.00500	0.01332
Ba-137m	0.00464	0.00001	0.00002	0.00468	0.01245
Ba-140	0.00203	0.00001	0.00003	0.00207	0.00552
La-140	0.00272	0.00002	0.00005	0.00279	0.00743
Ce-141	0.00003	0.0	0.0	0.00004	0.00009
Ce-143	0.00006	0.0	0.00001	0.00007	0.00019
Pr-143	0.00005	0.0	0.0	0.00005	0.00013
Ce-144	0.00117	0.0	0.00001	0.00119	0.00316
Pr-144	0.00117	0.0	0.00001	0.00119	0.00316
All others	0.00001	0.0	0.0	0.00001	0.00002
Total (except tritium)	0.09398	0.00043	0.00182	0.09623	0.25623
Tritium release = 1010 curies per year					

Notes:

1. The release totals include an adjustment of 0.16 Ci/yr added by PWR-GALE code to account for anticipated operational occurrences such as operator errors that result in unplanned releases.
2. An entry of 0.0 indicates that the value is less than 10^{-5} Ci/yr.

Table 11.2-8 (Sheet 1 of 2)

COMPARISON OF ANNUAL AVERAGE LIQUID RELEASE CONCENTRATIONS WITH 10 CFR 20 FOR EXPECTED RELEASES EFFLUENT CONCENTRATION LIMITS

Nuclide	Discharge Concentration (μCi/ml)(1)	Effluent Concentration Limit (μCi/ml)(2)	Fraction of Concentration Limit
Na-24	1.7E-10	5.0E-05	3.4E-06
Cr-51	1.9E-10	5.0E-04	3.9E-07
Mn-54	1.4E-10	3.0E-05	4.5E-06
Fe-55	1.0E-10	1.0E-04	1.0E-06
Fe-59	2.1E-11	1.0E-05	2.1E-06
Co-58	3.5E-10	2.0E-05	1.8E-05
Co-60	4.6E-11	3.0E-06	1.5E-05
Zn-65	4.3E-11	5.0E-06	8.6E-06
W-187	1.4E-11	3.0E-05	4.5E-07
Np-239	2.5E-11	2.0E-05	1.3E-06
Br-84	2.1E-12	4.0E-04	5.2E-09
Rb-88	2.8E-11	4.0E-04	7.1E-08
Sr-89	1.0E-11	8.0E-06	1.3E-06
Sr-91	2.1E-12	2.0E-05	1.0E-07
Y-91m	1.0E-12	2.0E-03	5.2E-10
Y-93	1.2E-11	2.0E-05	5.8E-07
Zr-95	2.9E-11	2.0E-05	1.5E-06
Nb-95	2.6E-11	3.0E-05	8.7E-07
Mo-99	8.4E-11	2.0E-05	4.2E-06
Tc-99m	8.0E-11	1.0E-03	8.0E-08
Ru-103	5.2E-10	3.0E-05	1.7E-05
Rh-103m	5.2E-10	6.0E-03	8.6E-08
Ru-106	7.7E-09	3.0E-06	2.6E-03

Table 11.2-8 (Sheet 2 of 2)

COMPARISON OF ANNUAL AVERAGE LIQUID RELEASE CONCENTRATIONS WITH 10 CFR 20 FOR EXPECTED RELEASES EFFLUENT CONCENTRATION LIMITS

Nuclide	Discharge Concentration (μCi/ml)(1)	Effluent Concentration Limit (μCi/ml)(2)	Fraction of Concentration Limit
Ag-100m	1.1E-10	6.0E-06	1.8E-05
Te-129m	1.3E-11	7.0E-06	1.8E-06
Te-129	1.6E-11	4.0E-04	3.9E-08
Te-131m	9.4E-12	8.0E-06	1.2E-06
Te-131	3.1E-12	8.0E-05	3.9E-08
I-131	1.5E-09	1.0E-06	1.5E-03
Te-132	2.5E-11	9.0E-06	2.8E-06
I-132	1.7E-10	1.0E-04	1.7E-06
I-133	7.0E-10	7.0E-06	1.0E-04
I-134	8.5E-11	4.0E-04	2.1E-07
Cs-134	1.0E-09	9.0E-07	1.2E-03
I-135	5.2E-10	3.0E-05	1.7E-05
Cs-136	6.6E-11	6.0E-06	1.1E-05
Cs-137	1.4E-09	1.0E-06	1.4E-03
Ba-140	5.8E-10	8.0E-06	7.2E-05
La-140	7.8E-10	9.0E-06	8.6E-05
Ce-141	9.4E-12	3.0E-05	3.1E-07
Ce-143	2.0E-11	2.0E-05	9.9E-07
PR-143	1.4E-11	2.5E-05	5.4E-07
Ce-144	3.3E-10	3.0E-06	1.1E-04
Pr-144	3.3E-10	6.0E-04	5.5E-07
H-3	1.1E-04	1.0E-03	1.1E-01
			Total = 0.11

Notes:
1. Annual average discharge concentration based on release of average daily discharge for 292 days per year with 6000 gpm dilution flow.
2. Effluent concentration limits are from Reference 1.

Table 11.2-9 (Sheet 1 of 2)

COMPARISON OF ANNUAL AVERAGE LIQUID RELEASE CONCENTRATIONS WITH 10 CFR 20 EFFLUENT CONCENTRATION LIMITS FOR RELEASES WITH MAXIMUM DEFINED FUEL DEFECTS

Nuclide	Discharge Concentration (μCi/ml)(1)	Effluent Concentration Limit (μCi/ml)(2)	Fraction of Concentration Limit
Na-24	1.7E-10	5.0E-05	3.4E-06
Cr-51	1.6E-10	5.0E-04	3.2E-07
Mn-54	1.4E-10	3.0E-05	4.5E-06
Fe-55	1.0E-10	1.0E-04	1.0E-06
Fe-59	2.1E-11	1.0E-05	2.1E-06
Co-58	3.5E-10	2.0E-05	1.8E-05
Co-60	4.6E-11	3.0E-06	1.5E-05
Zn-65	4.3E-11	5.0E-06	8.6E-06
W-187	1.4E-11	3.0E-05	4.5E-07
Np-239	2.5E-11	2.0E-05	1.3E-06
Br-84	4.6E-12	4.0E-04	1.1E-08
Rb-88	2.9E-10	4.0E-04	7.1E-07
Sr-89	1.8E-10	8.0E-06	2.3E-05
Sr-91	9.1E-12	2.0E-05	4.5E-07
Y-91m	7.0E-12	2.0E-03	3.5E-09
Y-93	1.2E-11	2.0E-05	5.8E-07
Zr-95	4.3E-11	2.0E-05	2.2E-06
Nb-95	4.6E-11	3.0E-05	1.5E-06
Mo-99	5.4E-09	2.0E-05	2.7E-04
Tc-99m	4.9E-09	1.0E-03	4.9E-06
Ru-103	3.4E-10	3.0E-05	1.1E-05
Rh-103m	3.4E-10	6.0E-03	5.7E-08
Ru-106	1.6E-08	3.0E-06	5.5E-03

Table 11.2-9 (Sheet 2 of 2)

COMPARISON OF ANNUAL AVERAGE LIQUID RELEASE CONCENTRATIONS WITH 10 CFR 20 EFFLUENT CONCENTRATION LIMITS FOR RELEASES WITH MAXIMUM DEFINED FUEL DEFECTS

Nuclide	Discharge Concentration (μCi/ml)(1)	Effluent Concentration Limit (μCi/ml)(2)	Fraction of Concentration Limit
Ag-100m	1.4E-10	6.0E-06	2.3E-05
Te-129m	3.9E-10	7.0E-06	5.6E-05
Te-129	1.6E-11	4.0E-04	3.9E-08
Te-131m	7.4E-11	8.0E-06	9.3E-06
Te-131	4.0E-12	8.0E-05	5.0E-08
I-131	1.2E-08	1.0E-06	1.2E-02
Te-132	2.3E-09	9.0E-06	2.5E-04
I-132	3.6E-10	1.0E-04	3.6E-06
I-133	3.3E-09	7.0E-06	4.6E-04
I-134	8.5E-11	4.0E-04	2.1E-07
Cs-134	2.0E-07	9.0E-07	2.3E-01
I-135	9.1E-10	3.0E-05	3.0E-05
Cs-136	1.5E-07	6.0E-06	2.6E-02
Cs-137	1.5E-07	1.0E-06	1.5E-01
Ba-140	5.8E-10	8.0E-06	7.2E-05
La-140	7.8E-10	9.0E-06	8.6E-05
Ce-141	2.9E-11	3.0E-05	9.5E-07
Ce-143	2.0E-11	2.0E-05	9.9E-07
PR-143	1.4E-11	2.5E-05	5.4E-07
Ce-144	3.3E-10	3.0E-06	1.1E-04
Pr-144	3.3E-10	6.0E-04	5.5E-07
H-3	1.1E-04	1.0E-03	1.1E-01
			Total = 5.3E-01

Notes:
1. Annual average discharge concentration based on release of average daily discharge for 292 days per year with 6000 gpm dilution flow.
2. Effluent concentrations limits are from Reference 1.

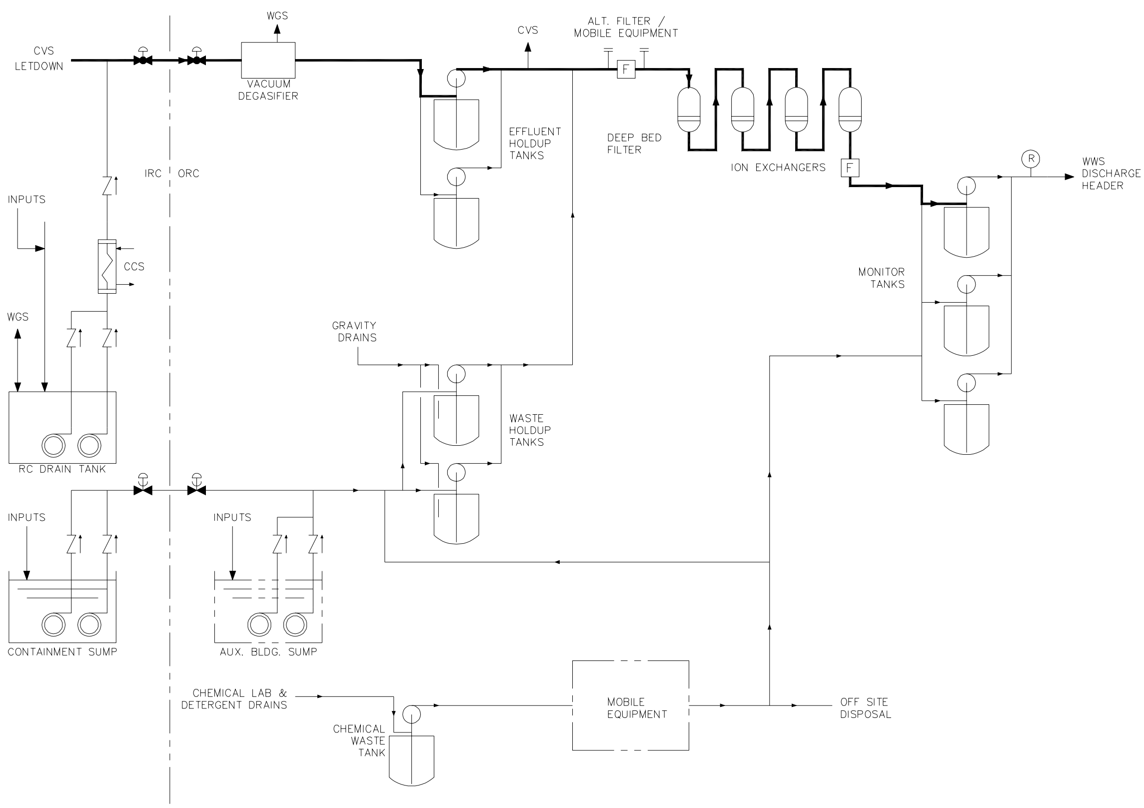


Figure 11.2-1

Liquid Radwaste System
Simplified Piping and Instrumentation Diagram
(REF) WLS

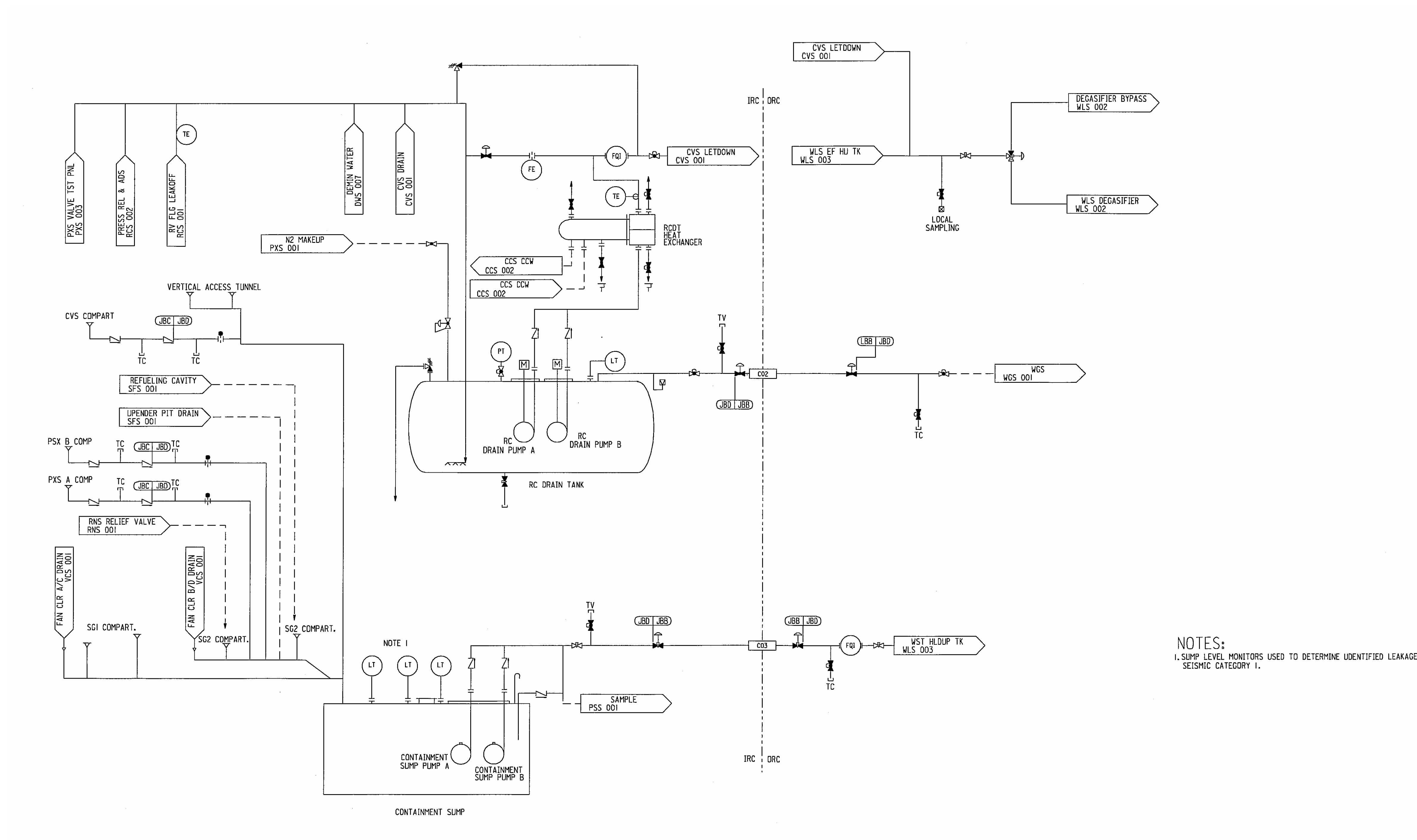
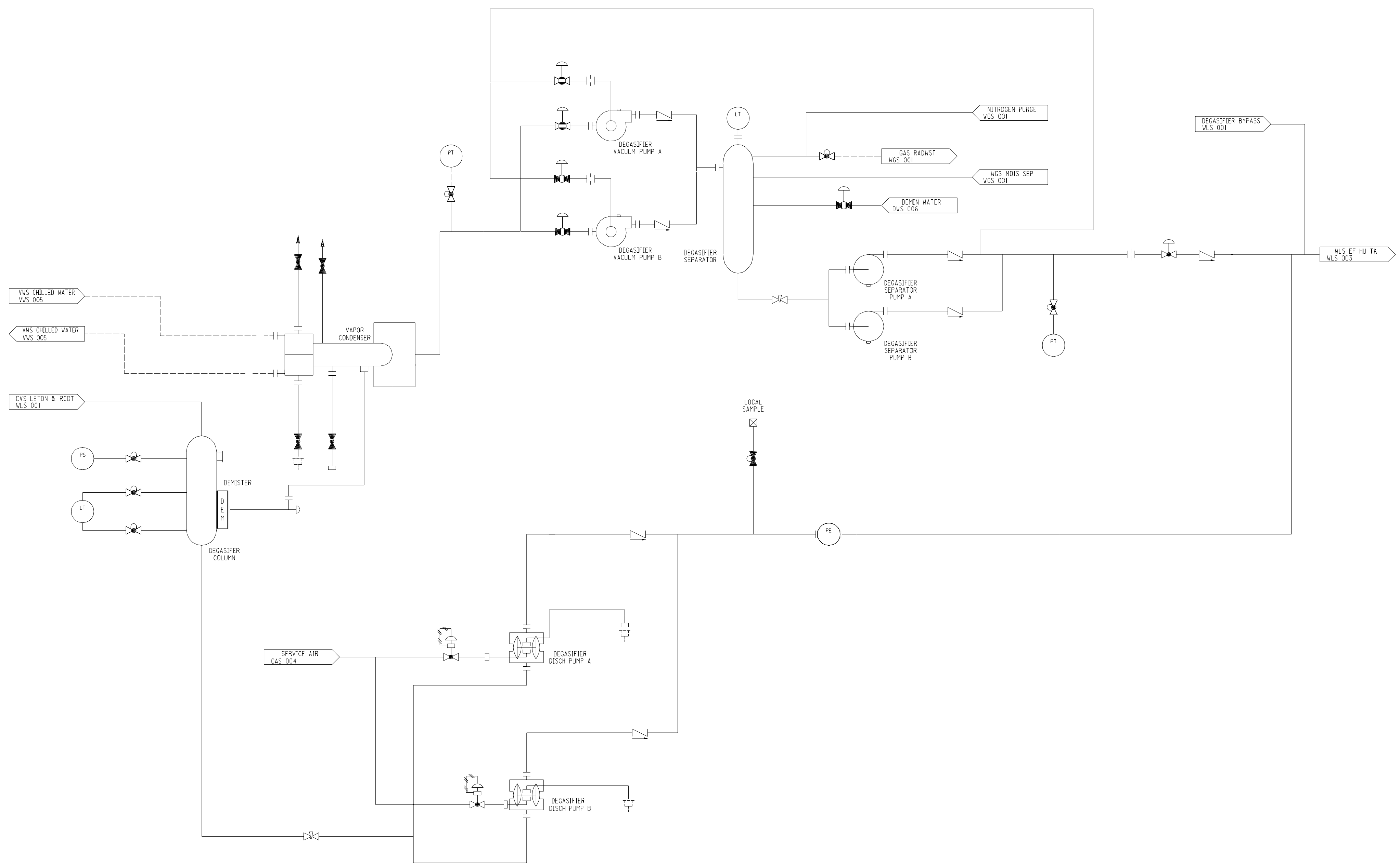


Figure 11.2-2 (Sheet 1 of 6)

Liquid Radwaste System Piping and Instrumentation Diagram (REF) WLS 001



Inside Auxiliary Building

Figure 11.2-2 (Sheet 2 of 6)

Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 002

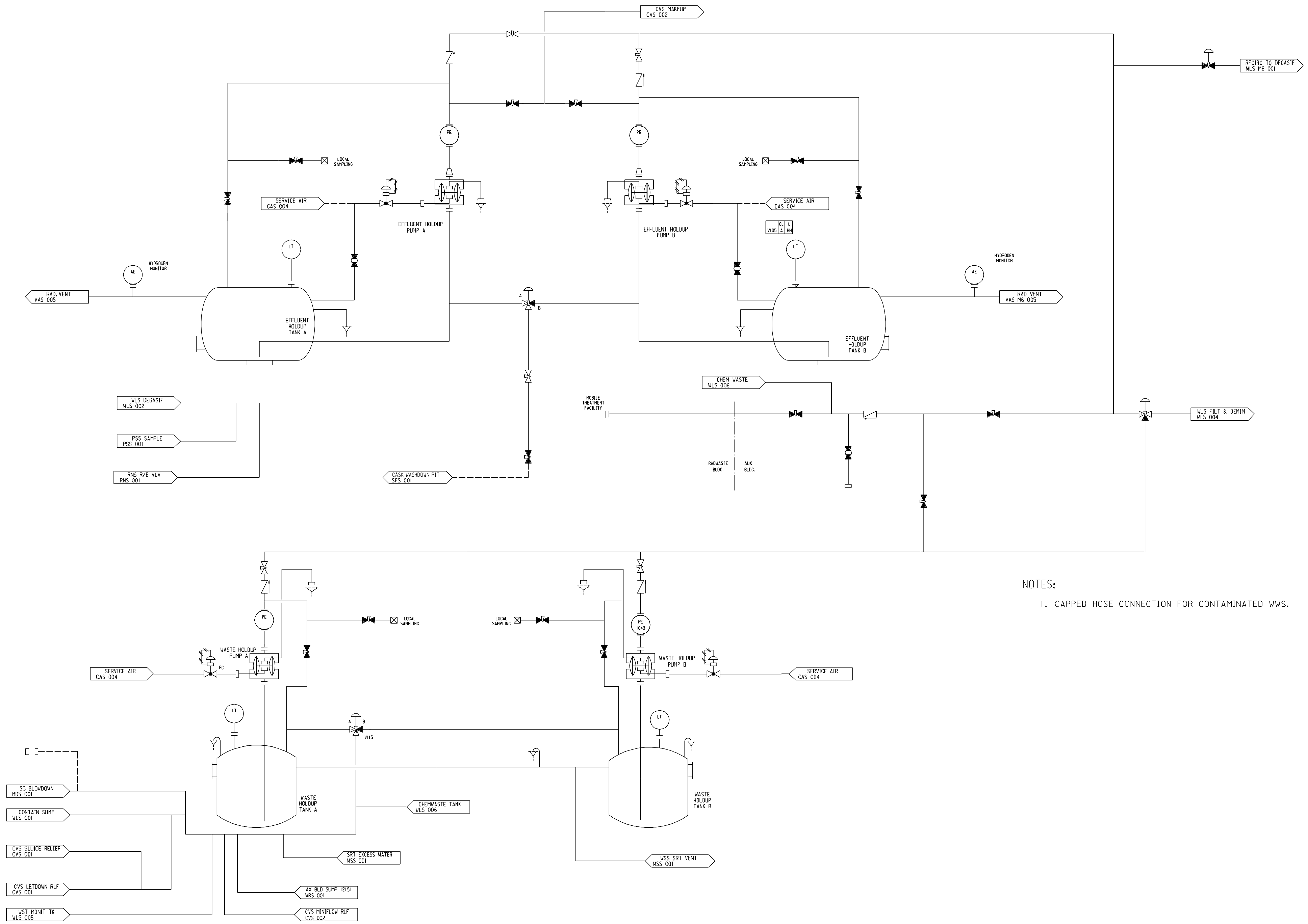


Figure 11.2-2 (Sheet 3 of 6)

Liquid Radwaste System
Piping and Instrumentation Diagram
(REF WLS 003)

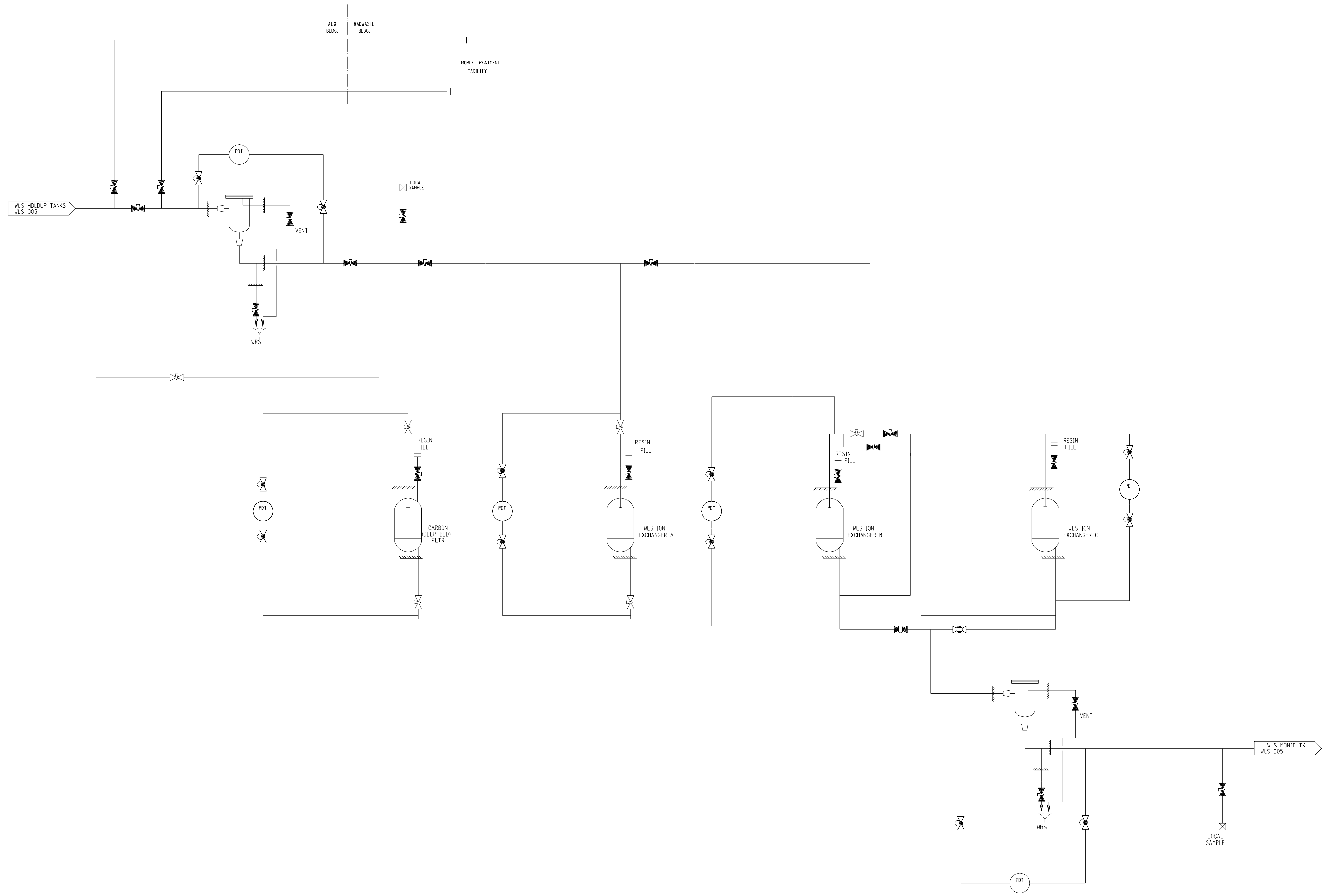


Figure 11.2-2 (Sheet 4 of 6)

Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 004

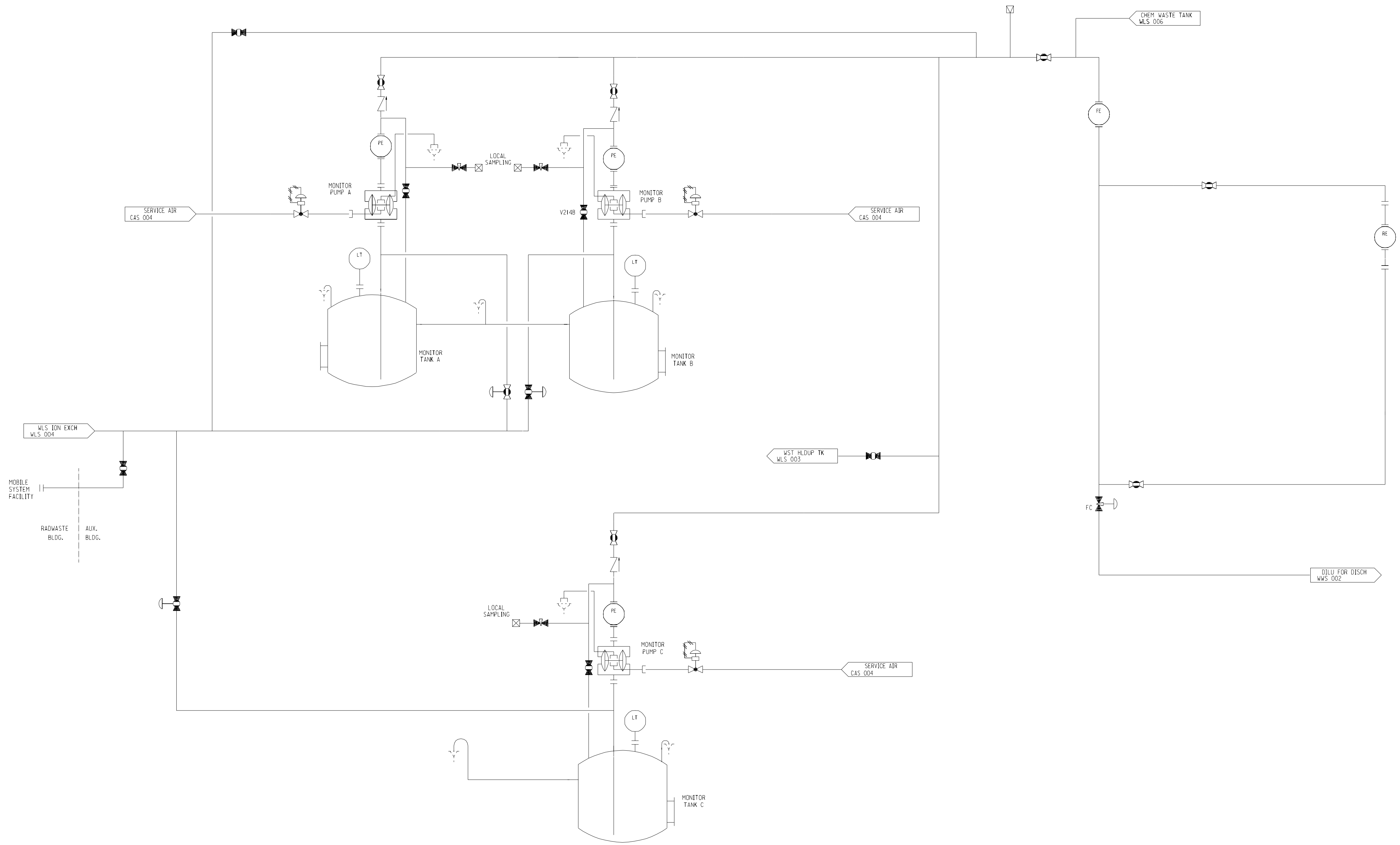
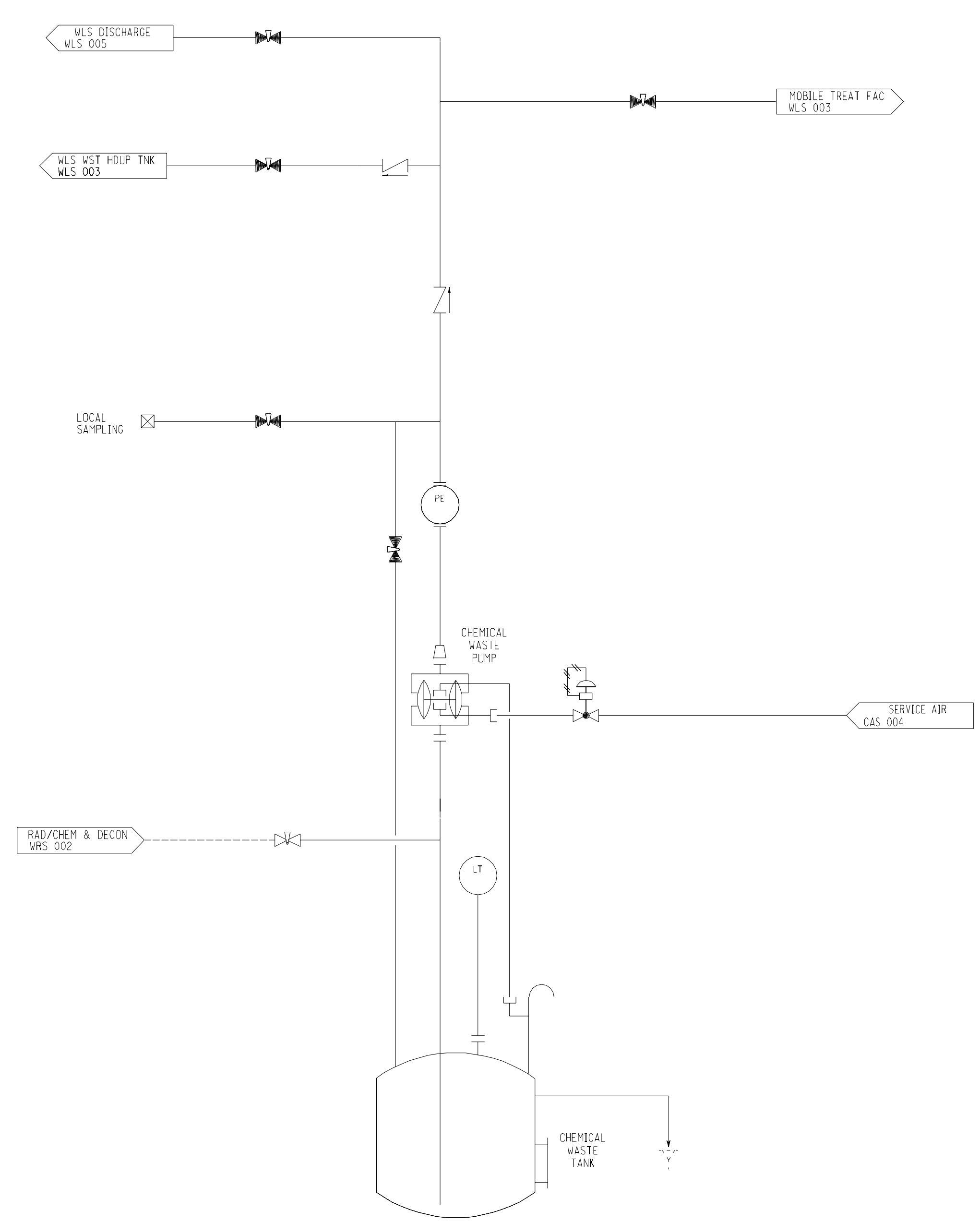


Figure 11.2-2 (Sheet 5 of 6)

Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 005



Inside Auxiliary Building

Figure 11.2-2 (Sheet 6 of 6)

Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 006

11.3 Gaseous Waste Management System

During reactor operation, radioactive isotopes of xenon, krypton, and iodine are created as fission products. A portion of these radionuclides is released to the reactor coolant because of a small number of fuel cladding defects. Leakage of reactor coolant thus results in a release to the containment atmosphere of the noble gases. Airborne releases can be limited both by restricting reactor coolant leakage and by limiting the concentrations of radioactive noble gases and iodine in the reactor coolant system.

Iodine is removed by ion exchange in the chemical and volume control system (CVS). Removal of the noble gases from the reactor coolant system (RCS) is not normally necessary because the gases will not build up to unacceptable levels when fuel defects are within normally anticipated ranges. If noble gas removal is required because of high reactor coolant system concentration, the chemical and volume control system can be operated in conjunction with the liquid radwaste system degasifier, to remove the gases. See Subsection 9.3.6 for a description of these operations.

The AP1000 gaseous radwaste system (WGS) is designed to perform the following major functions:

- Collect gaseous wastes that are radioactive or hydrogen bearing
- Process and discharge the waste gas, keeping off-site releases of radioactivity within acceptable limits.

In addition to the gaseous radwaste system release pathway, release of radioactive material to the environment occurs through the various building ventilation systems. These systems are described in Section 9.4 with a summary of system air flow rates and filter efficiencies provided in Table 9.4-1. The estimated annual release reported in subsection 11.3.3 includes contributions from the major building ventilation pathways.

11.3.1 Design Basis

Subsection 1.9.1 discusses the conformance of the gaseous radwaste system design with the criteria of Regulatory Guide 1.143.

11.3.1.1 Safety Design Basis

The gaseous radwaste system serves no safety-related functions and therefore has no nuclear safety design basis.

11.3.1.2 Power Generation Design Basis

11.3.1.2.1 Capacity

11.3.1.2.1.1 Gaseous Waste Collection

The gaseous radwaste system is designed to receive hydrogen bearing and radioactive gases generated during process operation. The radioactive gas flowing into the gaseous radwaste system enters as trace contamination in a stream of hydrogen and nitrogen.

The design basis period of operation is the last 45 days of a fuel cycle. During this time, reactor coolant system dilution and subsequent letdown from the chemical and volume control system into the liquid radwaste system is at a maximum. Gaseous radwaste system inputs are as follows:

- Letdown diversion for dilution, reactor coolant system with maximum hydrogen concentration. This input is 0.5 standard cubic feet per minute (scfm) on an intermittent basis carrying a very small volume of radiogas, yielding 550 scf total hydrogen.

- Letdown diversion for reactor coolant system degassing, assumed to remove gases from the reactor coolant system to a level of 1 cc/kg beginning with the reactor coolant system at the maximum hydrogen concentration of 40 cc/kg. At its maximum this input is 0.5 scfm hydrogen carrying a very small volume of radiogas yielding 245 scf total hydrogen.

- Reactor coolant drain tank liquid transfer to maintain proper reactor coolant drain tank level, assuming 0.25 gallons per minute liquid input from the reactor coolant system, intermittently yielding 0.5 scfm hydrogen and nitrogen carrying a very small volume of radiogas, yielding about 80 scf hydrogen and nitrogen total.

- Reactor coolant drain tank gas venting, conservatively estimated at 1 scf per day, yielding 45 scf total nitrogen and hydrogen.

11.3.1.2.1.2 Waste Gas Processing

The gaseous radwaste system is designed to reduce the controlled activity releases in support of the overall AP1000 release goals.

Given the various inputs to the gaseous radwaste system, with licensing basis assumptions for analysis and with normally operating gaseous radwaste system equipment available, the combined plant releases must be within the limits outlined in 10 CFR 20 and 10 CFR 50 Appendix I (References 1 and 2, respectively).

11.3.1.2.2 Failure Tolerance

11.3.1.2.2.1 System Leakage

The gaseous radwaste system operates at low pressures, slightly above atmospheric pressure, thus limiting the potential for leakage. Manual valves are the type which eliminate the potential for stem leakage. The system is of welded construction to further limit leakage.

11.3.1.2.2.2 Water Incursion

A number of features prevent wetting the activated carbon delay beds. These features include controls and alarms in the liquid radwaste system to prevent high degasifier separator water level, the gas cooler/vapor condenser moisture separator and traps in the gaseous radwaste system, and moisture monitors in the gaseous radwaste system. Additional protection is provided by the activated carbon guard bed, which removes residual moisture as well as iodine from the gas stream.

If moisture enters the first activated carbon delay bed, the operator bypasses that bed and either dries it with a nitrogen purge or replaces the activated carbon.

11.3.1.2.3 Anticipated Operational Occurrences

11.3.1.2.3.1 Prevention of Hydrogen Ignition

Since the carrier gas for the radiogas inputs to the gaseous radwaste system includes hydrogen, the gaseous radwaste system is designed to prevent hydrogen ignition both within its own boundaries and in connected systems (the liquid radwaste system and the nuclear island radioactive ventilation system).

The gaseous radwaste system is operated at a slightly positive pressure to prevent air ingress. The room containing gaseous radwaste system components incorporates a hydrogen monitor to detect leakage out of the system before combustible levels are reached. In addition, continuous oxygen analysis, using independent, redundant monitors, is provided within the gaseous radwaste system. Upon high oxygen level in the system, an alarm alerts the operator. At an operator selectable oxygen concentration of 4 percent or less, the liquid radwaste system vacuum pumps automatically stop to isolate potentially oxygenated inputs to the gaseous radwaste system, and a valve automatically opens to initiate a nitrogen purge. The discharge isolation valve of the gaseous radwaste system is continuously pressurized with nitrogen to prevent ingress of air into the system from the discharge path.

The gaseous radwaste system also eliminates sources of hydrogen ignition. The system incorporates spark-proof valves, electrical grounding, and a nitrogen purge. Discharge to the heating, ventilating and air-conditioning duct is downstream of the exhaust fans to provide additional protection against hydrogen ignition.

11.3.1.2.4 Controlled Release of Radioactivity

11.3.1.2.4.1 Expected Releases

The AP1000 design prevents the annual average concentration limits established by 10 CFR 20 (Appendix B, table 2, column 1) (Reference 1) for gaseous releases from being exceeded due to the releases resulting during plant operation. Subsection 11.3.3 describes the calculated releases of radioactive materials from the gaseous radwaste system and other pathways during normal operation.

Subsection 11.3.3 also contains an evaluation which demonstrates that the doses to individuals, at or beyond the site boundary, resulting from the expected releases from the gaseous waste management systems are within numerical design objectives of Appendix I of 10 CFR 50 (Reference 2).

11.3.1.2.4.2 Monitoring Releases

Releases from the gaseous radwaste system are continuously monitored by a radiation detector in the discharge line. In addition, the system includes provisions for taking grab samples of the

discharge flow stream for analysis. In this manner, the requirements of General Design Criterion 64 are met as described in Section 3.1. Section 11.5 discusses radiation monitoring.

11.3.1.2.4.3 Operator Error or Equipment Malfunction

To prevent the release of radioactive gases resulting from equipment failure or operator error, a radiation monitor is located in the discharge line. This instrument provides an alarm signal at a high level setpoint to alert operators of rising radiation levels. The monitor is also interlocked with an isolation valve in the discharge line; the valve closes at a higher level setpoint.

Few operator actions are required during gaseous radwaste system operation since, once aligned for operation, the system operates automatically in response to the control signals from the instrumentation.

11.3.2 System Description

11.3.2.1 General Description

The AP1000 gaseous radwaste system, as shown on Figure 11.3-1 is a once-through, ambient-temperature, activated carbon delay system. The system includes a gas cooler, a moisture separator, an activated carbon-filled guard bed, and two activated carbon-filled delay beds. Also included in the system are an oxygen analyzer subsystem and a gas sampling subsystem.

The radioactive fission gases entering the system are carried by hydrogen and nitrogen gas. The primary influent source is the liquid radwaste system degasifier. The degasifier extracts both hydrogen and fission gases from the chemical and volume control system letdown flow which is diverted to the liquid radwaste system or from the reactor coolant drain tank discharge.

Reactor coolant degassing is not required during power operation with fuel defects at or below the design basis level of 0.25 percent. However, the gaseous radwaste system periodically receives influent when chemical and volume control system letdown is processed through the liquid radwaste system degasifier during reactor coolant system dilution and volume control operations. Since the degasifier is a vacuum type and requires no purge gas, the maximum gas influent rate to the gaseous radwaste system from the degasifier equals the rate that hydrogen enters the degasifier (dissolved in liquid).

The other major source of input to the gaseous radwaste system is the reactor coolant drain tank. Hydrogen dissolved in the influent to the reactor coolant drain tank enters the gaseous radwaste system either via the tank vent or the liquid radwaste system degasifier discharge.

The tank vent is normally closed, but is periodically opened on high pressure to vent the gas that has come out of solution. The reactor coolant drain tank liquid is normally discharged to the liquid radwaste system via the degasifier, where the remaining hydrogen is removed.

The reactor coolant drain tank is purged with nitrogen gas to discharge nitrogen and fission gases to the gaseous radwaste system before operations requiring tank access. The reactor coolant drain tank is also purged with nitrogen gas to dilute and discharge oxygen after tank servicing or inspection operations which allow air to enter the tank.

Influents to the gaseous radwaste system first pass through the gas cooler where they are cooled to about 45°F by the chilled water system. Moisture formed due to gas cooling is removed in the moisture separator.

After leaving the moisture separator, the gas flows through a guard bed that protects the delay beds from abnormal moisture carryover or chemical contaminants. The gas then flows through two 100-percent capacity delay beds where the fission gases undergo dynamic adsorption by the activated carbon and are thereby delayed relative to the hydrogen or nitrogen carrier gas flow. Radioactive decay of the fission gases during the delay period significantly reduces the radioactivity of the gas flow leaving the system.

The effluent from the delay bed passes through a radiation monitor and discharges to the ventilation exhaust duct. The radiation monitor is interlocked to close the gaseous radwaste system discharge isolation valve on high radiation. The discharge isolation valve also closes on low ventilation system exhaust flow rate to prevent the accumulation of hydrogen in the aerated vent.

11.3.2.2 System Operation

11.3.2.2.1 Normal Operation

The gaseous radwaste system is used intermittently. Most of the time during normal operation of the AP1000, the gaseous radwaste system is inactive. When there is no waste gas inflow to the system, a small nitrogen gas flow is injected into the discharge line at the inlet of the discharge isolation valve. This nitrogen gas flow maintains the gaseous radwaste system at a positive pressure, preventing the ingress of air during the periods of low waste gas flow.

When the gaseous radwaste system is in use, its operation is passive, using the pressure provided by the influent sources to drive the waste gas through the system.

The largest input to the gaseous radwaste system is from the liquid radwaste system degasifier, which processes the chemical and volume control system letdown flow when diverted to the liquid radwaste system and the liquid effluent from the liquid radwaste system reactor coolant drain tank.

The chemical and volume control system letdown flow is diverted to the liquid radwaste system only during dilutions, borations, and reactor coolant system degassing in anticipation of shutdown. The design basis influent rate from the liquid radwaste system degasifier is the full diversion of the chemical and volume control system letdown flow, when the reactor coolant system is operating with maximum allowable hydrogen concentration. Since the liquid radwaste system degasifier is a vacuum type that operates without a purge gas, this input rate is very small, about 0.5 scfm.

The liquid radwaste system degasifier is also used to degas liquid pumped out of the reactor coolant drain tank. The amount of fluid pumped out, and therefore the gas sent to the gaseous radwaste system, is dependent upon the input into the reactor coolant drain tank. This is smaller than the input from the chemical and volume control system letdown line.

The final input to the gaseous radwaste system is from the reactor coolant drain tank vent. A nitrogen cover gas is maintained in the reactor coolant drain tank. This input consists of nitrogen,

hydrogen, and radioactive gases. The tank operates at nearly constant level, with its vent line normally closed, so this input is minimal. Venting is required only after enough gas has evolved from the input fluid to increase the reactor coolant drain tank pressure.

The influent first passes through a gas cooler. Chilled water flows through the gas cooler at a fixed rate to cool the waste gas to about 45°F regardless of waste gas flow rate. Moisture formed due to gas cooling is removed in the moisture separator, and collected water is periodically discharged automatically. To reduce the potential for waste gas bypass of the gas cooler in the event of valve leakage, a float-operated drain trap is provided which automatically closes on low water level.

The gas leaving the moisture separator is monitored for moisture, and a high alarm alerts the operator to an abnormal condition requiring attention. Oxygen concentration is also monitored. On a high oxygen alarm, a nitrogen purge is automatically injected into the influent line.

The waste gas then flows through the guard bed, where iodine and chemical (oxidizing) contaminants are removed. The guard bed also removes any remaining excessive moisture from the waste gas.

The waste gas then flows through the two delay beds where xenon and krypton are delayed by a dynamic adsorption process. The discharge line is equipped with a valve that automatically closes on either high radioactivity in the gaseous radwaste system discharge line or low ventilation exhaust duct flow.

The adsorption of radioactive gases in the delay bed occurs without reliance on active components or operator action. Operator error or active component failure does not result in an uncontrolled release of radioactivity to the environment. Failure to remove moisture prior to the delay beds (due to loss of chilled water or other causes) results in a gradual reduction in gaseous radwaste system performance. Reduced performance is indicated by high moisture and discharge radiation alarms. High-high radiation automatically terminates discharge.

11.3.2.2.2 Purge Operations

The gaseous radwaste system is purged with nitrogen gas to expel residual oxygen gas after servicing operations. The system is purged until the effluent from the outlet indicates a low oxygen concentration. The gaseous radwaste system oxygen analyzer is temporarily aligned to monitor the flow in the discharge line. Nitrogen connections are also provided to the sample system and to the system discharge line for purge before and after maintenance operations.

11.3.2.3 Component Description

The general descriptions and summaries of the design basis requirements for the gaseous radwaste system components follow. Table 11.3-2 lists the key design parameters for the gaseous radwaste system components.

The seismic design classification and safety classification for the gaseous radwaste system components are listed in Section 3.2. The components listed are located in the Seismic Category I Nuclear Island.

11.3.2.3.1 Sample Pumps

Two sample pumps are provided. One sample pump normally operates continuously to provide flow through the oxygen analyzers. The other sample pump is periodically used to provide flow from various sample points through a sample cylinder. It is used as a backup to provide flow through the oxygen analyzers.

11.3.2.3.2 Gas Cooler

The gas cooler heat exchanger is designed to cool the gas flow to near the temperature of the chilled water supply (45°F) for efficient moisture removal. The pressure of the gas flow through the gas cooler is less than the chilled water pressure to minimize the potential for contaminating the chilled water system.

11.3.2.3.3 Gaseous Radwaste System Tanks

Moisture Separator

The moisture separator is sized for the design basis purge gas flow rate and is oversized for the lower normal flow rate. The unit includes connections for high and low water level sensors.

Guard Bed

The activated carbon guard bed protects the delay beds from abnormal moisture or chemical contaminants. Under normal operating conditions, the guard bed provides increased delay time for xenon and krypton and removes iodine entering the system.

The flow through the activated carbon bed is downward. A retention screen on the outlet of the guard bed prevents the loss of activated carbon from the unit. Activated carbon can be added to or vacuumed from the unit via a blind flange port.

Delay Beds

Two activated carbon delay beds in series are provided. Each delay bed is designed to provide 100 percent of the required system capacity under design basis conditions. During normal operation a single bed provides adequate performance. This provides operational flexibility to permit continued operation of the gaseous radwaste system in the event of operational upsets in the system that require isolation of one bed.

The waste gas flows vertically through columns of activated carbon. The activated carbon volume is twice the theoretical amount required to achieve the holdup times given in Table 11.3-1.

No retention screens are required on the delay beds since the flow enters and leaves each delay bed at its top.

The guard bed and the delay beds, including supports, in the gaseous radwaste system are designed for seismic loads in conformance with Regulatory Guide 1.143. These are the only

AP1000 components used to store or delay the release of gaseous radioactive waste. The beds are located in the seismic Category I auxiliary building at elevation 66′6″.

11.3.2.3.4 Remotely Operated Valves

Moisture Separator Level Control Valve

This normally closed, fail-closed globe valve is located in the liquid drain line from the moisture separator outlet line. It maintains the level in the moisture separator by regulating the flow from the moisture separator to the liquid radwaste system. The valve receives a signal to automatically open on a high level in the moisture separator and to close on low level. The valve can also be manually controlled from the gaseous waste panel.

A float-operated drain trap serves as a backup to this valve. This drain trap automatically closes on a low water level in the moisture separator to stop drain flow to the liquid radwaste system in the event of a valve or instrument failure. This prevents waste gas bypass around the gas cooler due to level control valve failure.

Gaseous Radwaste System Discharge Isolation Valve

This normally closed, fail-closed globe valve is at the outlet of the system. The valve is interlocked to close on a high-high radiation signal in the gaseous radwaste system discharge line to prevent the release of radioactivity in the event of a gaseous radwaste system failure. The valve also receives a signal to automatically close in the event of a low ventilation system exhaust flow rate which prevents accumulation of a flammable or explosive concentration of hydrogen in the aerated vent line.

Manual control is provided on the gaseous radwaste panel.

Nitrogen Purge Pressure Control Valve

This is a self-contained pressure regulating valve in the nitrogen purge line. It is set to maintain a small positive pressure in the gaseous radwaste system to prevent ingress of air during periods of low flow.

11.3.3 Radioactive Releases

Releases of radioactive effluent by way of the atmospheric pathway occur due to:

- Venting of the containment which contains activity as a result of leakage of reactor coolant and as a result of activation of naturally occurring Ar-40 in the atmosphere to form radioactive Ar-41
- Ventilation discharges from the auxiliary building which contains activity as a result of leakage from process streams
- Ventilation discharges from the turbine building

- Condenser air removal system (gaseous activity entering the secondary coolant as a result of primary to secondary leakage is released via this pathway)

- Gaseous radwaste system discharges.

These releases are on-going throughout normal plant operations. There is no gaseous waste holdup capability in the gaseous waste management system and thus no criteria are required for determining the timing of releases or the release rates to be used.

11.3.3.1 Discharge Requirements

The release of radioactive gaseous and particulate effluents to the atmosphere may not exceed the concentration limits specified in Reference 1 nor may the releases result in the annual offsite dose limits specified in 10 CFR 50, Appendix I (Reference 2) being exceeded.

11.3.3.2 Estimated Annual Releases

The annual average airborne releases of radionuclides from the plant are determined using the PWR-GALE code (Reference 3). The GALE code models releases using realistic source terms derived from data obtained from the experience of many operating pressurized water reactors. The code input parameters used in the analysis to model the AP1000 plant are provided in Table 11.2-6. The expected annual releases for a single unit site are presented in Table 11.3-3.

To demonstrate compliance with the effluent concentration limits in Reference 1, the expected releases from Table 11.3-3 are used to determine the annual average concentration at the site boundary, and the results are compared with the Reference 1 concentration limits for unrestricted areas in Table 11.3-4. As shown in Table 11.3-4, the overall fraction of the effluent concentration limit for the expected releases is 0.030, which is significantly below the allowable value of 1.0.

11.3.3.3 Release Points

Airborne effluents are normally released through the plant vent or the turbine building vent. The plant vent provides the release path for containment venting releases, auxiliary building ventilation releases, annex building releases, radwaste building releases, and gaseous radwaste system discharge. The turbine building vents provide the release path for the condenser air removal system, gland seal condenser exhaust and the turbine building ventilation releases.

11.3.3.4 Estimated Doses

With the annual airborne releases listed in Table 11.3-3, the air doses at ground level at the site boundary are 2.1 mrad for gamma radiation and 10.1 mrad for beta radiation. These doses are based on the annual average atmospheric dispersion factor from Section 2.3 (2.0×10^{-5} seconds per cubic meter). These doses are below the 10 CFR 50, Appendix I, design objectives of 10 mrad per year for gamma radiation or 20 mrad per year for beta radiation.

11.3.3.5 Maximum Release Concentrations

The annual releases of radioactive gases and iodine provided in Table 11.3-3 represent expected releases from the plant and reflect an expected level of fuel cladding defects. If the plant operates with the maximum defined fuel defect level, the releases would be substantially greater. The maximum defined fuel defect level corresponds to the Technical Specification limit on coolant activity which is based on 0.25 percent fuel defects. To demonstrate compliance with the effluent concentration limits of Reference 1, the releases from Table 11.3-3 have been adjusted to reflect operation with the maximum defined fuel defect level, and the resulting airborne radionuclide concentrations at the site boundary are compared in Table 11.3-4 with the Reference 1 limits for concentrations in unrestricted areas. As shown in Table 11.3-4, the overall fraction of the effluent concentration limit for operation with the maximum defined fuel defect level is 0.33, which is well below the allowable value of 1.0.

11.3.3.6 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the gaseous radwaste system is in accordance with the overall quality assurance program described in Chapter 17.

11.3.4 Inspection and Testing Requirements

11.3.4.1 Preoperational Testing

Preoperational tests are performed to verify the proper operation of the WGS. The operational tests include automatic closure of the discharge control/isolation valve, WGS-PL-V051, upon receipt of a simulated high radiation signal. The discharge line of the gaseous radwaste system includes a radiation monitor, WGS-RE017, which detects a high radiation condition and generates an alarm that automatically closes the discharge control/isolation valve. By imposing a simulated high radiation alarm signal, proper operation of the discharge control/isolation valve is confirmed by its closure.

11.3.4.2 Preoperational Inspection

The proper performance of the gaseous radwaste system depends upon delay of gaseous radionuclides by chemical adsorption on activated carbon. As the radionuclides are delayed, they decay and are no longer available for release to the environment. The rate of release and site boundary dose rates have been evaluated based upon the quantity of activated carbon in a delay bed being at least 80 cubic feet. An inspection of the gaseous radwaste system activated carbon delay beds, WGS-MV01A and WGS-MV02B, will confirm that the contained volume of each delay bed is at least 80 cubic feet.

11.3.5 Combined License Information

11.3.5.1 Cost Benefit Analysis of Population Doses

The analysis performed to determine offsite dose due to gaseous effluents is based upon the AP1000 generic site parameters included in Chapter 1 and Tables 11.3-1, 11.3-2 and 11.3-4. The Combined License applicant will provide a site specific cost-benefit analysis to demonstrate compliance with 10 CFR 50, Appendix I, regarding population doses due to gaseous effluents.

11.3.5.2 Identification of Adsorbent Media

The Combined License applicant will identify the types of adsorbent media to be used in the gaseous radwaste system.

11.3.6 References

1. "Annual Limits on Intake (ALIs) and Derived Air Concentrations (DACs) of Radionuclides for Occupational Exposure; Effluent Concentrations; Concentrations for Release to Sewerage," 10 CFR Part 20, Appendix B, Issued by 58 FR 67657, April 28, 1995.

2. "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As-Low-As-Is-Reasonably-Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," 10 CFR Part 50, Appendix I.

3. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," NUREG-0017, Revision 1, March 1985.

Table 11.3-1

GASEOUS RADWASTE SYSTEM PARAMETERS

Design operating influent pressure (psig)	2
Design influent flow rate (scfm)	0.5
Activated carbon bed design operating temperature (°F)	77
Activated carbon bed design operating dew point (°F)	45
Activated carbon in delay beds (average) (pounds combined total)	4600
Xenon dynamic adsorption coefficient (cc/gm)	1050
Krypton dynamic adsorption coefficient (cc/gm)	38
Xenon holdup time[a]	61.2 days at 0.5 scfm
Krypton holdup time[a]	2.2 days at 0.5 scfm

Note:

a. Holdup times shown are conservatively based on credit for only one half of the activated carbon available in the delay beds and no credit for the guard bed.

Table 11.3-2 (Sheet 1 of 2)

COMPONENT DATA (NOMINAL) – GASEOUS RADWASTE SYSTEM

Mechanical Components

Pumps		
Sample Pumps		
Number	2	
Type	Diaphragm	
Design pressure (psig)	2	
Design temperature (°F)	45	
Design flow (scfm)	0.2	
Heat Exchangers		
Gas Cooler		
Number	1	
Type	Shell and tubes	
	Tube Side	**Shell Side**
Design pressure (psig)	100	150
Design temperature (°F)	200	150
Design flow	0.7 scfm	2 gpm
Temperature inlet (°F)	175	45
Temperature outlet (°F)	46	51
Material	Stainless steel	Stainless steel
Tanks		
Guard Bed		
Number	1	
Nominal volume (ft^3)	8	
Type	Vertical pipe	
Design pressure (psig)	100	
Design temperature (°F)	150	
Material	Stainless steel	
Delay Bed		
Number	2	
Nominal volume (ft^3)	80	
Type	Vertical serpentine	
Design pressure (psig)	100	
Design temperature (°F)	150	
Material	Carbon steel	
Moisture Separator		
Number	1	
Nominal volume (gal)	3	
Type	Vertical	
Design pressure (psig)	100	
Design temperature (°F)	150	
Material	Stainless steel	

Table 11.3-2 (Sheet 2 of 2)

COMPONENT DATA (NOMINAL) – GASEOUS RADWASTE SYSTEM
SUMMARY OF INSTRUMENT INDICATION AND ALARMS

Instrumentation	Indicate (Note 4)	Alarm
Gas Cooler		
Gas inlet temperature	X	
Cooling water outlet temperature	X	
Gas inlet pressure	X	X – Hi
Carbon Guard Bed		
Gas inlet temperature	X	X – Hi
Gas inlet moisture	X	X – Hi
Carbon Delay Beds		
Gas inlet temperature	X	X – Hi
Gas outlet temperature 2 channels	X	X – Hi
Gas outlet flow	X	
Gas outlet radiation (Note 3)	X	X – Hi
Gas outlet pressure	X	
Carbon Bed Vault		
Vault hydrogen (Note 2)	X	X – Hi
Vault temperature (Note 1)	X	X – Hi
Moisture Separator		
Water level	X	X – Hi
Sampling Subsystem		
Hydrogen concentration	X	X
Oxygen concentration 2 channels	X	X – Hi
Gas flow	X	X – Lo

Notes:
1. Vault temperature monitor common for guard bed and delay bed.
2. Vault hydrogen monitor common for guard bed and delay bed.
3. High outlet radiation alarm closes gas outlet isolation valve.
4. Monitoring of the gaseous radwaste system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication and control are available on portable displays which may be connected to the data display and processing system. See Chapter 7.

Table 11.3-3 (Sheet 1 of 3)

EXPECTED ANNUAL AVERAGE RELEASE OF AIRBORNE RADIONUCLIDES AS DETERMINED BY THE PWR-GALE CODE, REVISION 1

(RELEASE RATES IN Ci/yr)

		Building/Area Ventilation				
Noble Gases[1]	**Waste Gas System**	**Cont.**	**Auxiliary Building**	**Turbine Building**	**Condenser Air Removal System**	**Total**
Kr-85m	0.	3.0E+01	4.0E+00	0.	2.0E+00	3.6E+01
Kr-85	1.65E+02	2.4E+03	2.9E+01	0.	1.4E+01	4.1E+03
Kr-87	0.	9.0E+00	4.0E+00	0.	2.0E+00	1.5E+01
Kr-88	0.	3.4E+01	8.0E+00	0.	4.0E+00	4.6E+01
Xe-131m	1.42E+02	1.6E+03	2.3E+01	0.	1.1E+01	1.8E+03
Xe-133m	0.	8.5E+01	2.0E+00	0.	0.	8.7E+01
Xe-133	3.0E+01	4.5E+03	7.6E+01	0.	3.6E+01	4.6E+03
Xe-135m	0.	2.0E+00	3.0E+00	0.	2.0E+00	7.0E+00
Xe-135	0.	3.0E+02	2.3E+01	0.	1.1E+01	3.3E+02
Xe-138	0.	1.0E+00.	3.0E+00	0.	2.0E+00	6.0E+00
					Total	1.1E+04

Additionally:

H-3 released via gaseous pathway	350
C-14 released via gaseous pathway	7.3
Ar-41 released via containment vent	34

Table 11.3-3 (Sheet 2 of 3)

EXPECTED ANNUAL AVERAGE RELEASE OF AIRBORNE RADIONUCLIDES AS DETERMINED BY THE PWR-GALE CODE, REVISION 1

(RELEASE RATES IN Ci/yr)

	Building/Area Ventilation					
Iodines(1)	**Fuel Handling Area(2)**	**Cont.**	**Auxiliary Building**	**Turbine Building**	**Condenser Air Removal System**	**Total**
I-131	4.5E-03	2.3E-03	1.1E-01	0.	0.	1.2E-01
I-133	1.6E-02	5.5E-03	3.8E-01	2.0E-04	0.	4.0E-01

Table 11.3-3 (Sheet 3 of 3)

EXPECTED ANNUAL AVERAGE RELEASE OF AIRBORNE RADIONUCLIDES AS DETERMINED BY THE PWR-GALE CODE, REVISION 1

(RELEASE RATES IN Ci/yr)

		Building/Area Ventilation			
Radionuclide(1)	**Waste Gas System**	**Cont.**	**Auxiliary Building**	**Fuel Handling Area(2)**	**Total**
Cr-51	1.4E-05	9.2E-05	3.2E-04	1.8E-04	6.1E-04
Mn-54	2.1E-06	5.3E-05	7.8E-05	3.0E-04	4.3E-04
Co-57	0.	8.2E-06	0.	0.	8.2E-06
Co-58	8.7E-06	2.5E-04	1.9E-03	2.1E-02	2.3E-02
C0-60	1.4E-05	2.6E-05	5.1E-04	8.2E-03	8.7E-03
Fe-59	1.8E-06	2.7E-05	5.0E-05	0.	7.9E-05
Sr-89	4.4E-05	1.3E-04	7.5E-04	2.1E-03	3.0E-03
Sr-90	1.7E-05	5.2E-05	2.9E-04	8.0E-04	1.2E-03
Zr-95	4.8E-06	0.	1.0E-03	3.6E-06	1.0E-03
Nb-95	3.7E-06	1.8E-05	3.0E-05	2.4E-03	2.5E-03
Ru-103	3.2E-06	1.6E-05	2.3E-05	3.8E-05	8.0E-05
Ru-106	2.7E-06	0.	6.0E-06	6.9E-05	7.8E-05
Sb-125	0.	0.	3.9E-06	5.7E-05	6.1E-05
Cs-134	3.3E-05	2.5E-05	5.4E-04	1.7E-03	2.3E-03
Cs-136	5.3E-06	3.2E-05	4.8E-05	0.	8.5E-05
Cs-137	7.7E-05	5.5E-05	7.2E-04	2.7E-03	3.6E-03
Ba-140	2.3E-05	0.	4.0E-04	0.	4.2E-04
Ce-141	2.2E-06	1.3E-05	2.6E-05	4.4E-07	4.2E-05

Notes:
1. The appearance of 0. in the table indicates less than 1.0 Ci/yr for noble gas or less than 0.0001 Ci/yr for iodine. For particulates, release is not observed and assumed less than 1 percent of the total particulate releases.
2. The fuel handling area is within the auxiliary building but is considered separately.

Table 11.3-4 (Sheet 1 of 2)

COMPARISON OF CALCULATED OFFSITE AIRBORNE CONCENTRATIONS WITH 10 CFR 20 LIMITS

Radionuclide	Effluent Concentration Limit µCi/ml[(a)]	Expected Site Boundary[(b)] Concentration Limit µCi/ml	Fraction of Concentration Limit[(b)] (expected)	Maximum Site Boundary Concentration Limit µCi/ml[(c)]	Fraction of Concentration Limit[(c)] (maximum)
Kr-85m	1.0E-07	2.9E-11	2.9E-04	1.2E-10	1.2E-03
Kr-85	7.0E-07	3.3E-09	4.6E-03	6.9E-09	9.9E-03
Kr-87	2.0E-08	1.2E-11	5.9E-04	2.9E-11	1.5E-03
Kr-88	9.0E-09	3.6E-11	4.1E-03	1.6E-10	1.8E-02
Xe-131m	2.0E-06	1.4E-09	7.1E-04	1.7E-09	8.7E-04
Xe-133m	6.0E-07	6.9E-11	1.1E-04	1.3E-09	2.1E-03
Xe-133	5.0E-07	3.6E-09	7.3E-03	1.3E-07	2.5E-01
Xe-135m	4.0E-08	5.5E-12	1.4E-04	6.0E-12	1.5E-04
Xe-135	7.0E-08	2.6E-10	3.7E-03	8.7E-10	1.2E-02
Xe-138	2.0E-08	4.8E-12	2.4E-04	7.8E-12	3.9E-04
I-131	2.0E-10	9.5E-14	4.8E-04	2.0E-12	9.9E-03
I-133	1.0E-09	3.2E-13	3.2E-04	2.6E-12	2.6E-03
H-3	1.0E-07	2.8E-10	2.8E-03	2.8E-10	2.8E-03
C-14	3.0E-09	5.8E-12	1.9E-03	5.8E-12	1.9E-03
Ar-41	1.0E-08	2.7E-11	2.7E-03	2.7E-12	2.7E-04
Cr-51	3.0E-08	4.8E-16	1.6E-08	4.8E-16	1.6E-08
Mn-54	1.0E-09	3.4E-16	3.4E-07	3.4E-16	3.4E-07
Co-57	9.0E-10	6.5E-18	7.2E-09	6.5E-18	7.2E-09
Co-58	1.0E-09	1.8E-14	1.8E-05	1.8E-14	1.8E-05
Co-60	5.0E-11	6.9E-15	1.4E-04	6.9E-15	1.4E-04
Fe-59	5.0E-10	6.3E-17	1.3E-07	6.3E-17	1.3E-07
Sr-89	2.0E-10	2.4E-15	1.2E-05	1.0E-13	5.2E-04
Sr-90	6.0E-12	9.5E-16	1.6E-04	3.8E-15	6.3E-04
Zr-95	4.0E-10	7.9E-16	2.0E-06	1.7E-15	4.4E-06
Nb-95	2.0E-09	2.0E-15	9.9E-07	6.0E-15	3.0E-06
Ru-103	9.0E-10	6.3E-17	7.0E-08	6.3E-17	7.0E-08

Table 11.3-4 (Sheet 2 of 2)

COMPARISON OF CALCULATED OFFSITE AIRBORNE CONCENTRATIONS WITH 10 CFR 20 LIMITS

Radionuclide	Effluent Concentration Limit μCi/ml[(a)]	Expected Site Boundary[(b)] Concentration Limit μCi/ml	Fraction of Concentration Limit[(b)] (expected)	Maximum Site Boundary Concentration Limit μCi/ml[(c)]	Fraction of Concentration Limit[(c)] (maximum)
Ru-106	2.0E-11	6.2E-17	3.1E-06	2.5E-16	1.2E-05
Sb-125	7.0E-10	4.8E-17	6.9E-08	4.8E-17	6.9E-08
Cs-134	2.0E-10	1.8E-15	9.1E-06	9.5E-13	4.8E-03
Cs-136	9.0E-10	6.7E-17	7.5E-08	4.2E-13	4.7E-04
Cs-137	2.0E-10	2.9E-15	1.4E-05	7.9E-13	4.0E-03
Ba-140	2.0E-09	3.3E-16	1.7E-07	1.4E-16	7.1E-08
Ce-141	8.0E-10	3.3E-17	4.2E-08	1.9E-16	2.4E-07
			Total = 3.0E-02		Total = 3.3E-01

Notes:

a. Effluent concentration limit is from Reference 1.

b. Expected site boundary concentration based on annual releases predicted by the PWR-GALE code (Table 11.3-3) and an annual average X/Q of 2.0 x 10^{-5} seconds per cubic meter.

c. Maximum site boundary concentration based on adjusting the releases predicted by the PWR-GALE code (Table 11.3-3) to reflect operation with maximum defined fuel defect level and an annual average X/Q of 2.0 x 10^{-5} seconds per cubic meter.

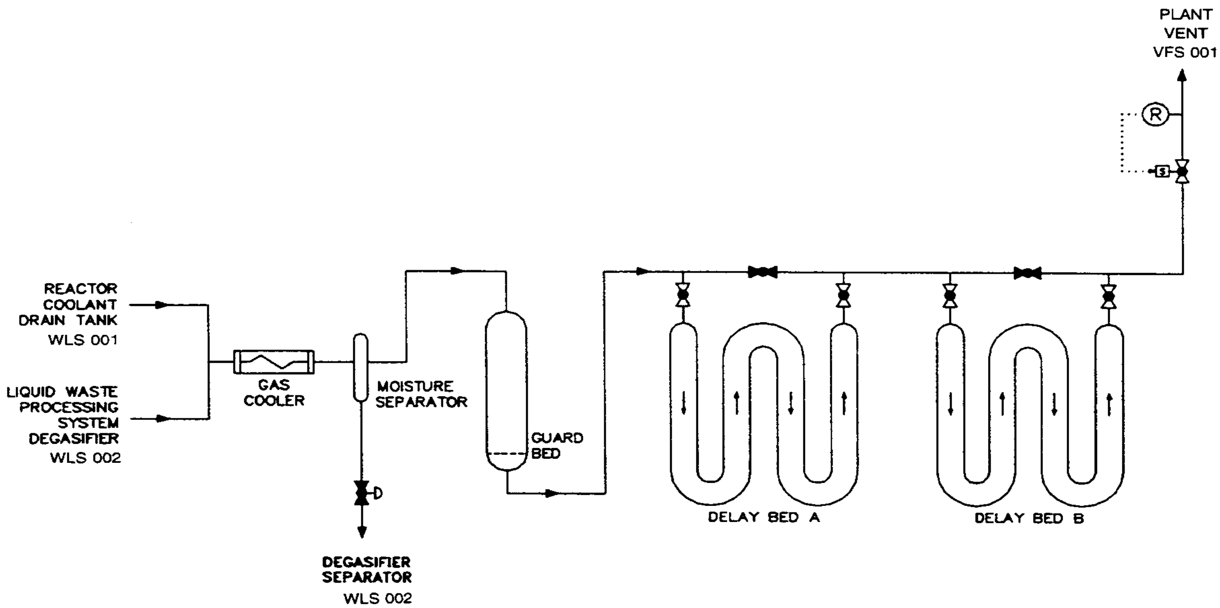
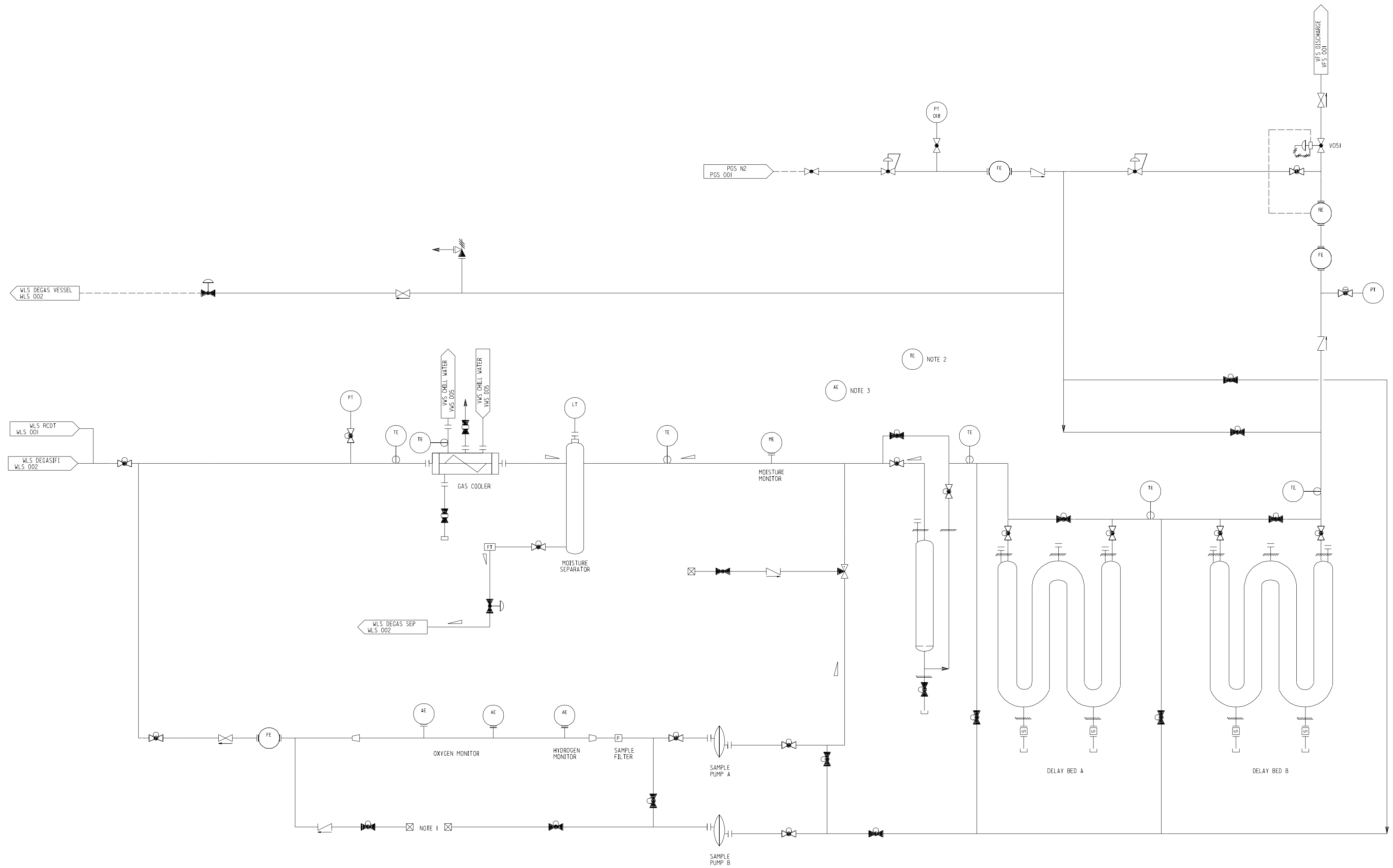


Figure 11.3-1

Gaseous Radwaste System
Piping and Instrumentation Diagram



NOTES:

1. QUICK CONNECT COUPLINGS PIPED TO RECEIVED PLANT SAMPLE VESSEL.
2. ACTIVATED CARBON BED VAULT TEMPERATURE MONITORING EQUIPMENT TO BE PROVIDED.
3. HYDROGEN MONITOR TO BE PROVIDED IN ACTIVATED CARBON BED VAULT.

Figure 11.3-2

Gaseous Radwaste System
Piping and Instrumentation Diagram
(REF) WGS 001

11.4 Solid Waste Management

The solid waste management system (WSS) is designed to collect and accumulate spent ion exchange resins and deep bed filtration media, spent filter cartridges, dry active wastes, and mixed wastes generated as a result of normal plant operation, including anticipated operational occurrences. The system is located in the auxiliary and radwaste buildings. Processing and packaging of wastes are by mobile systems in the auxiliary building rail car bay and in the mobile systems facility part of the radwaste building. The packaged waste is stored in the auxiliary and radwaste buildings until it is shipped offsite to a licensed disposal facility.

The use of mobile systems for the processing functions permits the use of the latest technology and avoids the equipment obsolescence problems experienced with installed radwaste processing equipment. The most appropriate and efficient systems may be used as they become available.

This system does not handle large, radioactive waste materials such as core components or radioactive process wastes from the plant's secondary cycle. However, the volumes and activities of the secondary cycle wastes are provided in this section.

11.4.1 Design Basis

11.4.1.1 Safety Design Basis

The solid waste management system performs no function related to the safe shutdown of the plant. The system's failure does not adversely affect any safety-related system or component; therefore, the system has no nuclear safety design basis.

There are no safety related systems located near heavy lifts associated with the solid waste management system. Therefore, a heavy loads analysis is not required.

11.4.1.2 Power Generation Design Basis

The solid waste management system provides temporary onsite storage for wastes prior to processing and for the packaged wastes. The system has a 60-year design objective and is designed for maximum reliability, minimum maintenance, and minimum radiation exposure to operating and maintenance personnel. The system has sufficient temporary waste accumulation capacity based on maximum waste generation rates so that maintenance, repair, or replacement of the solid waste management system equipment does not impact power generation.

11.4.1.3 Functional Design Basis

The solid waste management system is designed to meet the following objectives:

- Provide for the transfer and retention of spent radioactive ion exchange resins and deep bed filtration media from the various ion exchangers and filters in the liquid waste processing, chemical and volume control, and spent fuel cooling systems

- Provide the means to mix, sample, and transfer spent resins and filtration media to high integrity containers or liners for dewatering or solidification as required

- Provide the means to change out, transport, sample, and accumulate filter cartridges from liquid systems in a manner that minimizes radiation exposure of personnel and spread of contamination

- Provide the means to accumulate spent filters from the plant heating, ventilation, and air-conditioning systems

- Provide the means to segregate solid wastes (trash) by radioactivity level and to temporarily store the wastes

- Provide the means to accumulate radioactive hazardous (mixed) wastes

- Provide the means to segregate clean wastes originating in the radiologically controlled area (RCA)

- Provide the means to store packaged wastes for at least 6 months in the event of delay or disruption of offsite shipping

- Provide the space and support services required for mobile processing systems that will reduce the volume of and package radioactive solid wastes for offsite shipment and disposal according to applicable regulations, including Department of Transportation regulation 49 CFR 173 (Reference 1) and NRC regulation 10 CFR 71 (Reference 2)

- Provide the means to return liquid radwaste to the liquid radwaste system (WLS) for subsequent processing and monitored discharge

The solid waste management system is designed according to NRC Regulatory Guide 1.143 to meet the requirements of General Design Criterion (GDC) 60 as discussed in Sections 1.9 and 3.1. The seismic design classifications of the radwaste building and system components are provided in Section 3.2.

Provisions are made in the auxiliary and radwaste buildings to use mobile radwaste processing systems for processing and packaging each waste stream including concentration and solidification of chemical wastes from the liquid waste management system, spent resin dewatering, spent filter cartridge encapsulation and dry active waste sorting and compaction.

The radioactivities of influents to the solid waste management system are based on estimated radionuclide concentrations and volumes. These estimates are based on operating plant experience, adjusted for the size and design differences of AP1000. The influent source terms are consistent with Section 11.1.

The solid waste management system airborne process effluents are released through the monitored plant vent as described as part of the 10 CFR 50 (Reference 3), Appendix I, analysis presented in subsection 11.3.3.

The solid waste management system collects and stores radioactive wastes within shielding to maintain radiation exposure to plant operation and maintenance personnel as low as is reasonably

achievable (ALARA) according to General Design Criteria 60 as discussed in Section 3.1 and Regulatory Guide 8.8. Personnel exposures will be maintained well below the limits of 10 CFR 20 (Reference 4). Design features incorporated to maintain exposures ALARA include remote and semi-remote operations, automatic resin transport line flushing, and shielding of components, piping and containers holding radioactive materials. Access to the solid waste storage areas is controlled, to minimize inadvertent personnel exposure, by suitable barriers such as heavy storage cask covers and locked or key-card-operated doors or gates (see Section 12.1).

The solid waste management system conforms with the design criteria of NRC Branch Technical Position ETSB 11-3. Suitable fire protection systems are provided as described in subsection 9.5.1.

Waste disposal containers are to be selected from available designs that meet the requirements of the DOT and NRC. The solid waste management system does not require source-specific waste containers. Waste containers must meet the regulatory requirements for radioactive waste transportation in 49 CFR 173 and for radioactive waste disposal in 10 CFR 61 (Reference 5) as well as specific disposal facility requirements.

11.4.2 System Description

11.4.2.1 General Description

The solid waste management system includes the spent resin system. The flows of wastes through the solid waste management system are shown on Figure 11.4-1. The radioactivity of influents to the system are dependent on reactor coolant activities and the decontamination factors of the processes in the chemical and volume control system, spent fuel cooling system, and the liquid waste processing system.

The parameters used to calculate the estimated activity of the influents to the solid waste management system are listed in Table 11.4-1. The estimated expected isotopic curie content of the primary spent resin and filter cartridge wastes to be processed on an annual basis is listed on Table 11.4-2. Table 11.4-3 provides the same information for the estimated maximum annual activities. The AP1000 has sufficient radwaste storage capacity to accommodate the maximum generation rate.

The radioactivity of the dry active waste is expected to normally range from 0.1 curies per year to 8 curies per year with a maximum of about 16 curies per year. This waste includes spent HVAC filters, compressible trash, non-compressible components, mixed wastes and solidified chemical wastes. These activities are produced by relatively long lived radionuclides (such as Cr-51, Fe-55, Co-58, Co-60, Nb-95, Cs-134 and Cs-137), and therefore, radioactivity decay during processing and storage is minimal. These activities thus apply to the waste as generated and to the waste as shipped.

The estimated expected and maximum annual quantities of waste influents by source and form are listed in Table 11.4-1 with disposal volumes. The annual radwaste influent rates are derived by multiplying the average influent rate (e.g. volume per month, volume per refueling cycle) by one year of time. The annual disposal rate is determined by applying the radwaste packaging efficiency to the annual influent rate. The influent volumes are conservatively based on an

18-month refueling cycle. Annual quantities based on a 24-month refueling cycle are less than those for an 18-month cycle. The estimated expected isotopic curie content of the primary spent resin and filter cartridge wastes to be shipped offsite are presented in Table 11.4-4 based on 90 days of decay before shipment. The same information is presented in Table 11.4-5 for the estimated maximum activities based on 30 days of decay before shipment.

Section 11.1 provides the bases for determination of liquid source terms used to calculate several of the solid waste management system influent source terms. The influent data presented in Tables 11.4-2 and 11.4-3 are conservatively based on Section 11.1 design basis (Technical Specification) values.

All radwaste which is packaged and stored by AP1000 will be shipped for disposal. The AP1000 has no provisions for permanent storage of radwaste. Radwaste is stored ready for shipment. Shipped volumes of radwaste for disposal are estimated in Table 11.4-1 from the estimated expected or maximum influent volumes by making adjustments for volume reduction processing by mobile systems and the expected container filling efficiencies. For drum compaction, the overall volume reduction factor, including packaging efficiency, is 3.6. For box compaction, the overall volume reduction factor is 5.4. These adjustments result in a packaged internal waste volume for each waste source, and the number of containers required to hold this volume is based on the container's internal volume. The disposal volume is based on the number of containers and the external (disposal) volume of the containers.

The expected disposal volumes of wet and dry wastes are approximately 547 and 1417 cubic feet per year, respectively as shown in Table 11.4-1. The wet wastes shipping volumes include 510 cubic feet per year of spent ion exchange resins and deep bed filter activated carbon, 20 cubic feet of volume reduced liquid chemical wastes and 17 cubic feet of mixed liquid wastes. The spent resins and activated carbon are initially stored in the spent resin storage tanks located in the rail car bay of the auxiliary building. When a sufficient quantity has accumulated, the resin is sluiced into two 158 cubic feet high-integrity containers in anticipation of transport for offsite disposal. Liquid chemical wastes are reduced in volume and packaged into three 55-gallon drums per year (about 20 cubic feet) and are stored in the packaged waste storage room of the radwaste building. The mixed liquid wastes fill less than three drums per year (about 17 cubic feet per year) and are stored on containment pallets in the waste accumulation room of the radwaste building until shipped offsite for processing.

The two spent resin storage tanks (275 cubic feet usable, each) and one high integrity container in the spent resin waste container fill station at the west end of the rail car bay of the auxiliary building provide more than a year of spent resin storage at the expected rate, and several months of storage at the maximum generation rate. The expected radwaste generation rate is based upon the following:

- All ion exchange resin beds are disposed and replaced every refueling cycle.
- The WGS activated carbon guard bed is replaced every refueling cycle.
- The WGS delay beds are replaced every ten years.

- All wet filters are replaced every refueling cycle.
- Rates of compatible and non-compatible radwaste, chemical waste and mixed wastes are estimated using historical operating plant data.

The maximum radwaste generation rate is based upon the following:

- The ion exchange resin beds are disposed based upon operation with 0.25% fuel defects.
- The WGS activated carbon guard bed is replaced twice every refueling cycle.
- The WGS delay beds are replaced every five years.
- All wet filters are replaced based upon operation with 0.25% fuel defects.
- The expected rates of compatible and non-compatible radwaste, chemical waste and mixed wastes are increased by about 50%.
- Primary to secondary system leakage contaminates the condensate polishing system and blowdown system resins and membranes which are replaced.

The dry solid radwaste includes 1383 cubic feet per year of compactible and non-compactible waste packed into about 14 boxes (90 cubic feet each) and ten drums per year. Drums are used for higher activity compactible and non-compactible wastes. Compactible waste includes HVAC exhaust filter, ground sheets, boot covers, hair nets, etc. Non-compactible waste includes about 60 cubic feet per year of dry activated carbon and other solids such as broken tools and wood. Solid mixed wastes will occupy 7.5 cubic feet per year (one drum). The low activity spent filter cartridges may be compacted to fill about 0.40 drums per year (3 ft^3/year) and are stored in the packaged waste storage room. Compaction is performed by mobile equipment or is performed offsite. High activity filter cartridges fill three drums per year (22.5 cubic feet per year) and are stored in portable processing or storage casks in the rail car of the auxiliary building.

The total volume of radwaste to be stored in the radwaste building packaged waste storage room is 1417 cubic feet per year at the expected rate and 2544 cubic feet per year at the maximum rate. The compactible and non-compactible dry wastes, packaged in drums or steel boxes, are stored with the mixed liquid and mixed solid, volume reduced liquid chemical wastes, and the lower activity filter cartridges. The quantities of liquid radwaste stored in the packaged waste storage room of the radwaste building consists of 20 cubic feet of chemical waste and 17 cubic feet of mixed liquid waste. The useful storage volume in the packaged waste storage room is approximately 3900 cubic feet (10 feet deep, 30 feet long, and 13 feet high), which accommodates more than one full offsite waste shipment using a tractor-trailer truck. The packaged waste storage room provides storage for more than two years at the expected rate of generation and more than a year at the maximum rate of generation. One four-drum containment pallet provides more than 8 months of storage capacity for the liquid mixed wastes and the volume reduced liquid chemical wastes at the expected rate of generation and more than 4 months at the maximum rate.

A conservative estimate of solid wet waste includes blowdown material based on continuous operation of the steam generator blowdown purification system, with leakage from the primary to secondary cycles. The volume of radioactively contaminated material from this source is estimated to be 540 cubic feet per year. Provisions for processing and disposal of radioactive steam generator blowdown resins and membranes are described in subsection 10.4.8. Note that, although included here for conservatism, this volume of contaminated resin will be removed from the plant within the contaminated electrodeionization unit and not stored as wet waste.

The condensate polishing system includes mixed bed ion exchanger vessels for purification of the condensate as described in subsection 10.4.6. Should the resins become radioactive, the resins are transferred from the condensate polishing vessel directly to a temporary processing unit or to the temporary processing unit via the spent resin tank. The processing unit, located outside of the turbine building, dewaters and processes the resins as required for offsite disposal. Radioactive condensate polishing resin will have very low activity. It will be disposed in containers as permitted by DOT regulations. After packaging, the resins may be stored in the radwaste building. Based on a typical condensate polishing system operation of 30 days per refueling cycle with leakage from the primary system to the secondary system, the volume of radioactively contaminated resin is estimated to be 206 cubic feet per year (one 309 cubic foot bed per refueling cycle). Normal disposal of nonradioactive condensate polishing system resins is described in subsection 10.4.6.

The parameters used to calculate the activities of the steam generator blowdown solid waste and condensate polishing resins are given in Table 11.4-1. Based on the above volumes, the disposal volume is estimated to be 939 cubic feet per year. The expected and maximum activities of the resins as generated are given in Tables 11.4-6 and 11.4-7, respectively. The expected and maximum activities of resins as shipped, based on 90 days decay prior to shipment, are given in Tables 11.4-8 and 11.4-9, respectively.

11.4.2.2 Component Description

The seismic design classification and safety classification for the solid waste management system components are listed in Section 3.2. The components listed are located in the Seismic Category I Nuclear Island. Table 11.4-10 lists the solid waste management system equipment design parameters. The following subsections provide a functional description of the major system components.

11.4.2.2.1 Spent Resin Tanks

The spent resin tanks provide holdup capacity for spent resin and filter bed media decay before processing. High- and low-activity resins may be mixed to limit the radioactivity concentration in the waste containers to 10 Ci/ft^3 in accordance with the USNRC Technical Position on Waste Form (Reference 6).

Resin mixing capability is provided by mixing eductors in each tank, and resin dewatering, air sparging and complete draining capabilities are also provided. The ultrasonic level sensors and dewatering screens are arranged for remote removal. The vent and overflow connections have screens to prevent the inadvertent discharge of spent resin.

11.4.2.2.2 Resin Mixing Pump

The resin mixing pump provides the motive force to fluidize and mix the resins in the spent resin tanks, to transfer water between spent resin tanks, to discharge excess water from the spent resin tanks to the liquid waste processing system, and to flush the resin transfer lines.

11.4.2.2.3 Resin Fines Filter

The resin fines filter minimizes the spread of high-activity resin fines and dislodged crud particles by filtering the water used for line flushing or discharged from the spent resin tanks to the liquid waste processing system.

11.4.2.2.4 Resin Transfer Pump

The resin transfer pump provides the motive force for recirculation of spent resins via either one of the spent resin tanks for mixing and sampling, for transferring spent resin between tanks, and for blending high- and low-activity resins to meet the specific activity limit for disposal. The resin transfer pump is also used to transfer spent resins to a waste container in the fill station or in its shipping cask located in the auxiliary building rail car bay.

11.4.2.2.5 Resin Sampling Device

The resin sampling device collects a representative sample of the spent resin either during spent resin recirculation or during spent resin waste container filling operations. A portable shielded cask is provided for sample jar transfer.

11.4.2.2.6 Filter Transfer Cask

The filter transfer cask permits remote changing of filter cartridges, dripless transport to the storage area in the auxiliary building, transfer of the filter cartridges into and out of the filter storage, and loading of the filter cartridges into disposal containers.

11.4.2.3 System Operation

11.4.2.3.1 Spent Resin Handling Operations

Demineralized water is used to transfer spent resins from the various ion exchangers to the spent resin tanks. A demineralized water transfer pump provides the pressurized water flow to transfer the spent resins as described in subsection 9.2.4. Before the transfer operation, it is verified that the selected spent resin tank is aligned as a receiver and has the capacity to accept the bed. It is also verified that the resin mixing pump is aligned to discharge excess transfer water through the resin fines filter to the liquid waste processing system.

During the transfer operation the tank level is monitored and the resin mixing pump is operated, if required, to limit tank water level. The operator stops the transfer when the CCTV camera viewing the sight flow glass indicates on a control panel monitor that the sluice water is clear and the transfer line is, therefore, flushed of resins.

After the bed transfer, the tank solids level can be checked by operating the resin mixing pump to lower the water level below the solids level. The solids level can be determined by the ultrasonic surface detector.

Between bed transfer operations the water level in the spent resin tanks is maintained above the solids level. Demineralized water is supplied for water level adjustment as well as a backup water source for flushing resin handling lines after resin recirculation and waste disposal container filling operations.

The solids bed can be agitated and mixed at any time by using compressed air or by operating the resin mixing pump in the resin mixing mode. In the resin mixing mode, water is drawn from the spent resin tank via resin retention screens. The water is returned via tank mixing eductors that generate a resin slurry recirculation within the tank equivalent to about four times the flow rate generated by the resin mixing pump. The solids bed is locally fluidized during this operation.

The resin mixing mode is established to fluidize and mix the solids bed in the spent resin tank before waste disposal container filling. The resin transfer pump is then started in the recirculation mode. A resin slurry is drawn from the spent resin tank and returned to the same tank. A representative resin sample may be obtained during recirculation or container filling modes by operating the sampling device.

The portable system's container fill valve is opened to initiate the filling operation. The resin dewatering pump of the portable dewatering system is started to dewater the resin as it accumulates in the container. The resin dewatering pump discharges the water to the recirculation line. The water flows back to the spent resin tank, thereby preserving the water inventory in the system and retaining any resin fines or dislodged crud within the system.

The resin mixing pump can be stopped at any time during the filling operation. When the solids level nears the top of the container, as detected by level sensors and observed by a television camera, the fill valve is closed and cycled to top off the container. Excessive water or solids level automatically closes the fill valve.

When the filling operation is complete, the line flushing sequence controller is manually initiated to automatically operate the pumps and valves to flush the resin transfer lines back to the spent resin tank. The container fill valve is opened for a short time period to flush the remaining resin to the waste container. The resin mixing pump supplies filtered flush water from the spent resin tank. The portable dewatering system's dewatering pump is operated periodically until no further dewatering flow is detected by the pump discharge pressure indicator and/or audible indications from the pump.

11.4.2.3.2 Spent Filter Processing Operations

A filter transfer cask is used to change the higher-activity filters of the chemical and volume control system and spent fuel cooling system. The filter vessel is drained, and the filter cover is opened remotely. The shield plug of the port over the filter is removed and the transfer cask, without its bottom shield cover, is lifted and positioned on the port directly over the cartridge in the filter vessel.

A grapple inside the transfer cask is remotely lowered and connected to the filter cartridge. The cartridge is lifted into the transfer cask, and the cask is transferred over plastic sheeting to the bottom shield cover. The dose rate of the cartridge is measured with a long probe, and the cask is lowered onto and connected to the bottom shield cover. The transfer cask is then moved to the auxiliary building rail car bay.

If recent applicable sample analysis results are available, the filter cartridge can be loaded directly into a disposal container as described in the following paragraph. If analysis is required, a sample of the filter media is obtained through a port in the transfer cask. The filter cartridge is placed in one of nine high-activity filter storage tubes until sample analysis results are available. The transfer cask bottom cover is disconnected, the transfer cask is lifted by the crane and transferred to a position over one of the temporary storage tubes, and the spent filter cartridge is lowered into the tube. After moving the transfer cask away, the crane is used to install a shield plug onto the storage tube. Any water draining from the filter during storage collects in the storage tube which may be drained to a floor drain for subsequent transfer to the liquid radwaste system.

When sample analysis is complete and packaging requirements are established, the transfer cask is used to retrieve the spent cartridges from storage and deposit them into a waste container via a port in the top of a portable processing and storage cask. Plastic coverings are removed and the container is capped, smear-surveyed, and decontaminated as required, using reach rod tools through a cask port. The dose rate survey is also made through a cask port. Transfer of the filled waste container to the shipping cask, including cask cover handling, is then performed using the rail car bay crane under remote control.

Filters with dose rates less than 15 R/hr on contact may be changed from outside of filter vessel shielding by using reach rod tools. The filter vessel is drained, and the cover is removed. Then the spent filter cartridge is grappled and lifted out and into a filter transfer cask.

At the radwaste building, low and moderate activity filter cartridges are deposited into disposal or storage drums. The drums are stored within portable shield casks in the shielded accumulation room, which is serviced by the mobile systems facility crane. Depending on dose rates and analysis results, stabilization may or may not be required. Cartridges not requiring stabilization are loaded into standard, 55 gallon shipping drums with absorbent and may be compacted using a mobile system. When stabilization is required, the cartridges may be loaded into either high integrity containers or standard drums. If standard drums are used, mobile equipment is used to encapsulate the contents of the drums.

The drum covers are manually installed, and the drums are smear surveyed, decontaminated by wiping, if required, weighed, stacked on pallets, and placed in the packaged waste storage room.

When a truck-load quantity of waste containers accumulates, shipment to a low-level waste disposal facility is initiated by loading pallets of drums and other low-level waste containers into a closed van using the scissor lift or onto a flat-bed trailer using the crane. If the activity level is too high for unshielded shipment, the drums are loaded onto a cask pallet and into a shielded shipping cask using the mobile systems facility crane.

Radioactive filters from ventilation exhaust filtration units are bagged and transported to the radwaste building, where they are temporarily stored. The filters are compacted along with other dry active wastes by a mobile system as described in the following subsection.

11.4.2.3.3 Dry Waste Processing Operations

Dry wastes are segregated by measuring the contact dose rate of the wastes to determine the appropriate processing method. The contact dose rates for initial waste segregation are as follows:

Low activity	<5 mR/hr
Moderate activity	5 mR/hr to 100 mR/hr
High activity	>100 mR/hr

These activity levels may be adjusted by the operator to minimize exposures while maximizing processing efficiency.

Wastes from surface contamination areas in the radiologically controlled area are placed in bags or containers and tagged at the point of origin with information on radiation levels, waste type, and destination. The bags or containers are transported to the radwaste building, where they are placed into low-, moderate-, or high-activity storage, segregated by portable shielding as appropriate.

The high-activity wastes (greater than 100 mR/hr) are normally expected to be compacted in drums using a mobile compactor system in the same manner as lower-activity filter cartridges.

Moderate-activity wastes (5 mR/hr to 100 mR/hr) are expected to be sorted in a mobile system to remove reusable items such as protective clothing articles and tools, hazardous wastes, and larger noncompressible items. The remaining wastes are normally compacted by mobile equipment. The packaged wastes may be loaded directly onto a truck for shipment or may be stored in the packaged waste storage room until a truck load quantity accumulates.

Low-activity, dry active waste (less than 5 mR/hr) generally contains a large amount of nonradioactive material. It is expected that these wastes normally will be processed through a mobile radiation monitoring and sorting system to remove non-radioactive items for reuse or local disposal. A radiation survey allows identification and removal of potentially clean items for the clean waste verification. The remaining radioactive wastes are normally compacted or packaged for disposal as appropriate.

Materials that enter the radiologically controlled area are verified as nonradioactive before being released for reuse or disposal. Tools and equipment belonging to personnel and contractors are surveyed at the radiologically controlled area exit in the annex building. If these items cannot be released or decontaminated, they become plant inventory or dry active waste and are handled as described previously.

Other wastes generated in the radiologically controlled area but outside of surface contamination areas are collected in bags or containers and are delivered to the temporary storage location in the radwaste building. These wastes normally are processed through a mobile radiation monitoring system to verify that they are nonradioactive and suitable for disposal in a local waste landfill.

11.4.2.3.4 Mixed Waste Processing Operations

Mixed wastes from the radiologically controlled area are collected in suitable containers and brought to the radwaste building, where separate containment pallets and accumulation drums are provided for solid and liquid mixed wastes. Mixed wastes are normally sent to an offsite facility having mixed-waste processing and disposal capabilities.

11.4.2.4 Waste Processing and Disposal Alternatives

11.4.2.4.1 Portable and Mobile Radwaste Systems Capabilities

Portable or mobile processing and packaging systems can be located in the auxiliary building rail car bay or the radwaste building mobile systems facility. Chemical wastes are normally processed in the radwaste building by a mobile concentration and/or solidification system when a batch accumulates in the chemical waste tank. Mobile systems are also used to encapsulate high-activity filters, to sort, decontaminate and compact dry active wastes, and to verify nonradioactive wastes.

The spent resin system includes connections in the fill station and rail car bay to allow spent resins to be delivered to a disposal container in either location for dewatering using portable equipment.

Branch Technical Position ETSB 11-3 provides guidance for portable solid waste systems in Section IV. Compliance with the four guidance items is achieved as follows:

IV.I The spent resin tanks are the only tanks that contain a significant volume of wet wastes, and these tanks are permanently installed. Concentrates that may be produced by mobile evaporation systems will be produced and stored by the mobile systems only in small batches prior to being solidified by the mobile systems. As described in subsection 1.2.7, the radwaste building is designed to retain spillage from mobile or portable systems.

IV.2 Permanently installed piping for transport of radioactive wastes to mobile or portable systems is routed close to the mobile or portable systems thereby minimizing the use of flexible interfacing hose. The hydrostatic test requirements of Regulatory Guide 1.143 will be applied to the flexible interfacing hose.

IV.3 Portable or mobile systems will be located in either the rail car bay of the auxiliary building or in the mobile systems facility in the radwaste building. The spent resin waste container fill station or the shipping cask in the auxiliary building collects spillage of spent resin during waste container filling operations. The radwaste and auxiliary buildings contain and drain spillage to the liquid radwaste system via the radioactive waste drain system as described in subsection 1.2.7 and Section 11.2. Portable or mobile systems will, when required, have their own HEPA filtered exhaust ventilation system. HEPA filtered exhaust is required when airborne radioactivity would exceed 10 CFR 20 derived air concentration limits for radiation workers. The mobile systems facility has connections on the exhaust ventilation ducts for connecting exhaust duct from mobile or portable processing systems to the building's exhaust ventilation system.

IV.4 Although the seismic criteria of Regulatory Guide 1.143 are not applicable to structures housing mobile or portable solid radwaste systems, the portable equipment used for spent

resin container filling and dewatering and high-activity filter cartridge packaging will be housed within the Seismic Category I auxiliary building. The radwaste building, which provides shelter for mobile or portable radwaste systems, is non-seismic in accordance with Branch Technical Position ETSB 11-3.

11.4.2.4.2 Central Radwaste Processing Facility

As an alternative to the mobile or portable processes for lower-activity wastes (generally wastes reading below 200 mR/hr), the wastes may be sent to a licensed central radwaste processing facility for processing and disposal. This option requires minimal onsite processing to remove hazardous materials from the waste streams. The wastes are loaded into a cargo container. The mobile systems facility includes a designated laydown area, and the mobile systems facility crane may be used to handle a cargo container.

11.4.2.5 Facilities

11.4.2.5.1 Auxiliary Building

Resin and filtration media transfer lines from the various ion exchangers are routed to the spent resin tanks on elevation 100′ - 0″ in the southwest corner of the auxiliary building. The spent resin system pumps, valves, and piping are located in shielded rooms near the spent resin tanks.

Liquid radwaste system transfer lines to and from the radwaste building are routed to the south wall of the auxiliary building where they penetrate and enter into a shielded pipe pit in the base mat of the radwaste building.

Accessways in the auxiliary building are used to move the filter transfer casks. This includes filter transfer cask handling from the containment, where the chemical and volume control filters are located, to the auxiliary building rail car bay, where the filter cartridges are stored and subsequently packaged using mobile equipment. These accessways are also used to move dry active waste from various collection locations to the radwaste building. An enclosed accessway is provided between the auxiliary building and the radwaste building on elevation 100′-0″ (grade level).

11.4.2.5.2 Radwaste Building

The radwaste building, described in Section 1.2, houses the mobile systems facility. It also includes the waste accumulation room and the packaged waste storage room. These rooms are serviced by the mobile systems facility crane.

In the mobile systems facility, three truck bays provide for mobile or portable processing systems and for waste disposal container shipping and receiving. A shielded pipe trench to each of the truck bays is used to route liquid radwaste supply and return lines from the connections in the shielded pipe pit at the auxiliary building wall. Separate areas are reserved for empty (new) waste disposal container storage, container laydown, and forklift charging. An area is reserved near the door to the auxiliary building for protective clothing dropoff and frisking.

The waste accumulation room (pre-processing) is divided as needed, using partitions and portable shielding to adjust the storage areas for different waste categories as needed to complement the radioactivity levels and volumes of generated wastes. The accumulation room has lockable doors to minimize unauthorized entry and inadvertent exposure.

The packaged waste storage room may be separated into high- and low-activity areas, using portable shielding to minimize exposure while providing operational flexibility. A lockable door is provided to minimize unauthorized entry and radiation exposure.

The heating and ventilating system for the radwaste building is described in subsection 9.4.8.

11.4.3 System Safety Evaluation

The solid waste management system has no safety-related function and therefore requires no nuclear safety evaluation.

11.4.4 Tests and Inspections

Preoperational tests are conducted as described in subsection 14.2.8. Tests are performed to demonstrate the capability to transfer ion exchange resins and deep bed filtration media from the ion exchangers and filters to the spent resin tanks or directly to a waste disposal container. Preoperational tests of the solid waste management system components are performed to prepare the system for operation.

After plant operations begin, the operability and functional performance of the solid waste management system is periodically evaluated according to Regulatory Guide 1.143 by monitoring for abnormal or deteriorating performance during routine operations. Instruments and setpoints are also calibrated on a scheduled basis. The preventive maintenance program includes periodic inspection and maintenance of active components.

11.4.5 Quality Assurance

The quality assurance program for design, installation, procurement, and fabrication issues of the solid waste management system is in accordance with the overall quality assurance program described in Chapter 17.

11.4.6 Combined License Information for Solid Waste Management System Process Control Program

The Combined License applicant will develop a process control program in compliance with 10 CFR Sections 61.55 and 61.56 for wet solid wastes and 10 CFR Part 71 and DOT regulations for both wet and dry solid wastes. Process control programs will also be provided by vendors providing mobile or portable processing or storage systems. It will be the plant operators responsibility to assure that the vendors have appropriate process control programs for the scope of work being contracted at any particular time. The process control program will identify the operating procedures for storing or processing wet solid wastes. The mobile systems process control program will include a discussion of conformance to Regulatory Guide 1.143 (Reference 7), Generic Letter GL-80-009 (Reference 8), and Generic Letter GL-81-039

(Reference 9) and, information of equipment containing wet solid wastes in the nonseismic Radwaste Building. In the event additional onsite storage facilities are a part of Combined License plans, this program will include a discussion of conformance to Generic Letter GL-81-038 (Reference 10).

11.4.7 References

1. "Shippers-General Requirements for Shipments and Packagings," 49 CFR 173.

2. "Packaging and Transportation of Radioactive Material," 10 CFR 71.

3. "Domestic Licensing of Production and Utilization Facilities," 10 CFR 50.

4. "Standards for Protection Against Radiation," 10 CFR 20.

5. "Licensing Requirements for Land Disposal of Radioactive Waste," 10 CFR 61.

6. "USNRC Technical Position on Waste Form," Rev. 1, January 1991.

7. Regulatory Guide 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants."

8. USNRC Generic Letter GL-80-009, "Low Level Radioactive Waste Disposal," dated January 29, 1980.

9. USNRC Generic Letter GL-81-039, "NRC Volume Reduction Policy (Generic Letter No. 81-39)," dated November 30, 1981.

10. USNRC Generic Letter GL-81-038, "Storage of Low-Level Radioactive Wastes at Power Reactor Sites," dated November 10, 1981.

Table 11.4-1

ESTIMATED SOLID RADWASTE VOLUMES

Source	Expected Generation (ft^3/yr)	Expected Shipped Solid (ft^3/yr)	Maximum Generation (ft^3/yr)	Maximum Shipped Solid (ft^3/yr)
WET WASTES				
Primary Resins (includes spent resins and wet activated carbon)	400[(2)]	510	1700[(4)]	2160
Chemical	350	20	700	40
Mixed Liquid	15	17	30	34
Condensate Polishing Resin[(1)]	0	0	206[(5)]	259
Steam Generator Blowdown[(1)(6)] Material (Resin and Membrane)	0	0	540[(5)]	680
Wet Waste Subtotals	**765**	**547**	**3176**	**3173**
DRY WASTES				
Compactible Dry Waste	4750	1010	7260	1550
Non-Compactible Solid Waste	234	373	567	910
Mixed Solid	5	7.5	10	15
Primary Filters (includes high activity and low activity cartridges)	5.2[(3)]	26	9.4[(3)]	69
Dry Waste Subtotals	**4994**	**1417**	**7846**	**2544**
TOTAL WET & DRY WASTES	**5759**	**1964**	**11,020**	**5717**

Notes:
1. Radioactive secondary resins and membranes result from primary to secondary systems leakage (e.g., SG tube leak).
2. Estimated activity basis is ANSI 18.1 source terms in reactor coolant.
3. Estimated activity basis is breakdown and transfer of 10% of resin from upstream ion exchangers.
4. Reactor coolant source terms corresponding to 0.25% fuel defects.
5. Estimated activity basis from Table 11.1-5, 11.1-7 and 11.1-8 and a typical 30 day process run time, once per refueling cycle.
6. Estimated volume and activity used for conservatism. Resin and membrane will be removed with the electrodeionization units and not stored as wet waste. See subsection 10.4.8.

Table 11.4-2 (Sheet 1 of 2)

EXPECTED ANNUAL CURIE CONTENT OF PRIMARY INFLUENTS

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	---	---
Br-84	1.98E-01	1.98E-02
Br-85	---	---
I-129	---	---
I-130	---	---
I-131	1.42E+02	1.42E+01
I-132	1.04E+01	1.04E+00
I-133	5.29E+01	5.29E+00
I-134	6.89E+00	6.89E-01
I-135	3.49E+01	3.49E+00
Rb-86	---	---
Rb-88	9.72E-01	9.72E-02
Rb-89	---	---
Cs-134	3.06E+02	3.06E+01
Cs-136	3.16E+00	3.16E-01
Cs-137	4.64E+02	4.64E+01
Cs-138	---	---
Ba-137m	4.44E+02	4.44E+01
Cr-51	3.21E+01	3.21E+00
Mn-54	1.04E+02	1.04E+01
Mn-56	---	---
Fe-55	1.04E+02	1.04E+01
Fe-59	5.00E+00	5.00E-01
Co-58	2.05E+02	2.05E+01
Co-60	9.59E+01	9.59E+00
Zn-65	3.02E+01	3.02E+00
Sr-89	2.67E+00	2.67E-01
Sr-90	1.13E+00	1.13E-01
Sr-91	1.72E-01	1.72E-02
Sr-92	---	---
Ba-140	6.29E+01	6.29E+00
Y-90	---	---
Y-91m	---	---
Y-91	3.74E-06	3.74E-07

Table 11.4-2 (Sheet 2 of 2)

EXPECTED ANNUAL CURIE CONTENT OF PRIMARY INFLUENTS

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	---	---
Y-93	---	---
La-140	---	---
Zr-95	2.80E-04	2.80E-05
Nb-95	---	---
Mo-99	---	---
Tc-99m	---	---
Ru-103	5.35E-03	5.35E-04
Ru-106	6.37E-02	6.37E-03
Rh-103m	---	---
Rh-106	---	---
Te-132	---	---
Te-125m	---	---
Te-127m	---	---
Te-127	---	---
Te-129m	1.36E-04	1.36E-05
Te-129	---	---
Te-131m	---	---
Total:	2.11E+03	2.11E+02

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-3 (Sheet 1 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF PRIMARY INFLUENTS

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	7.03E+00	7.03E-01
Br-84	3.42E-01	3.42E-02
Br-85	3.74E-03	3.74E-04
I-129	3.44E-03	3.44E-04
I-130	9.00E+00	9.00E-01
I-131	5.45E+03	5.45E+02
I-132	1.97E+02	1.97E+01
I-133	1.66E+03	1.66E+02
I-134	7.31E+00	7.31E-01
I-135	3.81E+02	3.81E+01
Rb-86	2.97E+01	2.97E+00
Rb-88	2.52E+01	2.52E+00
Rb-89	9.83E-01	9.83E-02
Cs-134	9.57E+03	9.57E+02
Cs-136	1.72E+03	1.72E+02
Cs-137	9.14E+03	9.14E+02
Cs-138	1.06E+01	1.06E+00
Ba-137m	8.66E+03	8.66E+02
Cr-51	3.95E+01	3.95E+00
Mn-54	1.18E+02	1.18E+01
Mn-56	4.75E+01	4.75E+00
Fe-55	1.14E+02	1.14E+01
Fe-59	5.84E+00	5.84E-01
Co-58	3.03E+02	3.03E+01
Co-60	2.45E+02	2.45E+01
Zn-65	---	---
Sr-89	4.56E+01	4.56E+00
Sr-90	1.09E+01	1.09E+00
Sr-91	1.16E+00	1.16E-01
Sr-92	9.96E-02	9.96E-03
Ba-140	1.19E+01	1.19E+00
Y-90	1.07E+01	1.07E+00
Y-91m	3.48E-01	3.48E-02
Y-91	5.48E-01	5.48E-02

Table 11.4-3 (Sheet 2 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF PRIMARY INFLUENTS

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	4.19E-02	4.19E-03
Y-93	9.07E-05	9.07E-06
La-140	1.07E+01	1.07E+00
Zr-95	---	---
Nb-95	---	---
Mo-99	---	---
Tc-99m	---	---
Ru-103	---	---
Ru-106	---	---
Rh-103m	---	---
Rh-106	---	---
Te-132	---	---
Te-125m	---	---
Te-127m	---	---
Te-127	---	---
Te-129m	---	---
Te-129	---	---
Te-131m	---	---
Total:	3.78E+04	3.78E+03

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-4 (Sheet 1 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SHIPPED PRIMARY WASTES

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	---	---
Br-84	---	---
Br-85	---	---
I-129	---	---
I-130	---	---
I-131	6.04E-02	6.04E-03
I-132	---	---
I-133	---	---
I-134	---	---
I-135	---	---
Rb-86	---	---
Rb-88	---	---
Rb-89	---	---
Cs-134	2.81E+02	2.81E+01
Cs-136	2.61E-02	2.61E-03
Cs-137	4.61E+02	4.61E+01
Cs-138	---	---
Ba-137m	4.61E+02	4.61E+01
Cr-51	3.37E+00	3.37E-01
Mn-54	8.50E+01	8.50E+00
Mn-56	---	---
Fe-55	9.75E+01	9.75E+00
Fe-59	1.23E+00	1.23E-01
Co-58	8.51E+01	8.51E+00
Co-60	9.29E+01	9.29E+00
Zn-65	2.34E+01	2.34E+00
Sr-89	8.05E-01	8.05E-02
Sr-90	1.13E+00	1.13E-01
Sr-91	---	---
Sr-92	---	---
Ba-140	4.80E-01	4.80E-02
Y-90	1.13E+00	1.13E-01
Y-91m	---	---
Y-91	4.03E-04	4.03E-05

Table 11.4-4 (Sheet 2 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SHIPPED PRIMARY WASTES

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	---	---
Y-93	---	---
La-140	5.52E-01	5.52E-02
Zr-95	1.09E-04	1.09E-05
Nb-95	1.31E-04	1.31E-05
Mo-99	---	---
Tc-99m	---	---
Ru-103	1.10E-03	1.10E-04
Ru-106	5.38E-02	5.38E-03
Rh-103m	1.11E-03	1.11E-04
Rh-106	5.38E-02	5.38E-03
Te-132	---	---
Te-125m	---	---
Te-127m	---	---
Te-127	---	---
Te-129m	2.10E-05	2.10E-06
Te-129	1.37E-05	1.37E-06
Te-131m	---	---
Total:	1.60E+03	1.60E+02

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-5 (Sheet 1 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF SHIPPED PRIMARY WASTES

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	---	---
Br-84	---	---
Br-85	---	---
I-129	3.44E-03	3.44E-04
I-130	---	---
I-131	4.10E+02	4.10E+01
I-132	---	---
I-133	6.27E-08	6.27E-09
I-134	---	---
I-135	---	---
Rb-86	9.76E+00	9.76E-01
Rb-88	---	---
Rb-89	---	---
Cs-134	9.31E+03	9.31E+02
Cs-136	3.47E+02	3.47E+01
Cs-137	9.13E+03	9.13E+02
Cs-138	---	---
Ba-137m	9.13E+03	9.13E+02
Cr-51	1.86E+01	1.86E+00
Mn-54	1.10E+02	1.10E+01
Mn-56	---	---
Fe-55	1.12E+02	1.12E+01
Fe-59	3.66E+00	3.66E-01
Co-58	2.26E+02	2.26E+01
Co-60	2.42E+02	2.42E+01
Zn-65	---	---
Sr-89	3.06E+01	3.06E+00
Sr-90	1.09E+01	1.09E+00
Sr-91	---	---
Sr-92	---	---
Ba-140	2.35E+00	2.35E-01
Y-90	1.09E+01	1.09E+00
Y-91m	---	---
Y-91	3.90E-01	3.90E-02

Table 11.4-5 (Sheet 2 of 2)

MAXIMUM ANNUAL CURIE CONTENTS OF SHIPPED PRIMARY WASTES

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	---	---
Y-93	---	---
La-140	2.70E+00	2.70E-01
Zr-95	---	---
Nb-95	---	---
Mo-99	---	---
Tc-99m	---	---
Ru-103	---	---
Ru-106	---	---
Rh-103m	---	---
Rh-106	---	---
Te-132	---	---
Te-125m	---	---
Te-127m	---	---
Te-127	---	---
Te-129m	---	---
Te-129	---	---
Te-131m	---	---
Total:	2.91E+04	2.91E+03

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-6 (Sheet 1 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SECONDARY WASTE AS GENERATED

Isotope	Secondary Resin Total Ci/yr
Na-24	1.83E-02
Cr-51	4.29E-02
Mn-54	2.95E-02
Fe-55	2.35E-02
Fe-59	4.49E-03
Co-58	7.78E-02
Co-60	1.03E-02
Zn-65	9.56E-03
Br-84	2.22E-05
Rb-88	8.99E-05
Sr-89	2.24E-03
Sr-90	2.37E-04
Sr-91	2.11E-04
Y-90	2.06E-04
Y-91	2.53E-04
Y-91m	1.82E-04
Y-93	9.80E-04
Zr-95	6.53E-03
Nb-95	5.19E-03
Nb-95m	4.74E-03
Mo-99	1.52E-02
Tc-99m	1.41E-02
Ru-103	1.13E-01
Ru-106	1.65E+00
Rh-103m	1.39E-01
Rh-106	2.11E+00
Ag-110	2.12E-02
Ag-110m	2.45E-02
Te-129	2.29E-03
Te-129m	2.79E-03
Te-131	1.14E-03
Te-131m	1.42E-03
Te-132	4.74E-04

Table 11.4-6 (Sheet 2 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SECONDARY WASTE AS GENERATED

Isotope	Secondary Resin Total Ci/yr
I-131	1.70E-01
I-132	7.93E-03
I-133	5.23E-02
I-134	1.18E-03
I-135	2.56E-02
Xe-131m	---
Xe-133	---
Xe-135	---
Cs-134	2.50E-01
Cs-135	4.70E-10
Cs-136	1.48E-02
Cs-137	3.39E-01
Ba-136m	1.39E-02
Ba-137m	3.42E-01
Ba-140	1.17E-01
La-140	1.47E-01
Ce-141	2.13E-03
Ce-143	2.91E-03
Ce-144	7.35E-02
Pr-143	2.04E-03
Pr-144	6.37E-02
Total:	5.96E+00

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-7 (Sheet 1 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF SECONDARY WASTE AS GENERATED

Isotope	Secondary Resin Total Ci/yr
Na-24	4.62E-04
Cr-51	5.17E-01
Mn-54	3.55E-01
Mn-56	2.24E-01
Fe-55	2.78E-01
Fe-59	5.88E-02
Co-58	9.25E-01
Co-60	1.23E-01
Br-83	3.73E-02
Br-84	1.41E-03
Br-85	1.64E-06
Kr-83m	---
Kr-85	---
Kr-85m	---
Rb-88	4.56E-02
Rb-89	1.53E-03
Sr-89	9.10E-01
Sr-90	5.00E-02
Sr-91	2.13E-02
Sr-92	7.25E-04
Y-90	4.60E-02
Y-91	4.34E-02
Y-91m	2.11E-02
Y-92	2.66E-03
Y-93	1.04E-03
Zr-95	7.74E-02
Nb-95	8.25E-02
Nb-95m	5.52E-02
Mo-99	1.52E+01
Tc-99m	1.68E+01
Ru-103	6.28E-02
Ru-103m	3.87E-02
Rh-103m	6.29E-02
Rh-106	5.95E-02

Table 11.4-7 (Sheet 2 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF SECONDARY WASTE AS GENERATED

Isotope	**Secondary Resin Total Ci/yr**
Ag-110	1.34E-02
Ag-110m	2.24E-01
Te-129	1.19E+00
Te-129m	1.10E+00
Te-131	2.35E+00
Te-131m	2.01E-01
Te-132	6.75E+00
Te-134	1.49E-03
I-130	1.19E-01
I-131	1.37E+02
I-132	6.77E+00
I-133	2.51E+01
I-134	4.99E-02
I-135	3.99E+00
Xe-131m	---
Xe-133	---
Xe-135	---
Cs-134	6.90E+02
Cs-135	6.16E-08
Cs-136	5.15E+02
Cs-137	5.00E+02
Cs-138	3.41E-02
Ba-136m	6.35E+02
Ba-137m	5.14E+02
Ba-140	2.83E-01
La-140	3.31E-01
Ce-141	6.42E-02
Ce-143	4.94E-03
Ce-144	6.33E-02
Pr-143	4.63E-02
Pr-144	6.33E-02
Total:	3.08E+03

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-8 (Sheet 1 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SHIPPED SECONDARY WASTES

Isotope	Secondary Resin Total Ci/yr
Na-24	---
Cr-51	4.55E-03
Mn-54	2.40E-02
Fe-55	2.19E-02
Fe-59	1.14E-03
Co-58	3.25E-02
Co-60	9.95E-03
Zn-65	7.42E-03
Br-84	---
Rb-88	---
Sr-89	6.86E-04
Sr-90	2.36E-04
Sr-91	---
Y-90	2.31E-04
Y-91	6.71E-09
Y-91m	---
Y-93	---
Zr-95	2.52E-03
Nb-95	4.06E-03
Nb-95m	2.32E-03
Mo-99	---
Tc-99m	---
Ru-103	2.34E-02
Ru-106	1.38E+00
Rh-103m	2.87E-02
Rh-106	1.77E+00
Ag-110	1.66E-02
Ag-110m	1.92E-02
Te-129	3.44E-04
Te-129m	4.48E-04
Te-131	---
Te-131m	---

Table 11.4-8 (Sheet 2 of 2)

EXPECTED ANNUAL CURIE CONTENT OF SHIPPED SECONDARY WASTES

Isotope	**Secondary Resin Total Ci/yr**
Te-132	---
I-131	7.32E-05
I-132	---
I-133	---
I-134	---
I-135	---
Xe-131m	---
Xe-133	---
Xe-135	---
Cs-134	2.31E-01
Cs-135	4.86E-10
Cs-136	1.56E-04
Cs-137	3.36E-01
Ba-136m	1.47E-04
Ba-137m	3.40E-01
Ba-140	8.97E-04
La-140	1.05E-03
Ce-141	3.13E-04
Ce-143	---
Ce-144	5.91E-02
Pr-143	2.38E-05
Pr-144	5.12E-02
Total:	4.38E+00

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-9 (Sheet 1 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF SHIPPED SECONDARY WASTES

Isotope	Secondary Resin Total Ci/yr
Na-24	---
Cr-51	5.47E-02
Mn-54	2.89E-01
Mn-56	---
Fe-55	2.60E-01
Fe-59	1.50E-02
Co-58	3.87E-01
Co-60	1.19E-01
Br-83	---
Br-84	---
Br-85	---
Kr-83m	---
Kr-85	---
Kr-85m	---
Rb-88	---
Rb-89	---
Sr-89	2.79E-01
Sr-90	4.96E-02
Sr-91	---
Sr-92	---
Y-90	5.12E-02
Y-91	1.12E-06
Y-91m	---
Y-92	---
Y-93	---
Zr-95	2.98E-02
Nb-95	5.19E-02
Nb-95m	2.70E-02
Mo-99	2.72E-09
Tc-99m	3.04E-09
Ru-103	1.30E-02
Ru103m	3.27E-02

Table 11.4-9 (Sheet 2 of 2)

MAXIMUM ANNUAL CURIE CONTENT OF SHIPPED SECONDARY WASTES

Isotope	**Secondary Resin Total Ci/yr**
Rh-103m	1.30E-02
Rh-106	5.03E-02
Ag-110	1.05E-02
Ag-110m	1.76E-01
Te-129	1.92E-01
Te-129m	1.77E-01
Te-131	---
Te-131m	---
Te-132	2.90E-08
Te-134	---
I-130	---
I-131	5.94E-02
I-132	2.36E-08
I-133	---
I-134	---
I-135	---
Xe-131m	---
Xe-133	---
Xe-135	---
Cs-134	6.35E+02
Cs-135	6.36E-08
Cs-136	5.42E+00
Cs-137	4.98E+02
Cs-138	---
Ba-136m	6.69E+00
Ba-137m	5.11E+02
Ba-140	2.18E-03
La-140	2.87E-03
Ce-141	9.41E-03
Ce-143	---
Ce-144	5.08E-02
Pr-143	4.75E-04
Pr-144	5.08E-02
Total:	1.66E+03

Note:
Values shown as "---" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-10 (Sheet 1 of 2)

COMPONENT DATA – SOLID WASTE MANAGEMENT SYSTEM (NOMINAL)

Tanks

Spent resin tank

Number	2
Total volume (ft^3)	300
Type	Vertical, conical bottom, dished top
Design pressure (psig)	15
Design temperature (°F)	150
Material	Stainless steel

Pumps

Resin mixing pump

Number	1
Type	Pneumatic diaphragm
Design pressure (psig)	125
Design temperature (°F)	150
Design flow rate (gpm)	120
Design head (ft)	160
Air supply pressure (psig)	100
Air consumption (scfm)	130
Material	Stainless steel housing, Buna N diaphragms

Resin transfer pump

Number	1
Type	Progressing cavity
Design pressure (psig)	150
Design temperature (°F)	150
Design flow rate (gpm)	100
Material	Stainless steel housing, internals and rotor, Buna N stator liner

Table 11.4-10 (Sheet 2 of 2)

COMPONENT DATA – SOLID WASTE MANAGEMENT SYSTEM (NOMINAL)

Filters

Resin fines filter

Number	1
Type	Filter cartridge for inside to outside flow
Design pressure (psig)	150
Design temperature (°F)	150
Design flowrate (gpm)	120
Filtration rating	10 microns
Material	Stainless steel housing and pleated polypropylene cartridge with stainless steel screen outer jacket

Sampler

Resin sampling device

Number	1
Type	Inline sampler, positive displacement sample collection and portable pig for sample jar
Material	Stainless steel and EPDM wetted parts

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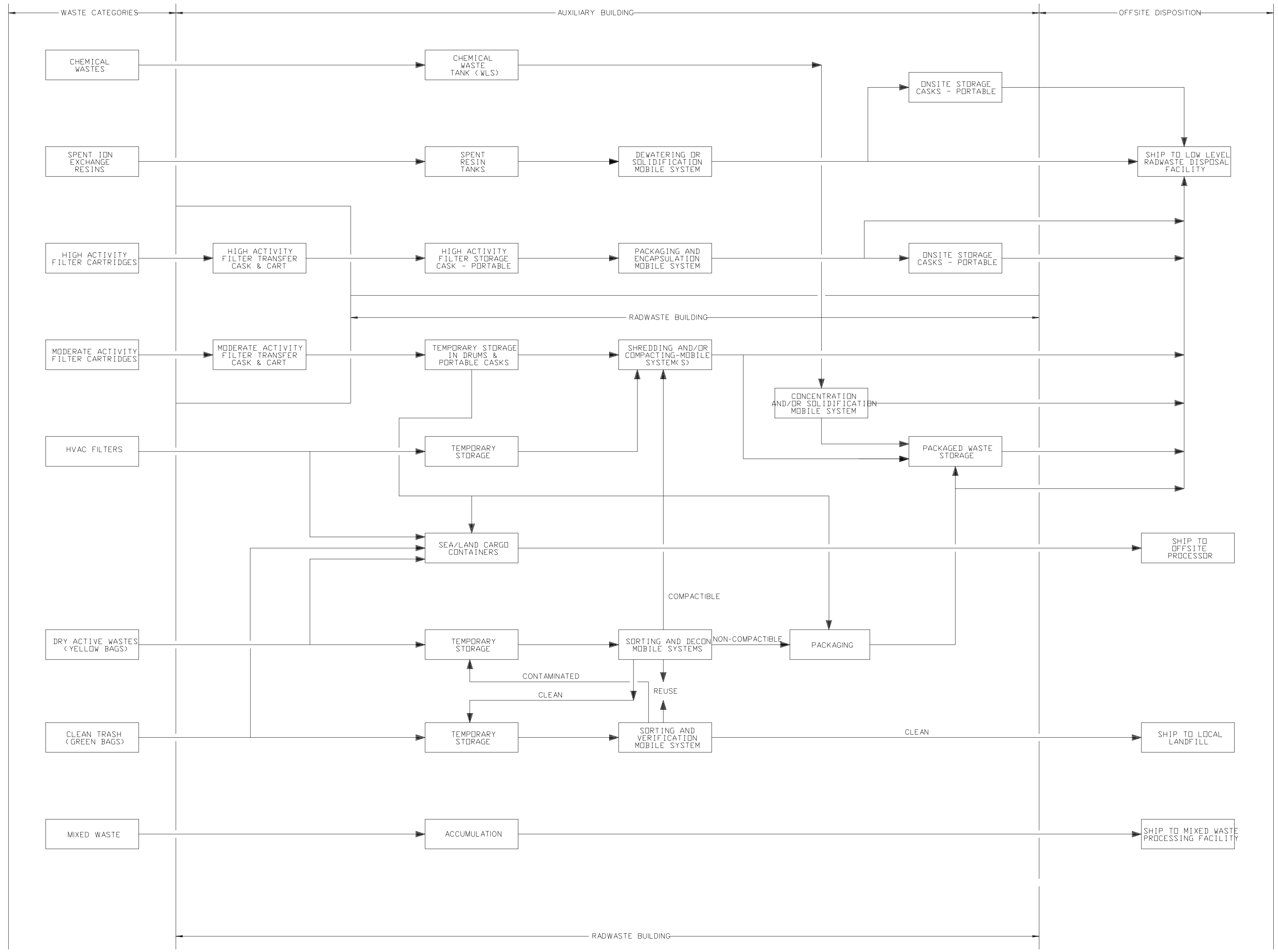

Figure 11.4-1

Waste Processing System Flow Diagram

11.5 Radiation Monitoring

The radiation monitoring system (RMS) provides plant effluent monitoring, process fluid monitoring, airborne monitoring, and continuous indication of the radiation environment in plant areas where such information is needed. Radiation monitors that have a safety-related function are qualified environmentally, seismically, or both. Class 1E radiation monitors conform to the separation criteria described in subsection 8.3.2 and to the fire protection criteria described in subsection 9.5.1. Equipment qualification requirements, including seismic qualification requirements, and general location information for radiation monitors are listed in Section 3.11. Seismic Categories for the buildings housing radiation monitors are listed in Section 3.2.

The radiation monitoring system is installed permanently and operates in conjunction with regular and special radiation survey programs to assist in meeting applicable regulatory requirements. The radiation monitoring system is designed in accordance with ANSI N13.1-1969.

The radiation monitoring system is divided functionally into two subsystems:

- Process, airborne, and effluent radiological monitoring and sampling
- Area radiation monitoring

11.5.1 Design Basis

11.5.1.1 Safety Design Basis

While the radiation monitoring system is primarily a surveillance system, certain detector channels perform safety-related functions. The components used in these channels meet the qualification requirements for safety-related equipment as described in subsection 7.1.4.

Channel and equipment redundancy is provided for safety-related monitors to maintain the safety-related function in case of a single failure.

The design objectives of the radiation monitoring system during postulated accidents are:

- Initiate containment air filtration isolation in the event of abnormally high radiation inside the containment (High-1)

- Initiate normal residual heat removal system suction line containment isolation in the event of abnormally high radiation inside the containment (High-2)

- Initiate main control room supplemental filtration in the event of abnormally high gaseous radioactivity in the main control room supply air

- Initiate main control room ventilation isolation and actuate the main control room emergency habitability system in the event of abnormally high particulate or iodine radioactivity in the main control room supply air

- Provide long-term post-accident monitoring (using both safety-related and nonsafety-related monitors)

The scope of the radiation monitoring system for post-accident monitoring is set forth in General Design Criterion 64 and in the provisions of Regulatory Guide 1.97.

11.5.1.2 Power Generation Design Basis

The radiation monitoring system is designed to support the requirements of 10 CFR 20 and to provide:

- Equipment to meet the applicable regulatory requirements for both normal operation and transient events
- Data to aid plant health physics personnel in limiting release of radioactivity to the environment and limiting exposure of operation and maintenance personnel to meet ALARA (as-low-as-reasonably-achievable) guidance
- Early indication of a system or equipment malfunction that could result in excessive radiation dose to plant personnel or lead to plant damage
- Data collection and data storage to support compliance reporting for the applicable NRC requirements and guidelines, such as General Design Criterion 64 and Regulatory Guide 1.21.
- Exhausts to the environment from the personnel areas in the annex building, electrical and mechanical equipment rooms in the annex and auxiliary buildings, and the diesel generator rooms will not be radioactive because they contain no radioactive materials. These ventilation exhausts are not monitored.

11.5.2 System Description

11.5.2.1 Radiation Monitoring System

The radiation monitoring system uses distributed radiation monitors, where each radiation monitor consists of one or more radiation detectors and a dedicated radiation processor.

Each radiation processor receives, averages and stores radiation data and transmits alarms and data to the plant control system (protection and safety monitoring system for safety-related monitors) for control (as required), display and recording. These alarms include: low (fail), alert, and high. Selected channels have a rate-of-rise alarm. Storage of radiation readings is provided.

Each radiation detector, except the in-duct radiation detectors and the containment high range ion chambers, has a check source that is actuated from the associated local radiation processor. The check source is used to verify detector and monitor operation. The check source is shielded to meet ALARA requirements, and returns to its fully retracted/shielded position upon loss of actuator power. Check sources on detectors can be actuated from the main control room. The in-duct radiation detector operation may be checked using an internal LED to simulate light pulses emitted in response to radiation. The containment high range monitors have an internal source that provides a minimum reading; loss of signal from the detector indicates detector inoperability.

Radiation monitoring data, including alarm status, are provided to AP1000 operators via the plant control system (and the protection and safety monitoring system for Class 1E monitors). The information is available in either counts per minute (count rate), microCuries/cc (activity concentration), or R/hr (radiation dose rate).

Safety-related channels are environmentally qualified and are powered from the Class 1E dc and uninterruptible power supply system. Nonsafety-related channels are powered from the non-Class 1E dc and uninterruptible power supply system.

11.5.2.2 Monitor Functional Description

The process and effluent radiological monitoring and sampling subsystem provides radiation monitoring for the four functional classifications listed below. Individual monitors may provide functionality in more than one of these classifications.

- Fluid process monitors determine concentrations of radioactive material in plant fluid systems

- Airborne monitors provide operators with information on concentrations of radioactivity at various points in the ventilation system, providing information on airborne concentrations in the plant

- Liquid and gaseous effluent monitors measure radioactive materials discharged to the environs

- Post-accident monitors monitor potential pathways for release of radioactive materials during accident conditions

The area radiation monitoring subsystem provides plant personnel information on radiation at fixed locations in AP1000. Post-accident monitoring functions are also performed by certain area monitors.

11.5.2.3 Monitor Descriptions

For offline gaseous monitors, the radiation monitor includes a low pressure drop flow sensor suitable for measuring the sample flow. The radiation processor receives an analog signal input from this flow sensor. This signal is used by the radiation processor to control sample flow. The analog signal is transmitted to the plant control system (protection and safety monitoring system for safety-related monitors). For offline liquid monitors, a flow indicator is provided for manual adjustment of the flow.

Those airborne radiation monitors which monitor plant areas which may be occupied by plant personnel will be capable of detecting 10 DAC-hours. The specific radiation monitors which are included in this category are identified in Table 11.5-1.

11.5.2.3.1 Fluid Process Monitors

Steam Generator Blowdown Radiation Monitors

The steam generator blowdown radiation monitors (BDS-JE-RE010, RE011) measure the concentration of radioactive material in the blowdown from the steam generators. One measures radiation in the purification process effluent before it is returned to the condensate system. The other measures radioactivity in the blowdown system electrodeionization waste brine before it is discharged to the waste water system. The presence of radioactive material in the steam generator blowdown indicates a leak between the primary side and the secondary side of the steam generator. Refer to subsection 5.2.5 for details of leakage monitoring and to subsections 10.4.8 and 11.2 for process system details. The steam generator blowdown radiation monitors meet the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

AP1000 has two steam generators, each of which has a blowdown line. Each blowdown line has a heat exchanger upstream of the blowdown flow control valve. The steam generator blowdown radiation detectors are located in the lines downstream of these heat exchangers. Therefore, the radiation monitors do not require a sample cooler.

When its predetermined setpoint is exceeded, each steam generator blowdown radiation monitor initiates an alarm in the main control room, initiates closure of the steam generator blowdown containment isolation valves and the steam generator blowdown flow control valves, and diverts flow to the liquid radwaste system.

The steam generator blowdown radiation monitors use inline gamma-sensitive, thallium-activated, sodium iodide scintillation detectors. The steam generator blowdown radiation monitor detector range and principal isotopes are listed in Table 11.5-1.

The arrangement for the steam generator blowdown radiation monitor is shown in Figure 11.5-1.

Component Cooling Water System Radiation Monitor

The component cooling water system radiation monitor (CCS-JE-RE001) measures the concentration of radioactive material in the component cooling water system. Radioactive material in the component cooling water system provides indication of leakage. Refer to subsection 5.2.5 for details of leakage monitoring and to subsection 9.2.2 for process system details.

If the concentration of radioactive materials exceeds a predetermined setpoint, the component cooling water system radiation monitor initiates an alarm in the main control room.

The component cooling water system radiation monitor is an offline monitor that uses a gamma-sensitive, thallium-activated, sodium iodide scintillation detector. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the component cooling water system radiation monitor is shown in Figure 11.5-7.

Main Steam Line Radiation Monitors

The main steam line radiation monitors (SGS-JE-RE026 and SGS-JE-RE027) measure the concentration of radioactive materials in the two main steam lines. Additionally, the main steam line radioisotope concentration data are used to calculate releases to the environment if the steam generator safety relief or power operated relief valves release steam to the atmosphere. Each main steam line radiation monitor meets the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5. If the concentration of radioactive materials exceeds a predetermined setpoint, the main steam line radiation monitors initiate alarms in the main control room.

The main steam line radiation monitors are positioned adjacent to the steam lines. Each monitor detector shield is arranged so that the detector sensitive volume is exposed to the radiation originating inside the steam line on which it is located, and is shielded from radiation originating in the other steam line. Radioactive material in the main steam line provides early indication of leakage in the form of a steam generator tube leak. Refer to subsection 5.2.5 for details of leakage monitoring and to Section 10.3 for process system details.

The main steam line radiation monitor detectors use gamma-sensitive detectors.

Each main steam line radiation monitor range and principal isotopes are listed in Table 11.5-1.

The arrangement for a main steam line radiation monitor is shown in Figure 11.5-8.

Service Water Blowdown Radiation Monitor

The service water blowdown radiation monitor (SWS-JE-RE008) measures the concentration of radioactive materials in the blowdown flow from the service water system. Upstream of the radiation monitor, local grab sampling is available.

The service water blowdown radiation monitor initiates an alarm in the main control room if the concentration of radioactive materials exceeds a predetermined setpoint. Following the alarm, the operator can manually isolate the blowdown flow. Refer to subsection 9.2.1 for system details.

The service water blowdown monitor is an offline monitor using a gamma-sensitive, thallium-activated, sodium iodide scintillation detector that views the liquid sample volume. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the service water blowdown radiation monitor is shown in Figure 11.5-7.

Primary Sampling System Liquid Sample Radiation Monitor

The primary sampling system (PSS) liquid sample radiation monitor (PSS-JE-RE050) measures and indicates the concentration of radioactive materials in the samples from the reactor coolant system. The liquid sample radiation monitor's primary function is to indicate elevated sample radiation levels following a design basis or severe accident. High radiation levels show the need for sample dilution to limit operator exposure during sampling and sample transport for analysis. The monitor may also be used to provide early indication of a significant increase in the

radioactivity of the reactor coolant indicating a possible fuel cladding breach. When a predetermined setpoint is exceeded, the primary sampling system liquid sample radiation monitor isolates the sample flow by closing the outside containment isolation valve and initiates an alarm in the main control room and locally to alert the operator. Refer to subsection 9.3.3 for system details.

The primary sampling system liquid sample radiation monitor utilizes a gamma-sensitive radiation detector that is adjacent to the sampling line immediately downstream of the sample cooler. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the primary sampling system liquid sample radiation monitor is shown in Figure 11.5-8.

Primary Sampling System Gaseous Sample Radiation Monitor

The primary sampling system gaseous sample radiation monitor (PSS-JE-RE052) measures the concentration of radioactive materials in the gaseous samples taken from containment atmosphere. The gaseous sample radiation monitor is used to provide indication of significant radioactivity in the gaseous sample being taken and the need for dilution of the sample to limit operator exposure during sampling and transport for analysis. When a predetermined setpoint is exceeded, the primary sampling system gaseous sample radiation monitor initiates an alarm locally and in the main control room to alert the operator. Refer to subsection 9.3.3 for system details.

The primary sampling system gaseous sample radiation monitor utilizes a gamma-sensitive radiation detector that is adjacent to the sampling line immediately upstream of the sample bottle. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the primary sampling system gaseous sample radiation monitor is shown in Figure 11.5-8.

Main Control Room Supply Air Duct Radiation Monitors

The main control room supply air duct radiation monitors (particulate detectors VBS-JE-RE001A and VBS-JE-RE001B, iodine detectors VBS-JE-RE002A and VBS-JE-RE002B, and noble gas detectors VBS-JE-RE003A and VBS-JE-RE003B) are offline monitors that continuously measure the concentration of radioactive materials in the air that is supplied to the main control room by the nuclear island nonradioactive ventilation system air handling units. The technical support center ventilation is also part of this air supply system. The air supply is partially outside air. Refer to subsection 9.4.1 for system details. The main control room supply air duct radiation monitors receive safety-related power. When predetermined setpoints are exceeded, the monitors provide signals to initiate the supplemental air filtration system on high gaseous concentration, and to isolate the main control room air intake and exhaust ducts and activate the main control room emergency habitability system on high particulate or iodine concentrations. Alarms are also provided in the main control room for these high concentrations.

The main control room supply air duct radiation monitor components are qualified environmentally and seismically in accordance with the guidelines of Regulatory Guides 1.89 and 1.100, respectively. Each monitor meets the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

The particulate detectors are beta-sensitive scintillation detectors that view a fixed filter. The iodine detectors are gamma-sensitive, thallium-activated, sodium iodide scintillation detectors that view a fixed charcoal filter. The gas detectors are beta-sensitive scintillation detectors. The range and principal radioisotopes are listed in Table 11.5-1.

The arrangement for a main control room supply air duct radiation monitor is shown in Figure 11.5-6.

Containment Air Filtration Exhaust Radiation Monitor

The containment air filtration exhaust radiation monitor (VFS-JE-RE001) measures the concentration of radioactive materials in the containment purge exhaust air.

The monitor provides an alarm in the main control room when the concentration of radioactive gases in the exhaust exceeds a predetermined setpoint. Refer to subsection 9.4.7 for system details.

The containment air filtration exhaust radiation monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located downstream of the containment air filtration units with its sensitive volume inside the duct. The detector range and principal radioisotopes are listed in Table 11.5-1.

The arrangement of the containment air filtration exhaust radiation monitor is shown in Figure 11.5-5.

Gaseous Radwaste Discharge Radiation Monitor

The gaseous radwaste discharge radiation monitor (WGS-JE-RE017) measures the concentration of radioactive materials in the releases from the gaseous radwaste system to the plant vent. The measurement is made before the discharge reaches the plant vent or is diluted by any other flows.

The gaseous radwaste discharge radiation monitor provides an alarm in the main control room and terminates the release of radioactive gas to the plant vent by closing the discharge isolation valve when a predetermined setpoint is exceeded. Refer to Section 11.3 for system details.

The monitor is an inline monitor using a beta-sensitive scintillation detector with its sensitive volume inside the piping. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the gaseous radwaste discharge radiation monitor is shown in Figure 11.5-1.

Containment Atmosphere Radiation Monitor

The containment atmosphere radiation monitor measures the radioactive gaseous (PSS-JE-RE026) and N^{13}/F^{18} (PSS-JE-RE027) concentrations in the containment atmosphere. The containment atmosphere radiation monitor is a part of the reactor coolant pressure boundary leak detection system described in subsection 5.2.5. The presence of gaseous or N^{13} radioactivity in the containment atmosphere is an indication of reactor coolant pressure boundary leakage. Refer to subsection 5.2.5 for further details. Conformance with Regulatory Guide 1.45 is discussed in Appendix 1A.

The containment atmosphere radiation monitor accepts analog signal inputs for sample flow and temperature. These signals are used to calculate concentrations at standard conditions.

The radiogas detector is a beta-sensitive scintillation detector. The N^{13}/F^{18} detector is a gamma-sensitive, thallium-activated, sodium iodide scintillation detector with a window at the N^{13}/F^{18} 0.511 MeV decay energy. The ranges and principal isotopes are listed in Table 11.5-1.

The arrangement for the containment atmosphere radiation monitor is shown in Figure 11.5-3.

11.5.2.3.2 Airborne Monitors

Fuel Handling Area Exhaust Radiation Monitor

The fuel handling area exhaust radiation monitor (VAS-JE-RE001) measures the concentration of radioactive materials in the exhaust air from the fuel handling area. This radiation monitor is located upstream of the exhaust air isolation damper.

When a predetermined setpoint is exceeded, the fuel handling area exhaust radiation monitor provides signals to alarm in the main control room, to initiate closure of the fuel handling area supply and exhaust air isolation dampers, to open the fuel handling area exhaust air isolation damper to the containment air filtration exhaust units, and to start a containment air filtration exhaust unit. These actions provide a filtered air path from the fuel handling area to the plant vent. Refer to subsection 9.4.3 for system details.

The fuel handling area exhaust radiation monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the fuel handling area exhaust radiation monitor is shown in Figure 11.5-5.

Auxiliary Building Exhaust Radiation Monitor

The auxiliary building exhaust radiation monitor (VAS-JE-RE002) measures the concentration of radioactive materials in the radiologically controlled area ventilation system exhaust air from the auxiliary building. The auxiliary building radiation monitor detector is upstream of the exhaust air isolation damper.

When a predetermined setpoint is exceeded, indicating abnormal airborne radiation, the auxiliary building exhaust radiation monitor provides signals to alarm in the main control room, to initiate closure of the auxiliary building supply and exhaust air isolation dampers, to open the auxiliary building exhaust air isolation damper to the containment air filtration exhaust units, and to start a containment air filtration exhaust unit. These actions provide a filtered air path from the auxiliary building to the plant vent. Refer to subsection 9.4.3 for system details.

The auxiliary building exhaust radiation monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the auxiliary building exhaust radiation monitor is shown in Figure 11.5-5.

Annex Building Exhaust Radiation Monitor

The annex building exhaust radiation monitor (VAS-JE-RE003) measures the concentration of radioactive materials in the radiologically controlled area ventilation system exhaust air from the annex building. The annex building exhaust radiation monitor is located upstream of the annex building exhaust air isolation damper.

When a predetermined setpoint is exceeded, indicating abnormal airborne radiation, the annex building exhaust radiation monitor provides signals to alarm in the main control room, to initiate closure of the annex building supply and exhaust air isolation dampers, to open the annex building exhaust air isolation damper to the containment air filtration units, and to start a containment air filtration exhaust unit. These actions provide a filtered air path from the annex building to the plant vent. Refer to subsection 9.4.3 for system details.

The annex building monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the annex building exhaust radiation monitor is shown in Figure 11.5-5.

Health Physics and Hot Machine Shop Exhaust Radiation Monitor

The health physics and hot machine shop exhaust radiation monitor (detector VHS-JE-RE001) measures the concentration of radioactive materials in the exhaust air from the health physics area and the hot machine shop. The monitor provides an alarm in the main control room when the concentration of radioactive gases in the exhaust exceeds a predetermined setpoint. Refer to subsection 9.4.11 for system details.

The monitor is an offline monitor, located downstream of the exhaust fans, that uses a beta-sensitive scintillation detector viewing a fixed particulate filter. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the health physics and hot machine shop exhaust radiation monitor is shown in Figure 11.5-9.

Radwaste Building Exhaust Radiation Monitor

The radwaste building exhaust radiation monitor (VRS-JE-RE023) measures the concentration of radioactive materials in the exhaust air from the radwaste building. The monitor provides an alarm in the main control room when radioactive material concentrations in the exhaust duct exceed a predetermined setpoint. Refer to subsection 9.4.8 for system details.

The monitor is an offline monitor, located downstream of the exhaust fans, that uses a beta-sensitive scintillation detector viewing a fixed particulate filter. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the radwaste building exhaust radiation monitor is shown in Figure 11.5-9.

11.5.2.3.3 Liquid and Gaseous Effluent Monitors

Plant Vent Radiation Monitor

The plant vent radiation monitor measures the concentration of radioactive airborne contamination being released through the plant vent, which is the only design pathway for the release of radioactive materials to the atmosphere. The plant vent radiation monitor sample is provided using an isokinetic sampling nozzle assembly that has flow sensors. Heat tracing is provided for the sample line. The monitor also provides particulate, iodine, and gaseous grab sampling capability.

The plant vent is sampled continuously for the full range of concentrations between normal conditions and those postulated in Regulatory Guide 1.97. The plant vent radiation monitor is a post-accident monitor and meets the guidelines of Regulatory Guide 1.97 and NUREG-0737 as discussed in Appendix 1A and Section 7.5. Alarms are provided in the main control room if radioactivity concentrations exceed predetermined setpoints. The plant vent radiation monitor also provides data for plant effluent release reports identified in Regulatory Guide 1.21. For further process details, refer to subsection 11.3.3.

The normal range particulate detector, VFS-JE-RE101, uses a beta-sensitive scintillation detector that views a fixed filter. The accident range particulate filter is fixed and identical to the normal range filter. The accident range particulate filter is analyzed in an onsite laboratory.

The normal range iodine detector, VFS-JE-RE102, is a gamma-sensitive, thallium-activated, sodium iodide, scintillation detector that views a fixed charcoal filter. The accident range iodine filter is a fixed silver zeolite filter. The accident range iodine filter is analyzed in an onsite laboratory.

The three radiogas channels measure the entire specified range, with overlap in the detector ranges. The normal range radiogas detector, VFS-JE-RE103, is a beta-sensitive scintillation detector. The accident range radiogas detectors, VFS-JE-RE104A (mid-range) and VFS-JE-RE104B (high-range), are beta/gamma-sensitive detectors with small sensitive volumes compared to the normal range radiogas detector.

The plant vent radiation monitor detector ranges and principal radioisotopes are listed in Table 11.5-1. The arrangement for the plant vent radiation monitor is shown in Figure 11.5-4.

The plant vent radiation monitor accepts analog signal inputs from process and sample sensors for plant vent effluent flow and temperature. These signals are used to control the sample flow to maintain isokinetic extraction at the sample nozzles, and to calculate concentrations, releases and flow rates at standard conditions. These analog signals are also used to calculate total process flow, total sample flow, and total discharge for an operator-selected period.

The normal range particulate, iodine, and radiogas detectors are deactivated automatically when the gas channel concentration exceeds the normal range. The sample flow bypasses the normal range detectors and a small portion is extracted for the accident range particulate and iodine sample filters and radiogas detectors. This prevents normal range detector damage and allows these detectors to be used to measure the concentrations after they decrease again to within the normal range detector ranges.

Turbine Island Vent Discharge Radiation Monitor

The turbine island vent discharge radiation monitor (TDS-JE-RE001) measures the concentration of radioactive gases in the steam and non-condensable gases that are discharged by the condenser vacuum pumps and the gland seal steam condenser. This measurement provides early indication of leakage between the primary and secondary sides of the steam generators. The monitor provides an alarm in the main control room if concentrations exceed a predetermined setpoint. Refer to subsection 5.2.5 for leakage monitoring details and to subsections 10.4.2 and 10.4.3 for process system details. The turbine island vent discharge radiation monitor meets the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

The turbine island vent discharge radiation monitor is designed per the guidelines of ANSI N13.1 and provides data for reports of gaseous releases of radioactive materials in accordance with Regulatory Guide 1.21. The monitor is an inline monitor that uses two beta/gamma-sensitive Geiger-Mueller tubes with overlap in the detector ranges. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the turbine island vent discharge radiation monitor is shown in Figure 11.5-1.

Liquid Radwaste Discharge Radiation Monitor

The liquid radwaste discharge radiation monitor (WLS-JE-RE229) measures the concentration of radioactive materials in liquids released to the environment. The liquid releases are made in batches that are mixed thoroughly and sampled. The samples are analyzed on site before discharge to determine that the discharge is within allowable concentration limits and within allowable totals.

The liquid radwaste discharge radiation monitor provides data for reports of liquid releases of radioactive materials in accordance with Regulatory Guide 1.21.

The liquid radwaste discharge radiation monitor is an offline monitor that provides signals to isolate the discharge of liquid radwaste, stop the liquid radwaste system discharge pumps and alarms in the main control room if the concentrations exceed a predetermined setpoint. For process system details refer to Section 11.2.

The range and principal isotopes are listed in Table 11.5-1. The detector is a gamma-sensitive, thallium-activated, sodium iodide scintillation detector that views the liquid sample volume.

The arrangement for the liquid radwaste discharge radiation monitoring channel is shown in Figure 11.5-7.

Waste Water Discharge Radiation Monitor

The waste water discharge radiation monitor (WWS-JE-RE021) measures the concentration of radioactive materials in the discharge from the waste water system. The waste water discharge radiation monitor provides data for reports of liquid releases of radioactive materials in accordance with Regulatory Guide 1.21.

The waste water discharge radiation monitor is an offline monitor. It stops the turbine building sump pumps and the basin transfer pumps and initiates an alarm in the main control room if the concentration of radioactive materials exceeds a predetermined setpoint. Following an alarm, the operator can manually realign the discharge to the liquid radwaste system for processing. For process system details refer to subsection 9.2.9.

The range and principal isotopes are listed in Table 11.5-1. The detector is a gamma-sensitive, thallium-activated, sodium iodide scintillation detector that views the liquid sample volume.

The arrangement for the waste water discharge radiation monitor is shown in Figure 11.5-7.

11.5.2.4 Inservice Inspection, Calibration, and Maintenance

The operability of each radiation monitoring system channel is checked periodically.

Test and inspection requirements for safety-related channels and certain nonsafety-related channels are provided in the Technical Specifications, Chapter 16.

11.5.3 Effluent Monitoring and Sampling

The primary means of quantitatively evaluating the isotopic activities in effluent paths is a program of sampling and onsite laboratory measurements. Gross activity measurements provided by the radiation monitors described in subsection 11.5.2.3 are used to determine the activities released in effluent paths by calibrating the monitors against normalized laboratory results.

Sample points are located on the gaseous effluent radiation monitor skids.

The requirements of General Design Criterion 64 are satisfied by the sampling program and the effluent radiation monitors described in subsection 11.5.2.3.

11.5.4 Process and Airborne Monitoring and Sampling

Radiation monitors are used to initiate automatic closure of isolation valves and dampers in liquid and gaseous process systems as described in subsection 11.5.2.3. These radiation monitors address the requirement of General Design Criterion 60 to suitably control the release of radioactive materials in gaseous and liquid effluents.

Radiation monitors are used in the radioactive waste processing systems as described in subsection 11.5.2.3. These radiation monitors address the requirement of General Design Criterion 63 to monitor radiation levels in radioactive waste systems.

Radiation monitors are used in the ventilation systems as described in subsection 11.5.2.3 to ensure that airborne concentrations within the plant are within the limits of 10 CFR 20.

11.5.5 Post-Accident Radiation Monitoring

The radiation monitors listed below meet the guidelines of Regulatory Guide 1.97 and are described in subsections 11.5.2.3 and 11.5.6.2. For further Regulatory Guide 1.97 information refer to Appendix 7A and Section 7.5.

- Main steam line radiation monitors
- Steam generator blowdown radiation monitor
- Main control room supply air duct radiation monitors
- Plant vent radiation monitor
- Turbine island vent discharge radiation monitor
- Containment high range radiation monitors
- Primary sampling room area monitor
- Technical support center area monitor

The post-accident sampling system is described in subsection 9.3.3 and is used to obtain samples for onsite laboratory analysis, including radioisotopic analysis, after a postulated accident.

11.5.6 Area Radiation Monitors

The area radiation monitors are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20, 10 CFR 50, and 10 CFR 70; and Regulatory Guides 1.97, 8.2, and 8.8.

During refueling operations in containment and the fuel handling area, criticality monitoring functions, as stated in 10 CFR 70.24, are performed by the area radiation monitors in combination with portable bridge monitors.

11.5.6.1 Design Objectives

The design objectives of the area radiation monitors during normal operating plant conditions and anticipated operational occurrences are to:

- Measure the radiation intensities in specific areas of AP1000
- Warn of uncontrolled or inadvertent movement of radioactive material in AP1000
- Provide local and remote indication of ambient gamma radiation and local and remote alarms at key points where substantial changes in radiation flux might be of immediate importance to personnel
- Annunciate and warn of possible equipment malfunctions and leaks in specific areas of AP1000
- Furnish information for radiation surveys
- Minimize the time, effort, and radiation received by operating personnel during routine maintenance and calibration
- Incorporate modular design concepts throughout, to provide easy maintenance

By meeting the above objectives, the radiation monitoring system aids health physics personnel in keeping radiation exposures as-low-as-reasonably-achievable (ALARA).

Locations of area monitor detectors are based on the following criteria:

- Area monitors are located in areas that are normally accessible and where changes in normal plant operating conditions can cause significant increases in exposure rates above those expected for the areas.
- Area monitors are located in areas that are normally or occasionally accessible where significant increases in exposure rates might occur because of operational transients or maintenance activities.
- Area monitors are located to best measure the increase in exposure rates within a specific area and to avoid shielding of the detector by equipment or structural materials.
- In the selection of area monitors, consideration is given to the environmental conditions under which the monitor operates.

- Area monitors are located to provide access so that minimal maintenance equipment is required and to provide an uncluttered area near the detector and local processing electronics to allow for field alignment and calibration.

The area radiation monitors are listed in Table 11.5-2.

11.5.6.2 Post-Accident Area Monitors

The following area monitors are provided to meet Regulatory Guide 1.97 guidelines as discussed in Appendix 1A and Section 7.5.

Containment High Range Radiation Monitor

The containment high range radiation monitors (PXS-JE-RE160, PXS-JE-RE161, PXS-JE-RE162, and PXS-JE-RE163) measure the radiation from the radioactive gases in the containment atmosphere. The monitors receive safety-related power. The detectors are ion chambers, designed to measure the radiation from the radioactive gases inside the containment in accordance with Regulatory Guide 1.97 and NUREG-0737. The monitors are qualified environmentally and seismically in accordance with the guidelines of Regulatory Guides 1.89 and 1.100, respectively.

The containment high range radiation data are displayed in the main control room. When predetermined setpoints are exceeded, the containment high range radiation monitors provide main control room alarms and signals to the protection and safety monitoring system for containment air filtration isolation and normal residual heat removal system valve closure (refer to Section 7.3 for further details). The containment high range radiation monitors provide data for maintaining a record of the gamma radiation intensities after a postulated accident as a function of time, so that the inventory of radioactive materials in the containment volume can be estimated.

The range and principal isotopes are listed in Table 11.5-1.

The high range radiation detectors are mounted inside the containment on the containment wall in widely separated locations. The locations allow the detectors to be exposed to a significant volume of containment atmosphere without obstruction so that the readouts are representative of the containment atmosphere. The arrangement for a containment high range monitor is shown in Figure 11.5-2.

Primary Sampling Room Area Monitor

The primary sampling station is the location where samples are collected and/or analyzed after a postulated accident. The primary sampling room area radiation monitor (RMS-JE-RE008) is located so that its readout is representative of the radiation to which the operating personnel are exposed. A local readout, an audible alarm, and visual alarms are provided in the primary sampling room to alert operating personnel to increasing exposure rates. A local readout, an audible alarm, and visual alarms are provided outside of the primary sampling room and are visible to operating personnel prior to entry. Indication and alarms are also provided in the main control room.

The monitor is an extended range monitor that uses a gamma-sensitive ion chamber. The monitor range and principal isotopes are listed in Table 11.5-2.

Technical Support Center Area Monitor

The Technical Support Center is the location from which engineering support will be provided to the operators following a postulated accident. The Technical Support Center area radiation monitor (RMS-JE-RE016) is located so that its readout is representative of the radiation to which the support personnel are exposed. A local readout, an audible alarm, and visual alarms are provided locally to alert personnel to increasing exposure rates. A local readout, an audible alarm, and visual alarms are provided outside of the room and are visible to personnel prior to entry. Indication and alarms are also provided in the main control room.

The monitor is a normal range monitor that uses a gamma-sensitive Geiger-Mueller tube. The monitor range and principal isotopes are listed in Table 11.5-2.

11.5.6.3 Normal Range Area Monitors

Normal range area radiation monitors are located in accordance with the location criteria given in subsection 11.5.6.1. A local readout, an audible alarm, and visual alarms are provided in each monitored area to alert operating personnel to increasing exposure rates. Visual alarms are provided outside of each monitored area so that they are visible to operating personnel prior to entry. Indication and alarms are also provided in the main control room.

The monitor detectors are gamma-sensitive Geiger-Mueller tubes. The monitors and their ranges are listed in Table 11.5-2.

11.5.6.4 Fuel Handling Area Criticality Monitors

Criticality monitoring of the fuel handling and storage areas is performed in accordance with 10 CFR 70.24 by radiation monitors RMS-JE-RE012 and RMS-JE-RE020. The area radiation monitoring is augmented during fuel handling operations by a portable radiation monitor on the machine handling fuel. The fuel handling area radiation monitor parameters are provided in Table 11.5-2.

The permanent criticality monitors are physically separated by a large distance and have overlapping fields of view. Each detector's field of view can detect radiation from a fuel criticality accident in the areas occupied by personnel where fuel is stored and handled. The criticality monitors do not have a direct line of sight in the new fuel storage pit because the arrangement of new fuel prevents accidental criticality. The alarm set points of the radiation monitors are below the sensitivity needed to detect the 10 CFR 70.24 specified 20 rads/minute dose rate in soft tissue of combined gamma and neutron radiation from an unshielded source at two meters distance. A criticality excursion will produce an audible local alarm and an alarm in the plant MCR.

11.5.6.5 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the radiation monitoring system and radiation monitors from other systems is in accordance with the overall quality assurance program described in Chapter 17.

11.5.7 Combined License Information

The Combined License applicant will develop an offsite dose calculation manual that contains the methodology and parameters used for calculation of offsite doses resulting from gaseous and liquid effluents. The Combined License applicant will address operational setpoints for the radiation monitors and address programs for monitoring and controlling the release of radioactive material to the environment, which eliminates the potential for unmonitored and uncontrolled release. The offsite dose calculation manual will include planned discharge flow rates.

The Combined License applicant is responsible for the site-specific and program aspects of the process and effluent monitoring and sampling per ANSI N13.1 and Regulatory Guides 1.21 and 4.15.

The Combined License applicant is responsible for addressing the 10 CFR 50, Appendix I guidelines for maximally exposed offsite individual doses and population doses via liquid and gaseous effluents.

Table 11.5-1 (Sheet 1 of 2)

RADIATION MONITOR DETECTOR PARAMETERS

Detector	Type	Service	Isotopes	Nominal Range
BDS-JE-RE010	γ	Steam Generator Blowdown Electrodeionization Effluent	Cs-137	1.0E-6 to 1.0E-1 μCi/cc
BDS-JE-RE011	γ	Steam Generator Blowdown Electrodeionization Brine	Cs-137	1.0E-6 to 1.0E-1 μCi/cc
CCS-JE-RE001	γ	Component Cooling Water System	Cs-137	1.0E-7 to 1.0E-2 μCi/cc
VFS-JE-RE101	β	Plant Vent Particulate	Sr-90 Cs-137	1.0E-12 to 1.0E-7 μCi/cc
VFS-JE-RE102	γ	Plant Vent Iodine	I-131	1.0E-11 to 1.0E-6 μCi/cc
VFS-JE-RE103	β	Plant Vent Gas (Normal Range)	Kr-85 Xe-133	1.0E-7 to 1.0E-2 μCi/cc
VFS-JE-RE104A	β/γ	P.V. Extended Range Gas (Accident Mid Range)	Kr-85 Xe-133	1.0E-4 to 1.0E+2 μCi/cc
VFS-JE-RE104B	β/γ	P.V. Extended Range Gas (Accident High Range)	Kr-85 Xe-133	1.0E-1 to 1.0E+5 μCi/cc
PSS-JE-RE026	β	Containment Atmosphere Gas (Note 2) (Note 5)	Kr-85 Xe-133	1.0E-7 to 1.0E-2 μCi/cc
PSS-JE-RE027	γ	Containment Atmosphere N^{13}/F^{18} (Note 2) (Note 5)	N-13 F-18	1.0E-7 to 1.0E-2 μCi/cc
PSS-JE-050	γ	Primary Sampling Liquid	I-131 Cs-137	1.0E-4 to 1.0E+2 μCi/cc
PSS-JE-052	γ	Primary Sampling Gaseous	Kr-85 Xe-133	1.0E-7 to 1.0E-2 μCi/cc
SGS-JE-RE026	γ	Main Steam Line	Cs-137	1.0E-1 to 1.0E+3 μCi/cc
SGS-JE-RE027	γ	Main Steam Line	Cs-137	1.0E-1 to 1.0E+3 μCi/cc
SWS-JE-RE008	γ	Service Water Blowdown	Cs-137	1.0E-7 to 1.0E-2 μCi/cc
TDS-JE-RE001	ß/γ	Turbine Island Vent Discharge (Note 3)	Kr-85 Xe-133	1.0E-6 to 1.0E+5 μCi/cc (Note 4)
VAS-JE-RE001	β	Fuel Handling Area Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 1.0E-1 μCi/cc
VAS-JE-RE002	β	Auxiliary Building Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 1.0E-1 μCi/cc
VAS-JE-RE003	β	Annex Building Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 1.0E-1 μCi/cc
VBS-JE-RE001A	β	Main Control Room Supply Air Duct (Particulate) (Note 1) (Note 5)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 μCi/cc

Table 11.5-1 (Sheet 2 of 2)

RADIATION MONITOR DETECTOR PARAMETERS

Detector	Type	Service	Isotopes	Nominal Range
VBS-JE-RE001B	β	Main Control Room Supply Air Duct (Particulate) (Note 1) (Note 5)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
VBS-JE-RE002A	γ	MCR Supply Air Duct (Iodine) (Note 1) (Note 5)	I-131	1.0E-11 to 1.0E-5 µCi/cc
VBS-JE-RE002B	γ	MCR Supply Air Duct (Iodine) (Note 1) (Note 5)	I-131	1.0E-11 to 1.0E-5 µCi/cc
VBS-JE-RE003A	β	MCR Supply Air Duct (Gas) (Note 1) (Note 5)	KR-85 Xe-133	1.0E-7 to 1.0E-2 µCi/cc
VBS-JE-RE003B	β	MCR Supply Air Duct (Gas) (Note 1) (Note 5)	Kr-85 Xe-133	1.0E-7 to 1.0E-2 µCi/cc
VFS-JE-RE001	β	Containment Air Filtration Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 1.0E-1 µCi/cc
VHS-JE-RE001	β	H.P. & Hot Machine Shop Exhaust (Note 5)	Sr-90 Cs-137	1.0E-13 to 1.0E-7 µCi/cc
VRS-JE-RE023	β	Radwaste Building Exhaust (Note 5)	Sr-90 Cs-137	1.0E-13 to 1.0E-7 µCi/cc
WGS-JE-RE017	β	Gaseous Radwaste Discharge	Kr-85 Xe-133	1.0E-5 to 1.0E+1 µCi/cc
WLS-JE-RE229	γ	Liquid Radwaste Discharge	Cs-137	1.0E-7 to 1.0E-2 µCi/c
WWS-JE-RE021	γ	Waste Water Discharge	Cs-137	1.0E-7 to 1.0E-2 µCi/cc

Notes:

1. Safety-related
2. Seismic Category 1
3. The condenser air removal system (CMS) and the gland seal system (GSS) discharge into the turbine island vents, drains and relief system (TDS). The exhaust from the TDS into the turbine island vent is continuously monitored for radiation.
4. Turbine island vent radiation monitor includes two G-M tubes with nominal ranges of 1.0E-6 to 1.0E+0 µci/cc and 1.0E-1 to 1.0E+5 µci/cc.
5. Monitor is sensitive enough to detect 10 Derived Air Concentration (DAC)-hours.

Table 11.5-2

AREA RADIATION MONITOR DETECTOR PARAMETERS

Detector	Type	Service	Nominal Range
PXS-JE-RE160	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE161	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE162	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE163	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
RMS-JE-RE008	γ	Primary Sampling Room	1.0E-1 to 1.0E+7 mR/hr
RMS-JE-RE009	γ	Containment Area - Personnel Hatch	1.0E-1 to 1.0E+4 mR/hr (Note 1)
RMS-JE-RE010	γ	Main Control Room	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE011	γ	Chemistry Laboratory Area	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE012	γ	Fuel Handling Area	1.0E-1 to 1.0E+4 mR/hr (Note 2)
RMS-JE-RE013	γ	Rail Car Bay Area/Auxiliary Bldg. Loading Bay (Note 4)	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE014	γ	Liquid and Gaseous Radwaste Area	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE016	γ	Technical Support Center	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE017	γ	Radwaste Bldg. Mobile Systems Facility (Note 4)	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE018	γ	Hot Machine Shop	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE019	γ	Annex Staging & Storage Area	1.0E-1 to 1.0E+4 mR.hr
RMS-JE-RE020	γ	Fuel Handling Area	1.0E-1 to 1.0E+4 mR/hr (Note 2)

Notes:

1. Radiation levels are monitored by the permanent containment area radiation monitor and by a portable bridge monitor during refueling operations. The containment area radiation monitor is located to best measure the increase in exposure rates for this area and to provide an alarm locally and in the main control room.
2. Radiation levels are monitored by the permanent fuel handling area radiation monitors and by a portable bridge monitor during fuel handling operations. The fuel handling area radiation monitors are located to best measure the increase in exposure rates for this area and to provide an alarm locally and in the main control room.
3. Safety-related
4. Monitors areas used for storage of wet wastes (including processed and packaged spent resins) and dry wastes.

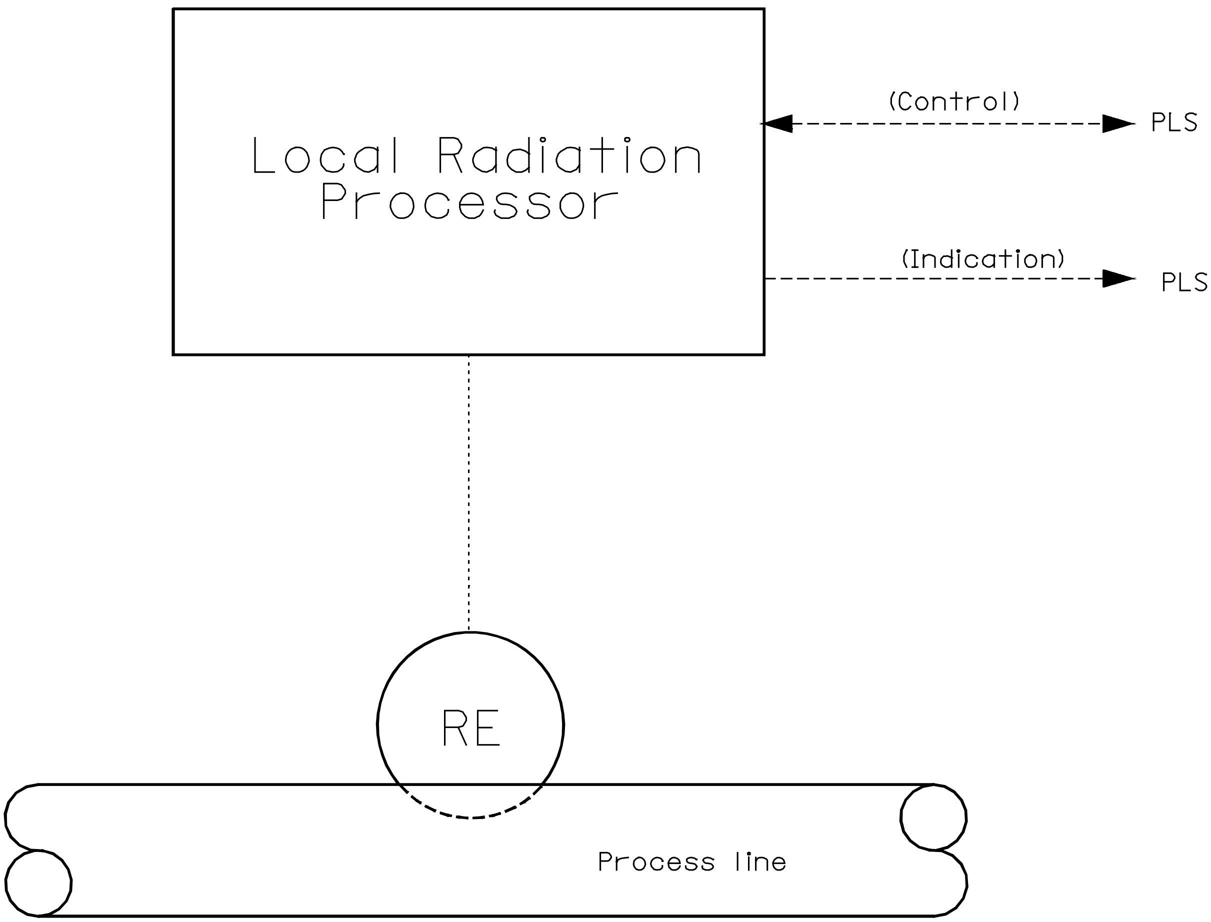

Figure 11.5-1

Process In-Line Radiation Monitor

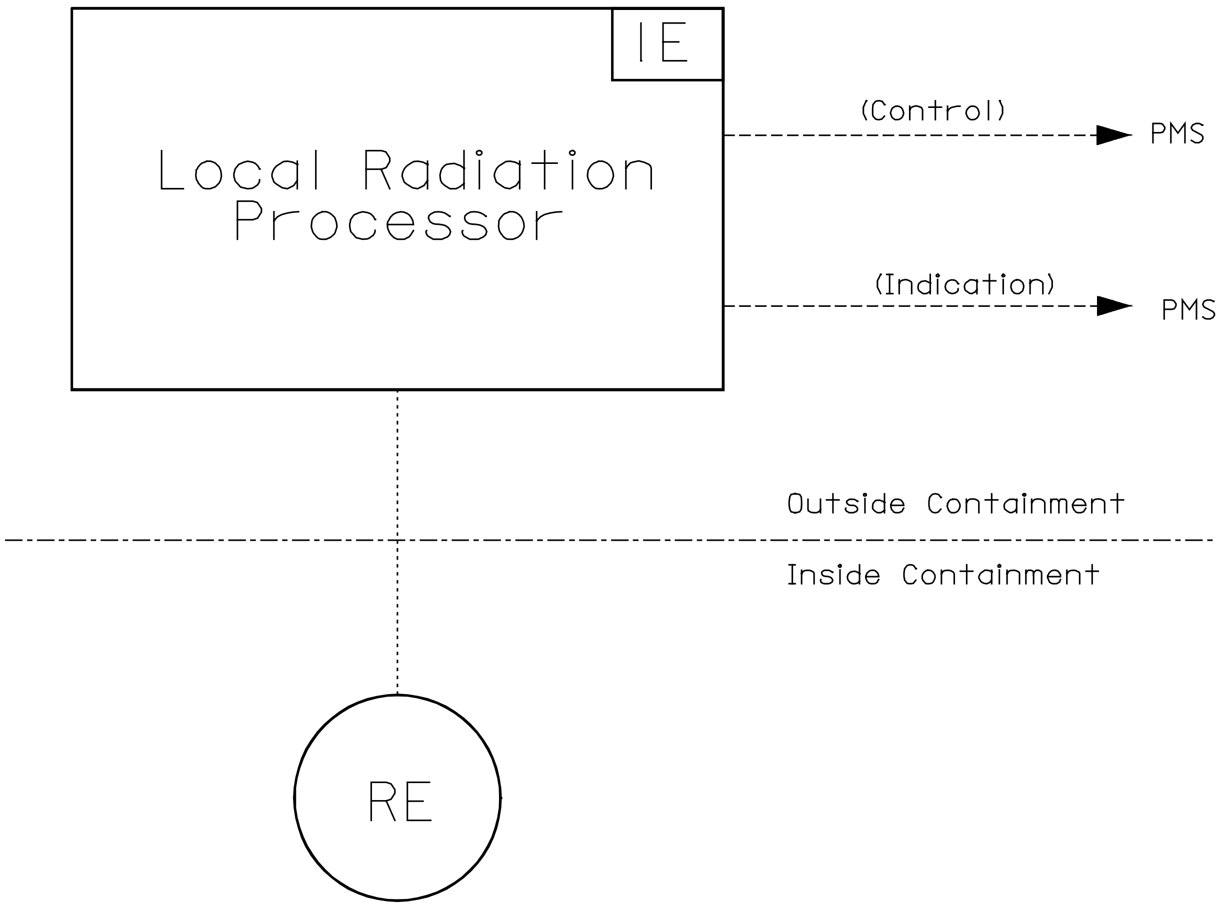

Figure 11.5-2

Safety-Related Containment High Range Radiation Monitor

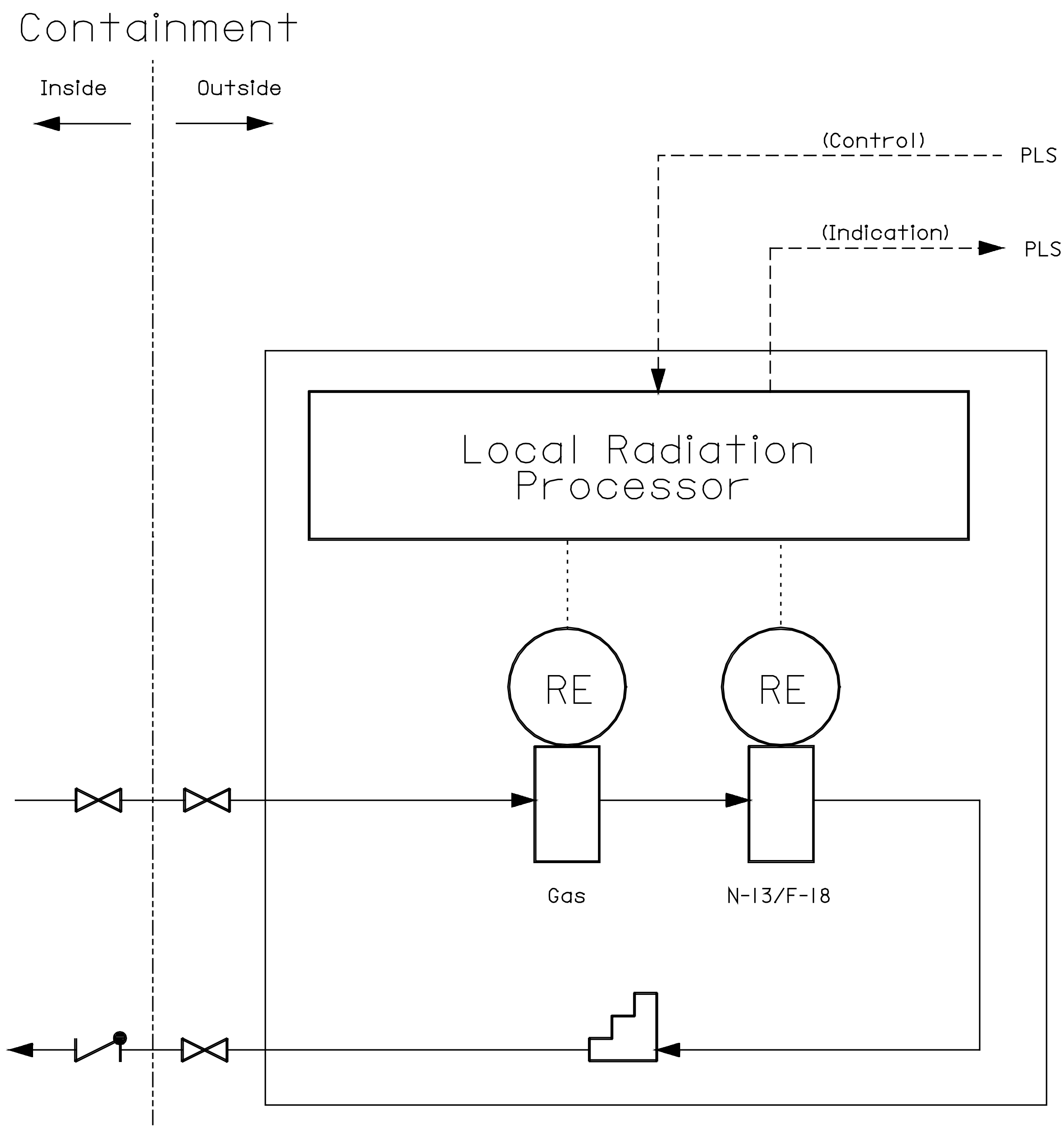

Figure 11.5-3

Containment Atmosphere Radiation Monitor

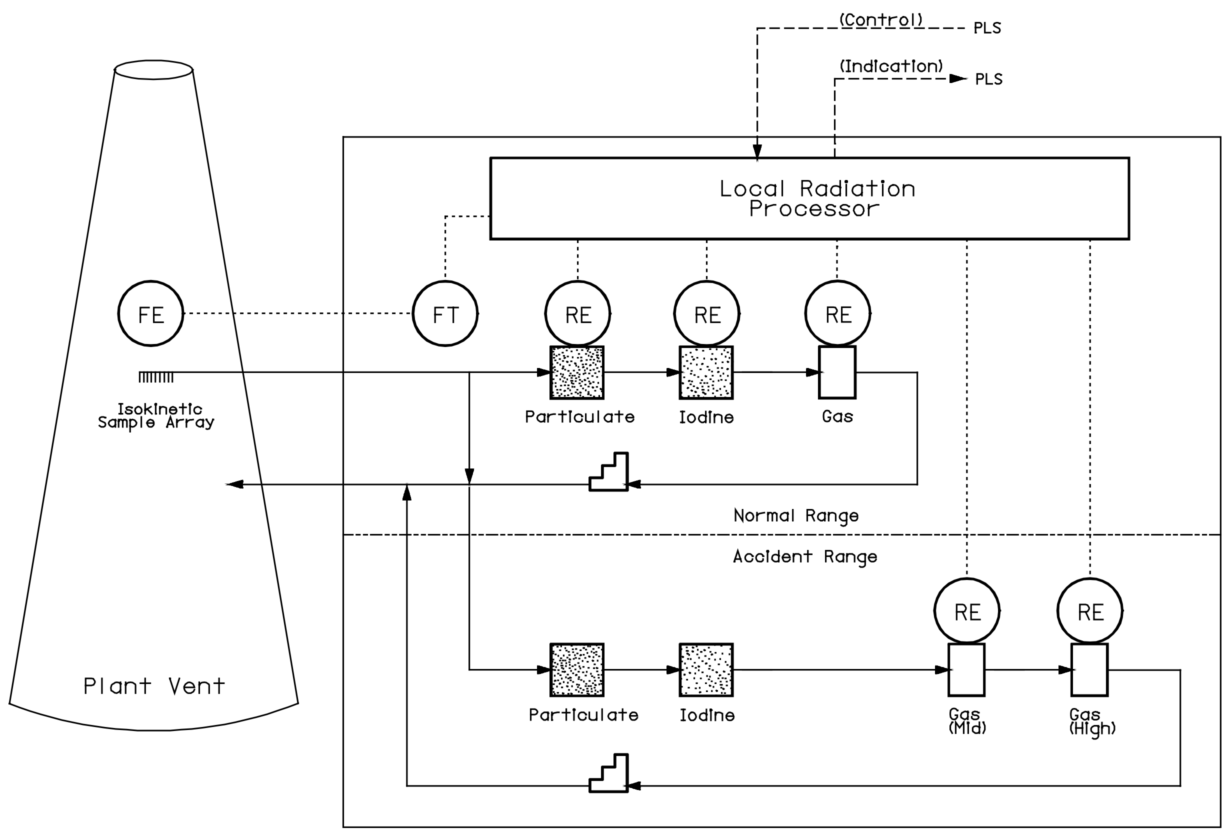

Figure 11.5-4

Plant Vent Radiation Monitor

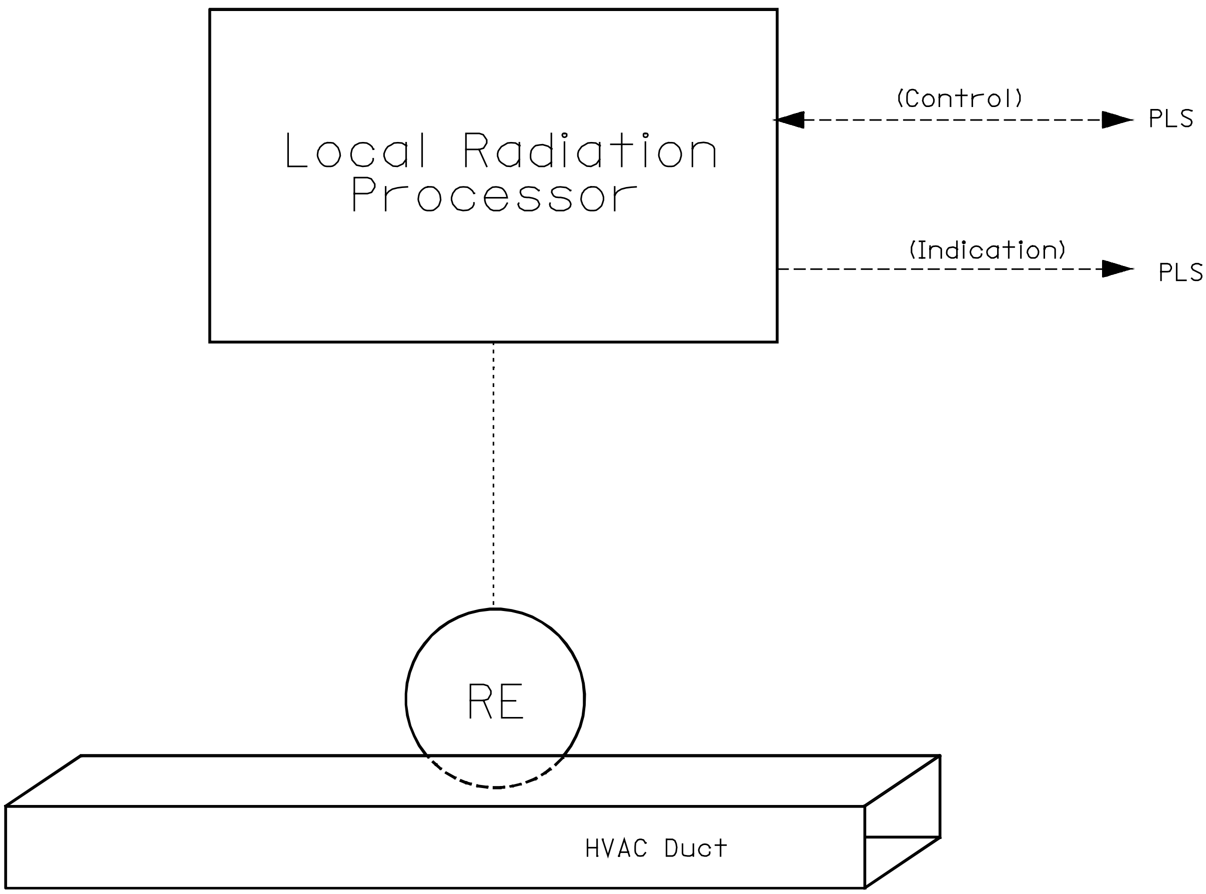

Figure 11.5-5

In-Line HVAC Duct Radiation Monitor

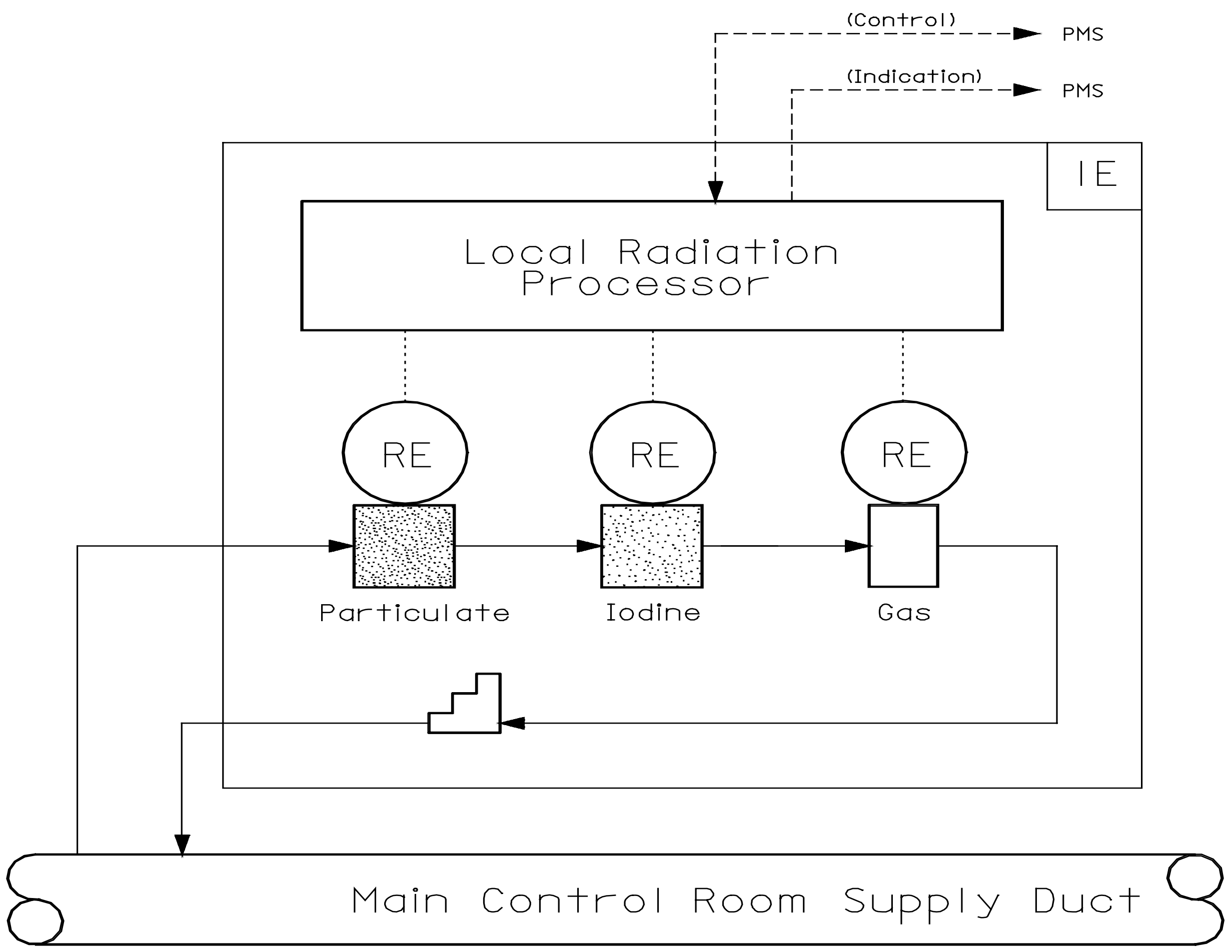

Figure 11.5-6

Safety-Related Main Control Room Supply Duct Radiation Monitor

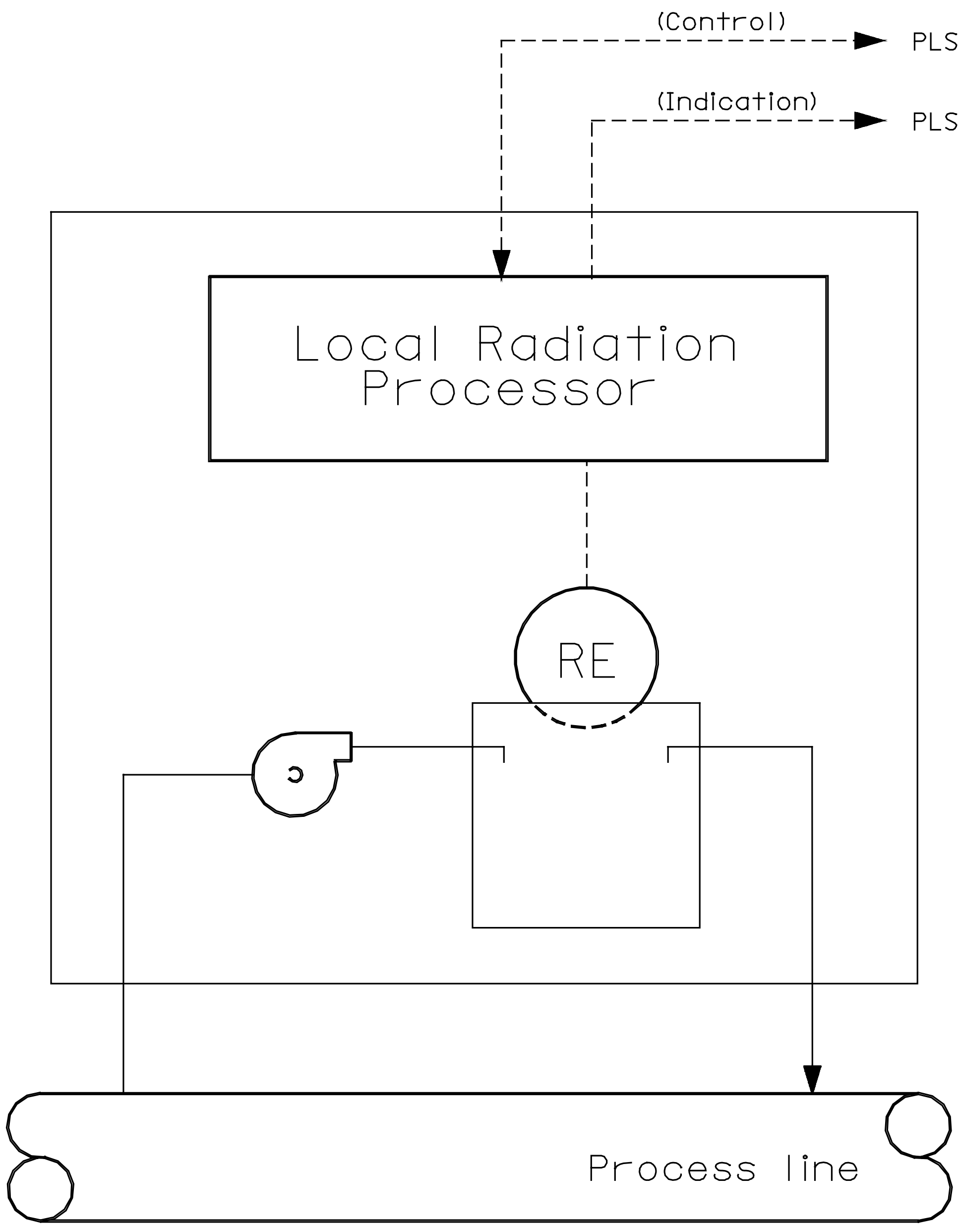

Figure 11.5-7

Liquid Offline Radiation Monitor

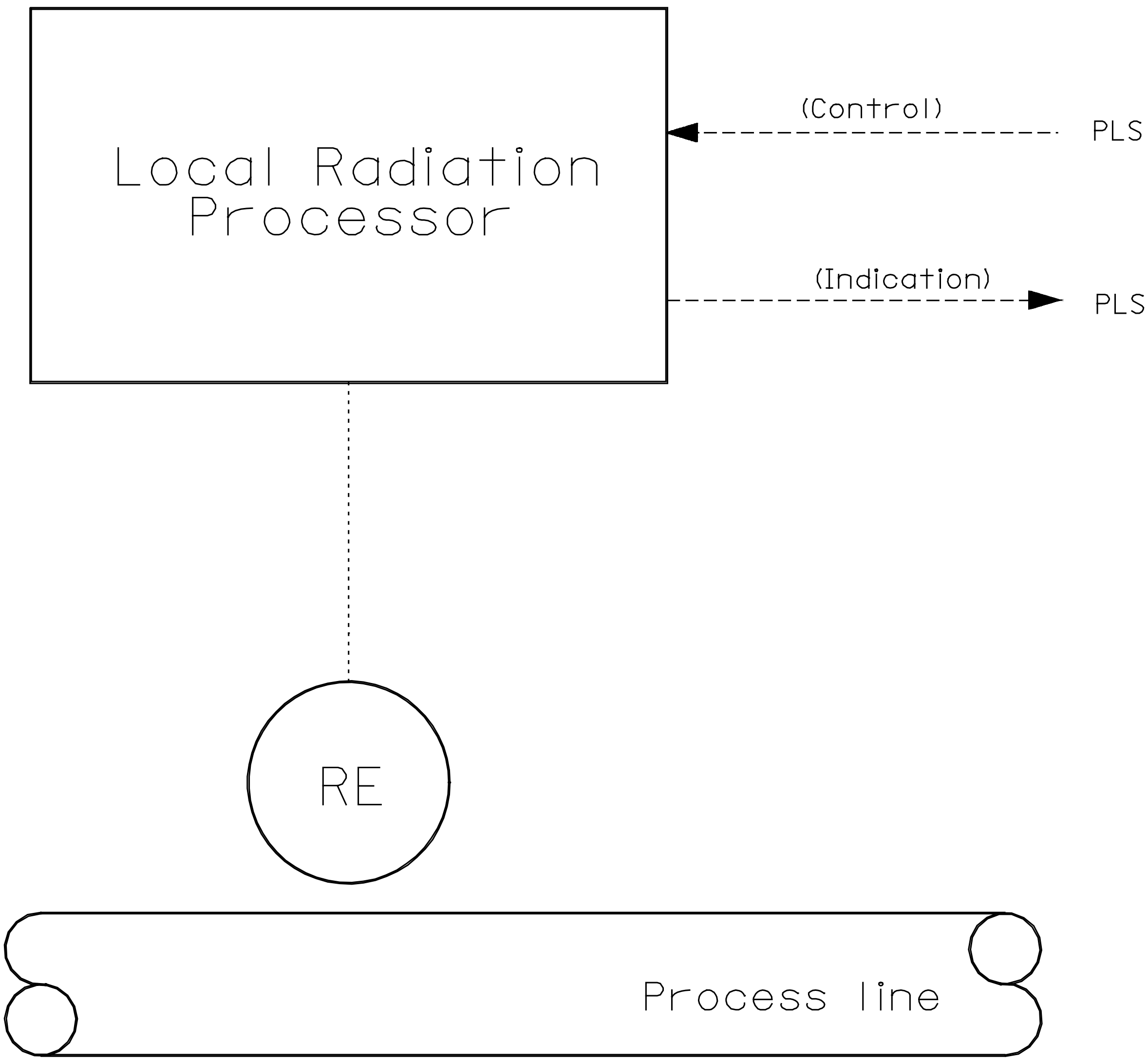

Figure 11.5-8

Adjacent to Line Radiation Monitor

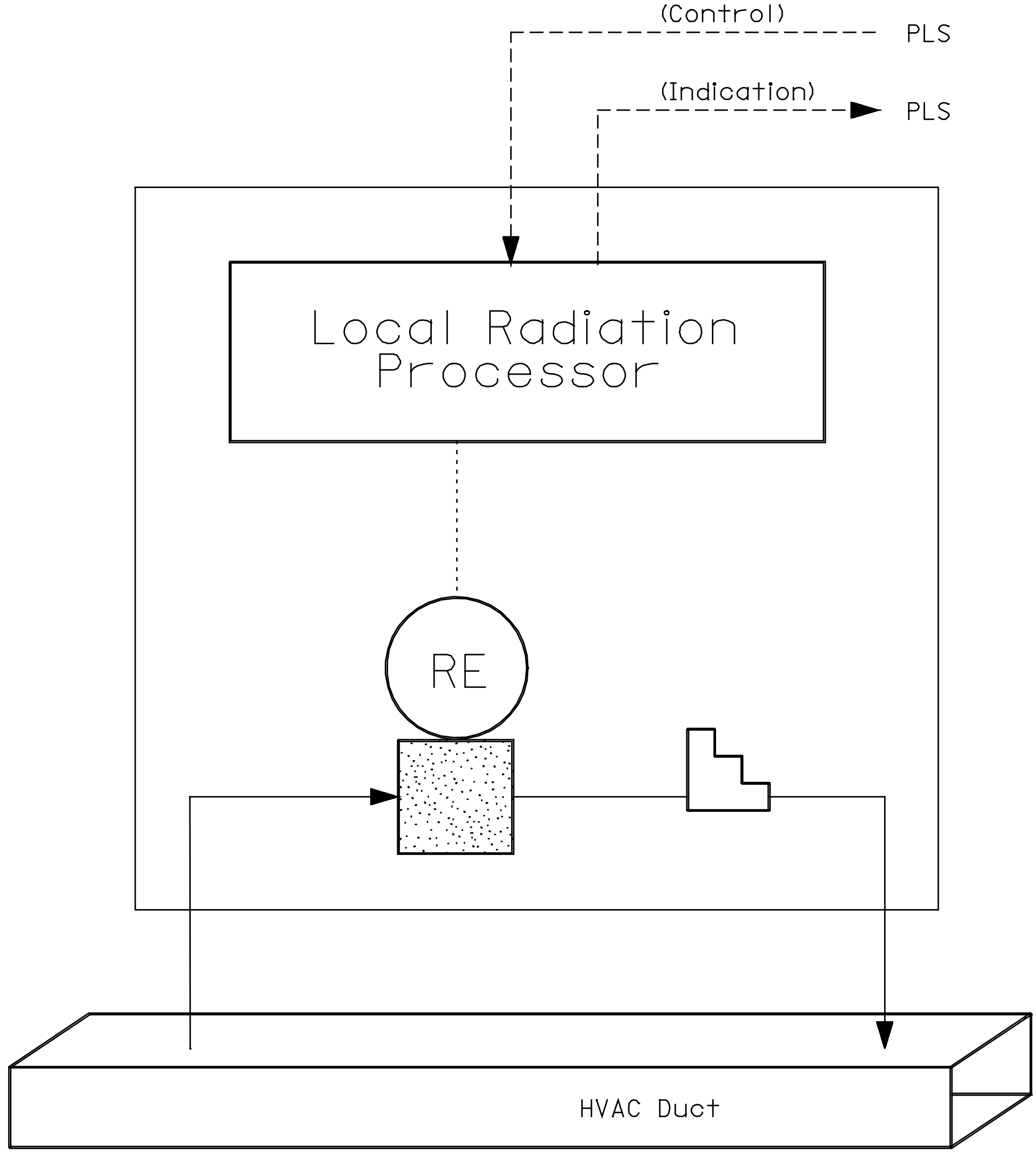

Figure 11.5-9

HVAC Duct Particulate Radiation Monitor

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CHAPTER 12

RADIATION PROTECTION

12.1 Assuring that Occupational Radiation Exposures Are As-Low-As-Reasonably Achievable (ALARA)

12.1.1 Policy Considerations

The AP1000 plant is designed with administrative programs and procedures to maximize the incorporation of good engineering practices and lessons learned to accomplish ALARA objectives.

12.1.1.1 Design and Construction Policies

The ALARA policy is applied during the design of AP1000. The design is reviewed for ALARA considerations and updated and modified as experience from operating plants is applied. ALARA reviews include the plant design and integrated layout, considering shielding, ventilation, and monitoring instrument designs as they relate to traffic control, security, access control and health physics.

Similarly, routing of pipe containing radioactive fluids is reviewed as part of the design effort. This confirms that lines expected to contain significant radiation sources are adequately shielded and properly routed to minimize exposure of personnel.

Many of the engineers and supervisors assigned to the AP1000 design have performed similar design work or service work on other nuclear power plants. Through this experience, they have acquired knowledge of the radiation protection aspects which are applied to AP1000. Nuclear plant operating experience is incorporated through Nuclear Regulatory Commission (NRC) inspection and enforcement bulletins, information notices, and other documents. Independent reviews are conducted by the Electric Power Research Institute (EPRI) and Utility Steering Committee and its subcommittees. Knowledge of radiation protection and ALARA is applied to AP1000 design. This allows integration of experience and ALARA considerations from plant operators and plant designers and promotes incorporation of recent operating and service experience and lessons learned.

12.1.1.2 Operation Policies

The Combined Operating License applicant will address the activities conducted by management personnel who have plant operational responsibility for radiation protection.

12.1.1.3 Compliance with 10 CFR 20 and Regulatory Guides 1.8, 8.8, and 8.10

Compliance of the design with 10 CFR 20 is confirmed by compliance of the design and operation of the facility within the guidelines of Regulatory Guides 1.8, 8.8, and 8.10. The Combined Operating License applicant will address compliance with Regulatory Guides 1.8, 8.8, and 8.10.

The design of AP1000 meets the guidelines of Regulatory Guide 8.8, Sections C.2 and C.4, which address facility, equipment and instrumentation design features. Features of the plant that are examples of compliance with Regulatory Guide 8.8 are delineated in Section 12.3.

12.1.2 Design Considerations

Provisions and designs for maintaining personnel exposures ALARA are presented in the following paragraphs. The basic management philosophy guiding the AP1000 design effort so that radiation exposures are ALARA can be expressed as:

- Design structures, systems and components for reliability and maintainability, thereby effectively reducing the maintenance requirements on radioactive components.

- Design structures, systems and components to reduce the radiation fields, thereby allowing operation, maintenance and inspection activities to be performed in the minimum design radiation field.

- Design structures, systems and components to reduce access, repair and removal times, thereby effectively reducing the time spent in radiation fields during operation, maintenance, and inspection.

- Design structures, systems and components to accommodate remote and semi-remote operation, maintenance and inspection, thereby effectively reducing the time spent in radiation fields.

12.1.2.1 General Design Considerations for ALARA Exposures

General design considerations and methods to maintain in-plant radiation exposures ALARA consistent with the recommendations of Regulatory Guide 8.8 have two objectives:

- Minimizing the necessity for access to and personnel time spent in radiation areas

- Minimizing radiation levels in routinely occupied plant areas in the vicinity of plant equipment expected to require personnel attention

Equipment and facility layouts and designs are considered for maintaining exposures ALARA during plant operations, including:

- Normal operation
- Maintenance and repairs
- Refueling operations and fuel storage
- Inservice inspection and calibrations
- Radioactive waste handling and disposal
- Other anticipated operational occurrences
- Decommissioning

The actual design features are described in Section 12.3. Examples of features that assist in maintaining exposures ALARA include:

- Provision of features to allow draining, flushing, and decontaminating equipment and piping
- Design of equipment to minimize the creation and buildup of radioactive material and to ease flushing of crud traps
- Provision of shielding for personnel protection during maintenance or repairs and during decommissioning
- Provision of means and adequate space for the use of movable shielding
- Separation of more highly radioactive equipment from less radioactive equipment and provision of separate shielded compartments for adjacent items of radioactive equipment
- Provision of shielded access hatches for installation and removal of plant components
- Provision of design features, such as the chemical and volume control system, to minimize crud buildup
- Provision for means and adequate space for the use of remote and robotic maintenance and inspection equipment
- Simplifying the plant design compared to previous pressurized water reactors with design approaches such as:
  - Elimination of boron recycle
  - Elimination of evaporators
  - Use of an extended fuel cycle
  - Reduction in components containing radioactive fluids
  - Clearly and deliberately separating clean areas from potentially radioactive ones

12.1.2.2 Equipment General Design Considerations for ALARA

Equipment design considerations to minimize the necessity for, and amount of, time spent in a radiation area generally include:

- Reliability, durability, constructibility, and design features of equipment, components, and materials to reduce or eliminate the need for repair or preventive maintenance.
- Servicing convenience for anticipated maintenance or potential repair, including ease of disassembly and modularization of components for replacement or removal to a lower radiation area for repair (For example, the passive residual heat removal heat exchanger is designed with extra tubes to allow for plugging of some tubes. Heat exchangers have drains to allow draining of the shell side water.)

- Provisions, where practicable, to remotely or mechanically operate, repair, service, monitor, or inspect equipment.
- Redundancy of equipment or components to reduce the need for immediate repair when radiation levels may be high and when there is no feasible method available to reduce radiation levels.
- Provisions for equipment to be operated from, and have its instrumentation and control in, accessible areas both during normal and abnormal operating conditions.
- Provisions for remote operation, draining and flushing of systems such as the chemical and volume control system.
- Past experience and lessons learned from servicing currently operating nuclear power plants.

Equipment design considerations directed toward minimizing radiation levels near equipment or components requiring personnel attention include:

- Selection of materials that minimize the creation of radioactive contamination.
- Provision of equipment and piping designs that minimize the accumulation of radioactive materials (for example, the use of seamless piping and minimizing the number of fittings reduces radiation accumulation at the seams and welds).
- Provisions for draining, flushing, or if necessary, remote cleaning or decontamination of equipment containing radioactive materials.
- Provision in the design for limiting leaks or controlling the fluid that does leak. This includes the use of high quality valves and valve packings, and the direction of leakage via drip pans and piping to sumps and floor drains.
- Provisions for isolating equipment from radioactive process fluids.
- Provisions for the chemical and volume control system; the spent fuel pit cleanup system; and the liquid radwaste cleanup system to limit radioactive isotope levels in the process water.

12.1.2.3 Facility Layout General Design Considerations for ALARA

Facility design considerations to minimize the amount of personnel time spent in a radiation area include the following:

- Locating equipment, instruments, and sampling stations that require routine maintenance, calibration, operation, or inspection, in a manner that promotes ease of access and minimum of required occupancy time in radiation areas

- Laying out plant areas to allow remote or mechanical operation, service, monitoring, or inspection of highly radioactive equipment

- Providing, where practicable, for transportation of equipment or components requiring service to a lower radiation area

Facility design considerations directed toward minimizing radiation levels in plant access areas and in the vicinity of equipment requiring personnel attention generally include the following:

- Separating radiation sources and occupied areas, where practicable (for example, pipes or ducts containing potentially highly radioactive fluids do not pass through occupied areas). Redundant components requiring periodic maintenance that are a source of radiation are located in separate compartments to allow maintenance of one component while the other component is in operation.

- Providing shielding to separate equipment such as demineralizers and filters from nonradioactive equipment to provide unrestricted maintenance on the nonradioactive equipment.

- Providing shielding between radiation sources and access and service areas.

- Providing labyrinth entrances to radioactive pump, equipment, and valve rooms. Adequate space is provided in labyrinth entrances for easy access. Highly radioactive passive components with minimal maintenance requirements are located in completely enclosed compartments and are provided with access via a shielded hatch or removable blocks.

- Separating equipment or components in service areas with permanent shielding, where appropriate.

- Providing means and adequate space for using movable shielding for sources within the service area, when required.

- Incorporating, within the plant layout, restrictions and control of access to the various radiation zones. Access to a given radiation zone generally does not require passing through a higher radiation zone. In the case of an abnormal occurrence or accident, the zone restrictions may change due to increased dose rates. Special access controls would be implemented at that time by the combined license holder.

- Locating equipment, instruments, and sampling sites in the lowest practicable radiation zone.

- Providing control panels to permit remote operation of essential instrumentation and controls from the lowest radiation zone practicable.

- Providing means to control contamination or facilitate decontamination of potentially contaminated areas.

- Providing means for decontamination of service areas.

- Maintaining ventilation air flow patterns from areas of lower radioactivity to areas of higher radioactivity.

- Provide adequate lighting and support services (electrical power, compressed air, demineralized water, ventilation, and communications) at workstations.

12.1.3 Combined License Information

Operational considerations of ALARA, as well as operational policies and continued compliance with 10 CFR 20 and Regulatory Guides 1.8, 8.8, and 8.10, will be addressed by the Combined Operating License applicant. In addition, the Combined Operating License applicant will address operational considerations of the Standard Review Plan to the level of detail provided in Regulatory Guide 1.70. Regulatory Guides that will be addressed include: 8.2, 8.7, 8.9, 8.13, 8.15, 8.20, 8.25, 8.26, 8.27, 8.28, 8.29, 8.34, 8.35, 8.36, and 8.38.

12.2 Radiation Sources

This section describes the sources of radiation that form the basis for shielding design calculations and the sources of airborne radioactivity used for the design of personnel protection measures and dose assessment.

12.2.1 Contained Sources

The shielding design source terms are based on the three plant conditions of normal full-power operation, shutdown, and design basis accident events.

12.2.1.1 Sources for Full-Power Operation

The primary sources of radioactivity during normal full-power operation are direct core radiation, coolant activation processes, leakage of fission products from pinhole defects in fuel rod cladding, and activation of reactor coolant corrosion products. The design basis for fission product activities is operation with cladding defects in fuel rods producing 0.25 percent of the core thermal power. The design basis for activation and corrosion product activities is derived from measurements at operating plants and is independent of the fuel defect level.

12.2.1.1.1 Reactor Core

The neutron and gamma flux from the reactor core is reduced by the reactor internals and by the reactor vessel. Table 12.2-1 lists the neutron and gamma energy flux spectra in the reactor cavity outside the reactor vessel for several energy groups. The values are maximum values on the inside surface of the primary shield concrete at the core midplane.

12.2.1.1.2 Reactor Coolant System

Sources of radiation in the reactor coolant system are fission products released from fuel and activation of the coolant and of corrosion products that are circulated in the reactor coolant. These sources and their bases are described in Section 11.1.

The activation product, nitrogen-16 (N-16), is the predominant contributor to the activity in the reactor coolant pumps, steam generators, and reactor coolant piping during operation. The N-16 activity in each of the components depends on the total transit time to the component and the average residence time in the component. Table 12.2-3 presents the reactor coolant N-16 activity as a function of transport time in a reactor coolant loop. The N-16 activity for the pressurizer is tabulated in Table 12.2-4.

Fission and corrosion product activities circulating in the reactor coolant system and out-of-core crud deposits comprise the remaining significant radiation sources during full-power operation. The fission and corrosion product activities circulating in the reactor coolant are given in Section 11.1. The fission and corrosion product source strengths and specific activities in the pressurizer liquid and vapor phases are given in Table 12.2-5.

The isotopic composition and specific activity of typical out-of-core crud deposits are given in Table 12.2-6. Typically, one milligram of deposited crud material is found on one square

centimeter of a relatively smooth surface. This may be as much as 50 times higher in crud trap areas. Crud trap areas are generally locations of high turbulence, areas of high momentum change, gravitational sedimentation areas, high affinity material areas, and possibly thin boundary layer regions.

The N-16 activity is not a factor in the radiation sources for systems and components located outside containment. This is due to its short, half-life (7.11 seconds) and the greater than one minute transport time before flow exits the containment. The normal letdown flow path is entirely inside containment. Primary coolant is directed outside containment only when it is diverted to the liquid radwaste system (e.g., due to boron dilution operations or for degassing prior to shutdown).

12.2.1.1.3 Chemical and Volume Control System

Radiation sources in the chemical and volume control system consist of radionuclides carried in the reactor coolant. The chemical and volume control system components in the purification path are located inside containment. The chemical and volume control system carries radioactive fluid out of the containment only when reactor coolant is directed to the liquid radwaste system.

The shielding design of the chemical and volume control system components is based on processing reactor coolant having the design basis source term presented in Section 11.1. The regenerative and letdown heat exchanger sources include contributions from N-16. Owing to its short half-life, the concentration of N-16 is highly sensitive to the location of these heat exchangers with respect to the reactor coolant loop piping. The concentration of N-16 at the heat exchangers is assumed to be the value in the reactor coolant when it exits the steam generator (see Table 12.2-3). The radiation sources for the other components in the purification loop do not include a contribution from N-16. The N-16 contribution to the shielding source term for the filter and demineralizers is determined based on the additional decay afforded by the time delay resulting from the system layout. The chemical and volume control system component sources are provided in Table 12.2-7.

12.2.1.1.4 Service Water System and Component Cooling Water System

These systems are normally nonradioactive or, if there is inleakage of radioactive material into the systems, of very low level activity. For shielding and dose assessment purposes, these systems are assumed to be nonradioactive.

12.2.1.1.5 Spent Fuel Pool Cooling System

One of the functions of the spent fuel pool cooling system is to provide cleanup of the water in the spent fuel pool, the refueling cavity, and the in-containment refueling water storage tank. The equipment considered in designing shielding are the spent fuel pool cooling system demineralizers and filters which accumulate activity, primarily Co-58 and Co-60 from radioactive crud that is resuspended in the water during the course of fuel handling. The source terms for this equipment are provided in Table 12.2-8. Based on operating experience, the remainder of the spent fuel pool cooling system may contain a significant amount of crud and thus requires shielding. The composition of crud is provided in Table 12.2-6.

12.2.1.1.6 Main Steam Supply System

Potential radioactivity in the main steam supply system is a result of steam generator tube leaks and is sufficiently low so that no radiation shielding for equipment in secondary systems is required to meet radiation zone requirements.

12.2.1.1.7 Liquid Radwaste System

Radioactive inputs include fission and activation product radionuclides produced in the core and reactor coolant. Shielding for each component of the liquid radwaste system is based on the sources listed on Table 12.2-9. Radiation sources for the various pumps in the liquid radwaste system are assumed to be identical to the liquid sources in the tank from which the pump takes suction.

12.2.1.1.8 Gaseous Radwaste System

Radioactive gases and hydrogen removed from the reactor coolant when coolant is discharged to the liquid radwaste system comprise the bulk of the gas processed by the gaseous radwaste system. There is no gas stripping performed in the reactor coolant purification loop of the chemical and volume control system. The result is that the volume of gases processed by the gaseous radwaste system is small. Table 12.2-10 lists the shielding sources for the components in the gaseous radwaste system.

12.2.1.1.9 Solid Radwaste System

The solid radwaste system handles various radioactive waste products ranging from relatively low activity materials to high activity spent resins and filter cartridges. Solid wastes are packaged for shipment to a burial or long-term storage facility.

Prior to packaging, the spent resin is stored in a spent resin storage tank. Two spent resin storage tanks are provided, one for high activity resins and the other for low activity resins. The initial gamma source strength in the high activity spent resin storage tank is assumed to be the same as that in the chemical and volume control system mixed bed demineralizer. After a 30-day decay period, only the cesium and cobalt isotopes are significant contributors to the radiation field. Table 12.2-11 lists the source strengths and specific activities both initially and after 30 days of decay.

Spent filter cartridge sources are as listed in Tables 12.2-7, 12.2-8, and 12.2-9.

12.2.1.1.10 Miscellaneous Sources

There are additional contained sources used for instrument calibration or for radiography. The Combined License applicant will identify these sources.

12.2.1.2 Sources for Shutdown

In the reactor shutdown condition, the only additional significant sources requiring permanent shielding consideration are the spent reactor fuel, the residual heat removal system, and the incore

detector system. Individual components may require shielding during shutdown due to deposited crud material. Estimates of accumulated crud in the reactor coolant system are given in subsection 12.2.1.1. The radiation sources in the reactor coolant system and other systems addressed in subsection 12.2.1.1 are bounded by the sources given for full power operation with the exception of a short time period (less than 24 hours) following shutdown, during which crud bursts can result in increased radiation sources. Crud bursts are the resuspension of a portion of the accumulated deposited corrosion products into the reactor coolant system during shutdown operation. Activity increases also occur during planned coolant oxygenation procedures prior to refueling activities.

12.2.1.2.1 Normal Residual Heat Removal System

The maximum gamma ray source strengths in the normal residual heat removal system for four and eight hours after reactor shutdown are given in Table 12.2-12 along with the listing of contributing nuclides. The system may be placed in operation at the maximum flow rate at approximately four hours following a shutdown. The system removes decay heat from the reactor for the duration of the shutdown. The sources given are maximum values taking into account activity increases due to coolant oxygenation measures.

12.2.1.2.2 Reactor Core

The core average gamma ray and neutron source strengths are used in the evaluation of radiation levels within and around the shutdown reactor.

The basis for the core average source strengths is an equilibrium cycle core at end-of-life. Feed enrichment of 4.9 (68 assemblies) weight-percent U-235 were assumed. The regions operate at a specific power of 40.7 megawatts (thermal) per metric ton of uranium for 520, 1040, and 1561 effective full-power days, respectively (this is for an 18 month fuel cycle with an 95 percent capacity factor).

Core average gamma ray source strengths are presented in Table 12.2-2 for various times after shutdown. These source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the core power density (109.7 watts/cc).

Neutrons are produced in the shutdown reactor by spontaneous fission of the transplutonium isotopes and by (α,n) reactions of alpha particles with 0-17 and 0-18 in the uranium dioxide fuel.

Core average neutron source strengths are given in Table 12.2-13 for various times after shutdown. The neutron source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the power density.

12.2.1.2.3 Spent Fuel

Spent fuel gamma ray and neutron source strengths are used in the evaluation of radiation levels for fuels handling, spent fuel storage, and shipping.

The basis for the spent fuel data presented here is the discharge region of an equilibrium cycle core at end of life. A feed enrichment of 4.9 weight-percent U-235 is assumed. The discharge

region was operated at a specific power of 40.7 megawatts (thermal) per metric ton of uranium for 1561 effective full-power days.

Spent fuel gamma ray source strengths are presented in Table 12.2-14 for various times after shutdown. These source strengths may be put on a per-unit volume of homogenized core basis by multiplying by the power density (109.7 watts/cc).

Spent fuel neutron source strengths are given in Table 12.2-13 for various times after shutdown. The neutron source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the power density.

12.2.1.2.4 Irradiated Control Rods, Gray Rods, and Secondary Source Rods

The gamma ray source strengths of the irradiated control rods, gray rods, and secondary source rods are used in establishing radiation shielding requirements during refueling operations and during shipping of irradiated rods.

The absorber material used in the control rods is silver-indium-cadmium (Ag-In-Cd). The gray rods contain either type 304 stainless steel or Ag-In-Cd pellets. The gamma ray source strengths associated with the irradiated Ag-In-Cd absorber are listed in Table 12.2-15 for various times after shutdown.

The photoneutron source material used in the secondary source rods is an equal volume mixture of antimony and beryllium (Sb-Be). The gamma ray source strengths associated with the secondary source rods are listed in Table 12.2-16 for various times after shutdown and Table 12.2-17 lists the neutron source strengths. The source values are per cubic centimeter of source material for an irradiation period of 400 days.

The material used for the control rod cladding, gray rod cladding and/or pellets and secondary source rod cladding is Type 304 stainless steel with an assumed maximum cobalt content of 0.12 weight percent. The gamma ray source strengths associated with the irradiated stainless steel are listed in Table 12.2-18 for various times after shutdown.

12.2.1.2.5 Incore Flux Thimbles

Irradiated incore flux thimble gamma ray source strengths are given in Table 12.2-19. These source strengths are used in determining shielding requirements during refueling operations when the flux thimbles are withdrawn from the reactor core.

12.2.1.3 Sources for the Core Melt Accident

The AP1000 is designed to provide adequate core cooling in the event of a postulated loss of coolant accident (LOCA) so that there is no significant core damage. Following a LOCA, the normal residual heat removal system could be used, if available, to provide post-accident cooling, use of the normal residual heat removal system is acceptable only if the source term is close to the design basis source term (see Table 12.2-12).

For the evaluation of the radiological consequences of the LOCA, it is assumed that major degradation of the core takes place, including melting of the core. The source term used for the LOCA dose analysis assumes no core release for 10 minutes, then there is a gap release from a small number of fuel rods before the onset of core degradation. The first half hour of core release is restricted to releases from the fuel cladding gap; this gap release phase is followed by the in-vessel core melt phase that has a duration of 1.3 hours. After the in-vessel core melt phase, there is assumed to be no further release of activity from the core. This core activity release model is based on the source term model from NUREG-1465 (Reference 1). The source term is described in detail in subsection 15.6.5.3.

If there is core degradation, core cooling would be provided by the passive core cooling system which is totally inside the containment such that no high activity sump solution would be recirculated outside the containment. The shielding provided for the containment addresses this post-LOCA source term. The source strengths as a function of time are provided in Table 12.2-20 and the integrated source strengths are provided in Table 12.2-21.

12.2.2 Airborne Radioactive Material Sources

This subsection deals with the models, parameters, and sources required to evaluate airborne concentration of radionuclides during plant operations in various plant radiation areas where personnel occupancy is expected.

12.2.2.1 Containment Atmosphere

The main sources of airborne activity in the containment is leakage of primary coolant and activation of naturally occurring argon in the atmosphere. During normal power operation, excessive activity buildup in the containment atmosphere is prevented by periodic purging of the containment (approximately 20 hours per week). When the plant is shut down for refueling or maintenance, additional purging of the containment atmosphere is performed to further reduce the activity levels consistent with the increased level of worker presence in the containment. The assumptions and parameters used to determine the airborne activity levels in the containment are listed in Table 12.2-22. The airborne concentrations are provided in Table 12.2-23. Three situations are considered: normal power operation without purge, normal power operation with 20 hours of purge operation per week, and shutdown operation.

12.2.2.2 Fuel-Handling Area Atmosphere

The source of airborne activity in the fuel-handling area is leakage from stored spent fuel assemblies and the evaporation losses from the spent fuel pool. The maximum airborne concentration in the fuel-handling area is calculated using the assumptions and parameters in Table 12.2-24. The resulting airborne isotopic concentrations are provided in Table 12.2-25.

12.2.2.3 Auxiliary Building Atmosphere

The source of airborne activity in the auxiliary building atmosphere is primarily equipment leakage. The ventilation system constantly removes activity and discharges it to the plant vent. The maximum airborne concentration in the auxiliary building is calculated using the assumptions

and parameters in Table 12.2-26. The resulting airborne isotopic concentrations are provided in Table 12.2-27.

12.2.2.4 Airborne Activity Model

The airborne concentration of each nuclide in the atmosphere is calculated by:

$$C_i(t) = \frac{(LR)_i\, A_i\, (PF)_i\, (1 - e^{-\lambda_{Ti} t})}{(V)\,(\lambda_{Ti})}$$

where:

$(LR)_i$ = leak or evaporation rate of the I^{th} radioisotope in the applicable region (g/s)

A_i = activity concentration of the I^{th} leaking or evaporating radioisotope (μCi/g)

$(PF)_i$ = partition factor or the fraction of the leaking activity that is airborne for the I^{th} radioisotope

λ_{Ti} = total removal rate constant for the I^{th} radioisotope from the applicable region (s^{-1})

= $\lambda_{di} + \lambda_e$, the removal rate constants in s^{-1} due to radioactive decay for the I^{th} radioisotope and the exhaust from the applicable region, respectively

t = time elapsed from the start of the leak and the time at which the concentration is evaluated (s)

V = free volume of the region in which the leak occurs (cm^3)

$C_i(t)$ = airborne concentration of the I^{th} radioisotope at time t in the applicable region ($\mu Ci/cm^3$).

From the above equation, the peak or equilibrium concentration, C_{Egi}, of the I^{th} radioisotope in the applicable volume is given by the following expression:

$$C_{Egi} = (LR)_I\, A_I\, (PF)_I\, /V_{\lambda Ti}$$

With high exhaust rates, this peak concentration is reached within a few hours.

12.2.3 Combined License Information

The Combined License applicant will address any additional contained radiation sources not identified in subsection 12.2.1, including radiation sources used for instrument calibration or radiography.

12.2.4 References

1. L. Soffer, et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

Table 12.2-1

RADIATION FLUX AT THE PRIMARY SHIELD CONCRETE

Neutron Flux

Energy	Flux (n/cm^2-sec)
≥ 1 Mev	2.4E+09
0.1 Mev to 1 Mev	1.8E+10
0.414 ev to 0.1 Mev	2.7E+10
< 0.414 ev	6.4E+9

Gamma Energy Flux

Energy	Flux (Mev/cm^2-sec)
≥ 6.0 Mev	1.2E+10
3.0 Mev to 6.0 Mev	8.3×10^9
1.0 Mev to 3.0 Mev	5.9×10^9
< 1.0 Mev	3.9×10^9

Table 12.2-2 (Sheet 1 of 2)

CORE AVERAGE GAMMA RAY SOURCE STRENGTHS AT VARIOUS TIMES AFTER SHUTDOWN

Energy Group	Source Strength at Time After Shutdown (Mev/watt-sec)				
Mev/gamma	12 Hours	24 Hours	100 Hours	1 Week	1 Month
0.000-0.020	1.8E+08	1.5E+08	6.5E+07	3.1E+07	1.4E+06
0.020-0.030	4.2E+07	3.7E+07	2.2E+07	1.6E+07	3.9E+06
0.030-0.045	1.1E+08	1.0E+08	6.1E+07	4.5E+07	1.5E+07
0.045-0.070	6.5E+07	5.9E+07	3.2E+07	2.0E+07	1.9E+06
0.070-0.100	3.6E+08	3.2E+08	1.6E+08	9.4E+07	8.6E+06
0.100-0.150	1.5E+09	1.3E+09	6.3E+08	3.6E+08	8.7E+07
0.150-0.300	2.2E+09	1.8E+09	7.1E+08	3.5E+08	1.4E+07
0.300-0.450	9.3E+08	8.2E+08	5.2E+08	3.9E+08	7.6E+07
0.450-0.700	5.3E+09	4.3E+09	2.4E+09	1.9E+09	9.5E+08
0.700-1.000	6.8E+09	5.9E+09	4.3E+09	3.8E+09	2.6E+09
1.000-1.500	2.0E+09	1.2E+09	4.9E+08	3.3E+08	9.2E+07
1.500-2.000	3.4E+09	3.1E+09	2.6E+09	2.3E+09	6.6E+08
2.000-2.500	3.0E+08	2.0E+08	1.4E+08	1.2E+08	4.9E+07
2.500-3.000	1.9E+08	1.8E+08	1.5E+08	1.3E+08	3.9E+07
3.000-4.000	5.2E+06	1.9E+06	1.6E+06	1.4E+06	4.4E+05
4.000-6.000	3.5E+05	1.9E+04	4.6E+00	4.6E+00	4.4E+00
6.000-8.000	7.4E-01	7.4E-01	7.4E-01	7.4E-01	7.1E-01
8.000-11.000	1.2E-01	1.2E-01	1.2E-01	1.1E-01	1.1E-01

Table 12.2-2 (Sheet 2 of 2)

CORE AVERAGE GAMMA RAY SOURCE STRENGTHS AT VARIOUS TIMES AFTER SHUTDOWN

Energy Group	Source Strength at Time After Shutdown (Mev/watt-sec)			
Mev/gamma	**3 Months**	**6 Months**	**1 Year**	**5 Years**
0.000-0.020	3.0E+05	1.7E+05	1.0E+05	2.9E+04
0.020-0.030	9.6E+05	3.8E+05	2.2E+05	7.4E+04
0.030-0.045	6.7E+06	4.3E+06	2.8E+06	4.5E+05
0.045-0.070	2.5E+05	1.6E+05	1.1E+05	5.6E+04
0.070-0.100	2.5E+06	1.9E+06	1.3E+06	1.4E+05
0.100-0.150	3.4E+07	1.6E+07	8.7E+06	7.0E+05
0.150-0.300	1.5E+06	6.4E+05	3.8E+05	2.0E+05
0.300-0.450	5.6E+06	2.5E+06	1.9E+06	6.4E+05
0.450-0.700	4.8E+08	3.1E+08	2.3E+08	9.4E+07
0.700-1.000	1.5E+09	7.2E+08	2.0E+08	3.3E+07
1.000-1.500	4.3E+07	3.5E+07	2.7E+07	8.4E+06
1.500-2.000	2.9E+07	2.8E+06	1.8E+06	2.9E+05
2.000-2.500	2.1E+07	1.6E+07	1.0E+07	3.1E+05
2.500-3.000	1.7E+06	1.6E+05	1.0E+05	6.6E+03
3.000-4.000	4.8E+04	2.8E+04	1.9E+04	1.2E+03
4.000-6.000	4.1E+00	3.8E+00	3.4E+00	2.7E+00
6.000-8.000	6.7E-01	6.2E-01	5.5E-01	4.4E-01
8.000-11.000	1.0E-01	9.6E-02	8.6E-02	6.8E-02

Table 12.2-3

REACTOR COOLANT NITROGEN-16 ACTIVITY

Position in Loop	Loop Transit Time (sec)	Nitrogen-16 Activity (μCi/g)
Leaving core	0.0	280
Leaving reactor vessel	0.9	256
Entering steam generator	1.2	249
Leaving steam generator	6.8	144
Entering reactor vessel	8.0	128
Entering core	9.5	122
Leaving core	10.3	280

Table 12.2-4

PRESSURIZER NITROGEN-16 SOURCE STRENGTHS

		Source Strength	
Discrete Energy (Mev/gamma)	**Energy Group (Mev/gamma)**	**Liquid Phase[(a)] (Mev/gram-sec)**	**Steam Phase[(b)] (Mev/cm^3-sec)**
1.75	1.35 - 1.80	5.4E-02	1.4E-01
2.74	2.6 - 3.0	5.0E-01	1.3E+00
6.13	6.0 - 7.0	1.0E+02	2.6E+02
7.12	7.0 - 7.5	8.5E+00	2.2E+01

Notes:
(a) Based on an insurge to the pressurizer following a ten percent step load power increase.
(b) Based on a boron equalization spray rate of 80 gpm.

Table 12.2-5 (Sheet 1 of 4)

PRESSURIZER LIQUID AND STEAM PHASE SOURCE STRENGTHS AND SPECIFIC ACTIVITY

1000 Cubic Foot Liquid Phase Source Strengths

Energy Group (Mev/gamma)		Source Strength (Mev/gram-sec)
0-0.02		1.4E+03
0.02-0.03		1.6E+03
0.03-0.045		6.9E+04
0.045-0.07		3.2E+02
0.07-0.1		1.4E+05
0.1-0.15		1.1E+03
0.15-0.3		4.3E+04
0.3-0.45		2.3E+04
0.45-0.7		1.0E+05
0.7-1.0		1.3E+05
1.0-1.5		1.2E+05
1.5-2.0		5.9E+04
2.0-2.5		9.3E+04
2.5-3.0		1.5E+04
3.0-4.0		2.6E+03
4.0-6.0		5.0E+02
6.0-8.0		-
8.0-11.00		-
	Total	7.9E+05

Table 12.2-5 (Sheet 2 of 4)

PRESSURIZER LIQUID AND STEAM PHASE SOURCE STRENGTHS AND SPECIFIC ACTIVITY

1000 Cubic Foot Liquid Phase Specific Activity

Nuclide	Activity (μCi/gram)
Kr-87	4.7E-01
Kr-88	1.5E+00
Kr-89	3.5E-02
Xe-131m	1.3E+00
Xe-133m	1.7E+00
Xe-133	1.2E+02
Xe-135	3.5E+00
Br-84	1.7E-02
I-131	7.1E-01
I-132	9.3E-01
I-133	1.3E+00
I-134	2.2E-01
I-135	7.8E-01
Rb-88	1.5E+00
Cs-134	6.9E-01
Cs-136	1.0E+00
Cs-138	3.7E-01
Tc-99m	2.0E-01

Table 12.2-5 (Sheet 3 of 4)

PRESSURIZER LIQUID AND STEAM PHASE SOURCE STRENGTHS AND SPECIFIC ACTIVITY

1100 Cubic Foot Steam Phase Source Strengths (Mev/cm^3-sec)

Energy Group (Mev/gamma)		Normal 2-gpm Spray
0-0.02		2.3E+03
0.02-0.03		2.1E+03
0.03-0.045		1.3E+05
0.045-0.07		2.0E-04
0.07-0.1		2.7E+05
0.1-0.15		1.9E+00
0.15-0.3		6.7E+03
0.3-0.45		5.0E+02
0.45-0.7		1.7E+03
0.7-1.0		8.4E+02
1.0-1.5		6.3E+02
1.5-2.0		6.3E+02
2.0-2.5		2.9E+03
2.5-3.0		1.3E+02
3.0-4.0		4.3E+00
4.0-6.0		2.2E-05
6.0-8.0		-
8.0-11.00		-
	Total	4.1E+05

Table 12.2-5 (Sheet 4 of 4)

PRESSURIZER LIQUID AND STEAM PHASE SOURCE STRENGTHS AND SPECIFIC ACTIVITY

1100 Cubic Foot Steam Phase Specific Activity (μCi/cm^3)

Nuclide	Normal 2-gpm Spray
Kr-85m	5.2E-02
Kr-85	9.0E+00
Kr-87	6.7E-03
Kr-88	5.5E-02
Kr-89	1.7E-08
Xe-131m	2.9E+00
Xe-133m	1.4E+00
Xe-133	2.4E+02
Xe-135	4.6E-01
Xe-138	1.7E-04
I-131	7.1E-03
I-132	9.3E-03
I-133	1.3E-02
I-134	2.2E-03
I-135	7.8E-03

Table 12.2-6

ISOTOPIC COMPOSITION AND SPECIFIC ACTIVITY OF TYPICAL OUT-OF-CORE CRUD DEPOSITS[(a)]

Composition (Nuclide)	Activity (μCi/mg) of Deposited Crud for Effective Full Power Years of Plant Operation			
	1 Year	**2 Years**	**5 Years**	**10 Years**
Mn-54	1.0	1.1	1.3	1.4
Fe-59	0.5	0.5	0.5	0.5
Co-58	12.0	12.0	12.0	12.0
Co-60	1.5	2.3	4.0	6.0

Note:

(a) In addition to corrosion products, about 1.0 μg of mixed actinides and fission products may be present for each 1 g of deposited crud.

Table 12.2-7 (Sheet 1 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

A. Regenerative heat exchanger

Energy Group	Source Strength (Mev/gram-sec)	
Mev/gamma	**Tube Side**	**Shell Side**
0-0.02	1.4E+03	1.4E+03
0.02-0.03	1.6E+03	1.6E+03
0.03-0.045	6.9E+04	6.9E+04
0.045-0.07	3.2E+02	3.2E+02
0.07-0.1	1.4E+05	1.4E+05
0.1-0.15	1.1E+03	1.1E+03
0.15-0.3	4.3E+04	4.2E+04
0.3-0.45	2.3E+04	1.5E+04
0.45-0.7	1.0E+05	4.7E+04
0.7-1.0	1.3E+05	7.5E+04
1.0-1.5	1.2E+05	7.7E+04
1.5-2.0	7.1E+04	4.2E+04
2.0-2.5	9.3E+04	8.9E+04
2.5-3.0	1.3E+05	1.5E+04
3.0-4.0	2.6E+03	2.2E+03
4.0-6.0	5.0E+02	5.0E+02
6.0-8.0	2.5E+07	-
8.0-11.00	-	-
Total	2.5E+07	6.2E+05

Table 12.2-7 (Sheet 2 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

A. Regenerative heat exchanger

	Activity (μCi/gram)	
Nuclide	**Tube Side**	**Shell Side**
Kr-87	4.7E-01	4.7E-01
Kr-88	1.5E+00	1.5E+00
Kr-89	3.5E-02	3.5E-02
Xe-131m	1.3E+00	1.3E+00
Xe-133m	1.7E+00	1.7E+00
Xe-133	1.2E+02	1.2E+02
Xe-135	3.5E+00	3.5E+00
Br-84	1.7E-02	--
I-131	7.1E-01	--
I-132	9.3E-01	--
I-133	1.3E+00	--
I-134	2.2E-01	--
I-135	7.8E-01	--
Rb-88	1.5E+00	1.5E+00
Cs-134	6.9E-01	6.9E-01
Cs-136	1.0E+00	1.0E+00
Cs-138	3.7E-01	3.7E-01
Tc-99m	2.0E-01	2.0E-01
Ba-137m	--	4.7E-01
N-16	1.4E+02	--

Table 12.2-7 (Sheet 3 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

B. Letdown heat exchanger

Energy Group Mev/gamma		Source Strength (Mev/gram-sec)
0-0.02		1.4E+03
0.02-0.03		1.6E+03
0.03-0.045		6.9E+04
0.045-0.07		3.2E+02
0.07-0.1		1.4E+05
0.1-0.15		1.1E+03
0.15-0.3		4.3E+04
0.3-0.45		2.3E+04
0.45-0.7		1.0E+05
0.7-1.0		1.3E+05
1.0-1.5		1.2E+05
1.5-2.0		7.1E+04
2.0-2.5		9.3E+04
2.5-3.0		1.3E+05
3.0-4.0		2.6E+03
4.0-6.0		5.0E+02
6.0-8.0		2.5E+07
8.0-11.00		-
	Total	2.5E+07

Table 12.2-7 (Sheet 4 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

B. Letdown heat exchanger

Nuclide	Activity (μCi/gram)
Kr-87	4.7E-01
Kr-88	1.5E+00
Kr-89	3.5E-02
Xe-131m	1.3E+00
Xe-133m	1.7E+00
Xe-133	1.2E+02
Xe-135	3.5E+00
Br-84	1.7E-02
I-131	7.1E-01
I-132	9.3E-01
I-133	1.3E+00
I-134	2.2E-01
I-135	7.8E-01
Rb-88	1.5E+00
Cs-134	6.9E-01
Cs-136	1.0E+00
Cs-138	3.7E-01
Tc-99m	2.0E-01
N-16	1.4E+02

Table 12.2-7 (Sheet 5 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

C. Mixed bed demineralizer (50 cubic feet of resin)

Energy Group (Mev/gamma)	Source Strength (Mev/gram-sec)
0-0.02	1.7E+04
0.02-0.03	1.1E+05
0.03-0.045	3.5E+05
0.045-0.07	4.8E+04
0.07-0.1	2.2E+05
0.1-0.15	4.8E+03
0.15-0.3	2.2E+06
0.3-0.45	2.8E+07
0.45-0.7	1.8E+08
0.7-1.0	9.9E+07
1.0-1.5	2.8E+07
1.5-2.0	4.2E+06
2.0-2.5	8.7E+05
2.5-3.0	7.4E+05
3.0-4.0	9.9E+04
4.0-6.0	2.7E+03
6.0-8.0	-
8.0-11.00	-
Total	3.4E+08

Table 12.2-7 (Sheet 6 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

C. Mixed bed demineralizer (50 cubic feet of resin)

Nuclide	Activity (µCi/gram)
Mn-54	6.2E+01
Mn-56	1.3E+01
Co-58	7.2E+01
Co-60	7.8E+01
I-131	2.4E+03
I-132	4.3E+01
I-134	3.9E+00
I-135	9.9E+01
Rb-88	8.9E+00
Cs-134	3.0E+03
Cs-136	1.6E+02
Cs-137	3.0E+03
Ba-137m	2.8E+03

Table 12.2-7 (Sheet 7 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

D. Cation bed demineralizer (50 cubic feet of resin)

Energy Group (Mev/gamma)		Source Strength (Mev/gram-sec)
0-0.02		6.3E+03
0.02-0.03		-
0.03-0.045		3.3E+05
0.045-0.07		4.8E+04
0.07-0.1		3.1E+04
0.1-0.15		2.9E+03
0.15-0.3		5.1E+05
0.3-0.45		9.9E+05
0.45-0.7		1.6E+08
0.7-1.0		9.0E+07
1.0-1.5		1.6E+07
1.5-2.0		1.9E+06
2.0-2.5		4.4E+05
2.5-3.0		6.9E+05
3.0-4.0		9.3E+04
4.0-6.0		2.7E+03
6.0-8.0		-
8.0-11.00		-
	Total	2.7E+08

Table 12.2-7 (Sheet 8 of 8)

CHEMICAL AND VOLUME CONTROL SYSTEM COMPONENTS SOURCE STRENGTHS AND SPECIFIC ACTIVITY

D. Cation bed demineralizer (50 cubic feet of resin)

Nuclide	Activity (μCi/gram)
Rb-88	8.9E+00
Cs-134	3.0E+03
Cs-136	1.6E+02
Cs-137	3.0E+03
Cs-138	3.7E+00
Ba-137m	2.8E+03

E. Reactor coolant filter

Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec)
0.4 - 0.9	5.7E+07
0.9 - 1.35	1.5E+07

Table 12.2-8

SPENT FUEL POOL COOLING SYSTEM COMPONENT SOURCE STRENGTHS AND SPECIFIC ACTIVITY

A. Demineralizer (75 cubic feet of resin)

Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	3.0E+06
0.9 - 1.35	4.7E+06

Nuclide	**Activity (μCi/cm^3)**
Co-58	5.8E+01
Co-60	3.4E+01

B. Filters

Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	1.1E+07
0.9 - 1.35	3.0E+06

Source Dimensions (inches)	**Source Composition (volume percent)**
Radius = 3.375	Air – 67
Length = 19	Water – 33

Table 12.2-9 (Sheet 1 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

A. Reactor coolant drain tank

	Source Strength (Mev/cm^3-sec)	
Energy Group (Mev/gamma)	**Liquid Phase (450 gallons)**	**Gas Space (60 cubic feet)**
0.000-0.020	1.4E+03	1.4E+02
0.020-0.030	1.6E+03	2.0E+02
0.030-0.045	6.9E+04	7.6E+03
0.045-0.070	3.2E+02	6.1E-05
0.070-0.100	1.4E+05	1.5E+04
0.100-0.150	1.1E+03	8.4E-02
0.150-0.300	4.3E+04	4.2E+02
0.300-0.450	2.3E+04	2.6E+01
0.450-0.700	1.0E+05	4.1E+03
0.700-1.000	1.3E+05	2.3E+01
1.000-1.500	1.2E+05	1.4E+01
1.500-2.000	5.9E+04	3.3E+01
2.000-2.500	9.3E+04	2.0E+02
2.500-3.000	1.5E+04	1.0E+01
3.000-4.000	2.6E+03	3.7E-01
4.000-6.000	5.0E+02	2.2E-03
6.000-8.000	-	-
8.000-11.000	-	-
Total	7.9E+05	2.8E+04

Table 12.2-9 (Sheet 2 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

A. Reactor coolant drain tank

	Activity (μCi/cm^3)	
Nuclide	**Liquid Phase**	**Gas Space**
Mn-56	1.7E-01	-
I-132	9.3E-01	-
I-134	2.2E-01	-
Kr-87	4.7E-01	-
Kr-88	1.5E+00	-
I-131	7.1E-01	-
I-133	1.3E+00	-
Xe-133	1.2E+02	-
I-135	7.8E-01	-
Xe-135	3.5E+00	-
Xe-138	2.4E-01	-
Rb-88	1.5E+00	-
Cs-134	6.9E-01	-
Cs-136	1.0E+00	-
Ba-137m	4.7E-01	-
Cs-138	3.7E-01	-
Kr-85	-	5.0E+01
Kr-87	-	5.4E-04
Kr-88	-	3.8E-03
Xe-131m	-	3.4E-01
Xe-133m	-	8.0E-02
Xe-133	-	1.4E+01
Xe-135	-	2.8E-02

Note:
The liquid activities listed are 99% of the total source strength.
The vapor activities listed are essentially 100% of the source strength.

Table 12.2-9 (Sheet 3 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

B. Effluent tank (28,000 gal) and waste holdup tank (15,000 gal)

Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec) Effluent Tank Liquid Phase	Effluent Tank Vapor Phase	Holdup Tank Liquid
0.000-0.020	1.9E+01	3.4E+03	1.9E+01
0.020-0.030	1.6E+01	4.0E+03	1.2E+01
0.030-0.045	2.7E+02	1.8E+05	2.7E+02
0.045-0.070	3.2E+02	4.5E-05	3.2E+02
0.070-0.100	2.2E+02	3.7E+05	2.1E+02
0.100-0.150	1.0E+03	3.6E+01	9.8E+02
0.150-0.300	3.4E+03	7.6E+04	3.3E+03
0.300-0.450	7.5E+03	5.4E+03	7.0E+03
0.450-0.700	4.1E+04	6.1E+03	3.8E+04
0.700-1.000	6.5E+04	1.0E+04	5.6E+04
1.000-1.500	7.1E+04	6.5E+03	4.7E+04
1.500-2.000	2.5E+04	1.5E+04	2.1E+03
2.000-2.500	6.5E+03	9.1E+04	5.7E+02
2.500-3.000	7.3E+03	4.0E+03	1.4E+02
3.000-4.000	1.5E+03	1.3E+02	1.7E+01
4.000-6.000	4.5E+02	9.8E-18	-
6.000-8.000	-	-	-
8.000-11.000	-	-	-
Total	2.3E+05	7.7E+05	1.6E+05

Table 12.2-9 (Sheet 4 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

B. Effluent tank (28,000 gal) and waste holdup tank (15,000 gal)

	Activity (µCi/cm^3)		
	Effluent Tank		
Nuclides	**Liquid Phase**	**Vapor Phase**	**Holdup Tank Liquid**
Mn-56	1.7E-02	-	1.7E-02
I-131	-	-	7.1E-02
I-132	9.3E-02	-	9.3E-02
I-133	1.3E-01	-	1.3E-01
I-134	2.2E-02	-	-
I-135	7.8E-02	-	7.8E-02
Rb-88	1.5E+00	-	-
Rb-89	6.9E-02	-	-
Cs-134	6.9E-01	-	6.9E-01
Cs-136	1.0E+00	-	1.0E+00
Cs-137	5.0E-01	-	5.0E-01
Ba-137m	5.0E-01	-	5.0E-01
Sr-89	-	-	1.1E-04
Cs-138	3.7E-01	-	-
Mo-99	2.1E-01	-	2.1E-01
Kr-85m	-	1.3E+00	-
Kr-85	-	8.0E+00	-
Kr-87	-	2.1E-01	-
Kr-88	-	1.8E+00	-
Xe-131m	-	3.6E+00	-
Xe-133m	-	4.3E+00	-
Xe-133	-	3.3E+02	-
Xe-135	-	7.3E+00	-

Note:
The liquid activities listed are 99% of the total source strength.
The vapor activities listed are essentially 100% of the source strength.

Table 12.2-9 (Sheet 5 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

C. Chemical waste tank (15,000 gal)

Energy Group (Mev/gamma)		Source Strength (Mev/gram-sec)
0-0.02		6.3E-01
0.02-0.03		1.2E-01
0.03-0.045		2.5E+01
0.045-0.07		3.1E-04
0.07-0.1		5.3E-03
0.1-0.15		3.2E-02
0.15-0.3		3.8E+00
0.3-0.45		5.6E+00
0.45-0.7		1.6E+04
0.7-1.0		9.7E+03
1.0-1.5		1.0E+03
1.5-2.0		1.5E+02
2.0-2.5		3.2E+01
2.5-3.0		5.3E+01
3.0-4.0		6.9E+00
4.0-6.0		-
6.0-8.0		-
8.0-11.00		-
	Total	2.7E+04

Nuclide	Activity (µCi/gram)
Co-58	1.9E-03
Cs-134	3.4E-01
Cs-137	2.5E-01
Te-127m	3.8E-04
Ba-137m	2.3E-01
Ce-144	5.8E-05

Table 12.2-9 (Sheet 6 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

D. Waste ion exchanger and charcoal deep bed filter vessel(a)

	Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec)
	0-0.02	1.2E+03
	0.02-0.03	5.5E+03
	0.03-0.045	5.1E+04
	0.045-0.07	5.8E+04
	0.07-0.1	4.8E+04
	0.1-0.15	3.4E+03
	0.15-0.3	6.7E+05
	0.3-0.45	2.5E+06
	0.45-0.7	9.1E+06
	0.7-1.0	1.1E+07
	1.0-1.5	9.3E+06
	1.5-2.0	6.0E+05
	2.0-2.5	1.4E+05
	2.5-3.0	2.9E+04
	3.0-4.0	3.5E+03
	4.0-6.0	-
	6.0-8.0	-
	8.0-11.00	-
Total		3.3E+07

Note:
(a) Source term for the charcoal deep bed filter vessel is based on operation charged with resin instead of charcoal since this is the most conservative mode of operation for source terms.

Table 12.2-9 (Sheet 7 of 7)

LIQUID RADWASTE SYSTEM
COMPONENT SOURCE TERMS

D. Waste ion exchanger and charcoal deep bed filter vessel(a)

Nuclide	Activity (µCi/cm^3)
Mn-56	3.4E+00
I-131	1.2E+02
I-132	1.7E+01
I-133	1.1E+02
I-135	2.8E+01
Cs-134	1.4E+02
Cs-136	1.9E+02
Cs-137	9.9E+01
Ba-137m	9.4E+01

E. Waste prefilter and waste after filter

Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec)
0.4 - 0.9	1.1E+07
0.9 - 1.35	3.0E+06
Total	1.4E+07

Source Dimensions (inches)	Source Composition (volume percent)
Radius = 3.375	Air - 67
Length = 19	Water - 33

Note:
(a) Source term for the charcoal deep bed filter vessel is based on operation charged with resin instead of charcoal since this is the most conservative mode of operation for source terms.

Table 12.2-10 (Sheet 1 of 4)

GASEOUS RADWASTE SYSTEM
COMPONENT SOURCE TERMS

A. Gas cooler and moisture separator

Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec)
0.000-0.020	1.1E+03
0.020-0.030	1.2E+03
0.030-0.045	5.4E+04
0.045-0.070	2.3E-01
0.070-0.100	1.1E+05
0.100-0.150	2.2E+01
0.150-0.300	3.1E+04
0.300-0.450	5.6E+03
0.450-0.700	5.3E+03
0.700-1.000	7.8E+03
1.000-1.500	5.2E+03
1.500-2.000	1.4E+04
2.000-2.500	6.5E+04
2.500-3.000	5.9E+03
3.000-4.000	5.9E+02
4.000-6.000	3.6E+01
6.000-8.000	-
8.000-11.000	-
Total	3.1E+05

Table 12.2-10 (Sheet 2 of 4)

GASEOUS RADWASTE SYSTEM
COMPONENT SOURCE TERMS

A. Gas cooler and moisture separator

Nuclide	Activity (µCi/cm^3)
Kr-85m	6.6E-01
Kr-87	3.8E-01
Kr-88	1.2E+00
Xe-133m	1.3E+00
Xe-133	9.8E+01
Xe-135m	1.4E-01
Xe-135	2.8E+00
Xe-138	1.9E-01

Note:
The activities listed are 99% of the total source strength.

Table 12.2-10 (Sheet 3 of 4)

GASEOUS RADWASTE SYSTEM
COMPONENT SOURCE TERMS

B. Charcoal guard and delay beds (8 ft^3 guard bed and 80 ft^3 delay beds)

Energy Group (Mev/gamma)	Source Strength (Mev/cm^3-sec)	
	Guard Bed	**Delay Beds**
0.000-0.020	1.2E+06	1.1E+05
0.020-0.030	1.4E+06	1.3E+05
0.030-0.045	6.2E+07	5.8E+06
0.045-0.070	9.2E+00	8.6E-01
0.070-0.100	1.3E+08	1.2E+07
0.100-0.150	1.2E+04	1.2E+03
0.150-0.300	4.1E+07	3.8E+06
0.300-0.450	2.1E+06	2.0E+05
0.450-0.700	3.4E+06	3.1E+05
0.700-1.000	3.3E+06	3.1E+05
1.000-1.500	2.1E+06	1.9E+05
1.500-2.000	4.9E+06	4.6E+05
2.000-2.500	2.9E+07	2.7E+06
2.500-3.000	1.5E+06	1.4E+05
3.000-4.000	5.5E+04	5.1E+03
4.000-6.000	3.2E+02	3.0E+01
6.000-8.000	-	-
8.000-11.000	-	-
Total	2.8E+08	2.6E+07

Table 12.2-10 (Sheet 4 of 4)

GASEOUS RADWASTE SYSTEM
COMPONENT SOURCE TERMS

B. Charcoal guard and delay beds (8 ft^3 guard bed and 80 ft^3 delay beds)

	Activity (μCi/cm^3)	
Nuclide	**Guard Bed**	**Delay Beds**
Kr-85m	5.0E+02	4.6E+01
Kr-85	2.7E+03	2.5E+02
Kr-87	8.0E+01	7.4E+00
Kr-88	5.5E+02	5.2E+01
Xe-131m	1.2E+03	1.1E+02
Xe-133m	1.5E+03	1.4E+02
Xe-133	1.1E+05	1.1E+04
Xe-135	4.3E+03	4.0E+02
Xe-138	7.7E+00	7.2E-01

Note:
The activities listed are essentially 100% of the total source strength.

Table 12.2-11 (Sheet 1 of 2)

SPENT DEMINERALIZER RESIN
SOURCE STRENGTHS AND SPECIFIC ACTIVITIES

Energy Group (Mev/gamma)	Spent Resin Source Strength (Mev/cm^3-sec) Initial	After 30 Days
0-0.02	1.7E+04	1.3E+04
0.02-0.03	1.1E+05	8.1E+03
0.03-0.045	3.5E+05	3.0E+05
0.045-0.07	4.8E+04	9.7E+03
0.07-0.1	2.2E+05	2.1E+04
0.1-0.15	4.8E+03	5.7E+02
0.15-0.3	2.2E+06	2.6E+05
0.3-0.45	2.8E+07	2.3E+06
0.45-0.7	1.8E+08	1.6E+08
0.7-1.0	9.9E+07	8.8E+07
1.0-1.5	2.8E+07	1.7E+07
1.5-2.0	4.2E+06	1.9E+06
2.0-2.5	8.7E+05	3.8E+05
2.5-3.0	7.4E+05	6.4E+05
3.0-4.0	9.9E+04	8.3E+04
4.0-6.0	2.7E+03	-
6.0-8.0	-	-
8.0-11.00	-	-
Total	3.4E+08	2.7E+08

Table 12.2-11 (Sheet 2 of 2)

SPENT DEMINERALIZER RESIN
SOURCE STRENGTHS AND SPECIFIC ACTIVITIES

	Spent Resin Activity (μCi/cm^3)	
Nuclide	**Initial**	**After 30 Days**
Mn-54	6.2E+01	5.8E+01
Mn-56	1.3E+01	-
Co-58	7.2E+01	5.4E+01
Co-60	7.8E+01	7.7E+01
I-131	2.4E+03	1.8E+02
I-132	4.3E+01	-
I-134	3.9E+00	-
I-135	9.9E+01	-
Rb-88	8.9E+00	-
Cs-134	3.0E+03	3.0E+03
Cs-136	1.6E+02	3.1E+01
Cs-137	3.0E+03	3.0E+03
Ba-137m	2.8E+03	2.8E+03

Table 12.2-12 (Sheet 1 of 2)

NORMAL RESIDUAL HEAT REMOVAL SYSTEM SOURCE STRENGTHS AND SPECIFIC ACTIVITIES

Energy Group	Source Strength (Mev/gram-sec)	
Mev/gamma	**4 Hours After Shutdown**	**8 Hours After Shutdown**
0.000 -0.020	1.3E+03	1.2E+03
0.020 -0.030	1.5E+03	1.4E+03
0.030 -0.045	6.7E+04	6.6E+04
0.045 -0.070	2.1E+02	1.4E+02
0.070 -0.100	1.4E+05	1.3E+05
0.100 -0.150	9.6E+02	9.2E+02
0.150 -0.300	3.0E+04	2.2E+04
0.300 -0.450	1.1E+04	7.2E+03
0.450 -0.700	4.6E+04	2.7E+04
0.700 -1.000	3.5E+05	3.3E+05
1.000 -1.500	5.6E+04	3.5E+04
1.500 -2.000	2.0E+04	7.8E+03
2.000 -2.500	3.0E+04	1.1E+04
2.500 -3.000	2.6E+03	7.9E+02
3.000 -4.000	4.7E+02	1.7E+02
4.000 -6.000	1.7E+02	6.2E+01
6.000 -8.000	-	-
8.000-11.000	-	-
Total	7.6E+05	6.4E+05

Table 12.2-12 (Sheet 2 of 2)

NORMAL RESIDUAL HEAT REMOVAL SYSTEM SOURCE STRENGTHS AND SPECIFIC ACTIVITIES

	Activity (μCi/gram)	
Nuclide	**4 Hours After Shutdown**	**8 Hours After Shutdown**
Kr-87	5.3E-02	6.0E-03
Kr-88	5.5E-01	2.1E-01
Xe-131m	1.3E+00	1.3E+00
Xe-133m	1.6E+00	1.5E+00
Xe-133	1.2E+02	1.2E+02
Xe-135	2.7E+00	2.0E+00
I-131	4.7E-01	3.1E-01
I-132	1.9E-01	4.0E-02
I-133	7.5E-01	4.4E-01
I-135	3.4E-01	1.5E-01
Rb-88	5.9E-01	2.2E-01
Cs-134	4.6E-01	3.1E-01
Cs-136	6.8E-01	4.5E-01
Tc-99m	1.9E-01	1.8E-01
Ba-137m	3.1E-01	2.1E-01
Co-58	1.0E+01	1.0E+01
Co-60	1.0E-01	1.0E-01

Table 12.2-13

CORE AVERAGE AND SPENT FUEL NEUTRON SOURCE STRENGTHS AT VARIOUS TIMES AFTER SHUTDOWN

Time After Shutdown	Core Average (n/watt-sec)	Spent Fuel (n/watt-sec)
12 hours	22	77
24 hours	22	77
100 hours	22	76
1 week	22	76
1 month	21	75
3 months	20	71
6 months	18	68
1 year	16	63
5 years	13	51

Table 12.2-14 (Sheet 1 of 2)

SPENT FUEL GAMMA RAY SOURCE STRENGTHS

Energy Group	Source Strength at Time After Shutdown (Mev/watt-sec)				
Mev/gamma	**12 Hours**	**24 Hours**	**100 Hours**	**1 Week**	**1 Month**
0-0.02	2.3E+08	2.0E+08	8.4E+07	4.1E+07	1.7E+06
0.02-0.03	4.3E+07	3.7E+07	2.2E+07	1.6E+07	4.1E+06
0.03-0.045	1.1E+08	1.0E+08	6.0E+07	4.4E+07	1.5E+07
0.045-0.07	8.5E+07	7.6E+07	4.3E+07	2.9E+07	2.9E+06
0.07-0.1	4.4E+08	3.9E+08	1.9E+08	1.1E+08	9.6E+06
0.1-0.15	1.8E+09	1.6E+09	7.4E+08	4.0E+08	8.2E+07
0.15-0.3	2.5E+09	2.1E+09	8.6E+08	4.2E+08	1.6E+07
0.3-0.45	1.0E+09	8.9E+08	5.4E+08	3.9E+08	7.5E+07
0.45-0.7	5.4E+09	4.5E+09	2.7E+09	2.2E+09	1.2E+09
0.7-1.0	6.7E+09	5.9E+09	4.2E+09	3.6E+09	2.5E+09
1.0-1.5	2.3E+09	1.5E+09	7.6E+08	5.6E+08	1.8E+08
1.5-2.0	3.3E+09	3.0E+09	2.4E+09	2.1E+09	6.1E+08
2.0-2.5	3.9E+08	3.1E+08	2.4E+08	2.0E+08	7.9E+07
2.5-3.0	1.8E+08	1.7E+08	1.4E+08	1.2E+08	3.5E+07
3.0-4.0	4.6E+06	1.8E+06	1.5E+06	1.3E+06	4.2E+05
4.0-6.0	2.5E+05	1.3E+04	1.6E+01	1.6E+01	1.6E+01
6.0-8.0	2.6E+00	2.6E+00	2.6E+00	2.6E+00	2.6E+00
8.0-11.00	4.1E-01	4.1E-01	4.1E-01	4.1E-01	4.0E-01

Table 12.2-14 (Sheet 2 of 2)

SPENT FUEL GAMMA RAY SOURCE STRENGTHS

Energy Group	Source Strength at Time After Shutdown (Mev/watt-sec)			
Mev/gamma	**3 Months**	**6 Months**	**1 Year**	**5 Years**
0-0.02	3.8E+05	2.4E+05	1.6E+05	6.4E+04
0.02-0.03	1.2E+06	5.2E+05	3.2E+05	1.1E+05
0.03-0.045	6.8E+06	4.6E+06	3.1E+06	6.9E+05
0.045-0.07	3.4E+05	2.2E+05	1.7E+05	9.6E+04
0.07-0.1	2.7E+06	2.1E+06	1.4E+06	2.5E+05
0.1-0.15	3.3E+07	1.6E+07	9.1E+06	1.2E+06
0.15-0.3	1.9E+06	9.6E+05	6.6E+05	3.7E+05
0.3-0.45	6.8E+06	3.7E+06	2.9E+06	9.7E+05
0.45-0.7	7.3E+08	5.3E+08	4.1E+08	1.6E+08
0.7-1.0	1.5E+09	7.9E+08	3.2E+08	6.8E+07
1.0-1.5	7.7E+07	6.2E+07	5.0E+07	1.7E+07
1.5-2.0	3.1E+07	5.2E+06	3.3E+06	5.6E+05
2.0-2.5	2.3E+07	1.6E+07	1.0E+07	3.2E+05
2.5-3.0	1.6E+06	2.4E+05	1.6E+05	1.0E+04
3.0-4.0	6.6E+04	4.4E+04	3.1E+04	2.0E+03
4.0-6.0	1.5E+01	1.4E+01	1.3E+01	1.1E+01
6.0-8.0	2.5E+00	2.3E+00	2.2E+00	1.8E+00
8.0-11.00	3.8E-01	3.6E-01	3.4E-01	2.8E-01

Table 12.2-15

IRRADIATED SILVER-INDIUM-CADMIUM CONTROL ROD SOURCE STRENGTHS

Energy Group	Source Strength at Time After Shutdown (Mev/cm3-sec)		
Mev/gamma	**1 Day**	**1 Week**	**1 Month**
0.20 - 0.40	2.3E+08	2.3E+08	2.2E+08
0.40 - 0.90	1.1E+12	1.1E+12	1.0E+12
0.90 - 1.35	2.0E+11	1.9E+11	1.8E+11
1.35 - 1.80	3.7E+11	3.7E+11	3.4E+11
Mev/gamma	**6 Months**	**1 Year**	**5 Years**
0.20 - 0.40	1.4E+08	8.5E+07	1.5E+06
0.40 - 0.90	6.6E+11	4.0E+11	7.1E+09
0.90 - 1.35	1.2E+11	7.2E+10	1.3E+09
1.35 - 1.80	2.3E+11	1.4E+11	2.5E+09

Note:
The absorber cross-sectional area is 0.589 square centimeters per rod and the absorber material density is 10.2 grams per cubic centimeter.

Table 12.2-16

IRRADIATED SB-BE SECONDARY SOURCE ROD
GAMMA RAY SOURCE STRENGTHS

Energy Group	Source Strength at Time After Shutdown (Mev/watt-sec)		
Mev/gamma	1 Day	1 Week	1 Month
0.20 - 0.40	3.0E+10	2.9E+10	2.5E+10
0.40 - 0.90	1.1E+13	7.0E+12	4.6E+12
0.90 - 1.35	6.7E+11	4.8E+11	3.4E+11
1.35 - 1.80	7.6E+12	7.1E+12	5.5E+12
1.80 - 2.20	9.8E+11	9.1E+11	7.0E+11
Mev/gamma	6 Months	1 Year	5 Years
0.20 - 0.40	1.1E+10	3.7E+09	2.2E+07
0.40 - 0.90	8.1E+11	9.7E+10	1.8E+08
0.90 - 1.35	6.0E+10	7.0E+09	0
1.35 - 1.80	9.7E+11	1.2E+11	0
1.80 - 2.20	1.2E+11	1.5E+10	0

Notes:

- The Sb-Be material density is 3.38 grams per cubic centimeter.
- The secondary source rod cross-sectional area is 0.582 square centimeter per rod.
- The average neutron energy is 30 kev.

Table 12.2-17

IRRADIATED SB-BE SECONDARY SOURCE ROD NEUTRON SOURCE STRENGTHS

Time After Shutdown	Sb-124 Concentration (curies/cm3)	Neutron Source Strength (n/cm3-sec)
1 day	230	4.5E+08
1 week	210	4.2E+08
1 month	160	3.2E+08
6 months	29	5.8E+07
1 year	3.4	6.8E+06
5 years	0	0

Note:
- The Sb-Be material density is 3.38 grams per cubic centimeter.
- The secondary source rod cross-sectional area is 0.582 square centimeter per rod.
- The average neutron energy is 30 kev.

Table 12.2-18

IRRADIATED TYPE 304 STAINLESS STEEL SOURCE STRENGTHS (0.12 WEIGHT PERCENT COBALT)

Energy Group	Source Strength at Time After Shutdown (Mev/cm^3-sec)		
Mev/gamma	**1 Day**	**1 Week**	**1 Month**
0.20 - 0.40	7.1E+09	6.1E+09	3.4E+09
0.40 - 0.90	3.1E+10	2.9E+10	2.6 E+10
0.90 - 1.35	2.4E+11	2.3E+11	2.3E+11
1.35 - 1.80	1.9E+08	1.8E+08	1.4E+08
Mev/gamma	**6 Months**	**1 Year**	**5 Years**
0.20 - 0.40	8.3E+07	9.9E+05	0
0.40 - 0.90	1.2E+10	6.4E+09	2.3E+08
0.90 - 1.35	2.1E+11	2.0E+11	1.2E+11
1.35 - 1.80	3.3E+07	5.4E+06	0

Notes:
The various cross-section areas per rod are as follows:
- Ag-In-Cd control rod cladding - 0.136 cm^2
- Sb-Be secondary source rod cladding - 0.136 cm^2
- Gray rod cladding - 0.136 cm^2
- Gray rod pellet - 0.589 cm^2

Table 12.2-19

IRRADIATED FLUX THIMBLE
SOURCE STRENGTHS

Energy Group	Source Strength at Time After Shutdown (Mev/cm^3-sec)			
Mev/gamma	**12 Hours**	**1 Day**	**70 Hours**	**1 Week**
<0.15	1.2E+09	1.1E+09	1.1E+09	9.9E+08
0.15 - 0.45	1.3E+10	1.3E+10	1.2E+10	1.1E+10
0.45 - 1.0	1.3E+11	1.3E+11	1.3E+11	1.2E+11
1.0 - 1.5	3.5E+10	3.5E+10	3.5E+10	3.5E+10
1.5 - 2.0	2.5E+09	1.2E+09	1.1E+09	1.1E+09
2.0 - 2.5	8.4E+08	3.3E+07	3.3E+05	3.3E+05
2.5 - 3.0	1.4E+08	5.7E+06	-	-
3.0 - 4.0	1.5E+07	6.1E+05	-	-
Mev/gamma	**1 Month**	**6 Months**	**1 Year**	**5 Years**
<0.15	7.0E+08	1.3E+08	4.0E+07	1.3E+07
0.15 - 0.45	6.1E+09	1.8E+08	1.0E+07	7.0E+05
0.45 - 1.0	9.7E+10	2.2E+10	4.6E+09	3.8E+07
1.0 - 1.5	3.5E+10	3.2E+10	3.1E+10	1.8E+10
1.5 - 2.0	8.6E+08	1.9E+08	3.2E+07	-
2.0 - 2.5	3.3E+05	3.1E+05	2.9E+05	1.7E+05
2.5 - 3.0	-	-	-	-
3.0 - 4.0	-	-	-	-

Note:
The flux thimble and mandrel cross-sectional area is 0.574 square centimeter.

Table 12.2-20

CORE MELT ACCIDENT SOURCE STRENGTHS IN CONTAINMENT ATMOSPHERE AS A FUNCTION OF TIME

Energy Group	Source Strength at Time After Release (Mev/watt-sec)				
Mev/gamma	**10 Min.**	**40 Min**	**1.97 Hours**	**3.97 Hours**	**5.97 Hours**
<0.15	3.9E+06	6.1E+06	1.2E+08	1.3E+08	1.4E+08
0.15 - 0.45	3.8E+07	4.8E+07	5.1E+08	5.9E+08	6.6E+08
0.45 - 1.0	3.2E+08	4.2E+08	2.6E+09	3.1E+09	2.8E+09
1.0 - 1.5	2.2E+08	2.6E+08	1.2E+09	1.4E+09	1.2E+09
1.5 - 2.0	7.8E+07	9.4E+07	7.1E+08	7.3E+08	5.4E+08
2.0 - 2.5	8.6E+07	9.0E+07	8.2E+08	6.6E+08	3.5E+08
2.5 - 3.0	3.0E+07	2.7E+07	1.3E+08	8.8E+07	2.9E+07
3.0 - 4.0	1.1E+07	5.6E+06	1.9E+07	1.3E+07	4.9E+06
4.0 - 6.0	3.3E+06	4.2E+05	3.9E+06	3.4E+06	1.7E+06
6.0 - 11.0	-	-	1.7E-04	2.3E-03	4.4E-03
Beta	4.2E+08	4.3E+08	3.5E+09	3.6E+09	3.0E+09
Mev/gamma	**11.97 Hours**	**1 Day**	**1 Week**	**1 Month**	**1 Year**
<0.15	1.4E+08	1.3E+08	5.8E+07	4.2E+06	4.0E+05
0.15 - 0.45	6.0E+08	4.7E+08	1.9E+08	2.8E+07	5.5E+05
0.45 - 1.0	2.3E+09	1.7E+09	6.8E+08	3.4E+08	2.2E+08
1.0 - 1.5	7.4E+08	3.5E+08	7.8E+07	2.2E+07	8.3E+06
1.5 - 2.0	3.0E+08	1.8E+08	2.5E+08	7.7E+07	1.3E+04
2.0 - 2.5	1.1E+08	2.9E+07	7.9E+06	1.3E+06	5.5E+04
2.5 - 3.0	8.8E+06	7.4E+06	1.5E+07	4.6E+06	5.2E+02
3.00 - 4.00	1.1E+06	1.2E+05	1.5E+05	4.8E+04	9.7E+01
4.0 - 6.0	3.9E+05	2.1E+04	2.4E-02	2.3E-02	1.8E-02
6.0 - 11.0	4.4E-03	4.4E-03	4.4E-03	4.3E-03	3.3E-03
Beta	2.2E+09	1.5E+09	6.2E+08	2.0E+08	6.3E+07

Note:
No release from core until 10 minutes after incident (see subsection 15.6.5.3).

Table 12.2-21

CORE MELT ACCIDENT INTEGRATED SOURCE STRENGTHS IN CONTAINMENT ATMOSPHERE

Energy Group Mev/gamma	Source Strength at Time After Release (Mev/watt) 10 Min.	40 Min.	1.97 Hours	3.97 Hours
<0.15	3.9E+06	8.8E+09	3.6E+11	1.3E+12
0.15 - 0.45	3.8E+07	7.8E+10	1.6E+12	5.9E+12
0.45 - 1.0	3.2E+08	6.6E+11	8.6E+12	3.0E+13
1.0 - 1.5	2.2E+08	4.3E+11	4.4E+12	1.4E+13
1.5 - 2.0	7.8E+07	1.6E+11	2.4E+12	7.6E+12
2.0 - 2.5	8.6E+07	1.6E+11	3.2E+12	7.9E+12
2.5 - 3.0	3.0E+07	5.1E+10	6.1E+11	1.3E+12
3.0 - 4.0	1.1E+07	1.4E+10	9.2E+10	1.9E+11
4.0 - 6.0	3.3E+06	2.5E+09	1.5E+10	3.9E+10
6.0 - 11.0	-	-	4.0E-01	1.7E+01
Beta	4.2E+08	7.6E+11	1.2E+13	3.8E+13

Mev/gamma	11.97 Hours	1 Day	1 Week	1 Month	1 Year
<0.15	5.3E+12	1.1E+13	5.7E+13	9.8E+13	1.4E+14
0.15 - 0.45	2.5E+13	4.9E+13	1.9E+14	3.6E+14	5.6E+14
0.45 - 1.0	1.2E+14	2.0E+14	7.2E+14	1.7E+15	9.7E+15
1.0 - 1.5	5.0E+13	7.2E+13	1.5E+14	2.4E+14	6.4E+14
1.5 - 2.0	2.4E+13	3.5E+13	1.6E+14	4.5E+14	7.1E+14
2.0 - 2.5	2.0E+13	2.2E+13	2.9E+13	3.7E+13	4.8E+13
2.5 - 3.0	2.4E+12	2.8E+12	9.6E+12	2.7E+13	4.2E+13
3.0 - 4.0	3.7E+11	3.9E+11	4.6E+11	6.5E+11	8.7E+11
4.0 - 6.0	9.5E+10	1.0E+11	1.0E+11	1.0E+11	1.0E+11
6.0 - 11.0	1.4E+02	3.4E+02	2.6E+03	1.0E+04	9.5E+04
Beta	1.3E+14	2.1E+14	6.7E+14	1.4E+15	4.9E+15

Note:
No release from core until 10 minutes after incident (see subsection 15.6.5.3)

Table 12.2-22

PARAMETERS AND ASSUMPTIONS USED FOR CALCULATING CONTAINMENT AIRBORNE RADIOACTIVITY CONCENTRATIONS

Parameter/Assumption	Value
Reactor coolant leakage rate	30 lb/day
Time used to estimate equilibrium concentration	100 days
Containment free air volume	2.06E6 cu. ft
Flashing fraction	0.40
Fuel defects	0.250%
Reactor coolant tritium concentration	3.5 μCi/g
Normal operation purge flow rate	4,000 cfm
Normal operation purge duration	20 hrs/week
Shutdown purge flow rate	8,000 cfm

Table 12.2-23 (Sheet 1 of 3)

CONTAINMENT AIRBORNE RADIOACTIVITY CONCENTRATIONS
(μCi/cm^3)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Cr-51	5.1E-12	4.5E-12	1.0E-13
Mn-54	2.6E-12	2.3E-12	5.4E-14
Mn-56	5.2E-10	4.8E-10	1.9E-14
Fe-55	2.0E-12	1.7E-12	4.0E-14
Fe-59	5.1E-13	4.5E-13	1.0E-14
Co-58	7.4E-12	6.6E-12	1.5E-13
Co-60	8.6E-13	7.6E-13	1.8E-14
Br-83	9.7E-11	8.9E-11	2.1E-15
Br-84	2.8E-11	2.7E-11	1.8E-26
Br-85	4.9E-13	4.9E-13	-
Kr-83m	1.1E-08	8.1E-09	6.4E-13
Kr-85m	5.3E-08	3.0E-08	7.4E-10
Kr-85	6.8E-05	6.9E-07	1.2E-07
Kr-87	8.5E-09	7.0E-09	2.7E-14
Kr-88	6.0E-08	4.0E-08	1.5E-10
Kr-89	2.6E-11	2.6E-11	-
Rb-88	1.8E-09	1.7E-09	2.1E-35
Rb-89	7.2E-11	7.0E-11	5.1E-41
Sr-89	4.2E-12	3.7E-12	8.5E-14
Sr-90	1.9E-13	1.7E-13	3.9E-15
Sr-91	6.3E-12	5.7E-12	2.3E-14
Sr-92	1.3E-12	1.2E-12	6.3E-17
Y-90	4.8E-14	4.3E-14	7.8E-16
Y-91m	2.0E-12	1.8E-12	9.5E-23
Y-91	5.3E-13	4.7E-13	1.1E-14
Y-92	1.1E-12	9.9E-13	2.2E-16
Y-93	4.2E-13	3.7E-13	1.8E-15

Table 12.2-23 (Sheet 2 of 3)

CONTAINMENT AIRBORNE RADIOACTIVITY CONCENTRATIONS

(μCi/cm^3)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Zr-95	6.2E-13	5.5E-13	1.3E-14
Nb-95	6.2E-13	5.5E-13	1.3E-14
Mo-99	8.1E-10	7.3E-10	1.3E-11
Tc-99m	6.8E-10	6.1E-10	9.2E-13
Ru-103	5.3E-13	4.7E-13	1.1E-14
Ag-110m	1.6E-12	1.4E-12	3.2E-14
Te-127m	3.0E-12	2.6E-12	6.1E-14
Te-129m	1.0E-11	7.2E-12	2.1E-13
Te-129	9.3E-12	8.7E-12	1.4E-19
Te-131m	2.5E-11	2.3E-11	3.0E-13
Te-131	6.3E-12	6.0E-12	8.0E-31
Te-132	3.0E-11	2.7E-11	5.1E-13
TE-134	2.1E-11	1.9E-11	2.3E-23
I-129	5.8E-17	5.1E-17	4.7E-18
I-130	3.9E-11	3.5E-11	8.6E-13
I-131	2.7E-09	2.4E-09	2.1E-10
I-132	2.8E-09	2.6E-09	1.8E-13
I-133	4.8E-09	4.3E-09	1.8E-10
I-134	4.7E-10	4.4E-10	2.7E-19
I-135	2.7E-09	2.5E-09	1.9E-11
Xe-131m	5.3E-06	2.6E-07	5.2E-08
Xe-133m	1.2E-06	2.0E-07	5.0E-08
Xe-133	2.2E-04	2.0E-05	4.5E-06
Xe-135m	8.5E-10	8.1E-10	5.0E-37
Xe-135	4.5E-07	1.8E-07	2.2E-08
Xe-137	5.9E-11	5.9E-11	-
Xe-138	8.1E-10	7.8E-10	6.2E-40

Table 12.2-23 (Sheet 3 of 3)

CONTAINMENT AIRBORNE RADIOACTIVITY CONCENTRATIONS
(μCI/CM^3)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Cs-134	2.7E-09	2.4E-09	5.5E-11
Cs-136	4.0E-09	3.5E-09	7.7E-11
Cs-137	1.9E-09	1.7E-09	4.0E-11
Cs-138	6.2E-10	5.9E-10	5.8E-25
Ba-137m	1.1E-10	1.0E-10	-
Ba-140	4.0E-12	3.6E-12	7.8E-14
La-140	1.0E-11	8.9E-12	1.4E-13
Ce-141	6.0E-13	5.4E-13	1.2E-14
Ce-143	5.4E-13	4.8E-13	6.8E-15
Pr-143	5.8E-13	5.2E-13	1.1E-14
Ce-144	4.5E-13	4.0E-13	9.3E-15
Pr-144	1.3E-13	1.3E-13	3.4E-40
H-3	3.2E-05	3.2E-07	4.3E-09
Ar-41	1.6E-05	1.3E-05	4.8E-12
Total	3.4E-04	3.4E-05	4.7E-06
Iodines	1.4E-08	1.2E-08	4.1E-10
Particulates	1.3E-08	1.2E-08	1.9E-10
Noble Gases	3.1E-04	3.4E-05	4.7E-06

Table 12.2-24

PARAMETERS AND ASSUMPTIONS USED FOR CALCULATING FUEL HANDLING AREA AIRBORNE RADIOACTIVITY CONCENTRATIONS

Parameter/Assumption	Value
Ventilation flow through fuel handling area(1)	17,000 cfm(2)
Iodine filter efficiency	0
Particulate filter efficiency	0.99
Fuel handling area free air volume	200,000 ft^3
Fuel defects	0.25%
Time from shutdown to reactor vessel head removal	100 hours
Refueling time	10 days
Decontamination factors of mixed-bed demineralizer for spent fuel pool purification system:	
Iodines	100
Cs and Rb	2
Others	50
Spent fuel pool temperature	120°F
Evaporation rate of spent fuel pool water	486 lbs/hr
Spent fuel pool tritium concentration	1.0 µCi/g

Note:
1. This flow rate is defined as the sum of the fuel area exhaust fan flows minus the rail car bay/solid radwaste system exhaust flow.
2. This is the nominal expected ventilation flow rate. For conservatism, the calculated airborne radioactivity concentrations are based on a 10% lower flow rate.

Table 12.2-25 (Sheet 1 of 2)

FUEL HANDLING AREA AIRBORNE RADIOACTIVITY CONCENTRATIONS
($\mu Ci/cm^3$)

Isotope	Activity
Cr-51	3.4E-12
Mn-54	1.9E-12
Mn-56	5.9E-22
Fe-55	1.5E-12
Fe-59	3.5E-13
Co-58	5.3E-12
Co-60	6.4E-13
Br-83	1.3E-23
Br-84	4.5E-69
Kr-83m	5.1E-26
Kr-85m	7.9E-16
Kr-85	2.3E-10
Kr-87	8.3E-33
Kr-88	3.1E-19
Sr-89	3.0E-12
Sr-90	1.4E-13
Sr-91	2.9E-15
Sr-92	5.4E-24
Y-90	1.2E-14
Y-91	3.8E-13
Y-92	2.0E-21
Y-93	3.4E-16
Zr-95	4.4E-13
Nb-95	4.3E-13
Mo-99	2.1E-10
Tc-99m	4.2E-15
Ru-103	3.7E-13
Ag-110m	1.2E-12
Te-127m	2.2E-12
Te-129m	6.9E-12

Table 12.2-25 (Sheet 2 of 2)

FUEL HANDLING AREA AIRBORNE RADIOACTIVITY CONCENTRATIONS

(μCi/cm^3)

Isotope	**Activity**
Te-131m	1.8E-12
Te-131	1.9E-85
Te-132	9.3E-12
I-129	4.3E-16
I-130	1.0E-12
I-131	1.4E-08
I-132	9.4E-22
I-133	1.3E-09
I-135	5.0E-13
Xe-131m	1.8E-10
Xe-133m	3.3E-10
Xe-133	2.5E-08
Xe-135	5.3E-12
Cs-134	2.0E-09
Cs-136	2.4E-09
Cs-137	1.5E-09
Ba-140	2.4E-12
La-140	1.3E-12
Ce-141	4.1E-13
Ce-143	4.8E-14
Pr-143	3.5E-13
Ce-144	3.3E-13
H-3	1.1E-05
Total (excluding tritium)	4.8E-08
Iodines	1.6E-08
Particulates	6.2E-09
Noble Gases	2.6E-08

Table 12.2-26

PARAMETERS AND ASSUMPTIONS USED FOR CALCULATING AUXILIARY BUILDING AIRBORNE RADIOACTIVITY CONCENTRATIONS

Parameter/Assumption	Value
Ventilation exhaust flow(1)	25,000 cfm(2)
Free air volume	365,400 ft^3
Primary coolant leakage to auxiliary building	20 lb/day
Flashing fraction	0.4
Primary coolant source term	See Table 11.1-2
Fuel defects	0.25%

Note:

(1) This flow rate is defined as the sum of the aux/annex exhaust fan flow minus the annex building exhaust flow minus room 12555 (VES, containment access) exhaust flow.

(2) This is the nominal expected ventilation flow rate. For conservatism, the calculated airborne radioactivity concentrations are based on a 10% lower flow rate.

Table 12.2-27 (1 of 3)

AUXILIARY BUILDING AIRBORNE RADIOACTIVITY CONCENTRATIONS

(μCi/cm^3)

Isotope	Activity
Cr-51	5.1E-12
Mn-54	2.7E-12
Mn-56	6.7E-10
Fe-55	2.0E-12
Fe-59	5.1E-13
Co-58	7.5E-12
Co-60	8.7E-13
Br-83	1.3E-10
Br-84	6.6E-11
Br-85	7.8E-12
Kr-83m	1.8E-09
Kr-85m	8.3E-09
Kr-85	2.9E-08
Kr-87	4.7E-09
Kr-88	1.5E-08
Kr-89	3.5E-10
Rb-88	6.0E-09
Rb-89	2.7E-10
Sr-89	4.3E-12
Sr-90	1.9E-13
Sr-91	6.9E-12
Sr-92	1.6E-12
Y-90	5.0E-14
Y-91m	3.7E-12
Y-91	5.4E-13
Y-92	1.3E-12

Table 12.2-27 (2 of 3)

AUXILIARY BUILDING AIRBORNE RADIOACTIVITY CONCENTRATIONS
(μCi/cm^3)

Isotope	Activity
Y-93	4.5E-13
Zr-95	6.3E-13
Nb-95	6.3E-13
Mo-99	8.4E-10
Tc-99m	7.7E-10
Ru-103	5.4E-13
Ag-110m	1.6E-12
Te-127m	3.0E-12
Te-129m	1.0E-11
Te-129	1.5E-11
Te-131m	2.7E-11
Te-131	1.7E-11
Te-132	3.1E-11
Te-134	4.2E-11
I-129	5.9E-17
I-130	4.2E-11
I-131	2.8E-09
I-132	3.7E-09
I-133	5.1E-09
I-134	8.6E-10
I-135	3.1E-09
Xe-131m	1.3E-08
Xe-133m	1.7E-08
Xe-133	1.2E-06

Table 12.2-27 (3 of 3)

AUXILIARY BUILDING AIRBORNE RADIOACTIVITY CONCENTRATIONS
(μCi/cm^3)

Isotope	**Activity**
Xe-135m	2.3E-09
Xe-135	3.5E-08
Xe-137	6.6E-10
Xe-138	2.4E-09
Cs-134	2.7E-09
Cs-136	4.0E-09
Cs-137	2.0E-09
Cs-138	1.5E-09
Ba-137m	1.9E-09
Ba-140	4.1E-12
La-140	1.0E-11
Ce-141	6.1E-13
Ce-143	5.6E-13
Pr-143	5.9E-13
Ce-144	4.6E-13
Pr-144	4.6E-13
H-3	1.4E-08
Total	1.4E-06
Iodines	1.6E-08
Particulates	2.1E-08
Noble Gases	1.4E-06

12.3 Radiation Protection Design Features

12.3.1 Facility Design Features

Specific design features for maintaining personnel exposure as low as reasonably achievable (ALARA) are presented in this subsection. The design feature recommendations given in Regulatory Guide 8.8 are utilized to minimize exposures to personnel.

12.3.1.1 Plant Design Features for ALARA

The equipment and plant design features employed to maintain radiation exposures ALARA are based upon the design considerations of subsection 12.1.2 and are outlined in this subsection.

12.3.1.1.1 Common Equipment and Component Designs for ALARA

This subsection describes the design features utilized for several general classes of equipment or components. These classes of equipment are common to many of the plant systems; thus, the features employed for each system to maintain minimum exposures are similar and are presented by equipment class in the following paragraphs.

Reactor Vessel

The reactor vessel design includes an integrated head package which combines the head lifting rig, control and gray rod drive mechanism (CRDM/GRDM), lift columns, reactor vessel missile shield, control rod drive mechanism cooling system and power and instrumentation cabling into an effective, one-package reactor vessel head design. Mounted directly on the reactor vessel head, the system helps to minimize the time, manpower and radiation exposure associated with head removal and replacement during refueling. Integral in the design is permanent shielding for reducing work area dose rates from the control rod drive mechanism drive shafts and thermocouple/incore detector system.

The conventional top mounted instrumentation ports/conoseal thermocouple arrangement is replaced with a combination thermocouple/incore detector system. This eliminates the need to disassemble and reassemble the instrument port conoseals at each refueling, which has historically been a relatively high radiation exposure task.

The reactor vessel nozzle welds are designed to accommodate remote inspection with ultrasonic sensors. The nozzle area is tapered along the reinforced areas to provide a smooth transition, and pipe branch locations are selected to avoid interference from one branch to the next. Weld-to-pipe interfaces require a smooth, high quality finish.

Reactor Coolant Pumps

The canned high-inertia reactor coolant pumps are designed to require infrequent maintenance and inspection. When maintenance or replacement is required, the pump can be removed and moved to a low radiation background work area using a specially provided pump removal cart.

Reactor Vessel Insulation

Insulation in the area of the reactor vessel nozzle welds is fabricated in sections with a thin reflective metallic sheet covering and quick disconnect clasps to facilitate removal of the insulation. Permanent identification markings of the sections of insulation are provided to accommodate rapid reinstallation.

Steam Generators

The steam generator incorporates many design features to facilitate maintenance and inspection in reduced radiation fields. The tube ends are designed to be flush with the tube sheet in the steam generator channel head to eliminate a potential crud trap. The steam generator manways (entrance to channel head) are sized for easy entrance and exit of workers with protective clothing, and to facilitate the installation and removal of tooling.

The specification of low cobalt tubing material for the AP1000 steam generator design is an important feature of the design; not only in terms of reduced exposure relative to the steam generator, but to the total plant radiation source term. The cobalt content has been substantially reduced to 0.015 weight percent for the AP1000 steam generator tubing.

The steam generator design includes a sludge control system/mud drum which is designed to reduce the need for sludge lancing, and reduces tube and tube support degradation. Steam generator tube support plates design and full depth tubesheet expansion of tubes reduce corrosion and occupational exposure.

Reactor Coolant Pipe Connections

To minimize crud buildup in branch lines, piping connections to the reactor coolant loops are located on or above the horizontal centerline of the pipe wherever practicable.

Filters

Cartridges and filter bags that accumulate radioactivity are removed with semi-remote tools. Adequate space is provided to allow removing, and transporting the cartridge to storage and packaging areas as described in Section 11.4.

Liquid systems containing radioactive filters are provided with remote or semi-remote filter handling systems for the removal of spent radioactive filter elements from their housings and for their transfer to temporary storage or for packaging and shipment from the site for burial. The process is accomplished in such a manner that exposure to personnel and the possibility of inadvertent radioactive release to the environment is minimized. The filter handling is designed to be simple, with a minimum of components susceptible to malfunction.

Demineralizers

Demineralizers for radioactive systems are designed so that spent resins can be remotely and hydraulically transferred to spent resin tanks prior to processing and so that fresh resin can be loaded into the demineralizer remotely. The demineralizers and piping include provisions for

being flushed with demineralized water. The system design prevents inadvertent flushing of the resin into the purification loop through the demineralizer inlet.

Pumps

Air operated diaphragm, canned pumps or pumps with mechanical seals are used in radioactive systems to reduce leakage and seal servicing time. Pumps and associated piping are arranged to provide adequate space for access to the pumps for servicing. Small pumps are installed in a manner which allows easy removal if necessary. Large pumps are selected with back pullout features that permit removal of the pump impeller or mechanical seals without disassembly of attached piping. Pumps in radioactive waste systems are provided with flanged connections for ease of removal.

Tanks and Sumps

Tanks are provided with sloped bottoms and bottom outlet connections. Overflow lines are directed to the waste collection system to control contamination within plant structures. Tanks containing radioactivity are fabricated from stainless steel, and sumps which can contain radioactive liquid are lined with stainless steel to facilitate decontamination.

Heat Exchangers

Vertical heat exchangers are designed so that the shell-to-tube sheet joint need not be broken for inspection. The shell and tube assembly can be lifted intact above the channel head to expose the tube ends for inspection and testing for leaks.

Heat exchangers are provided with corrosion-resistant tubes of stainless steel to reduce leakage. Impingement plates are provided and as necessary and tube side and shell side velocities are limited to minimize erosive effects. Wherever practicable, the radioactive fluid passes through the tube side of the heat exchanger.

Instruments

Instrument devices are located in low radiation zones away from radiation sources whenever practicable. Primary instrument devices, which for functional reasons are located in high radiation zones, are designed for easy removal to a lower radiation zone for calibration. Transmitters and readout devices are located in low radiation zones, such as corridors for servicing. Non-contact type instruments or self cleaning instruments are used whenever possible.

Some instruments in high radiation zones, such as thermocouples, are provided in duplicate to reduce access and service time required. In-containment instruments are located outside the secondary shield (area of lower radiation at power and shutdown) whenever practicable.

Integral radiation check sources for response verification for airborne radiation monitors and area radiation monitors are provided.

Chemical seals are provided on the instrument sensing lines on process piping, which may contain highly radioactive solids, to reduce the servicing time required to keep the lines free of solids.

Instrument and sensing line connections are located slightly above the pipe midplane wherever practicable to minimize radioactive crud buildup.

Valves

To minimize personnel exposures from valve operations, motor-operated, air-operated, or other remotely actuated valves are used where justified by the activity levels and frequency of use. Valves are located in valve galleries so that they are shielded separately from the major components. Long runs of exposed piping are minimized in valve galleries. In areas where manual valves are used on frequently operated process lines, either valve stem extenders or shielding is provided such that personnel need not enter a high radiation area for valve operation.

Wherever testing is required, valves of the bolted body-to-bonnet forging type are used to permit the use of ultrasonic testing in place of radiography. This facilitates inspection and maintenance time. Valves under 2 inches in diameter located in the piping carrying radioactive fluids in containment or carrying highly radioactive fluids outside containment are hermetically sealed (packless) valves to preclude radioactive releases to the environment. The design of large-bore valves includes live-loaded packing and graphite packing materials to reduce the potential for steam leakage.

When equipment in high radiation areas is operated infrequently, those valves associated with normal processing are provided with remote-manual operators or reach rods. Other valve operations are performed with equipment in the shutdown mode.

For valves located in radiation areas, provisions are made to drain adjacent radioactive components when maintenance is required. To the extent practicable, valves are not located at piping low points.

Manually operated valves in the filter and demineralizer modules required for normal operation and shutdown are equipped with reach rods extending through the shield plates. Personnel do not enter the module during spent resin or cartridge transfer operations. The modules are designed to reduce personnel exposure during maintenance of components within or adjacent to the modules and to protect personnel who operate the valves.

Piping

The piping in pipe chases is designed for 60 year design objective with consideration for corrosion and operating environment. Pipe bends are used instead of elbows where practicable to reduce potential crud traps. Welds are made smooth to prevent crud traps from forming. Butt welds are used to the extent practicable. When radioactive piping is routed through areas where routine maintenance is required, pipe chases or distance separation are provided to reduce the radiation contribution from these pipes to levels appropriate for the inspection or maintenance requirements. Piping containing radioactive material is routed to minimize radiation exposure to plant personnel.

Floor and Equipment Drains

Floor drains and sloped floors are provided for rooms or cubicles containing serviceable components which contain radioactive liquids. When practicable, shielded pipe chases are used

for radioactive pipes. Floor coatings are specified which simplify cleanup of spills. If a radioactive drain line must pass through a plant area requiring personnel access, shielding or distance separation is provided as necessary to maintain radiation levels consistent with the required access.

Lighting

Wherever practicable, multiple electric lights are provided for rooms containing highly radioactive components so that the burnout of a single lamp does not require entry and immediate replacement of the defective lamp since sufficient illumination is still available. Incandescent lights are provided inside containment and in the fuel handling area. They require less time for servicing and, hence, the personnel exposure is reduced. The fluorescent lights which are used outside containment do not require frequent service due to the increased life of the tubes. Burned out lamps can be replaced when the radioactive system is drained and flushed.

Heating, Ventilation, and Air-Conditioning

The heating, ventilation, and air-conditioning (HVAC) system design facilitates replacement of the filter elements. Ventilation airflow is routed from areas of lower potential airborne contamination to areas of potentially higher contamination. In the radiologically-controlled area ventilation system (VAS) high airborne activity causes the exhaust air to be rerouted through HEPA and charcoal filters in the containment air filtration system (VFS).

Sample Stations

Proper shielding and ventilation are provided at the primary sample room to minimize personnel exposure during sampling. The counting room and laboratory facilities are described in Section 12.5. The use of concrete containing fly ash is prohibited for the counting room and laboratory areas.

Clean Services

Whenever practicable, clean services and equipment such as compressed air piping, clean water piping, ventilation ducts, and cable trays are not routed through radioactive pipeways.

Materials

Equipment specifications for components exposed to high temperature reactor coolant contain limitations on the cobalt content of the base metal as given in Table 12.3-1. The use of hard facing material with cobalt content such as stellite is limited to applications where its use is necessary for reliability considerations. Nickel-based alloys in the reactor coolant system (Co-58 is produced from activation of Ni-58) are similarly used only where component reliability may be compromised by the use of other materials. The major use of nickel-based alloys in the reactor coolant system is the inconel steam generator tubes.

General prohibitions on antimony and other low melting point metals are contained in subsection 6.1.1. In addition, the reactor coolant pump mechanical design criteria prohibits antimony completely from the reactor coolant pump and its bearings.

Single Integrated Gripper Mast Assembly Refueling Machine

To minimize the radiation exposure during refueling, a single integrated gripper mast assembly refueling machine is used. The machine permits removal and insertion of thimble plugs or rod control cluster assemblies while a fuel assembly is being handled by the refueling machine.

Improved Head Closure System

The head closure system is designed to minimize the reactor head stud tensioning time.

12.3.1.1.2 Common Facility and Layout Designs for ALARA

This subsection describes the design features utilized for standard plant process and layout situations. These features are employed in conjunction with the general equipment described in subsection 12.3.1.1.1 and include the features described in the following paragraphs.

Valve Modules

Selected valve modules are provided with shielded entrances for personnel protection. Floor drains are provided to control radioactive leakage. To facilitate decontamination, concrete surfaces are covered with a smooth surface coating which allows decontamination.

Piping

Pipes carrying radioactive materials are routed through controlled access areas properly zoned for that level of activity. Radioactive piping runs are analyzed to determine the potential radioactivity level and surface dose rate. Where it is necessary that radioactive piping be routed through corridors or other low radiation zone areas, shielded pipeways or distance separation are provided. Whenever practicable, valves and instruments are not placed in radioactive pipeways. Equipment compartments are used as pipeways for those pipes associated with equipment in the compartment.

When practicable, radioactive and nonradioactive piping are separated to minimize personnel exposure. Should maintenance be required, provision is made to isolate and drain radioactive piping and associated equipment.

Piping is designed to minimize low points and dead legs. Drains are provided on piping where low points and dead legs cannot be eliminated. In radioactive systems, the use of nonremovable backing rings in the piping joints is prohibited. Whenever practicable, branch lines having little or no flow during normal operation are connected above the horizontal midplane of the main pipe.

Piping which carries resin slurries is run vertically and horizontal runs carrying spent resin are sloped toward the spent resin tanks, as much as practicable. Large radius bends are utilized instead of elbows. Where sloped lines or large radius bends are impractical, adequate flush and drain capability is provided to prevent flow blockage and minimize crud traps.

Wall Penetrations

To minimize radiation streaming through wall penetrations, as many wall penetrations as practicable are located with offsets between the radioactive source and the normally accessible areas. If offsets are not practicable, penetrations are located as far as practicable above the floor elevation to reduce radiation exposure to personnel. If these two methods are not used, alternate means are employed, such as baffle shield walls or grouting the penetration annulus.

Contamination Control

Access control and traffic patterns are considered in the plant layout to reduce the spread of contamination. Equipment vents and drains from highly radioactive systems are piped directly to the collection system to minimize airborne and floor contamination. Welded piping systems are employed on radioactive systems to the maximum extent practicable to reduce system leakage and crud buildup at joints.

Decontamination of potentially contaminated areas and equipment within the plant is facilitated by the application of epoxy paints and suitable smooth-surface coatings to the concrete floors and walls. Sloping floors with floor drains are provided in potentially contaminated areas of the plant. In addition, radioactive and potentially radioactive drains are separated from nonradioactive drains.

In radiologically controlled areas where contamination is expected, radiation monitoring equipment is provided (Section 11.5). Those systems that become highly radioactive, such as the spent resin lines in the radwaste system, are provided with flush and drain connections.

The role of the ventilation systems in minimizing the spread of airborne contamination is described in subsection 12.3.3.

Equipment Layout

In those systems where process equipment is a major radiation source; pumps, valves, and instruments are separated from the process component. This allows servicing and maintenance of these items in reduced radiation zones. Control panels are located in low radiation zones.

Major components such as tanks, demineralizers, and filters in radioactive systems are located in shielded compartments insofar as practical. Labyrinth shields or shielding doors are provided for compartments where radiation could stream or scatter to access areas and exceed the radiation zone dose limits for those areas. For potentially high radiation components (such as ion exchangers, filters and spent resin tanks), shielded compartments with hatch openings or removable concrete block walls are used. Equipment in nonradioactive systems that requires lubrication is located in low radiation zones. Wherever practicable, lubrication of equipment in high radiation areas is achieved with the use of tube-type extensions to reduce exposure during maintenance.

Exposure from routine in-plant inspection is controlled by locating, whenever practicable, inspection points in low-background radiation areas. Radioactive and nonradioactive systems are separated as far as practicable to limit radiation exposure from routine inspection of

nonradioactive systems. For radioactive systems, emphasis is placed on adequate space and ease of motion in a properly shielded inspection area. Where longer times for routine inspection are required and permanent shielding is not feasible, space for portable shielding is provided.

Field Run Piping

Field run radioactive piping is minimized in the plant design. Radioactive process piping is routed dimensionally on orthographic drawings. Fabrication isometrics of radioactive process piping are reviewed to provide adequate shielding.

12.3.1.2 Radiation Zoning and Access Control

Access to areas inside the plant structures and plant yard area is regulated and controlled by posting of radiation signs, control of personnel, and use of alarms and locks (Section 12.5). During plant operation, access to radiologically restricted areas is through the access control area in the annex building.

Plant areas are categorized into radiation zones according to design basis radiation levels and anticipated personnel occupancy with consideration given toward maintaining personnel exposures ALARA and within the standards of 10 CFR 20. Rooms, corridors, and pipeways are evaluated for potential radiation sources during normal, shutdown, spent resin transfer, and emergency operations; for maintenance occupancy requirements; for general access requirements; and for material exposure limits to determine appropriate zoning. Each radiation zone defines the radiation level range expected in the zone. The radiation zone categories employed and zoning for each plant area under normal conditions is shown in Figure 12.3-1. The zoning for each plant area under accident conditions is shown in Figure 12.3-2. Radiation zones shown in the figures are based upon conservative design data. Actual in-plant zones and control of personnel access are based upon surveys conducted by the Combined License holder. Access control provisions for each plant area under normal expected conditions are shown in Figure 12.3-3. These provisions implement the requirements of 10 CFR 20 and utilize the alternative access control methods outlined in Regulatory Guide 8.38.

Based on actual operating plant data, ingress or egress of plant operating personnel to radiologically restricted areas is controlled and monitored by the Combined License holder such that radiation levels and exposures are within the limits prescribed in 10 CFR 20.

Posting of radiation signs, control of personnel access, and use of alarms and locks are Combined License applicant responsibilities.

12.3.2 Shielding

The bases for the nuclear radiation shielding and the shielding configurations are discussed in this subsection.

12.3.2.1 Design Objectives

The objective of the plant radiation shielding is to minimize personnel and population exposures, while maintaining a program of controlled personnel access to and occupancy of radiation areas.

Radiation levels are within the requirements of 10 CFR 50 during design basis accidents and ALARA within the requirements of 10 CFR 20 during normal operation. Shielding and equipment layout and design are considered in providing confidence that exposures are kept ALARA during anticipated personnel activities in areas of the plant containing radioactive materials. Design recommendations given in Regulatory Guide 8.8 are utilized where practicable.

The nuclear radiation shielding is designed to provide personnel protection and is based on the following operating states:

- Normal, full-power operation
- Shutdown operation
- Spent resin transfer
- Emergency operations (for required access to safety-related equipment)

The shielding design objectives for the plant during these operating states are:

- Radiation exposure to plant operating personnel, contractors, administrators, visitors, and site boundary occupants is ALARA and within the limits of 10 CFR 20.

- Sufficient personnel access and occupancy time is provided to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

- Reduce potential equipment neutron activation and mitigate the effects of radiation on materials.

- Provide sufficient shielding for the control room so that for design basis accidents (DBAs) the direct dose plus the inhalation dose (calculated in Chapter 15) does not exceed the limits of 10 CFR 50, Appendix A, General Design Criterion 19.

12.3.2.2 General Shielding Design

Systems containing radioactivity and other sources of radiation are identified for four plant conditions defined in subsection 12.3.2.1. Shielding is provided to attenuate direct radiation through walls and penetrations and scattered radiation to less than the upper limit of the radiation zone for each area shown in Figure 12.3-1. Design criteria for shield penetrations are consistent with the recommendations of Regulatory Guide 8.8 and are described in subsection 12.3.1.1.2.

Materials used in shielding typically include lead, steel, water, and concrete. The material used for most of the plant shielding is ordinary concrete with a bulk density of approximately 147 lb/ft^3. Whenever poured-in-place concrete has been replaced by concrete blocks, an equivalent shielding basis as determined by the density of the concrete block is selected. Steel is used as shielding in the chemical and volume control system and other modules, as well as around the reactor vessel flange at the floor of the refueling cavity. Water is used as the primary shield material for areas above the spent fuel storage area and refueling cavity during refueling operations.

12.3.2.2.1 Containment Shielding Design

During reactor operation, the shield building protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete shield building wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the shield building to less than 0.25 mrem/hr from sources inside containment. The shield building completely surrounds the reactor coolant system components.

For design basis accidents, the shield building and the main control room shielding reduce the plant radiation intensities from fission products inside the containment to acceptable levels, as defined by 10 CFR 50, Appendix A, General Design Criterion 19, for the main control room. (See subsection 12.3.2.2.7.)

Where personnel locks and equipment hatches or penetrations pass through the shield building wall, additional shielding is provided to attenuate radiation to the level defined by the outside radiation zone during normal operation and shutdown, and to acceptable levels during design basis accidents as defined by General Design Criterion 19.

12.3.2.2.2 Containment Interior Shielding Design

During reactor operation, many areas inside the containment are Zone V or greater and are normally inaccessible. Shielding is provided to reduce dose rates to approximately 100 mrem/hr or less in areas of the containment that potentially require access at power. These are the Zone IV or lower areas shown in Figure 12.3-1.

The main sources of radiation are the reactor vessel and the primary loop components, consisting of the steam generators, pressurizer, reactor coolant pumps, and associated piping. The reactor vessel is shielded by the concrete primary shield and by the concrete secondary shield which also surrounds other primary loop components. Air cooling is provided to prevent overheating, dehydration, and degradation of the shielding and structural properties of the primary shield.

The primary shield is a large mass of reinforced concrete surrounding the reactor vessel. The primary shield meets the following objectives:

- In conjunction with the secondary shield, reduce the radiation level from sources within the reactor vessel and reactor coolant system to allow limited access to the containment during normal, full-power operation.
- After shutdown, limit the radiation level from sources within the reactor vessel, permit limited access to the reactor vessel and the reactor coolant system equipment.
- Limit neutron activation of component and structural materials.

The secondary shield is a structural module filled with concrete surrounding the reactor coolant system equipment, including piping, pumps, and steam generators. This shield protects personnel from the direct gamma radiation resulting from reactor coolant activation products and fission products carried away from the core by the reactor coolant. In addition, the secondary shield

supplements the primary shield by attenuating neutron and gamma radiation escaping from the primary shield. The secondary shield is sized to allow limited access to the containment during full-power operation.

The reactor cavity has been designed so that the dose rates on the operating deck due to neutron streaming are less than 100 mrem/hr.

Components of the purification portion of the chemical and volume control system (CVS) in the containment are located in a shielded compartment. Shielding is provided for equipment in the purification system consistent with its postulated maximum activity (subsection 12.2.1) and with the access and zoning requirements of adjacent areas. This equipment includes the regenerative heat exchanger, the letdown heat exchanger, chemical and volume control system filters and demineralizers, and the letdown lines.

After shutdown, the containment is accessible for limited periods of time and access is controlled. Areas are surveyed to establish allowable working periods. Dose rates are expected to range from 0.5 to 1000 mrem/hr, depending on the location inside the containment (excluding reactor cavity). These dose rates result from residual fission products and neutron activation products (components and corrosion products) in the reactor coolant system.

Spent fuel is the primary source of radiation during refueling. Because of the high activity of the fission products contained in the spent fuel elements, extensive shielding is provided for areas surrounding the refueling cavity and the fuel transfer canal to limit the radiation levels to below zone levels specified for adjacent areas. Water provides the shielding over the spent fuel assemblies during fuel handling.

12.3.2.2.3 Auxiliary Building Shielding

During normal operations, the major components in the auxiliary building with potentially high radioactivity are those in liquid radwaste, gaseous radwaste, and spent resin handling systems. Shielding is provided consistent with the postulated maximum activity (See Sections 11.1, 11.2, 11.3, and 12.2) and with the access and zoning requirements of adjacent areas. (See Figure 12.3-1.)

Depending on the equipment in the compartments, the radiation zones vary. Corridors are generally shielded to allow Zone II access, and operator areas for valve modules are generally Zone II or III for access.

Concrete plugs are utilized to provide necessary access for equipment maintenance and spent filter cartridge replacement. Where necessary, labyrinth entrances with provisions for adequate ingress and egress for equipment maintenance and inspection are provided and are designed to be consistent with the access and zoning requirements of adjacent areas.

Following reactor shutdown, the normal residual heat removal (RNS) system pumps and heat exchangers are in operation to remove heat from the reactor coolant system. The radiation levels in the vicinity of this equipment temporarily reach Zone V or higher levels due to corrosion and fission products in the reactor coolant water. Shielding is provided to attenuate radiation from

normal residual heat removal equipment during shutdown cooling operations to levels consistent with the radiation zoning requirements of adjacent areas.

12.3.2.2.4 Fuel Handling Area Shielding Design

The concrete shield walls surrounding the spent fuel cask loading and decontamination areas, and the shield walls surrounding the fuel transfer and storage areas are sufficiently thick to limit radiation levels outside the shield walls in accessible areas to Zone II. The building external walls are sufficient to shield external plant areas which are not controlled to Zone I.

Spent fuel removal and transfer operations are performed under borated water to provide radiation protection and maintain subcriticality. Minimum allowable water depths above a fuel assembly during fuel handling are 10 feet in the reactor cavity and 10 feet in the fuel transfer canal and spent fuel pool. This limits the dose at the water surface to less than 2.5 mrem/hr for an assembly in a vertical position. Normal water depth above the stored assemblies is about 26 feet, and for this depth the dose rate at the pool surface is insignificant. The concrete walls of the fuel transfer canal and spent fuel pool walls supplement the water shielding and limit the maximum radiation dose levels in working areas to less than 2.5 mrem/hr.

The spent fuel pit cooling system (SFS) shielding (Section 9.1) is based on the activity discussed in subsection 12.2.1 and the access and zoning requirements of adjacent areas. Equipment in the spent fuel pit cooling system to be shielded includes the spent fuel cooling system heat exchangers, pumps, piping, filters and demineralizers which may be contaminated with radioactive crud.

12.3.2.2.5 Radwaste Building Shielding Design

Shielding is provided as necessary for the waste storage areas in the radwaste building to meet the radiation zone and access requirements. Depending on the equipment in the compartments, the radiation zoning varies from Zone I through IV as shown on the radiation zone drawing of Figure 12.3-1. Temporary partitions and shield walls will be provided, as required, to supplement the permanent shield walls surrounding the waste accumulation and packaged waste storage rooms inside the radwaste building.

12.3.2.2.6 Turbine Building Shielding Design

The steam generator blowdown demineralizers are shielded to meet the radiation zone and access requirements. Radiation shielding is not required for other process equipment located in the turbine building. Space has been provided so that shielding may be added around the condensate polishing demineralizers if they become radioactive.

12.3.2.2.7 Control Room Shielding Design

The design basis loss-of-coolant accident dictates the shielding requirements for the control room. Consideration is given to shielding provided by the shield building structure. Shielding combined with other engineered safety features is provided to permit access and occupancy of the control room following a postulated loss-of-coolant accident, so that radiation doses are limited to

five rem whole body from contributing modes of exposure for the duration of the accident, in accordance with General Design Criterion 19.

12.3.2.2.8 Miscellaneous Plant Areas and Plant Yard Areas

Sufficient shielding is provided for plant buildings containing radiation sources so that radiation levels at the outside surfaces of the buildings are maintained below Zone I levels. Plant yard areas that are frequently occupied by plant personnel are fully accessible during normal operation and shutdown. Tanks containing radioactive materials are not located in the yard.

12.3.2.2.9 Spent Fuel Transfer Canal and Tube Shielding

The spent fuel transfer tube is shielded to within adjacent area radiation zone limits. This is primarily achieved through the use of concrete and water. The only removable shielding consists of concrete or steel hatches which reduce radiation in accessible areas to within those levels prescribed in the normal operation radiation zone maps (Figure 12.3-1).

The spent fuel transfer tube is completely enclosed in concrete and there is no unshielded portion of the spent fuel transfer tube during the refueling operation. The only potential radiation streaming path associated with the tube shielding configuration is the 2 inch (5.08 cm) seismic gap between the fuel transfer tube shielding and the steel containment wall. Shielding of this gap is provided by a water-filled bladder. This "expansion gap" radiation shield provides effective reduction of the radiation fields during fuel transfer and accommodates relative movement between the containment and the concrete transfer tube shielding with no loss in shield integrity. A removable hatch in the shield configuration provides access for inspection of the fuel transfer tube welds. The opening of this hatch is administratively controlled and is treated as an entrance to a very high radiation area under 10 CFR 20. This hatch is in place during the spent fuel transfer operation.

12.3.2.3 Shielding Calculational Methods

The shielding thicknesses provided for compliance with plant radiation zoning and to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions described in Chapter 11 and Section 12.2. The thickness of each shield wall surrounding radioactive equipment is determined by approximating as closely as practicable the actual geometry and physical condition of the source or sources. The isotopic concentrations are converted to energy group sources using data from standard references (References 1 through 6).

The geometric model assumed for shielding evaluation of most tanks, heat exchangers, filters, ion exchangers, and the containment is a finite cylindrical volume source. For shielding evaluation of piping, the geometric model is a finite shielded cylinder. In cases where radioactive materials are deposited on surfaces such as pipe, the latter is treated as an annular cylindrical surface source.

Computer codes based on point kernel and Monte Carlo methods are used to calculate gamma dose rates. Most dose rates are calculated with a point kernel code MicroShield 4 (Reference 22), which is a PC version with a menu-guided user-interface of the mainframe code QAD. Some simplifications are made in the modeling, concerning non-active components connected to the sources, and shielding. As a rule, these simplifications result in conservative dose rate estimates,

but do not significantly affect the overall evaluation of the radiological conditions in the containment. Non-homogenous sources, such as fuel assemblies, ion exchange resin beds are homogenized, where this does not underestimate the dose rates.

Complex geometries are modeled in MCNP code (Reference 21). Due to the need of larger computer and work resources MCNP is used only in those cases that cannot be calculated by methods based on line-of-sight attenuation such as point kernel method. Such cases may involve labyrinth structures, penetrations, dominance of scattered radiation etc.

For very simple geometries also analytical formulas using gamma energy yields of radioactive isotopes are used.

The source activity (Ci) and gamma ray source strengths (MeV/sec) are calculated using one of the following computer codes: ORIGEN (Reference 17), SOURCE2/ACCUM (Reference 12), or RADGAS3 (Reference 13). ACCUM (Reference 12) is an option within SOURCE2 that computes isotope accumulation for several time periods from a given flow of isotopes in curies per second. This accumulated activity may then be decayed for any number of decay times at which gamma energy spectra and isotope Curie activity are computed. The generation of daughter products is included during the accumulation and decay periods. FIPCO, CORA, and RADGAS3 compute isotopic activity in radioactive liquid and gaseous systems. The total activity in system lines or equipment is computed from the initial isotope flow, equipment accumulating (operating) time, and parameters which describe the physical accounts for instantaneous mixing or uniform flow and plateout of particulate daughter products. Isotope data is based on the Table of Isotopes (Reference 5) and ORIGEN library data (Reference 6).

The shielding thicknesses of walls and slabs are selected to reduce the aggregate computed radiation level from the contributing sources below the upper limit of the radiation zone specified for each plant area. The labyrinths are constructed so that the scattered dose rate, plus the transmitted dose rate through the shield wall from all contributing sources, is below the upper limit of the radiation zone specified for each plant area. Shielding requirements in each plant area are evaluated at the point of maximum radiation dose through any wall. In addition, for shielding design purposes the concrete density of 147 lb/ft^3 was assumed. Therefore, the actual anticipated radiation level in each plant area is less than this maximum dose and consequently less than the radiation zone upper limit.

Neutron radiation is calculated either with MCNP code or hand calculation methods combined to literature data on neutron attenuation (References 7 and 8).

12.3.3 Ventilation

The plant heating, ventilating, and air-conditioning systems are designed to provide a suitable environment for personnel and equipment during normal operation.

12.3.3.1 Design Objectives

The plant heating, ventilating, and air-conditioning systems for normal operation are designed to meet the requirements of 10 CFR 20 and 10 CFR 50.

12.3.3.2 Design Criteria

Design criteria for the plant HVAC systems include the following:

- During normal operation the average and maximum airborne radioactivity levels to which plant personnel are exposed in restricted areas of the plant are ALARA and within the limits specified in 10 CFR 20. The average and maximum airborne radioactivity levels in unrestricted areas of the plant during normal operation, are ALARA and within the limits of 10 CFR 20.

- During normal operations the dose from concentrations of airborne radioactive material in unrestricted areas beyond the site boundary is ALARA and within the limits specified in 10 CFR 20 and 10 CFR 50, Appendix I.

12.3.3.3 Design Features

To accomplish the design objectives and to conform to the design criteria, the following design features are incorporated wherever practicable.

12.3.3.3.1 Design Features to Minimize Airborne Radioactivity

- Access control and traffic patterns are considered in the plant layout to minimize the spread of contamination.

- Equipment vents and drains are piped directly to a collection device connected to the collection system. This is to minimize airborne contamination and to prevent contaminated fluid from flowing across the floor to a floor drain.

- Welded piping systems are employed on systems containing radioactive fluids to the maximum extent practicable. If welded piping systems are not employed, drip trays are provided at the points of potential leakage. Drains from drip trays are piped directly to the collection system.

- Suitable coatings are applied to the concrete floors and walls of potentially contaminated areas to facilitate decontamination.

- Design of equipment incorporates features that minimize the spread of radioactivity during maintenance operations. These features include flush and drain connections on pump casings for draining and flushing the pump prior to maintenance and flush connections on piping systems that could become highly radioactive.

12.3.3.3.2 Design Features to Control Airborne Radioactivity

- The airflow is directed from areas with lesser potential for contamination to areas with greater potential for contamination.

- In building compartments with a potential for contamination, the exhaust is designed for greater volumetric flow than is supplied to that area. This minimizes the amount of uncontrolled exfiltration from the area.

- Consideration is given to the potential disruption of normal airflow patterns by maintenance operations, and provisions are made in the design to prevent adverse airflow direction.

- The ventilation system design for radiologically controlled areas is discussed in subsections 9.4.3, 9.4.7, 9.4.8, and 9.4.11. The exhaust air from these areas is normally unfiltered except for the containment atmosphere which is filtered by the containment air filtration system exhaust filters. A description of these filter units is given in subsection 12.3.3.5.

- Air discharged from the containment is passed through high efficiency particulate air filters and charcoal adsorbers to remove particulates and halogens. Air exhausted from the auxiliary building, fuel handling area of the auxiliary building, and the annex building is monitored for high airborne activity. Means are provided to shut off supply air and divert exhaust air through high efficiency particulate air filters and charcoal adsorbers upon detection of high airborne activity. Alarms are provided in the main control room for these discharge flows and for flows from the radwaste building and the health physics/hot machine shop area. These alarms alert the operator of high radioactivity concentrations in the air. This minimizes the discharge of contaminants to the environment and in-plant exposures.

- Atmospheric tanks which contain radioactive materials are vented to the respective building ventilation system for release to the monitored plant vent.

12.3.3.3.3 Design Features to Minimize Personnel Exposure from HVAC Equipment

- The guidelines of Regulatory Guide 8.8 have been utilized, as practicable, in the design of the plant ventilation systems.

- Ventilation fans and filters are provided with adequate access space to permit servicing with minimum personnel radiation exposure. The HVAC system is designed to allow rapid replacement of components.

- Ventilation ducts are designed to minimize the buildup of radioactive contamination within the ducts.

- Ventilating air for radiologically controlled areas of the plant is a once-through design.

- Access to ventilation systems in potentially radioactive areas can result in operator exposure during maintenance, inspection, and testing. Equipment locations are selected to minimize personnel exposures. The outside air supply units and building exhaust system components are located in ventilation equipment rooms. These equipment rooms are accessible to the operators. Work space is provided around each unit for anticipated maintenance, testing, and inspection.

12.3.3.4 Design Description

The ventilation systems serving the following structures are considered to be potentially radioactive and are discussed in detail in Section 9.4.

- Containment building (See subsection 9.4.7)
- Auxiliary building (See subsection 9.4.3)
- Fuel handling area of the auxiliary building (See subsection 9.4.3)
- Annex building (See subsection 9.4.3)
- Radwaste building (See subsection 9.4.8)
- Health physics and hot machine shop (See subsection 9.4.11)

The main control room is considered to be a nonradioactive area. The associated ventilation system design is described in Section 6.4 and subsection 9.4.1.

Other structures contain insignificant sources of airborne radioactivity and are not addressed in this chapter.

12.3.3.5 Air Filtration Units

The guidance and recommendations of Regulatory Guide 1.140 concerning maintenance and inplace testing provisions for atmospheric cleanup systems, air filtration, and adsorption units are used as a guide in the design of the various ventilation systems. The extent to which Regulatory Guide 1.140 has been incorporated is discussed in subsection 1.9.1. Figure 12.3-3 shows the typical layout of an air filtration unit.

Provisions specifically included to minimize personnel exposures and to facilitate maintenance or inplace testing operations are as follows.

A. The loading of the filters and adsorbers with radioactive material during normal plant operation is a slow process. Therefore, in addition to monitoring for pressure drop, the filters are checked for radioactivity on a scheduled maintenance basis with portable equipment. The filter elements are replaced before the radioactivity level is of sufficient magnitude to create a personnel hazard. No shielding is provided since it is not required for the level of radioactivity accumulation during normal operation. In case of excessive radioactivity caused by a postulated accident, the filter is replaced before normal personnel access is resumed. It is not necessary for workers to handle filter units immediately after a design basis accident, so exposures can be minimized by allowing the short-lived isotopes to decay before changing the filter.

B. Active components of the atmospheric cleanup systems are designed for ease of removal.

C. Access to active components is direct from working platforms to simplify element handling. Ample space is provided on the platforms for accommodating safe personnel movement during replacement of components, including the use of necessary material handling equipment and inplace testing devices.

D. No filter bank is more than three filter cells high, where each filter cell is 2 feet by 2 feet. The access to the level or platform at which the filter is serviced is by stairs.

E. The clear space for access to filter banks and active components is a minimum of 20 inches by 50 inches.

F. The HEPA filter banks are designed with replaceable cells that are clamped in place against compression seals. The charcoal adsorbers are designed to be replaced with bulk charcoal using a vacuum transfer system. The filter housing is designed and tested to be airtight with bulkhead type doors that are closed against compression seals.

12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

For a description of the radiation monitoring system (RMS), refer to Section 11.5.

12.3.5 Combined License Information

- The Combined License applicant will address the administrative controls for use of the design features provided to control access to radiologically restricted areas, including potentially very high radiation areas, such as the fuel transfer tube during refueling operations and to the reactor cavity.

- The Combined License applicant will address the criteria and methods for obtaining representative measurement of radiological conditions, including airborne radioactivity concentrations in work areas. The Combined License applicant will also address the use of portable instruments, and the associated training and procedures, to accurately determine the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

12.3.6 References

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4. Meek, M. E., and Gilbert, R. S., "Summary of γ and β Energy and Intensity Data," NEDO-12037, General Electric Company, January 1970.

5. Lederer, C. M., et al., Table of Isotopes, seventh edition, Lawrence Radiation Laboratory, University of California, April 1978.

6. Kee C.W., "A Revised Light Element Library for the ORIGEN Code," ORNL-TM-4896, Oak Ridge National Laboratory, May 1975.

7. Guidelines on the nuclear analysis and design of concrete radiation shielding for nuclear power plants. ANSI/ANS-6.4-1985.

8. Courtney, J. C. (ed.) A Handbook of Radiation Shielding Data. ANS. 1975.

9. Engle, W. W., Jr., "A User's Manual for ANISN: A One Dimensional Discrete Ordinates Transport Code with Anisotropic Scattering," Report No. K-1693, Union Carbide Corporation, 1967.

10. Soltesz, R.G., et al., "Nuclear Rocket Shielding Methods, Modification, Updating and Input Data Preparation. vol. 5 - Two-Dimensional Discrete Ordinates Transport Technique," WANL-PR(ll)-034, vol 5, August 1970.

11. SHIELD-SG - Point Kernel Gamma Shielding Program, Bechtel Corporation.

12. SOURCE2 - Radioisotope Decay Program, Bechtel Corporation.

13. RADGAS3 - Gaseous Radwaste Program, Bechtel Corporation.

14. RSIC Computer Code Collection CCC-120, SPACETRAN-I/SPACETRAN-II - Dose from Cylindrical Surface.

15. ALBEDO - A Program to Calculate Reflected Dose Rates from Concrete Surfaces, Bechtel Corporation.

16. QAD-CG - Combinatorial Geometry Version of QAD-P5A, Bechtel Corporation.

17. RSIC Computer Code Collection CCC-371, ORIGEN 2.1 - Isotope Generation and Depletion Code-Matrix Exponential Method.

18. FIPCO-VI - A Computer Code for Calculating the Distribution of Fission Products in Reactor Systems, Westinghouse Electric Corporation.

19. Kang, S. and Sejvar, J., "The CORA-II Model of PWR Corrosion Product Transport," EPRI NP-4246, September 1995.

20. RSIC Computer Code Collection CCC-543, TORT-DORT - Two- and Three-Dimensional Discrete Ordinates Transport, Version 2.73.

21. RSIC Computer Code Collection CCC-200, Monte Carlo Neutron and Photon Transport Code System.

22. Negin, C. A. & Worku, G. MicroShield, Version 4, User's Manual. Grove Engineering Inc. 1992.

Table 12.3-1

EQUIPMENT SPECIFICATION LIMITS FOR COBALT IMPURITY LEVELS

Region, Component or Application	Maximum Weight Percent of Cobalt
Inconel and stainless steel components in fuel assembly	0.05
Inconel tubing in steam generators	0.015
Components that are external to the active core, but in regions of high neutron flux. This typically includes: baffle plates, formers, lower and upper core plates, lower core barrel, and neutron panels or thermal shields	0.05
Surfaces in the steam generators other than the tubing	0.10
Other primary components and weld clad surfaces, except hard-facing and fasteners indicated below	0.05
Auxiliary heat exchangers exposed to reactor coolant	0.05
Bolting materials in reactor internals; other small components in region of high neutron flux	0.20
Bearing and hard-facing materials	Not limited (However low- or no-cobalt materials will be used, as available)
Auxiliary components such as valves piping instrumentation, tanks, and so on, including bolting materials in primary and auxiliary components	Not limited (Average ~ 0.20)
Welding material, except where used as weld cladding	Not limited (Average ~ 0.20)

LEGEND:

A. PLANT RADIATION ZONES:

DESIGNATION	MAXIMUM DESIGN DOSE RATE	DESCRIPTION
0	$\le$ 0.05 mRem/hr	NO RADIATION SOURCES; UNLIMITED GENERAL OCCUPANCY; OUTSIDE "CONTROLLED AREA"
I	$\le$ 0.25 mRem/hr	VERY LOW OR NO RADIATION SOURCES; INSIDE "CONTROLLED AREA" AND OUTSIDE "RESTRICTED AREA"
"RESTRICTED AREA" ZONES		
II	$\le$ 2.5 mRem/hr	LOW RADIATION SOURCES; UNLIMITED WORKER OCCUPANCY
III	$\le$ 15.0 mRem/hr	LOW-TO-MODERATE RADIATION SOURCES; LIMITED WORKER OCCUPANCY
IV	$\le$ 100 mRem/hr	MODERATE RADIATION SOURCES; LIMITED WORKER OCCUPANCY
V	$\le$ 1 Rem/hr	HIGH RADIATION SOURCES; LIMITED WORKER OCCUPANCY
VI	$\le$ 10 Rem/hr	SAME AS ZONE V ABOVE
VII	$\le$ 100 Rem/hr	SAME AS ZONE V ABOVE
VIII	$\le$ 500 Rad/hr	SAME AS ZONE V ABOVE
IX	> 500 Rad/hr	VERY HIGH RADIATION SOURCES; VERY LIMITED WORKER ACCESS

B. DRAWING SYMBOLS:

V / IV - UPPER RADIATION ZONE NUMERAL FOR FULL POWER OPERATION/ LOWER NUMERAL FOR 24 HOURS AFTER PLANT SHUTDOWN (IF DIFFERENT)

- RADIATION ZONE BOUNDARY

C. GENERAL DRAWING NOTES

1. ACCESS CONTROL REQUIREMENTS AND TRAFFIC PATTERNS ARE SHOWN IN SERIES 201 DRAWINGS.

2. DOSE RATES INSIDE CONTAINMENT DURING POWER OPERATION ARE SUBJECT TO SIGNIFICANT VARIABILITY OWING TO LOCALIZED NEUTRON STREAMING/SCATTERING EFFECTS. ACTUAL RADIATION FIELDS WILL BE DETERMINED FROM RADIATION SURVEYS AND ACCESS TO THE CONTAINMENT DURING POWER OPERATION WILL BE STRICTLY CONTROLLED.

Figure 12.3-1 (Sheet 1 of 16)

Radiation Zones, Normal Operation/Shutdown Legend

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Figure 12.3-1 (Sheet 2 of 16)

Site Radiation Zones, Normal Operations/Shutdown

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 3 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 66′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 4 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 5 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 6 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 7 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 8 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 9 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 153′-0″ & 160′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 10 of 16)

Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 160′-6″ & 180′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 11 of 16)

Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 12 of 16)

Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 117′-6″ & 126′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 13 of 16)

Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 135′-3″, 146′-3″, 156′-0″ & 158′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 14 of 16)

Radiation Zones, Normal Operations/Shutdown
Radwaste Building, Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 15 of 16)

Radiation Zones, Normal Operations/Shutdown
Turbine Building, Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-1 (Sheet 16 of 16)

Radiation Zones, Normal Operations/Shutdown
Turbine Building, Elevation 117′-6″

LEGEND:

A. POST-ACCIDENT RADIATION ZONES:

DESIGNATION	MAXIMUM DESIGN DOSE RATE	DESCRIPTION
0	≤ 0.05 mRem/hr	NO RADIATION SOURCES
I	≤ 0.25 mRem/hr	VERY LOW OR NO RADIATION SOURCES
II	≤ 2.5 mRem/hr	LOW RADIATION SOURCES
III	≤ 15.0 mRem/hr	LOW-TO-MODERATE RADIATION SOURCES
IV	≤ 100 mRem/hr	MODERATE RADIATION SOURCES
V	≤ 1 Rem/hr	HIGH RADIATION SOURCES
VI	≤ 10 Rem/hr	SAME AS ZONE V ABOVE
VII	≤ 100 Rem/hr	SAME AS ZONE V ABOVE
VIII	≤ 500 Rad/hr	SAME AS ZONE V ABOVE
IX	> 500 Rad/hr	VERY HIGH RADIATION SOURCES

B. DRAWING SYMBOLS:

VI / ECS – RADIATION ZONE NUMERAL AT POST-ACCIDENT PEAK / DOMINANT POST-ACCIDENT RADIATION SOURCE(S)

– NON-RADIOACTIVE AREA BOUNDARY

– RADIOACTIVE AREA BOUNDARY

– ANNEX AREA BOUNDARY

– RADIATION ZONE BOUNDARY

– POST-ACCIDENT ACCESS ROUTE

C. POST-ACCIDENT SOURCES:

SYMBOL	POST-ACCIDENT RADIATION SOURCE
ECS	EXTERNAL CLOUD SHINE
NRA	NON-RADIOACTIVE AUXILIARY BUILDING AREA CLOUD
RAC	RADIOACTIVE AUXILIARY BUILDING AREA CLOUD
SCC	SHIELDED CONTAINMENT CLOUD
UCC	UNSHIELDED CONTAINMENT CLOUD
CPS	CONTAINMENT AND PENETRATION RADIATION STREAMING
AXC	ANNEX BUILDING AREA CLOUD
PAS	POST-ACCIDENT SAMPLE PIPING

D. GENERAL DRAWING NOTES:

1. ZONING IS BASED ON PEAK POST-ACCIDENT DOSE RATES IN THE DESIGNATED AREA.
2. INCLUDES CONTRIBUTIONS FROM POST-ACCIDENT CONTAINED AND AIRBRONE CLOUD SOURCES.

Figure 12.3-2 (Sheet 1 of 15)

Radiation Zones, Post-Accident Legend

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Figure 12.3-2 (Sheet 2 of 15)

Site Radiation Zones, Post-Accident

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 3 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 66′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 4 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 5 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 6 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 7 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 8 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 9 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 153′-0″ & 160′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 10 of 15)

Radiation Zones, Post-Accident
Nuclear Island, Elevation 160′-6″ & 180′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 11 of 15)

Radiation Zones, Post-Accident
Annex Building, Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 12 of 15)

Radiation Zones, Post-Accident
Annex Building, Elevation 117′-6″ & 126′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 13 of 15)

Radiation Zones, Post-Accident
Annex Building, Elevation 135′-3″, 146′-3″, 156′-0″ & 158′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 14 of 15)

Radiation Zones, Post-Accident
Radwaste Building, Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-2 (Sheet 15 of 15)

Radiation Zones, Post-Accident
Turbine Building, Elevation 100′-0″

LEGEND:

A. PLANT ACCESS CONTROL PROVISIONS:

AREA TYPE	DOSE RATE	SINGLE AREA	MULTIPLE AREAS
RADIATION AREA	> 5 mRem/hr		
HIGH RADIATION AREA	> 100 mRem/hr	BARRICADED OR ALARMED	BARRICADED OR ALARMED
HIGH RADIATION AREA	> 1 Rem/hr	LOCKED OR (IF OPEN AREA) BARRICADED WITH LOCAL ALARM	LOCKED OR BARRICADED WITH LOCKED COMMON ENTRY AND LOCAL CONTROL POINT
VERY HIGH RADIATION AREA	> 500 Rad/hr	LOCKED	LOCKED OR BARRICADED WITH LOCKED COMMON ENTRY, LOCAL CONTROL POINT AND SURVEILLANCE

B. DRAWING SYMBOLS:

⇨ - PERSONNEL TRAFFIC PATTERN

▲ - ENTRANCE BARRICADE (e.g. ROPE, CHAIN, ETC.)

● - LOCKED ENTRANCE

(C) - LOCAL ACCESS CONTROL POINT

(A) - ALARM LOCATION

(S) - SURVEILLANCE POINT

– – – – – – – - ACCESS CONTROL BARRIER (e.g. CHAIN LINK FENCE, ETC.)

———————— - "RESTRICTED" AREA BOUNDARY

–·–·–·–·–·– - "CONTROLLED" AREA BOUNDARY

C. GENERAL DRAWING NOTES:

1. ACCESS CONTROL PROVISIONS ARE BASED ON NORMAL EXPECTED RADIATION SOURCES.

Figure 12.3-3 (Sheet 1 of 16)

Radiological Access Controls Legend

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Figure 12.3-3 (Sheet 2 of 16)

Site Radiation Access Controls, Normal Operations/Shutdown

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 3 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 66′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 4 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 5 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 6 of 16)

Radiological Access Controls, Normal Operations/Shutdown Nuclear Island, Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 7 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 8 of 16)

Radiological Access Controls, Normal Operations/Shutdown Nuclear Island, Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 9 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 153′-0″ & 160′-6″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 10 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 160′-6″ & 180′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 11 of 16)

**Radiological Access Controls, Normal Operations/Shutdown
Annex Building, Elevation 100′-0″ & 107′-2″**

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 12 of 16)

Radiological Access Controls, Normal Operations/Shutdown Annex Building, Elevation 117′-6″ & 126′-3″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 13 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Annex Building Elevation 135′-3″, 146′-3″, 156′-0″ & 158′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 14 of 16)

Radiological Access Controls, Normal Operations/Shutdown Radwaste Building, Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 15 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Turbine Building, Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 12.3-3 (Sheet 16 of 16)

Radiological Access Controls, Normal Operations/Shutdown
Turbine Building, Elevation 117′-6″

12.4 Dose Assessment

Radiation exposures in the AP1000 are primarily due to direct radiation from components and equipment containing radioactive material. In addition, in some areas of the plant there can be radiation exposure to personnel due to the presence of airborne radionuclides. This section addresses the anticipated occupational radiation exposure (ORE) due to normal operation and anticipated inspection and maintenance.

12.4.1 Occupational Radiation Exposure

Radiation exposures to operating personnel are restricted to be within the limits of 10 CFR 20. The health physics program in Section 12.5 and the radiation protection features described in Section 12.3 together maintain occupational radiation exposures as low as reasonably achievable (ALARA).

In the analysis of occupational radiation exposure data from operating plants (domestic plants having Westinghouse designed nuclear steam supply systems), the best operating plant performance is 0.1 man-rem per MWe-year of electricity produced. Major factors contributing to this level of occupational radiation exposure include low plant radiation fields, good layout and access provisions, and operational practices and procedures that minimize time spent in radiation fields.

As discussed in Section 12.3, the AP1000 design incorporates features to reduce occupational radiation exposure that go beyond the designs provided for plants currently in operation.

The estimated annual occupational radiation exposures are developed within the following categories:

- Reactor operations and maintenance
- Routine maintenance
- Inservice inspection
- Special maintenance
- Waste processing
- Fuel handling operations

Exposure data obtained from operating plants have been reviewed to obtain a breakdown of the doses incurred within each category. For several routinely performed operations, this information has been used to develop detailed dose predictive models. These models identify the various steps that are included in the operation, the radiation zones, the required number of workers, and the time to perform each step. This information has been used to develop dose estimates for each of the preceding categories.

There is no separate determination of doses due to airborne activity. Past experience demonstrates that the dose from airborne activity is not a significant contributor to the total doses.

12.4.1.1 Reactor Operations and Surveillance

To support plant operations, the performance of various systems and components is monitored. Also, operation of some manual valves requires personnel to enter radiation fields. Examples of activities in this category are:

- Routine inspections of plant components and systems
- Unidentified leak checks
- Operation of manual valves
- Reading of instruments
- Routine health physics patrols and surveys
- Decontamination of equipment or plant work areas
- Calibration of electrical and mechanical equipment
- Chemistry sampling and analysis

When the plant is at power, the containment radiation fields are significantly higher than at plant shutdown. The frequency and duration of at-power containment entries is dependent on the plant operator. Based on review of current plant operations and on the AP1000 design changes and reliability improvements, it is assumed that 100 worker-hours per year spent in the containment during power operations.

Table 12.4-1 provides a breakdown of the collective doses for reactor operations and surveillance.

12.4.1.2 Routine Inspection and Maintenance

Routine inspection and maintenance are required for mechanical and electrical components. Table 12.4-2 provides a breakdown of the collective doses for routine inspection and maintenance. These estimates are based on having good access to equipment (a characteristic of the AP1000 layout).

Table 12.4-3 lists the doses associated with inspection of the canned motor reactor coolant pumps (RCPs). Table 12.4-4 itemizes the doses estimated to be incurred from steam generator sludge lancing operations and Table 12.4-5 lists the doses resulting from the visual examination of the secondary side of the steam generators.

12.4.1.3 Inservice Inspection

ASME Code, Section XI requires periodic inservice inspection (ISI) on plant safety-related components. The Code defines the inservice inspection interval as a 10-year period and sets requirements for each one-third interval (each 40 months). In general, at least 25 percent (with credit for no more than 33-1/3 percent) of the specified inspections must be performed in each 40-month testing interval. The amount of inspection required for an area varies according to the category but is explicitly defined in the Code. Table 12.4-6 provides the doses for inservice inspection activities.

Detailed listings of the doses associated with certain major inservice inspection activities appear in Table 12.4-7 (eddy current inspection of three percent of the steam generator tubes

and plugging of three tubes) and Table 12.4-8 (steam generator exterior). The dose estimates in Table 12.4-7 reflect the dose-reducing features of the AP1000 design, such as:

- Permanent work platforms
- Manway cover handling device
- Improved manway insert fasteners (tapered-end type)
- Trailer-mounted data collection station
- Use of robotics to perform eddy current inspection and tube plugging (no worker entry of the channel head required)

12.4.1.4 Special Maintenance

Maintenance that goes beyond the routine scheduled maintenance is considered to be special maintenance. This category includes both the modification of equipment to upgrade the plant and repairs to failed components. Dose estimates assume no significant equipment upgrade efforts. The occupational radiation exposure resulting from unscheduled repairs on valves, pumps, and other components will be lower for the AP1000 than for current plant designs because of the reduced radiation fields, increased equipment reliability, and the reduced number of components relative to currently operating plants.

In the past, special maintenance of the steam generators has resulted in significant personnel doses. The AP1000 benefits both from design changes and from improved primary and secondary water chemistry. The plugging of three tubes per steam generator each time eddy current examination is performed is included in the inservice inspection category.

No special maintenance activities are forecast for the canned motor reactor coolant pumps.

Table 12.4-9 provides the estimated doses due to special maintenance operations.

12.4.1.5 Waste Processing

The AP1000 radwaste system designs incorporate an uncomplicated approach to waste processing. The AP1000 design does not include waste or boron recycle evaporators and it does not include a catalytic hydrogen recombiner in the gaseous radwaste system. Elimination of high maintenance components contributes significantly to lower anticipated doses due to waste processing activities.

Estimated annual doses from waste processing operations appear in Table 12.4-10.

12.4.1.6 Fuel Handling

Criticality monitoring of the new fuel handling and storage areas is performed in accordance with 10 CFR 70.24. Details of the fuel handling area monitoring are provided in subsections 11.5.6 and 11.5.6.4. A criticality excursion will produce an audible local alarm and an alarm in the plant MCR.

The refueling process is labor intensive. Detailed planning and coordination of effort are essential in order to maintain personnel doses as-low-as-reasonably achievable. Incorporation

of advanced technology into the refueling process also reduces doses. Table 12.4-11 lists some of the AP1000 features that reduce doses during refueling operations.

Table 12.4-12 provides dose estimates for the various refueling activities.

12.4.1.7 Overall Plant Doses

The estimated annual personnel doses associated with the six activity categories discussed above are summarized below:

Category	Percent of Total	Estimated Annual
Reactor operations and surveillance	20.6	13.8
Routine inspection and maintenance	18.0	12.1
Inservice inspection	24.7	16.6
Special maintenance	22.4	15.0
Waste processing	7.7	5.2
Refueling	6.6	4.4
Total	100.0	67.1

These dose estimates are based on operation with an 18-month fuel cycle and are bounding for operation with a 24-month fuel cycle.

12.4.1.8 Post-Accident Actions

Requirements of 10 CFR 52.79(b) relative to plant area access and post-accident sampling (10 CFR 50.34 (f) (2)(viii) are included in Section 1.9.3. If procedures are followed, the design prevents radiation exposures to any individual from exceeding 5 rem to the whole body or 50 rem to the extremities. Figure 12.3-2 in Section 12.3 contains radiation zone maps for plant areas including those areas requiring post-accident access. This figure shows projected radiation zones in areas requiring access and access routes or ingress, egress and performance of actions at these locations. The radiation zone maps reflect maximum radiation fields over the course of an accident. The analyses that confirm that the individual personnel exposure limits following an accident are not exceeded reflect the time-dependency of the area dose rates and the required post-accident access times. The areas that require post-accident accessibility are:

- Main control room
- Class 1E regulating transformer areas
- Ventilation control area for MCR and I & C rooms with PAMS equipment
- Valve area to align spent fuel pool makeup
- Ancillary diesel room
- Passive containment water inventory makeup area

12.4.2 Radiation Exposure at the Site Boundary

12.4.2.1 Direct Radiation

The direct radiation from the containment and other plant buildings is negligible. The AP1000 design also provides storage of refueling water inside the containment instead of in an outside storage tank that eliminates it as a radiation source.

12.4.2.2 Doses due to Airborne Radioactivity

Subsection 11.3.3 discusses doses at the site boundary due to activity released as a result of normal operations.

12.4.3 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

Table 12.4-1

DOSE ESTIMATE FOR REACTOR OPERATIONS AND SURVEILLANCE

Work Description	**Annual Dose (man-rem)**
Operation Supervision	
Routine patrols and inspections	5.4
Valve line-ups (manual)	0.2
System flushing and testing	0.4
Health Physics	
Job coverage	1.9
Routine surveys	1.6
Decontamination of Equipment and Work Areas	2.7
Calibration of Instrumentation	1.1
Chemistry Sampling and Analysis	0.5
Total Collective Dose:	13.8

Table 12.4-2

DOSE ESTIMATE FOR ROUTINE INSPECTION AND MAINTENANCE

Work Description	Annual Dose (man-rem)
Valve Adjustment/Repacking	1.8
Auxiliary Pump Overhaul	3.8
SG Sludge Lance	2.24
Demineralizer Resin Change-out	1.1
Filter Replacement	0.8
Calibrate/Repair Electrical Components	1.2
Miscellaneous Work	0.8
SG Secondary Side Inspection	0.34
Total Collective Dose:	12.1

Table 12.4-3

DOSE ESTIMATE FOR REACTOR COOLANT PUMP INSPECTION

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
A. Electrical[(a)]				
Measure insulation resistance to ground	0	1	0.2	0
Measure winding resistance	0	1	0.2	0
B. Mechanical Specification				
Measure rotor breakaway torque	5	2	0.5	0.005
Measure rotor axial end play	5	2	0.5	0.005

Total RCP intermediate routine maintenance ORE = 0.010 man-rem/18 months
Total intermediate routine maintenance ORE for 4 RCPs = 0.04 man-rem/18 months
Annual total ORE for 4 RCPs = 0.027 man-rem/year[(b)]

Note:

(a) Electrical measurements may be made from RCP switchgear, which is located outside containment.
(b) The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.

Table 12.4-4

DOSE ESTIMATE FOR SLUDGE LANCING OF STEAM GENERATORS

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Move Equipment into Containment	10	6	4	0.24
Remove Insulation and Handhole Cover	40	1	0.5	0.02
Complete Pre-lance Water Balance	40	2	1	0.08
Install Lance on Handhole	40	2	0.5	0.04
Operate Water Lance	40	2	12	0.96
Complete Post-Lance Water Balance	40	2	1	0.08
Remove Equipment	10	6	4	0.24
Install Handhole Cover and Insulation	40	1	0.5	0.02

Total ORE per SG = 1.68 man-rem/18 months
Total ORE for both SG = 3.36 man-rem/18 months
Annual total ORE for two SGs = 2.24 man-rem/year[(a)]

Note:

(a) The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.

Table 12.4-5

DOSE ESTIMATE FOR VISUAL EXAMINATION OF STEAM GENERATOR SECONDARY SIDE

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Remove Insulation and 2 Manway Covers[(a)]	1	2	2.5	0.005
Inspect Separators Orifices and Feedwater Ring[(a)]	10	1	0.5	0.005
Install Two Manway Covers and Insulation and Lower Water Level below Handholes[(a)]	1	2	2.5	0.005
Remove Insulation and Secondary Handhole Cover	40	2	0.5	0.04
Photograph Support Plates	40	2	2	0.16
Install Handhole Covers and Insulation	40	2	0.5	0.04

Total ORE per SG = 0.255 man-rem/18 months
Total ORE for two SGs = 0.51 man-rem/18 months
Annual ORE for two SGs = 0.34 man-rem/year[(b)]

Note:

(a) Secondary side water level at the lower deck plate.
(b) The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.

Table 12.4-6

DOSE ESTIMATE FOR INSERVICE INSPECTION

Component	Annual Dose (man-rem)
Valve Bodies and Boltings	6.10
SG Primary Side Inspections	1.25
Reactor Vessel and Head	2.56
Reactor Coolant Loop Piping and Supports	1.45
SG Shell	0.12
Other Piping	2.83
Heat Exchanger Shells	0.73
Pressurizer Shell	1.20
Pumps	0.11
Tank Shells and Supports	0.15
Filter Housings and Supports	0.06
Total Dose:	16.6

Table 12.4-7 (Sheet 1 of 2)

DOSE ESTIMATE FOR STEAM GENERATOR EDDY CURRENT TUBE INSPECTION AND TUBE PLUGGING

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Move Equipment into Containment	2	4	4	0.032
Install Ventilation Equipment	50	1	1	0.050
Remove Insulation on both Manway Covers	50	2	0.2	0.020
Remove both Manway Covers with Handling Fixture	50	2	1	0.100
Remove both Manway Inserts	300	2	0.1	0.060
Install Fixture on Manway	300	2	0.1	0.060
Install Universal/Robotic Arm on Manway	50	2	0.25	0.025
Insert Nozzle Hot and Cold Leg Dams with Robotic Arm	50	2	0.5	0.050
Replace Dam Fixture Tool with EC End Effector on Robotic Arm (Hot Leg Channel)	50	1	0.25	0.013
Perform EC Exam of 33-1/3% of Tubes	1	1	111	0.111
Remove EC End Effector and Replace with Mechanical Plugging Tool	50	1	0.2	0.010
Insert Plugs in 3 Tubes	50	1	0.75	0.0375
Transfer Robotic Arm to Cold Leg Channel	50	2	0.25	0.025

Table 12.4-7 (Sheet 2 of 2)

DOSE ESTIMATE FOR STEAM GENERATOR EDDY CURRENT TUBE INSPECTION AND TUBE PLUGGING

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Insert Plugs in 3 Tubes	50	1	0.75	0.0375
Remove Robotic Arm	50	2	0.25	0.025
Remove Hinged Fixture	300	2	0.1	0.060
Install Manway Inserts	300	2	0.1	0.060
Install Both Manway Covers with Handling Fixture	50	2	1	0.100
Replace Insulation Both Manway Covers	50	2	0.2	0.020
Remove Ventilation Equipment	50	1	0.5	0.025
Move Equipment out of Containment	2	4	2	0.016

Total SG special maintenance ORE = 0.94 man-rem/18 months
Total SG special maintenance ORE for 2 SGs = 1.88 man-rem/18 months
Annual total ORE for 2 SGs = 1.25 man-rem/year[(a)]

Note:

(a) The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.

Table 12.4-8 (Sheet 1 of 2)

DOSE ESTIMATE FOR STEAM GENERATOR INSERVICE INSPECTION (10-YEAR INTERVAL)

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Move Equipment into Containment	2	4	4	0.032
Remove/Install Insulation				
Steam nozzle	1	2	0.1	0.0002[a]
Secondary manways	1	2	0.1	0.0002[a]
Feedwater nozzle	10	1	0.1	0.001[a]
Upper shell girth welds	5	2	1.0	0.010[a]
Secondary hand hole	40	1	0.1	0.004[b]
Lower shell girth welds	40	2	1.0	0.080[a]
Channel head to tubesheet weld	100	2	0.3	0.060[b]
Pump to channel head welds	100	2	0.2	0.040[b]
Passive core cooling system (PXS) pipe to channel head weld	100	1	0.1	0.010[b]
Hot leg to channel head weld	100	2	0.2	0.040[b]
Install Ultrasonic Inspection Rig				
Upper shell girth welds	5	2	0.3	0.003[a]
Lower shell girth welds	40	2	0.3	0.024[a]
Channel head to tube sheet weld	100	2	0.1	0.020[b]
Pump to channel head welds	100	2	0.2	0.040[b]
PXS pipe to channel head weld	100	1	0.1	0.010[b]
Hot leg to channel weld	100	1	0.3	0.030[b]
Ultrasonic Inspection[c]				
Upper shell girth welds	0.1	2	7.5	0.0015[a]
Lower shell girth welds	0.1	2	7.5	0.0015[a]
Channel head to tube sheet	0.1	2	3.0	0.0006[b]
Pump to channel head welds	0.1	2	2.0	0.0004[b]
PXS to channel head weld	0.1	2	0.5	0.0001[b]
Hot leg to channel head weld	0.1	2	1.0	0.0002[b]

Note:

(a) ISI requires inspection of only 1 SG during each inspection interval.
(b) ISI requires inspection on both SG during each inspection interval.
(c) Operations performed from a low radiation area.

Table 12.4-8 (Sheet 2 of 2)

DOSE ESTIMATE FOR STEAM GENERATOR INSERVICE INSPECTION (10-YEAR INTERVAL)

Activity	Average Dose Rate (millirem/hr)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-rem)
Dye Penetrant Inspection				
Steam nozzle	1	2	0.2	0.0004[(a)]
Feedwater nozzle	10	1	0.1	0.001[(a)]
Pump to channel head	100	2	0.5	0.100[(b)]
PXS to channel head	100	1	0.1	0.010[(b)]
Hot leg to channel head	100	2	0.2	0.040[(b)]
Visual Inspection[(b)]				
Secondary manway bolts	1	2	0.1	0.0002
Secondary handhole bolts	40	1	0.1	0.004
Primary handhole bolts	100	2	0.2	0.040
Primary manway bolts	100	2	0.1	0.020
SG support	100	1	0.1	0.010
Remove Equipment from Containment	2	4	4	0.032

Total in-service inspection ORE for one SG = 0.67 man-rem/10 years
Total in-service inspection ORE for two SGs = 1.15 man-rem/10 years
Annual total ISI ORE for two SGs = 0.12 man-rem/year

Note:

(a) ISI requires inspection of only 1 SG during each inspection interval.
(b) ISI requires inspection on both SG during each inspection interval.
(c) Operations performed from a low radiation area.

Table 12.4-9

DOSE ESTIMATE FOR SPECIAL MAINTENANCE OPERATIONS

Work Description	Annual Dose (man-rem)
Valve Repairs	3.8
Auxiliary Pump Repairs	4.1
Electrical Repairs	3.2
Repairs to Tanks, Heat Exchangers, Piping, etc.	1.3
SG Secondary Side Repairs	1.1
Pressurizer Repairs	1.0
CRDM Repairs	0.5
Total Collective Dose:	15.0

Table 12.4-10

DOSE ESTIMATE FOR WASTE PROCESSING

Work Description	**Annual Dose (man-rem)**
Radioactive Waste Handling	3.0
System Adjustments/Repairs	1.8
System Operation (Sampling, Valve Adjustments, Monitoring, etc.)	0.4
Total Collective Dose:	5.2

Table 12.4-11

DESIGN IMPROVEMENTS THAT REDUCE REFUELING DOSES

Improved Design/Method	Reference Design/Method
Integrated RV Head Package	Conventional RV head package
RV Head Insulation with Suitcase-Type Fasteners and Permanent ID Markings	Insulation fastened with screws (no markings)
Combination Thermocouples and Flux Detectors	Top-mounted thermocouples and bottom-mounted flux detectors
Quick-Opening Fuel Transfer Tube Closure System	Bolted cover
Quick-Acting Stud Tensioner	Threaded-on stud tensioner
Pass and One-Half Stud Tensioning Procedure	Three-pass stud tensioning procedure
Electrical-Driven Stud Spin-Out Tool	Air-driven, spin-out tool
Permanent Reactor Cavity Seal Ring	Bolted or inflatable seal ring
Expandable Stud Hole Plugs	Threaded stud hole plugs
RV O-Ring Spring Clips	Tab and screw O-ring retaining system
Shielded RV Head Storage Stand	Nonshielded stand
Smooth-Finish Reactor Cavity Liner (#1 Finish)	Rough-finish reactor cavity liner

Table 12.4-12

DOSE ESTIMATE FOR REFUELING ACTIVITIES

Refueling Operations Work Description	Dose (man-rem)
Preparation	0.2
Reactor Disassembly	1.6
Fuel Shuffle	0.6
Reactor Reassembly	4.1
Clean-Up	0.1
Total Refueling Dose:	6.6
Average Annual Dose:	4.4[(a)]

Note:

(a) Based on an 18-month fuel cycle. The stated dose bounds operation with a 24-month fuel cycle.

12.5 Health Physics Facilities Design

12.5.1 Objectives

The health physics (HP) facilities are designed with the objectives of:

- Providing capability for administrative control of the activities of plant personnel to limit personnel exposure to radiation and radioactive materials as low as reasonably achievable (ALARA) and within the guidelines of 10 CFR 20.

- Providing capability for administrative control of effluent releases from the plant to maintain the releases ALARA and within the limits of 10 CFR 20 and the plant Technical Specifications.

- Providing capability for administrative control of waste shipments from the plant to meet applicable requirements for the shipment and receipt of the material at the storage or burial site.

12.5.2 Equipment, Instrumentation, and Facilities

The health physics (HP) facilities are located at elevation 100′-0″ in the annex building. See Figure 1.2-18 for a plan view of elevation 100′-0″ of the annex building.

12.5.2.1 Access and Exit of Radiologically Controlled Areas

Access to the radiologically controlled area (RCA) encompassing the containment and potentially contaminated areas of the annex, auxiliary, and radwaste buildings is normally through the entry/exit area of the health physics section of the annex building. Exit from the RCA is at the same location.

12.5.2.2 Facilities

The ALARA briefing and operational support center is located off the main corridor immediately beyond the main entry to the annex building. Near this room are several offices that may be used for other health physics functions.

Changes rooms are provided where radiation workers remove street clothes and put on modesty garments. These rooms are provided with lockers, wash sinks, showers and toilet facilities.

Radiation workers don anti-contamination clothing in the protective clothing pickup and suitup room. Workers then proceed to the central health physics booth.

Personnel access to and from the RCA is controlled at the health physics booth at the entry/exit points of the health physics area. Logging into the Radiation Permit System and issuance of dosimetry is also handled at this location. The health physics booth is equipped with computer terminals, desks, filing cabinets, and shelves, and other facilities needed for effective control and monitoring of radiation workers in the RCA. Workers are logged into a radiation exposure

tracking system. The health physics and security log-in functions are integrated. Facilities and equipment are provided at the health physics booth for the following functions:

- Issuing respirators, as needed
- Issuing radiation dosimetry, as required
- Updating radiation work permits as needed based on information provided by health physics at local control points and at the work locations

The booth has a counter such that the health physics personnel can easily monitor the flow of workers. It is located adjacent to and visible from the health physics pickup and suitup room.

As radiation workers exit the work areas they go through personnel contamination monitors, shower for decontamination if needed, and receive radiologically controlled first-aid if needed. The health physics area contains the personnel contamination monitoring equipment, decontamination shower facilities, and first-aid equipment.

The hot machine shop is located at elevation 107′-2″ in the south end of the annex building. Contaminated equipment can be decontaminated at the facility and maintenance and repair operations can be performed in a low radiation background area with in the RCA and with appropriate radiation protection and contamination control measures in place.

12.5.2.3 Whole Body Counting Instrumentation

The whole body counter(s) is located in a low background radiation area in the Annex Building. The whole body counting equipment is capable of detecting fractional body burdens of gamma emitting radionuclides.

12.5.2.4 Portable Survey Instrumentation

Portable radiation survey instrumentation is stored at the access control health physics booth and at in-plant control points. This instrumentation allows plant personnel to perform radiation, contamination, and neutron surveys, as needed, as well as collect samples for airborne analysis. Shielded rooms are provided in the health physics area for radioactivity analysis laboratory facilities and for calibration of survey instruments.

12.5.2.5 Other Health Physics Instrumentation

The area radiation monitoring system is installed in areas where it is desirable to have constant dose rate information. Monitors indicate dose rate in the control room and provide appropriate alarms upon reaching a preset dose rate. Fixed continuous airborne radioactivity monitors are also provided at strategic locations, where personnel exposure to airborne radionuclides is likely. More information on these fixed instruments is given in Sections 12.3 and 11.5.

12.5.3 Other Design Features

12.5.3.1 Radiation Protection Design Features

Specific design features for maintaining personnel exposure ALARA and plant shielding provisions are incorporated into the plant design. These features are described in Section 12.3.

12.5.3.2 Job Planning Facilities

Areas are provided where personnel may study, as appropriate: blueprints, drawings, photographs, videotapes, previous inspection reports, previous radiation and contamination surveys, or previous RWPs appropriate to the particular job prior to entry into radiation areas to perform inspections. Work rooms are provided where equipment is checked or calibrated to verify it is operating properly prior to entry into the radiation area. The ALARA briefing and operational support room in the annex building is an example of such a facility where job planning and ALARA briefing and debriefing activities can take place.

12.5.3.3 Radwaste Handling

The handling of radwaste has been minimized by plant design. Some of the activities involving radwaste or radioactively contaminated materials are performed offsite or using mobile equipment brought onsite. Cleaning of protective clothing and respiratory protective equipment are activities that are performed offsite or in mobile equipment.

The radwaste system is shielded and incorporates remotely operated liquid and solid radwaste systems. The systems are designed to minimize operator exposure in waste processing and handling operations. The liquid radwaste system and solid waste handling system are described in Chapter 11.

12.5.3.4 Spent Fuel Cask Loading and Shipping

Spent fuel handling and loading of a shipping cask is designed to be performed underwater, using the fuel handling cranes and/or manual extension tools.

Some of the design features included to maintain exposure ALARA are:

- Maintenance of at least ten feet of water above the fuel assembly to minimize direct radiation.
- Purification of fuel pool water to minimize exposure due to water activity.
- Cooling of the spent fuel pool water.
- Providing continuous air sampling while moving fuel to evaluate airborne activity.

12.5.3.5 Normal Operation

The plant is designed so that significant radiation sources are minimized, locally shielded, and/or located in shield cubicles. Much of the instrumentation required for normal operation reads out remotely in the control room or in other low radiation areas. Instrumentation that cannot be placed remotely or that is read infrequently is situated, where possible, so that it can be read from the entrance to the cubicle or from a low radiation area within the cubicle.

Area radiation monitoring equipment, which is included as part of the process effluent radiological monitoring system, is available and provides indication of radiation levels and local alarms. The ventilation system is designed to minimize spread of airborne contamination.

12.5.3.6 Sampling

Provisions are made for sampling of radioactive systems in the sampling room. Protective clothing and gloves are available when sampling radioactive systems to prevent contamination of personnel.

12.5.3.7 Surface Coatings

Special coatings are applied to walls and floors of areas containing radioactive fluids, which aid in decontaminating these areas.

12.5.4 Controlling Access and Stay Time

Areas in the plant are classified as non-radiation areas and restricted radiologically controlled areas for radiation protection purposes. Restricted areas are further categorized as radiation areas, high radiation areas, airborne radioactivity areas, contamination areas, and radioactive materials areas, to comply with 10 CFR 20 and plant procedures and instructions.

Entrance to the RCA area is normally through the access control area at the health physics area entry/exit location in the annex building, see subsection 12.5.2.

High and very high radiation areas are segregated and identified in accordance with 10 CFR 20. The entrances to high and very high radiation areas are locked or barricaded and equipped with audible and/or visible alarms, as required.

12.5.5 Combined License Information

The Combined License applicant will address the organization and procedures used for adequate radiological protection and to provide methods so that personnel radiation exposures will be maintained ALARA.

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CHAPTER 13

CONDUCT OF OPERATIONS

This chapter provides information relating to the preparations and plans for operation of the AP1000. Its purpose is to provide reasonable assurance that the Combined License applicant can establish and maintain a staff of sufficient size and technical competence and that operating plans provide reasonable assurance of adequate protection of the public health and safety.

13.1 Organizational Structure of Applicant

This section is the responsibility of the Combined License applicant. The organizational structure must be consistent with the human system interface design assumptions. See Section 1.8 and Chapter 18 for interface requirements pertaining to organizational structure.

13.1.1 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will address adequacy of the organizational structure.

13.2 Training

Training programs are the responsibility of the Combined License applicant.

Chapter 18, Section 18.10 references WCAP 14655, "Designer's Input for the Training of the Human Factors Engineering Verification and Validation Personnel" that provides input for the Combined License applicant. This document describes input from the designer on the training of the operations personnel who participate as subjects in the human factors engineering (HFE) verification and validation. The WCAP also describes how training insights are passed from the designer to the Combined License applicant.

13.2.1 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will develop and implement training programs for plant personnel. This includes the training program for the operations personnel who participate as subjects in the human factors engineering verification and validation. These Combined License applicant training programs will address the scope of licensing examinations as well as new training requirements.

13.3 Emergency Planning

Emergency planning is the responsibility of the Combined License applicant. See subsection 1.2.5 for the locations of the technical support center, the operational support center and the decontamination facilities. See Section 9.4 for a description of the HVAC systems for the main control room/technical support center and the annex building. See Section 18.8 for the high level requirements for the technical support center and the operational support center. See Section 7.5 for identification of plant variables that are provided for interface to the emergency planning areas.

Communication interfaces among the main control room, the technical support center and the emergency planning centers are the responsibility of the Combined License applicant.

Staffing of the emergency operations facility occurs consistent with current operating practice and with revision 1 of NUREG-0654/FEMA-REP-1.

13.3.1 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will address emergency planning including post-72 hour actions and its communication interface.

Combined License applicants referencing the AP1000 certified design will address the activation of the emergency operations facility consistent with current operating practice and NUREG-0654/FEMA-REP-1.

13.4 Operational Review

This section is the responsibility of the Combined License applicant.

13.4.1 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will address each operational review.

13.5 Plant Procedures

Plant procedures are the responsibility of the Combined License applicant. References to applicable combined license information are included in Section 1.8. This includes, for example, reference to guidelines on inservice inspection in Chapters 3 and 6, and initial testing in Chapter 14. Operational experience and the resolution of generic issues to be considered in the preparation of plant procedures are outlined in Section 1.9. The Combined License applicant will establish procedures to perform rod control system surveillance tests specified in WCAP-13864, Revision 1 (Reference 7), at the beginning of each fuel cycle. The Combined License applicant will ensure that all portions of the safety-related logic circuitry are adequately covered in the surveillance procedures as described in Generic Letter 96-01 (Reference 8).

Reference 1 provides input to the Combined License applicant for the development of plant operating procedures, including information on the development and design of the AP600 emergency response guidelines and emergency operating procedures. Also included in Reference 1 is information on the computerized procedure system, which is the human system interface that allows the operators to execute the plant procedures. From an operational viewpoint, in particular with regards to plant procedures, the AP1000 is the same as the AP600. This allows the use of a common guide such as Reference 1.

The computerized procedure system is not part of the AP1000 design scope that the Nuclear Regulatory Commission is being asked to approve. The acceptability of the computerized procedure system, and its backup, for application to the AP1000 design will be determined during

the implementation of the AP1000 verification and validation program (see DCD Section 18.8) and reviewed as part of an application for a combined license.

The Combined License applicant is responsible for the development of plant specific refueling plans (DCD Appendix 19E provides input for refueling plans).

Outage plans, which are the responsibility of the Combined License applicant, should as a minimum address the following elements:

- An outage philosophy, which includes safety as a primary consideration in outage planning and implementation,

- Separate organizations responsible for scheduling and overseeing the outage; provisions for an independent safety review team that would be assigned to perform final review and grant approval for outage activities,

- Control procedures, which address both the initial outage plan and all safety-significant changes to schedule,

- Provisions to ensure that all activities receive adequate resources,

- Provisions to ensure defense-in-depth during shutdown and ensure that margins are not reduced; an alternate or backup system must be available if a safety system or a defense-in-depth system is removed from service, and

- Provisions to ensure that all personnel involved in outage activities are adequately trained; this should include operator simulator training to the extent practicable; other plant personnel, including temporary personnel, should receive training commensurate with the outage tasks they will be performing.

If freeze seals are to be used, the Combined License applicant must develop plant-specific guidelines to reduce the potential for loss of RCS boundary and inventory when they are in use.

13.5.1 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will address plant procedures including the following:

- Normal operation
- Abnormal operation
- Emergency operation
- Refueling and outage planning
- Alarm response
- Maintenance, inspection, test and surveillance
- Administrative
- Operation of post-72 hour equipment

13.6 Security

13.6.1 Preliminary Planning

As a result of the events of September 11, 2001, the NRC issued orders to power reactor licensees titled "Interim Compensatory Measures for High Threat Environment" (Reference 4). On April 29, 2003, the NRC also issued a revised "Design Basis Threat for Radiological Sabotage for Operating Power Reactors" (Reference 5). An assessment of the impact of References 4 and 5 is provided in the AP1000 Security Assessment (Reference 6) that has been submitted under separate cover in accordance with 10 CFR 73.21. The AP1000 Security Assessment Document provides an assessment of how References 4 and 5 are addressed in the AP1000 design, and identifies the applicable requirements in References 4 and 5 that are addressed by the Combined License applicant for an AP1000.

13.6.2 Security Plan

The comprehensive physical security program is the responsibility of the Combined License applicant and will be addressed in the security plan, contingency plan, and guard training plan provided by the Combined License applicant.

13.6.3 Plant Protection System

13.6.3.1 Introduction

A physical protection system and security organization is provided to protect the AP1000 from radiological sabotage, as required by 10 CFR 73.55. To achieve this objective, the physical protection system:

- Includes a security organization
- Locates vital equipment within vital areas
- Controls points of personnel, vehicle, and material access into the vital areas
- Annunciates alarms in a continuously manned central alarm station and at least one other continuously manned alarm station that is physically separated from the central alarm station
- Provides for continuous communications between the security officers and the continuously manned alarm stations
- Provides for testing and maintenance of the alarms, communications, and physical barriers
- Responds to threats of radiological sabotage in accordance with a developed contingency plan

13.6.4 Physical Security Organization

The description of the site-specific physical security organization is the responsibility of the Combined License applicant. The size and capabilities of the physical security organization's armed response team are established by a vulnerability analysis and protective strategy development prepared by the Combined License applicant.

13.6.5 Physical Barriers

13.6.5.1 Protected Area

The definition of the protected area is the responsibility of the Combined License applicant.

13.6.5.2 Vital Areas

Vital equipment is located within designated vital areas. The AP1000 vital areas are encompassed by the boundary formed by the shield building, a reinforced concrete and steel structure surrounding containment, and by portions of the reinforced concrete perimeter and interior walls of the auxiliary and annex buildings. Access points to vital areas are locked and alarmed with active intrusion detection systems. The vital areas and a listing of the vital equipment are provided in Reference 6.

13.6.5.3 Bullet-Resisting Barriers

The doors, walls, floor, and ceiling of the main control room and the continuously manned alarm stations are designed to meet the bullet-resisting criteria of UL-752, High Power Rifle Rating, including resistance to a level 4 round. The Combined License applicant is responsible for the detail design and bullet resistance of the structure that isolates the individual responsible for the last access control function for admission to the protected area.

13.6.5.4 Vehicle Barrier System

The Combined License Applicant is responsible for the definition, location, and the detail design of the AP1000 Vehicle Barrier System.

13.6.6 Access Requirements

The Combined License applicant is responsible for the following access control features:

- Positive control features are implemented to provide authorization for personnel and vehicles entering the vital areas.

- Means for positive identification of authorized personnel entering the protected and vital areas.

- Means for searching individuals, packages, and materials for firearms, explosives, and incendiary devices. This may be accomplished using detection devices such as metal detectors, explosive detectors, and x-ray machines.

The AP1000 design certification scope includes:

- Access portals entering the vital areas are identified and unmanned portals are provided with alarm annunciation in the continuously manned alarm stations.
- Vital area ingress and egress are designed to interface with other plant requirements and not impair plant operations during emergency conditions.

13.6.7 Detection Aids

The design of the detection aids is the responsibility of the Combined License applicant.

13.6.8 Security Lighting

The design of the AP1000 security lighting is the responsibility of the Combined License applicant.

13.6.9 Security Power Supply System

Security equipment that supports critical monitoring functions, such as intrusion detection, alarm assessment, and the security communication system, can receive power from the security-dedicated uninterruptible power supply (UPS) system. Switchover to the uninterruptible power supply system is automatic and does not cause false alarms on annunciation modules. The uninterruptible power supply system is capable of sustaining operation for a minimum of 24 hours. The location of the security power supply system is specified in Reference 6. The final design of the security power supply system is the responsibility of the Combined License applicant.

13.6.10 Communications

The final design of the security communication system will be addressed by the Combined License applicant.

Two two-way communications paths are provided between the control room and the alarm stations within the AP1000. A single act of sabotage cannot sever both communication paths. Security force members with responsibilities to respond to acts of sabotage have the capability for continuous two-way communication with the alarm stations, and with each other. The centralized communication equipment is located in a vital area so that it will remain operable during a radiological sabotage event.

Non-portable security communications equipment can be powered from the security power supply system so that it remains operable in the event of the loss of normal power.

13.6.11 Testing and Maintenance

The Combined License applicant will address testing and maintenance aspects of the plant security system.

13.6.12 Response Requirements

The Combined License applicant will address response requirements of the plant security program.

13.6.13 Combined License Information Item

13.6.13.1 Security Plans, Organization, and Testing

Combined License applicants referencing the AP1000 certified design will address site-specific information related to the security, contingency, and guard training plans. Those plans will include descriptions of the tests planned to show operational status, maintenance of the plant security system, the security organization, communication, and response requirements.

The Combined License applicant will develop the comprehensive physical security program which includes the security plan, contingency plan, and guard training plan. Each COL applicant will describe in its physical security plan how the requirements of 10 CFR Part 26 will be met. At least 60 days before loading fuel, the Combined License applicant will confirm that the security systems and programs described in its physical security plan, safeguards contingency plan, and training and qualification plan have achieved operational status and are available for the staff's inspection. Operational status means that the security systems and programs are functioning. The determination that operational status has been achieved will be based on tests conducted under realistic operating conditions of sufficient duration to demonstrate that:

- the equipment is properly operating;
- procedures have been developed, approved, and implemented; and
- personnel responsible for security operations and maintenance have been appropriately trained and have demonstrated their capability to perform their assigned duties and responsibilities.

13.6.13.2 Vital Equipment

Combined License applicants referencing the AP1000 certified design will verify that the as-built location of vital equipment is inside the vital areas identified in Reference 6.

13.6.13.3 Plant Security System

Combined License applicants referencing the AP1000 certified design will address site-specific information related to the design, maintenance, and testing of the plant security system, including definition of the protected area; definition and location of the site boundary fence; definition, location, and detail design of the vehicle barrier; definition of control points for personnel, vehicle, and material access into the protected areas; detail design and bullet resistance of the structure that isolates the individual responsible for the last access control function for admission to the protected area; detection and alarm design features; security lighting; security power supply including the interface to the UPS system; and communication system.

13.6.13.4 Nuclear Material Control System

Combined License applicants referencing the AP1000 certified design will address specific material control measures as required by 10 CFR Part 70 and the guidance provided in Reference 9.

13.7 References

1. WCAP-14690, "Designer's Input To Procedure Development for the AP600," Revision 1, June 1997.

2. Not used.

3. Not used.

4. Interim Compensatory Measures for High Threat Environment, February 25, 2002.

5. Design Basis Threat for Radiological Sabotage for Operating Power Reactors, April 29, 2003.

6. AP1000 Security Assessment, Revision 1, March 2004.

7. WCAP-13864, "Rod Control System Evaluation Program," Revision 1-A, November 1994.

8. USNRC Generic Letter GL-96-01, "Testing of Safety-Related Logic Circuits," January 10, 1996.

9. ANSI N15.8, "Nuclear Material Control Systems for Nuclear Power Plants," 1974.

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CHAPTER 14

INITIAL TEST PROGRAM

14.1 Specific Information to be Included in Preliminary/Final Safety Analysis Reports

Not applicable to the AP1000.

14.2 Specific Information to be Included in Standard Safety Analysis Reports

14.2.1 Summary of Test Program and Objectives

The purpose of this section is to describe the test program that is performed during initial startup of the AP1000 plant.

The overall objective of the test program is to demonstrate that the plant has been constructed as designed, that the systems perform consistent with the plant design, and that activities culminating in operation at full licensed power including initial fuel load, initial criticality, and power ascension are performed in a controlled and safe manner.

Preoperational and/or startup testing is performed on those systems that are:

a) Relied upon for safe shutdown and cooldown of the reactor under normal plant conditions and for maintaining the reactor in a safe condition for an extended shutdown period;

b) Relied upon for safe shutdown and cooldown of the reactor under transient and postulated accident conditions and for maintaining the reactor in a safe condition for an extended shutdown period following such conditions;

c) Relied upon for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications;

d) Classified as engineered safety features actuation systems (ESFAS) or are relied upon to support or ensure operation of engineered safety features actuation systems within design limits;

e) Assumed to function or for which credit is taken in the accident analysis of the AP1000 as described in this Design Control Document.

f) Used to process, store, control, or limit the release of radioactive materials.

g) Other systems identified in Regulatory Guide 1.68, Revision 2, Appendix A that are in the AP1000 and are not captured by criteria a) through f).

The inspections, tests, analyses and acceptance criteria of 10 CFR 52.47 (a)(1)(vi) relating to the AP1000 design are found in the AP1000 Certified Design Material (see Section 14.3).

The initial plant test program consists of a series of tests categorized as construction and installation, preoperational, and startup tests. These tests are the responsibility of the Combined License holder.

- Construction and installation tests are performed to determine that plant structures, components, and systems have been constructed or installed correctly and are operational.

- Preoperational tests are performed after construction and installation tests, but prior to initial fuel loading to demonstrate the capability of plant systems to meet performance requirements.

- Startup tests begin with the initial fuel loading and are performed to demonstrate the capability of individual systems, as well as the integrated plant, to meet performance requirements.

14.2.1.1 Construction and Installation Test Program Objectives

The adequacy of construction, installation, and preliminary operation of components and systems is verified by a construction and installation test program.

In this program, various electrical and mechanical tests are performed including the following:

- Cleaning and flushing
- Hydrostatic testing
- Checks of electrical wiring
- Valve testing
- Energization and operation of equipment
- Calibration of instrumentation

On a system basis, completion of this program demonstrates that the system is ready for preoperational testing.

Abstracts for tests constituting the construction and installation test program are not provided in support of Design Certification. Development of the construction and installation tests is based on the engineering information for the equipment and systems installed.

14.2.1.2 Preoperational Test Program Objectives

Following construction and installation testing, preoperational tests are performed to demonstrate that equipment and systems perform in accordance with design criteria so that initial fuel loading, initial criticality, and subsequent power operation can be safely undertaken. Preoperational tests at elevated pressure and temperature are referred to as hot functional tests.

The general objectives of the preoperational test program are the following:

- Demonstrate that essential plant components and systems, including alarms and indications, meet appropriate criteria based on the design

- Provide documentation of the performance and condition of equipment and systems

- Provide baseline test and operating data on equipment and systems for future use and reference

- Operate equipment for a sufficient period to demonstrate performance

- Demonstrate that plant systems operate on an integrated basis

Abstracts for the preoperational tests for portions of systems/components that perform safety-related functions; perform defense-in-depth functions; contain, transport, or isolate radioactive material; and for applicable systems that are specified in Regulatory Guide 1.68, Appendix A, Revision 2 are provided in this section.

Plant operating, emergency, and surveillance procedures are incorporated into the initial test program procedures. These procedures are verified through use, to the extent practicable, during the preoperational test program and revised if necessary, prior to fuel loading.

Plant equipment used in the performance of preoperational tests is operated in accordance with appropriate operating procedures, thereby giving the plant operating staff an opportunity to gain experience in using these procedures and demonstrating their adequacy prior to plant initial criticality.

14.2.1.3 Startup Test Program Objectives

The startup test program begins with initial fuel loading after the preoperational testing has been successfully completed.

Startup tests can be grouped into four broad categories:

- Tests related to initial fuel loading
- Tests performed after initial fuel loading but prior to initial criticality
- Tests related to initial criticality and those performed at low power (less than 5 percent)
- Tests performed at power levels greater than 5 percent

During performance of the startup test program, the plant operating staff has the opportunity to obtain practical experience in the use of normal and abnormal operating procedures while the plant progresses through heatup, criticality, and power operations.

The general objectives of the startup test program are:

- Install the nuclear fuel in the reactor vessel in a controlled and safe manner.

- Verify that the reactor core and components, equipment, and systems required for control and shutdown have been assembled according to design and meet specified performance requirements.

- Achieve initial criticality and operation at power in a controlled and safe manner.

- Verify that the operating characteristics of the reactor core and associated control and protection equipment are consistent with design requirements and accident analysis assumptions.

- Obtain the required data and calibrate equipment used to control and protect the plant.

- Verify that the plant is operating within the limits imposed by the Technical Specifications.

Abstracts of the startup tests are provided in this section.

14.2.2 Organization, Staffing, and Responsibilities

The Combined License holder is responsible for the establishment of a management organization with overall responsibility for defining the responsibilities, requirements, and interfaces necessary to safely and efficiently test, operate, and maintain the AP1000 plant.

The Combined License holder is responsible for developing the specific plant organization and staffing appropriate for the testing, operating and maintaining the AP1000 plant.

14.2.3 Test Specifications and Test Procedures

Preoperational and startup tests are performed using test specifications and test procedures.

For the preoperational and startup tests, test specifications are written to specify the following:

- Objectives for performing the test
- Test prerequisites
- Initial test conditions
- Data requirements
- Criteria for test results evaluation and reconciliation methods and analysis as required

For each test, the test procedure specifies the following:

- Objectives for performing the test
- Prerequisites that must be completed before the test can be performed
- Initial conditions under which the test is started
- Special precautions required for the safety of personnel or equipment
- Instructions delineating how the test is to be performed
- Identification of the required data to be obtained and the methods for documentation
- Data reduction analysis methods as appropriate

Test specifications and procedures are developed and reviewed by personnel with appropriate technical backgrounds and experience. This includes the participation of principle design organizations in the establishment of test performance requirements and acceptance criteria. Specifically, the principle design organizations will provide the combined license applicant with scoping documents (i.e., preoperational and startup test specifications) containing testing objectives and acceptance criteria applicable to its scope of design responsibility.

Available information on operating or testing experiences of operating reactors are factored into the test specifications and test procedures as appropriate.

Copies of the test specifications and test procedures for the startup tests are provided to NRC inspection personnel not less than 60 days prior to the scheduled fuel loading date.

Copies of the test specifications and test procedures are available to NRC inspection personnel approximately 60 days prior to the scheduled performance of the following preoperational tests:

- Tests of systems/components that perform safety-related functions
- Tests of systems/components that are nonsafety-related but perform defense in-depth functions.

Test specifications and test procedures for preoperational tests described in subsections 14.2.9.3 and 14.2.9.4 of the plant systems/components which perform no safety-related or defense-in-depth functions are available to NRC inspection personnel prior to the scheduled performance of these tests.

Preoperational and startup tests are performed with the quality assurance requirements as specified in Section 17.5.

14.2.3.1 Conduct of Test Program

Administrative procedures and requirements that govern the activities of the conduct of the initial test program include the following:

- Format and content of test procedures
- Process for both initial issue and subsequent revisions of test procedures
- Review process for test results
- Process for resolution of failures to meet performance criteria and of other operational problems or design deficiencies
- Various phases of the initial test program and the requirements for progressing from one phase to the next, as well as requirements for moving beyond selected hold points or milestones within a given phase
- Controls to monitor the as-tested status of each system and modifications including retest requirements deemed necessary for systems undergoing or already having completed testing
- Qualifications and responsibilities of the positions within the startup group

The startup administrative procedures supplement normal plant administrative procedures by addressing those administrative issues that are unique to the startup program.

14.2.3.2 Review of Test Results

Final review of the individual tests is the responsibility of plant management, which is also responsible for final review of overall test results and for review of selected milestones or hold points within the test phases.

14.2.3.3 Test Records

Retention periods for test records are based on considerations of their usefulness in documenting initial plant performance characteristics, and are retained in accordance with Regulatory Guide 1.28.

14.2.4 Compliance of Test Program with Regulatory Guides

Subsection 1.9.1 and Table 1.9-1 discuss compliance with the applicable NRC regulatory guides.

14.2.5 Utilization of Reactor Operating and Testing Experience in the Development of Test Program

The design, testing, startup, and operating experience from previous pressurized water reactor plants is utilized in the development of the initial preoperational and startup test program for the AP1000 plant. Other sources of experience reported and described in documents such as NRC reports, including Inspection and Enforcement bulletins and Institute of Nuclear Power Operations (INPO) reports, including Significant Operating Event Reports (SOER), are also utilized in the AP1000 initial preoperational and startup test program.

Special tests to further establish a unique phenomenological performance parameter of the AP1000 design features beyond testing performed for Design Certification of the AP600 and that will not change from plant to plant, are performed for the first plant only. Because of the standardization of the AP1000 design, these special tests (designated as first plant only tests) are not required on follow plants. These first plant only tests are identified in the individual test descriptions. (See subsections 14.2.9 and 14.2.10.) The following is a listing of the first plant only tests, and the corresponding section in which they appear.

First Plant Only Test	Section
IRWST Heatup Test	14.2.9.1.3 Item (h)
Pressurizer Surge Line Stratification Evaluation	14.2.9.1.7 Item (d)
Reactor Vessel Internals Vibration Testing	14.2.9.1.9 – Prototype Test
[Natural Circulation Tests]*	14.2.10.3.6, [14.2.10.3.7]*
Rod Cluster Control Assembly Out of Bank Measurements	14.2.10.4.6
Load Follow Demonstration	14.2.10.4.22

Other special tests which further establish a unique phenomenological performance parameter of the AP1000 design features beyond testing performed for Design Certification for the AP600 and that will not change from plant to plant, are performed for the first three plants. Because of the

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

standardization of the AP1000 design, once these special tests have affirmed consistent passive system function they are not required on follow plants. These tests required on the first three plants are identified in the individual test descriptions (See subsection 14.2.9). The following is a listing of the tests required on the first three plants, and the corresponding section in which they appear.

[*First Three Plant Tests*	*Section*
Core Makeup Tank Heated Recirculation Tests	*14.2.9.1.3 Items (k) and (w)*
ADS Blowdown Test	*14.2.9.1.3 Item (s)*

For subsequent plants, the COL applicant shall either perform the subject test, or shall provide a justification that the results of the first-plant-only tests or first-three-plant tests are applicable to the subsequent plant.]*

The justifications for the first-plant-only tests and the first-three-plant tests are provided below:

IRWST Heatup Test (14.2.9.1.3 item (h))

During preoperational testing of the passive core cooling system, a natural circulation test of the passive residual heat removal (PRHR) heat exchanger is conducted (item f). For the first plant only, thermocouples are placed in the IRWST to observe the thermal profile developed during the heatup of the IRWST water during PRHR heat exchanger operation. This test will be useful in confirming the results of the AP600 Design Certification Program PRHR tests with regards to IRWST mixing, and is useful in quantifying the conservatism in the Chapter 15 transient analyses.

Due to the standardization of the AP1000, the heatup and thermal stratification characteristics of the IRWST will not vary from plant to plant. The PRHR heat exchanger design, and the size and configuration of the IRWST are standardized, such that the heatup characteristics will not significantly change from plant to plant.

Therefore, since the phenomenon to be tested (i.e., heatup and mixing characteristics of the IRWST) will not vary significantly from plant to plant due to standardization, a first plant only test of the IRWST heatup characteristics is justified.

Core Makeup Tank Heated Recirculation Tests (14.2.9.1.3 Items (k) and (w))

During preoperational testing of the passive core cooling system, a test is performed for each plant to verify the CMT inlet piping resistances. In addition, cold draining tests of the CMTs are conducted that verify the discharge piping resistance and proper drain rate of the CMTs for each plant. For the first three plants, two additional CMT tests are conducted during hot functional testing of the RCS. These tests are a natural circulation heatup of the CMTs followed by a test to verify the ability of the CMTs to transition from a recirculation mode to a draindown mode while at elevated temperature and pressure.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Operation of the CMTs in their natural circulation mode is conducted on the first three plants only for the following reasons:

- Natural circulation of the CMTs will not vary from plant to plant, provided that the other verifications discussed above are performed as specified.
- Natural circulation testing of the CMTs was extensively tested as part of the Design Certification Tests.
- Performance of this test results in significant thermal transients on Class 1 components including the CMTs and the direct vessel injection nozzles.

ADS Blowdown Test (14.2.9.1.3 Item (s))

During preoperational testing of the passive core cooling system, the resistance of the automatic depressurization system Stage 1, 2, 3 flowpath(s) is verified. For the first three plants only, an automatic depressurization blowdown test is performed to verify proper operation of the ADS valves, and demonstrate the proper operation of the ADS spargers to limit the hydrodynamic loads in containment to less than design limits. This test is performed on only the first three plants for the following reasons:

- The operation of the ADS, and the resultant hydrodynamic loads will not vary significantly from plant to plant.
- Full scale automatic depressurization testing was performed in the AP600 Design Certification Program. Testing was conducted to conservatively bound ADS flow rates and resultant hydrodynamic loads that will be experienced by the plant during ADS operation.
- Performance of this test results in significant thermal transients on Class 1 components including the primary components. It also results in hydrodynamic loads in containment including the IRWST.

Pressurizer Surge Line Stratification Evaluation (14.2.9.1.7 Item (d))

As part of the AP1000 conformance to NRC Bulletin 88-11, a monitoring program will be implemented by the COL Applicant for the first AP1000 to record temperature distributions and thermal displacements of the surge line piping during hot functional testing and during the first fuel cycle, as discussed in subsection 3.9.3.

Reactor Vessel Internals Vibration Testing (14.2.9.1.9)

The preoperational vibration test program for the reactor internals of the AP1000 conducted on the first AP1000 is consistent with the guidelines of Regulatory Guide 1.20 for a comprehensive vibration assessment program. This program is discussed in subsection 3.9.2.

Natural Circulation Tests (14.2.10.3.6, 14.2.10.3.7)

Natural circulation tests using the steam generators and the passive residual heat removal heat exchanger are performed at low core power during the startup test phase of the initial test program for the first AP1000. This testing of the heat removal systems meets the intent of the requirement to perform natural circulation testing and the results of this testing is factored into the operator training as discussed in subsection 1.9.4, Item I.G.1. This test is only required to be performed once because its purpose is to obtain data to benchmark the operator training simulator.

Rod Cluster Control Assembly Out of Bank Measurements (14.2.10.4.6)

Rod cluster control assembly out of bank measurements are performed during power ascension tests. The test is performed at the 30-percent to 50-percent power level so the plant does not exceed peaking factor limits. The test is required to be performed only for the first plant because its purpose is to validate calculation tools and instrument responses.

Load Follow Demonstration (14.2.10.4.22)

A load follow demonstration test is not required by Regulatory Guide 1.68. However, the AP1000 performs load follow with grey rods, as opposed to current Westinghouse PWRs which manipulate RCS boron concentration to perform load follow operations. Therefore, Westinghouse has included a load follow test for the first AP1000, to demonstrate the ability of the AP1000 plant to load follow.

14.2.6 Use of Plant Operating and Emergency Procedures

As appropriate and to the extent practicable, plant normal, abnormal, and emergency operating procedures are used when performing preoperational startup tests.

The use of these procedures is intended:

- To demonstrate the adequacy of the specific procedure or to identify changes that may be required

- To increase the level of knowledge of plant personnel on the systems being tested

A test procedure using a normal, abnormal, or emergency operating procedure references the procedure directly or extracts a series of steps from the procedure in the way that accomplishes the operator training goals while safely and efficiently performing the specified testing.

14.2.7 Initial Fuel Loading and Initial Criticality

Initial fuel loading and subsequent initial criticality and power ascension to full licensed power are performed during the startup test program. Prior to the initiation of these operations, the systems and conditions necessary to bring the plant into compliance with the Technical

Specifications must be operable and satisfied. These operations are performed in a controlled and safe manner by using test procedures that specify:

- Required prerequisite testing
- Operational status of required systems
- Step-by-step instructions
- Precautions which must be observed
- Actions to be taken in the event of unanticipated or abnormal response

14.2.7.1 Initial Fuel Loading

The minimum conditions for initial core loading include:

- The composition, duties, and emergency procedure responsibilities of the fuel handling crew are established.

- Radiation monitors, nuclear instrumentation, manual initiation controls, and other devices to actuate alarms and ventilation controls are tested and verified to be operable.

- The status of systems required for fuel loading is established and verified.

- The status of protection systems, interlocks, mode switch, alarms, and radiation protection equipment is established and verified for fuel loading.

- Inspections of fuel and control rods have been made.

- Containment integrity has been established to the extent required by the Technical Specifications.

- The reactor vessel status has been established for fuel loading. Components are verified to be in place or out of the vessel as required for fuel loading.

- Required fuel handling tools are available, operational, and calibrated to include indexing of the manipulator crane with a dummy fuel element. The fuel handling tools have been successfully tested.

- Reactor coolant water quality requirements are established and the reactor coolant water quality is verified.

- The reactor vessel is filled with water to a level approximately equal to the center of the vessel outlet nozzles. The reactor coolant water is circulating at a rate which provides uniform mixing.

- The boron concentration in the reactor coolant is verified to be equal to or greater than required by the plant Technical Specifications for refueling and is being maintained under a surveillance program.

- Sources of unborated water to the reactor coolant system have been isolated and are under a surveillance program.

- At least two neutron detectors are calibrated, operable, and located in such a way that changes in core reactivity can be detected and recorded. One detector is connected to an audible count rate indicator and a containment alarm.

- A response check of nuclear instruments to a neutron source is required within 8 hours prior to loading (or resumption of loading if delayed for 8 hours or more).

Fuel assemblies together with inserted components (control rods, burnable poison assemblies, primary and secondary neutron sources) are placed in the reactor vessel, according to an established and approved sequence.

During and following the insertion of each fuel assembly, until the last fuel assembly has been loaded, the response of the neutron detectors is observed and compared with previous fuel loading data or calculations to verify that the observed changes in core reactivity are as expected. Specific instructions are provided if unexpected changes in reactivity are observed.

Because of the unique conditions that exist during initial fuel loading, temporary neutron detectors may be used in the reactor vessel to provide additional reactivity monitoring. Credit for the use of temporary detectors may be taken in meeting Technical Specifications requirements on the number of operable source range channels.

14.2.7.2 Initial Criticality

Following initial fuel loading, the reactor upper internals and the pressure vessel head are installed. Additional mechanical and electrical tests are performed in preparation for critical and power operations. The following conditions exist prior to initial criticality:

- The reactor coolant system is filled and vented.

- Tests are completed on the control rod drive system that demonstrate that the control rods have been latched, that the control and position indication systems are functioning properly, and that the rod drop time under hot full flow conditions is less than the Technical Specifications limit.

- Tests are completed that demonstrate that plant control and protection systems are operable and that the reactor trip breakers respond as designed to appropriate trip signals.

- The reactor coolant system is at hot no-load temperature and pressure. The reactor coolant boron concentration is such that the shutdown margin requirements of the Technical Specifications are satisfied for the hot shutdown condition.

Initial criticality is achieved in an orderly, controlled fashion by the combination of shutdown and control bank withdrawal and reactor coolant system boron concentration reduction.

During the approach to initial criticality, the response of the source range nuclear instruments is used as an indication of the rate of reactivity addition and the proximity to a critical condition so that criticality is achieved in a controlled, predictable fashion.

Rates for rod withdrawal and boron reduction are specified in such a way that the startup rate is less than one decade per minute.

Following criticality and prior to operation at power levels greater than 5 percent of rated power, physics tests are performed to verify that the operating characteristics of the reactor core are consistent with design predictions. During these tests, values are obtained for the reactivity worth of control and shutdown rod banks, isothermal temperature coefficient, and critical boron concentration for selected rod bank configurations.

Other tests at low power include verification of the response of the nuclear instrumentation system and radiation surveys.

14.2.7.3 Power Ascension

After the operating characteristics of the reactor have been verified by low-power testing, a power ascension program brings the unit to its full rated power level in successive stages. At each successive stage, hold points are provided to evaluate and approve test results prior to proceeding to the next stage. The minimum test requirements for each successive stage of power ascension are specified in the applicable startup test procedures.

During the power ascension program, tests are performed at various power levels as follows:

- Statepoint data, including secondary system heat balance measurements, are obtained at various power levels up to full licensed power. This information is used to project plant performance during power escalation, provide calibration data for the various plant control and protection systems, and provide the bases for plant trip setpoints.

- At prescribed power levels, the dynamic response characteristics of the primary and secondary systems are evaluated. System response characteristics are measured for design step load changes, rapid load reductions, and plant trips.

- Adequacy of the radiation shielding is verified by gamma and neutron radiation surveys. Periodic sampling is performed to verify the chemical and radiochemical analysis of the reactor coolant.

- Using the incore instrumentation as appropriate, the power distribution of the reactor core is measured to verify consistency with design predictions and Technical Specifications limits on peaking factors.

14.2.8 Test Program Schedule

The schedule for the initial fuel load and for each major phase of the initial test program includes the timetable for generation, review, and approval of procedures as well as the actual testing and analysis of results.

Preoperational testing is performed as system and equipment availability allows. The interdependence of systems is also considered.

Sequencing of the startup tests depends on specified power and flow conditions and intersystem prerequisites. The startup test schedule establishes that, prior to core load, the test requirements are met for those plant structures, systems, and components that are relied upon to prevent, limit, or mitigate the consequences of postulated accidents. Testing is sequenced so that the safety of the plant is not dependent on untested systems, components, or features.

14.2.9 Preoperational Test Descriptions

Test abstracts are provided for the preoperational testing of systems/components that perform safety-related functions; that are nonsafety-related but perform functions designated to provide defense in-depth; systems/components that may contain radioactive material; and other applicable nonsafety-related systems in accordance with Regulatory Guide 1.68, Revision 2, Appendix A. A limited number of these testing abstracts establish performance parameters of AP1000 design features that will not change from plant to plant. Because the AP1000 design is standardized, these tests need only be performed on the first AP1000 plant. These testing abstracts are clearly identified.

14.2.9.1 Preoperational Tests of Systems with Safety-Related Functions

14.2.9.1.1 Reactor Coolant System Testing

Purpose

The purpose of the reactor coolant system testing is to verify that the as-installed reactor coolant system properly performs the following safety-related functions:

- Provide reactor coolant system pressure boundary integrity as described in Section 5.2
- Provide core cooling and boration in conjunction with the passive core cooling system as described in Sections 5.1 and 6.3
- Measure process parameters required for safety-related actuations and safe shutdown as described in Sections 7.2, 7.3 and 7.4
- Measure selected process parameters required for post-accident monitoring as described in Section 7.5
- Vent the reactor vessel head as discussed in subsection 5.4.12

Testing is also performed to verify that the system properly performs the following defense-in-depth functions described in Section 5.2:

- Provide forced circulation cooling of the reactor core in conjunction with heat removal by the steam generator(s) as described in Section 5.1

- Provide core cooling by natural circulation of coolant in conjunction with heat removal by the steam generator(s) as described in Section 5.1
- In conjunction with the steam generator(s) and normal residual heat removal system, provide the capability to remove core decay heat and cool the reactor coolant to permit the reactor to be refueled and started up in a controlled manner
- Provide pressurizer pressure control during normal operation
- Provide pressurizer level control in conjunction with the chemical and volume control system
- Provide pressurizer spray

Prerequisites

The construction testing of the reactor coolant system has been successfully completed. The pre-operational testing of the component cooling water system, service water system, chemical and volume control system, main ac power electrical power system, and required interfacing systems is completed to the extent sufficient to support the specified testing. The reactor coolant system is filled, vented, and pressurized above the minimum required pressure for reactor coolant pump operation, and component cooling water flow to the reactor coolant pumps is initiated prior to starting the pumps.

In preparation for the hydrostatic test of the reactor coolant system, the reactor vessel lower and upper internals and the closure head are installed. The closure head studs are properly tensioned for the hydrostatic test pressure. The pressurizer safety valves and instrumentation within the test boundary are either removed, recalibrated or verified to be able to withstand the hydrostatic test pressure. Welds within the test boundaries are verified as ready for hydrostatic testing. A hydrostatic test pump is available for the pressure boundary integrity testing.

General Test Method and Acceptance Criteria

Reactor coolant system performance is observed and recorded during a series of individual component and system tests. The following testing demonstrates that the reactor coolant system can perform the functions described above and in appropriate design specifications:

a) The integrity and leaktightness of the reactor coolant system and the high-pressure portions of associated systems is verified by performing a cold hydrostatic pressure test in conformance with Section III of the American Society of Mechanical Engineers (ASME) Code. The reactor coolant system is pressurized in stages by operation of the temporary hydrostatic test pump, while monitoring system welds, piping, and components for leaks at each stage. The hydrostatic test verifies that there are no leaks at welds or piping within the test boundaries during the final inspection. Any identified pressure boundary leaks (i.e. piping walls, vessel walls, welds, valve bodies, etc.) are repaired and the hydrostatic test repeated.

Leakage through valve seats, valve packing, flanges, and threaded or mechanical fittings is acceptable during the hydrostatic test as long as the hydrostatic test pump can maintain the proper test pressure. Leakage through these items may, as necessary and practical, be isolated, repaired, and retested at a later date.

b) Proper operation of the safety-related reactor coolant system and reactor coolant pressure boundary valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6.

c) The operability of the pressurizer safety valves is demonstrated by a bench test at temperature and pressure with steam as the pressurizing fluid or with a suitable in-situ test. This testing verifies that each pressurizer safety valve actuates at the required set pressure, with appropriate tolerance as specified in the Technical Specifications. The safety valve rated capacity, as recorded on the valve vendor code plates, is verified to be greater than or equal to that described in Section 5.4.

d) During hot functional testing, reactor coolant system leakage is verified to be within the limits specified in the Technical Specifications. Proper calibration and operation of instrumentation controls, actuations, and interlocks related to reactor coolant system leak detection are verified. The pressurizer water level is set to the no-load level, the chemical and volume control system makeup pumps and letdown line do not operate, and no primary system samples are taken. During this test, the identified and unidentified reactor coolant system leakage rates are determined by monitoring the reactor coolant system water inventory, reactor coolant drain tank level, containment sump level, and other leak detection instrumentation as described in subsection 5.2.5 over a specified period of time.

e) The leakage across individual valves between high pressure and low pressure systems, as specified in the Technical Specifications, is verified to be less than design requirements.

f) The as-installed safety valve discharge chamber rupture disks are inspected to verify the manufacturer's stamped set pressure is within the limits specified in the appropriate design specifications.

g) Proper calibration and operation of safety-related instrumentation, controls, actuation signals and interlocks are verified. This testing includes the following:

- Hot leg and cold leg resistance temperature detectors
- Flow instrumentation at selected locations in the reactor coolant loop
- Reactor coolant system wide range pressure transmitters
- Hot leg level instruments
- Pressurizer pressure and level instruments
- Reactor coolant pump bearing water temperature detectors
- Reactor coolant pump speed sensor instruments
- Reactor vessel head vent valve controls

This testing includes demonstration of proper actuation of safety-related functions from the main control room.

h) Automatic trip of the reactor coolant pumps following appropriate safety-related actuation signals is demonstrated.

i) Proper operation of the reactor vessel head vent valves is verified with the reactor coolant system pressurized.

The following testing demonstrates that the system properly performs the defense-in-depth functions described above and in appropriate design specifications:

j) The pressurizer spray valves are verified to operate properly over the range of reactor coolant system operating temperatures and with the reactor coolant pumps operating.

k) Proper calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks are verified. This testing includes actuation of the pressurizer spray valves on receipt of appropriate signals, as well as actuation from the main control room.

l) Reactor coolant pump and motor performance and operating characteristics are initially verified with the reactor coolant system at cold conditions. This testing includes verification of the proper flow through the reactor coolant system when all four reactor coolant pumps are operated in various combinations and speeds as specified in the appropriate design specifications and operating procedures. In addition, the proper operation of the pump motor instrumentation, alarms, and interlocks is verified including:

- Motor current
- Motor power
- Pump vibration
- Motor Stator temperature
- Proper transfer from variable speed startup operation

m) The reactor coolant system is heated from cold conditions to hot standby conditions by operating the reactor coolant pumps and the pressurizer heaters. The reactor coolant system is operated at full flow conditions for at least 240 hours prior to core loading. The reactor coolant temperature is maintained at or above 515°F for at least one-half of this operating time. In addition to facilitating the reactor coolant system tests that are required to be performed hot and pressurized, these hot functional testing conditions allow the plant operators to control the plant using the plant operating procedures for the reactor coolant system, secondary side systems, and auxiliary systems.

Other preoperational tests that require these hot and/or dynamic conditions are conducted during this hot functional testing period.

n) During hot functional testing, the reactor coolant pump and motor operating characteristics are measured and recorded at various temperature plateaus during reactor coolant system heatup to verify proper operation over their operating temperature range. This testing includes verification of the proper pump flow; proper motor current, power, and stator temperature; and pump vibration level.

o) The pressurizer spray continuous flow rate is established, and the proper spray line temperature is verified for each pressurizer spray line.

p) The proper operation of the pressurizer heaters, pressurizer spray, and pressure control functions and alarms is verified during the heatup, operation at hot functional test conditions, and cooldown of the reactor coolant system.

q) The proper operation of the pressurizer level control functions and alarms is verified during the heatup, operation at hot functional test conditions, and cooldown of the reactor coolant system.

r) The pressure drops across the major components of the reactor coolant system are measured and recorded using temporary instrumentation during flow testing, and verified to be in accordance with appropriate design specifications.

Tests associated with the automatic depressurization functions of reactor coolant system components are described in subsection 14.2.9.1.3.

14.2.9.1.2 Steam Generator System Testing

Purpose

The purpose of the steam generator system testing is to verify that the as-installed components properly perform the following safety-related functions as described in Sections 5.4, 10.3 and 10.4:

- Provide steam generator isolation, including isolation of the main steam lines, feedwater lines, and blowdown lines

- Remove heat from the reactor coolant system and provide secondary side overpressure protection

- Measure process parameters required for safety-related actuations as described in Sections 7.2, 7.3, and 7.4

- Measure process parameters required for post-accident monitoring as described in Section 7.5

This testing also verifies that the as-installed components properly perform the following defense-in-depth functions as described in Section 10.4:

- Provide heat removal from the reactor coolant system

- Provide overpressure protection for the steam generators to minimize required actuations of the spring-loaded safety valves

- Measure process parameters and provide actuation signals for the diverse actuation system

Prerequisites

The construction tests of the as-installed system have been completed. The reactor coolant system as well as other systems used in power generation are functional since portions of the steam generator system testing is performed during the plant hot functional tests. Prerequisite testing of required interfacing systems are completed to the extent sufficient to support the specified testing and the appropriate system configuration. Construction and installation testing of the special monitoring system has been completed to the extent necessary to support preoperational testing. Required electrical power supplies are energized and operational.

General Test Method and Acceptance Criteria

The performance of the steam generator system is observed and recorded during a series of individual component and integrated system testing that characterizes its modes of operation. The following testing demonstrates that the steam generator system operates as specified in Sections 10.3 and 10.4, and appropriate design specifications:

a) Proper operation of the steam generator system safety-related valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6. In addition, the ability of these valves to perform their safety related functions is verified during hot functional testing with the steam generators at normal operating pressure and temperature. The following valves are tested:

   - Steam line condensate drain control and isolation valves
   - Main steam line isolation valves
   - Main and startup feedwater isolation valves
   - Steam generator blowdown isolation valves
   - Steam generator power-operated relief valves
   - Main steam isolation valve bypass isolation valves
   - Main and startup feedwater control valves

   This testing includes verification of the capability of the steam generator power operated relief valves to provide the required heat removal rate from steam generators/reactor coolant system.

b) Proper operation of safety-related and defense-in-depth instrumentation, controls, actuation signals, and interlocks is verified. This testing includes actuation of equipment from the main control room.

c) The proper operation of the steam generator safety valves is demonstrated in a bench test at temperature and pressure with steam as the pressurizing fluid or with suitable in-situ testing. The safety valve rated capacity recorded on the valve vendor code plates is verified to be greater than or equal to the required relief capacity.

Heat transfer performance of the steam generator system is verified by startup testing of the reactor coolant system described in other sections.

14.2.9.1.3 Passive Core Cooling System Testing

Purpose

The purpose of the passive core cooling system testing is to verify that the as-installed components and their associated piping and valves properly perform the following safety functions, described in Section 6.3:

- Emergency core decay heat removal
- Reactor coolant system emergency makeup and boration
- Safety injection
- Containment pH control

Prerequisites

The construction testing of the passive core cooling system, or of a specific portion of the system to be tested, is successfully completed. The preoperational testing of the reactor coolant system, normal residual heat removal system, chemical and volume control system, the refueling cavity, the Class 1E dc and uninterruptible power supply, the ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems is completed as needed to support the specified testing and system configurations. A source of water, of a quality acceptable for filling the passive core cooling system components and the reactor coolant system, is available.

General Test Method and Acceptance Criteria

The performance of the passive core cooling system is observed and recorded during a series of individual component testing and testing with the reactor coolant system. The following testing demonstrates that the passive core cooling system operates as described in Section 6.3 and appropriate design specifications.

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6. Also, the proper operation of non-safety-related valves is verified including manual valve locking devices. This testing does not include actuation of the squib valves, which is discussed in Item t, below.

b) Proper calibration and operation of safety-related instrumentation, controls, actuation signals, and safety related interlocks as specified in Section 7.6, is verified. This testing includes the following:

  - Passive residual heat removal heat exchanger flow
  - Core makeup tank level
  - In-containment refueling water storage tank level
  - Containment floodup level
  - Core makeup tank inlet/outlet valve controls
  - Passive residual heat removal heat exchanger inlet/outlet valve controls
  - In-containment refueling water storage tank outlet valve controls

- Containment recirculation valve controls
- Automatic depressurization valve controls
- In-containment refueling water storage tank gutter isolation valve controls

This testing includes demonstration of proper actuation of safety-related functions from the main control room.

c) Proper calibration and operation of instrumentation, controls, and interlocks required to demonstrate readiness of a safety-related component is verified. This testing includes the following:

- Accumulator pressure and level and alarms
- Passive residual heat removal heat exchanger temperatures
- Passive residual heat removal heat exchanger high point vent level
- Core makeup tank inlet line temperatures
- Core makeup tank inlet line high point levels
- Direct vessel injection line temperatures
- In-containment refueling water storage tank level and temperatures

d) Proper calibration and operation of temporary instrumentation and data recording devices used in this testing is verified. This testing includes the following:

- CMT level
- CMT flow and balance line temperatures
- PRHR supply line temperatures
- Accumulator wide range level
- In-containment refueling water storage tank and sump-recirculation flow
- ADS piping differential pressure

The passive core cooling system emergency core decay heat removal function is verified by the following testing of the passive residual heat removal heat exchanger.

e) During hot functional testing of the reactor coolant system, the heat exchanger supply and return line piping water temperatures are recorded to verify that natural circulation flow initiates.

f) The heat transfer capability of the passive residual heat removal heat exchanger is verified by measuring natural circulation flow rate and the heat exchanger inlet and outlet temperatures while the reactor coolant system is cooled to ≤ 420°F. This testing is performed during hot functional testing with the reactor coolant system initial temperature ≥ 540°F and the reactor coolant pumps not running. The acceptance criteria for the PRHR HX heat transfer under natural circulation conditions are that the heat transfer rate is ≥ 1.78 E+08 Btu/hr based on a 520°F hot leg temperature and ≥ 1.11 E+08 Btu/hr based on 420°F hot leg temperature with 80°F IRWST temperature and the design number of tubes plugged. These plant conditions are selected to be close to the expected test conditions and are different than those listed in DCD Table 6.3-4. The PRHR HX heat transfer rate has been adjusted to account for these

different conditions. The heat transfer rate measured in the test should be adjusted to account for differences in the hot leg and IRWST temperatures and number of tubes plugged.

g) The proper operation of the passive residual heat removal heat exchanger and its heat transfer capability with forced flow is verified by initiating and operating the heat exchanger with all four reactor coolant pumps running. This testing is performed during hot functional testing with the reactor coolant system at an elevated initial temperature $\geq$ 350°F. The heat exchanger heat transfer is determined by measuring the heat exchanger flow rate and its inlet and outlet temperatures while the reactor coolant system is cooled to $\leq$ 250°F. The acceptance criteria for the PRHR HX heat transfer under forced circulation conditions are listed in Table 3.9-17. The heat transfer rate measured in the test should be adjusted to account for differences in the hot leg and IRWST temperatures and number of tubes plugged.

h) The heatup characteristics of the in-containment refueling water storage tank water are verified by measuring the vertical water temperature gradient that occurs in the in-containment refueling water storage tank water at the passive residual heat removal heat exchanger tube bundle and at several distances from the tube bundle, during testing in Item e), above. **Note that this verification is required only for the first plant.** The acceptance criterion for the IRWST heatup characteristics is that they support meeting the RCS safe shutdown temperature criteria (refer to DCD subsection 19.E.4.10.2).

The passive core cooling system emergency makeup and boration function is verified by the following testing of the core makeup tanks.

i) The resistance of the core makeup tank cold leg balance lines is determined by filling the core makeup tanks with flow from the cold legs. This testing is performed by filling the cold, depressurized reactor coolant system using a constant, measured discharge flow from the normal residual heat removal pumps. The reactor coolant system is maintained at a constant level above the top of the cold leg balance line(s). The normal residual heat removal system flow rate and the differential pressure across the cold leg balance lines are used to determine the resistance of the balance lines. The acceptance criterion for the resistance of these lines is $\leq 7.21 \times 10^{-6}$ ft/gpm^2.

j) During hot functional testing of the reactor coolant system, the core makeup tank cold leg balance line piping water temperature at various locations is recorded to verify that the water in this line is sufficiently heated to initiate recirculation flow through the CMTs.

k) [*Proper operation of the core makeup tanks to perform their reactor water makeup and boration function is verified by initiating recirculation flow through the tanks during hot functional testing with the reactor coolant system at ≥ 530°F. This testing is initiated by simulating a safety signal which opens the tank discharge isolation valves, and stops reactor coolant pumps after the appropriate time delay. The proper tank recirculation flow after the pumps have coasted down is verified. Based on the cold leg temperature, CMT discharge temperature, and temporary CMT flow instrumentation, the net mass injection rate into the reactor is verified.* ***Note that this verification is required only for the first three plants.***]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The passive core cooling system safety injection function is verified by the following testing of the core makeup tanks, accumulators, in-containment refueling water storage tank, containment sump, automatic depressurization, and their associated piping and valves.

l) Proper flow resistance of each of the core makeup tank injection lines is verified by gravity draining each tank filled with cold water through the direct vessel injection flow path, while measuring the CMT level (driving head) and discharge flow rate. Air enters the top of the draining tank from the reactor coolant system cold leg via the cold leg balance line. If necessary, the flow limiting orifice in the core makeup tank discharge line is to be resized, and the core makeup tank retested to obtain the required line resistance. The acceptance criteria for the resistance of these lines are $\leq 2.25 \times 10^{-5}$ ft/gpm^2 and $\geq 1.81 \times 10^{-5}$ ft/gpm^2 with all valves open.

m) The proper flow resistance of each of the accumulator injection lines is verified by performing a blowdown from a partially pressurized accumulator through the direct vessel injection flow path, while measuring the change in accumulator level and pressure. If necessary, the flow orifice in the accumulator discharge line is to be resized and the accumulator retested to obtain the required discharge line resistance. The acceptance criteria for the resistance of these lines are $\leq 1.83 \times 10^{-5}$ ft/gpm^2 and $\geq 1.47 \times 10^{-5}$ ft/gpm^2.

n) The proper flow resistance of each of the in-containment refueling water storage tank injection lines is verified by gravity draining water from the tank through the direct vessel injection flow path, while measuring the water level (driving head) and discharge flow rate using temporary instrumentation. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of these lines are $\leq 9.20 \times 10^{-6}$ ft/gpm^2 and $\geq 5.53 \times 10^{-6}$ ft/gpm^2 for line A and $\leq 1.03 \times 10^{-5}$ ft/gpm^2 and $\geq 6.21 \times 10^{-6}$ ft/gpm^2 for line B with all valves open.

o) The flow resistance of each of the flow paths from the in-containment refueling water storage tank to each containment sump, and from each containment sump to the reactor is verified by a series of tests. These tests gravity drain water from the in-containment refueling water storage tank to the containment sump, and from the sump through the direct vessel injection flow path, while measuring the storage tank water level (driving head) and injection flow rate using temporary instrumentation. This testing is performed using temporary piping to prevent flooding of the containment. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of the lines between each containment sump and the reactor are $\leq 1.11 \times 10^{-5}$ ft/gpm^2 for line A and $\leq 1.03 \times 10^{-5}$ ft/gpm^2 for line B with all valves open. The acceptance criterion for the resistance of the lines between the IRWST and each containment sump is $\leq 4.07 \times 10^{-6}$ ft/gpm^2.

p) The resistance of each automatic depressurization stage 1, 2, and 3 flowpath and flowpath combination is verified by pumping cold water from the in-containment refueling water storage tank into the cold, depressurized, water-filled reactor coolant system; and back to the in-containment refueling water storage tank using the normal residual heat removal pump(s). The resistances are determined by measuring the residual heat removal pump flow rate and

the pressure drop across the flow paths tested using temporary instrumentation. The acceptance criteria for the resistance of these lines is $\leq 2.91 \times 10^{-6}$ ft/gpm^2 for each ADS stage 1,2,3 group with all valves open.

q) The resistance of each automatic depressurization stage 4 flowpath and their flowpath combinations is verified by pumping cold water from the in-containment refueling water storage tank into the cold, depressurized, water-filled reactor coolant system using the normal residual heat removal pump(s). The resistances are determined by measuring the residual heat removal pump flow rate and the pressure drop across the flow paths tested using temporary instrumentation. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of these lines are $\leq 1.70 \times 10^{-7}$ ft/gpm^2 for ADS stage 4 on loop 1 and $\leq 1.57 \times 10^{-7}$ ft/gpm^2 for ADS stage 4 on loop 2 with all valves open.

r) The proper operation of the vacuum breakers in the automatic depressurization discharge lines is verified.

s) [*During hot functional testing of the reactor coolant system, proper operation of automatic depressurization is verified by blowing down the reactor coolant system. This testing verifies proper operation of the stage 1, 2, and 3 components including the ability of the spargers to limit loads imposed on the in-containment refueling water storage tank by the blowdown. Proper operation of the stage 1, 2 and 3 valves is demonstrated during blowdown conditions.* ***Note that this verification is required only for the first three plants****.*]*

t) The proper operation of at least one of each squib valve size and type including a containment recirculation, in-containment refueling water storage tank injection, and a stage 4 automatic depressurization squib valve is demonstrated. The squib valve performance and the flow resistance of the actuated squib valves is compared to the squib valve qualification testing results.

u) The proper operation of the containment sump instrumentation is demonstrated by simulating the containment flood-up water levels.

v) The proper operation of the CMT level instrumentation is demonstrated during the draindown testing of the CMTs, specified in Item l) above.

w) [*In conjunction with the verification of the core makeup tanks to perform their reactor water makeup function and boration function described in item k) above, the proper operation of the core makeup tanks to transition from their recirculation mode of operation to their draindown mode of operation after heatup will be verified. This testing will also verify the proper operation of the core makeup tank level instrumentation to operate during draining of the heated tank fluid. The in-containment refueling water storage tank initial level is reduced to at least 3 feet below the spillway level as a prerequisite condition for this testing in order to provide sufficient ullage to accept the mass discharged from the reactor coolant system via the automatic depressurization stage 1.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The recirculation operation in Item k) above, should be continued until the core makeup tank fluid has been heated to ≥ 350°F. The core makeup tank isolation valves are then closed, the reactor coolant pumps are started, and the reactor coolant system is reheated up to hot functional testing conditions. This testing is initiated by shutting off the reactor coolant pumps, opening the core makeup tank isolation valves, and by opening one of the automatic depressurization stage 1 flow paths to the in-containment refueling water storage tank. This will initiate a large loss of mass from the reactor coolant system, depressurization of the reactor coolant system to the bulk fluid saturation pressure, and additional recirculation through the core makeup tank. Core makeup tank draindown initiates in response to the continued depressurization and mass loss from the reactor coolant system. The automatic depressurization stage 1 flow path is closed after the core makeup tank level has decreased below the level at which stage 4 actuation occurs. ***Note that this verification is required only for the first three plants.***]*

14.2.9.1.4 Passive Containment Cooling System Testing

Purpose

The purpose of the passive containment cooling system testing is to verify that the as-installed components perform properly to accomplish their safety-related functions to transfer heat from inside the containment to the environment, as described in subsection 6.2.2. The passive containment cooling water storage tank also provides a safety-related source of makeup water for the spent fuel pool, and provides a seismically qualified source of water for the fire protection system. Testing of these functions are discussed in subsections 14.2.9.2.7 Spent Fuel Pool Cooling System Testing, and 14.2.9.2.8 Fire Protection System Testing.

Prerequisites

The construction testing of the passive containment cooling system is successfully completed. The preoperational testing of the Class 1E dc electrical power and uninterruptible power supply systems, the non-Class 1E electrical power supply system, the compressed and instrument air system, and other interfacing systems required for operation of the above systems is available as needed to support the specified testing and system configurations. Additionally, a sufficient quantity of acceptable quality water for filling the passive containment cooling water storage tank and draining onto the containment is available, and a means of filling the tank is available.

General Test Acceptance Criteria and Methods

Passive containment cooling system performance is observed and recorded during a series of individual component testing that characterizes passive containment cooling system operation. The following testing demonstrates that the passive containment cooling system operates as described in Section 6.2 and appropriate design specifications:

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

b) Proper calibration and operation of safety-related, defense-in-depth, and system readiness instrumentation, controls, actuation signals and interlocks as discussed in Sections 7.3 and 7.5 are verified. This testing includes the following:

- Normal range containment pressure
- High range containment pressure
- Passive containment cooling water flow rate
- Passive containment cooling water storage tank level
- Passive containment cooling water isolation valve instrumentation and controls
- Diverse actuation system passive containment cooling initiation
- Passive containment cooling water storage tank water temperature
- Air inlet and shield plate freeze protection heater controls

This testing includes demonstration of proper actuation of these functions from the main control room.

c) Flow testing is performed to demonstrate proper system flow rates by draining the passive containment cooling system water storage tank. This testing demonstrates the proper resistance of the four passive containment cooling water storage tank delivery flowpaths. This testing also demonstrates that water is supplied at the specified flow rates and times for 72 hours consistent with the design basis analyses presented in subsection 6.2.1.

d) The proper operation of the passive containment cooling water distribution bucket and weirs is verified and proper wetting of the containment is observed and recorded during draindown testing in Item c, above. Water delivery and coverage is verified at the initial minimum water level and as each of the first two standpipes is uncovered. Water coverage is measured at the springline and the base of the upper annulus as described in subsection 6.2.2.4.2.

e) The proper operation of the drains in the upper containment/shield building annulus to drain the containment cooling water from the annulus floor is verified.

f) The resistance of the passive containment cooling air flowpath is verified by measuring the wind induced driving head developed from the air inlet plenum region of the shield building to the air exhaust at several locations along the flow path and at several circumferential locations, and measurement of the induced air flow velocity. Temporary instrumentation is used for this testing.

g) Sample coupons from the containment shell with and without an appropriate coating of paint are laboratory tested to determine their conductivity.

h) The proper operation of each of the PCS water storage tank recirculation/makeup pumps to makeup sufficient water to the PCS water storage tank from the PCS ancillary water storage tank is verified.

14.2.9.1.5 Chemical and Volume Control System Isolation Testing

Purpose

The purpose of the chemical and volume control system isolation testing is to verify that the as-installed components properly perform the following safety-related isolation functions, described in Section 9.3:

- Termination of inadvertent dilution of the reactor coolant boron concentration
- Isolation of unborated water sources for reactor makeup
- Reactor coolant system pressure boundary isolation
- Isolation/termination of excessive makeup to the reactor

Prerequisites

The construction testing of the chemical and volume control system has been successfully completed. The required preoperational testing of appropriate support and interfacing systems is completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Performance of the chemical and volume control system isolation functions is observed and recorded during a series of individual component and integrated system testing that characterizes the system isolation modes of operation. The following testing demonstrates that the chemical and volume control system properly performs the safety-related isolations as specified in Section 9.3 and appropriate design specifications:

a) Proper operation of the safety-related valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6, including:

   - Purification loop isolation valves
   - Letdown isolation valves
   - Demineralized water isolation valves
   - Makeup isolation valves
   - Auxiliary spray isolation valve

b) Proper calibration and operation of safety-related instrumentation, controls, actuation signals and interlocks is verified. This testing includes the following:

   - Purification isolation valve controls
   - Letdown isolation valve controls
   - Demineralized water isolation controls
   - Makeup isolation valve controls

   This testing includes demonstration of proper actuation of safety-related functions from the main control room.

14.2.9.1.6 Main Control Room Emergency Habitability System Testing

Purpose

The purpose of the main control room emergency habitability system testing is to verify that the as-installed components properly perform the safety-related functions described in Section 6.4, including the following:

- Provide sufficient breathable quality air to the main control room
- Maintain the main control room at positive pressure
- Provide passive cooling of designated equipment

In addition, the following safety-related functions performed by the nuclear island nonradioactive ventilation system described in subsection 9.4.1 are tested:

- Provide isolation of the main control room from the surrounding areas and outside environment during a design basis accident if the nuclear island nonradioactive ventilation system becomes inoperable.

- Monitor the radioactivity in the main control room normal air supply and provide signals to isolate the incoming air and actuate the main control room emergency habitability system.

Prerequisites

The construction testing of the main control room habitability system has been successfully completed. The required preoperational testing of the compressed and instrument air system, Class 1E electrical power and uninterruptible power supply systems, normal control room ventilation system, and other interfacing systems required for operation of the above systems is available as needed to support the specified testing and system configurations. The main control room air supply tanks are filled with air acceptable for breathing. The main control room construction is complete and its leak-tight barriers are in place.

General Test Acceptance Criteria and Methods

Performance of the main control room habitability system is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the habitability system operates as specified in Section 6.4 and as specified in the appropriate design specifications:

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in subsection 3.9.6.

b) Proper calibration and operation of safety-related and system readiness instrumentation, controls, actuation signals and interlocks is verified. This testing includes the following:

    - Air storage tank pressure
    - Refill line connection pressure

- Main control room differential pressure
- Air supply line flow rate
- Controls for the main control room pressure relief valves
- Controls for the air supply isolation valves
- Controls for the main control room air inlet isolation valves
- Air intake radiation

c) The proper flow rate of emergency air to the main control room is verified, demonstrating proper sizing of each air flow limiting orifice, proper operation of each air supply pressure regulator, and the ability to maintain proper control room air quality.

d) The ability of the emergency air supply to maintain the main control room at the proper positive pressure is demonstrated, verifying proper operation of the main control room pressure relief dampers.

e) The ability of the emergency air supply to limit air inleakage to the main control room is verified by inleakage testing as specified in subsection 6.4.5.4.

f) The ability to maintain the main control room environment within specified limits for 72 hours (Reference subsection 6.4.3.2) is verified with a test simulating a loss of the nuclear island nonradioactive ventilation system. This testing demonstrates the control room heatup from 0 to 6 hours with the actual heat loads from the battery powered equipment and personnel specified for this time period. This testing period includes the high 0 to 3 hour heat load and subsequent control room temperature changes versus time that occur when the equipment heat load is decreased when the 2 hour batteries are expended, for the 3 to 6 hour testing time period. The control room temperature versus time versus heat load data are used to verify the analysis basis used to assure that the control room conditions remain within specified limits for the 72 hour time period. Periodic grab samples will be taken of the control room air environment to support analyses to confirm that specified limits would not be exceeded for 72 hours.

g) The ability to maintain temperatures in the protection and safety monitoring system cabinet and emergency switchgear rooms within specified limits for 72 hours (Reference subsection 6.4.3.2) is verified with a test simulating a loss of the nuclear island nonradioactive ventilation system. This testing demonstrates the room heatup from 0 to 6 hours with the actual heat loads from battery powered equipment. The room temperature versus time versus heat load data are used to verify the analysis basis used to assure that the room temperature will not exceed the specified limit for the 72 hour time period.

14.2.9.1.7 Expansion, Vibration and Dynamic Effects Testing

Purpose

The purpose of the expansion, vibration and dynamic effects testing is to verify that the safety-related, high energy piping and components are properly installed and supported such that expected movement due to thermal expansion during normal heatup and cooldown, and as a result of transients; thermal stratification and thermal cycling; as well as vibrations caused by

steady-state or dynamic effects do not result in excessive stress or fatigue to safety-related plant systems and equipment, as described in Section 3.9.

Prerequisites

The construction testing and preoperational testing of the reactor coolant system at cold conditions has been successfully completed. Required portions of the chemical and volume control system, passive core cooling system, normal residual heat removal system, main feedwater system, startup feedwater system, steam generator system, and steam generator blowdown system are operational. Piping and components within the reactor coolant system and steam generator system pressure boundaries and their associated supports and restraints have been inspected and determined to be installed as designed. Permanently installed support devices have been verified to be in their expected cold, static positions and temporary restraining devices such as hanger locking pins have been removed. The instrumentation required for this testing is installed.

General Test Method and Acceptance Criteria

During hot functional testing, verifications that ASME Code Class 1, 2, and 3 high-energy piping system components, piping, support, and restraint deflections are unobstructed and within design basis functional requirements. The systems to be monitored during preoperational vibration and dynamic effects tests include:

- ASME Code, Class 1, 2, and 3 piping
- High-energy piping systems inside seismic Category I structures
- High-energy portions of systems whose failure could reduce the functioning of seismic Category I plant features to an unacceptable safety level
- Seismic Category I portions of moderate-energy piping systems located outside the containment

The high-temperature portions of the following systems are considered for inclusion in this test:

- Reactor coolant system
- Chemical and volume control system
- Passive core cooling system
- Steam generator system (including the safety-related portions of main steam system, main and startup feedwater systems, and steam generator blowdown system)
- Normal residual heat removal system

a) Thermal expansion testing during the preoperational testing phase consists of displacement measurements on the above systems during heatup and cooldown of the reactor coolant system and associated systems (including heatup and cooldown of the passive core cooling

system). The testing is performed in accordance with ASME OM Standard, Part 7 as discussed subsection 3.9.2.1.2 and consists of a combination of visual inspections and local and remote displacement measurements. This testing includes the inspection and measurement of deflection data associated with support thermal movements to verify support swing clearance at specified heatup and cooldown intervals; that there is no evidence of blocking of the thermal expansion of any piping or components, other than by installed supports, restraints, and hangers; that spring hanger movements remain within the hot and cold setpoints; that moveable supports do not become fully retracted or extended; and that piping and components return to their approximate baseline cold positions.

b) Vibration testing is performed on safety-related and high-energy system piping and components during both cold and hot conditions to demonstrate that steady-state vibrations are within acceptable limits. See subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to steady-state vibration. This testing includes visual observation and local and remote monitoring in critical steady-state operating modes. Results are acceptable when visual observations show no signs of excessive vibration and when measured vibration amplitudes are within acceptable levels.

c) Testing for significant vibrations caused by dynamic effects is conducted during hot functional testing and may be performed as part of other specified preoperational tests. This testing is conducted to verify that stress analyses of safety-related and high-energy system piping under transient conditions are acceptable. See subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to dynamic effects vibration. These tests are performed to verify that the dynamic effects caused by transients such as pump starts and stops, valve stroking, and significant process flow changes are within expected values. These tests include anticipated normal operating evolutions with system differential temperatures, such as startup, which could induce dynamic effects. Suitable instrumentation is used to monitor for the occurrence of water hammer noise and vibration. Visual inspections are performed to confirm the integrity of system piping and supports.

Deflection measurements during various plant transients are recorded and compared to acceptance limits and it is confirmed that no effects due to water hammer are detected.

d) As described in subsection 3.9.3, temperature sensors are installed on the pressurizer surge line and pressurizer spray line for monitoring thermal stratification and thermal cycling during power operation. Testing is performed to verify proper operation of these sensors. **Note that this verification is required only for the first plant.**

The main control room habitability system is classified as a high energy system based on the pressure criteria not temperature. Tests that measure thermal movements are not required. Vibration testing of the high pressure portion of the main control room habitability system is performed during testing of the air delivery rate provided to the control room. See subsection 14.2.9.1.6 for information on the testing of the main control room habitability system.

14.2.9.1.8 Control Rod Drive System

Purpose

The purpose of the control rod drive system testing is to verify the proper operation of the control rod drive mechanisms, motor-generator sets and system components as described in subsection 3.9.4 and Section 4.6, and in appropriate design specifications.

Prerequisites

The construction tests of the control rod system have been completed. Required interfacing systems, as needed, are completed to the extent sufficient to support the specified testing and the appropriate system configuration. Required electrical power supplies are energized and operational.

For the control rod drive mechanism cooling test, the plant is at or near normal operating temperature and pressure, and hot functional testing is in progress. The integrated head and control rod drive mechanism cooling system are in their normal operational alignment.

For the control rod drive mechanism motor-generator sets tests, a three-phase load bank is available for motor generator set testing under loaded conditions.

General Test Methods and Acceptance Criteria

Performance is observed and recorded during a series of individual component and integrated system tests. The following tests verify that the control rod drive system operates properly:

a) Tests are conducted to verify the current command sequence, timing, and rod speed signal voltages by initiating control rod drive mechanism withdrawal and insertion. Proper operation of the bank overlap unit to control rod bank sequence and movement is verified.

b) Tests are conducted to verify the adequacy of the integrated head and control rod drive mechanism cooling system for maintaining control rod drive mechanism temperature. This test is conducted by measuring control rod drive mechanism coil resistances and calculating the coil temperatures.

c) Tests are conducted to verify control rod drive mechanism motor-generator set and system component control circuits, including interlock and alarm functions.

d) Tests are conducted to verify generator phasing for parallel generator operation. Operation of the control rod drive mechanism motor generator sets and control system during starting, running, and parallel operations is verified.

14.2.9.1.9 Reactor Vessel Internals Vibration Testing

Purpose

The AP1000 reactor internals testing is part of a comprehensive vibration assessment program performed in accordance with Regulatory Guide 1.20 as discussed in subsection 3.9.2.4. This testing obtains data to verify the structural integrity of the AP1000 reactor internals with regard to flow-induced vibrations, as part of an internals vibration assessment program. This program also includes visual examination of the reactor internals after testing is completed, and analysis of the test data. Testing is performed for the first plant only.

AP1000 plants subsequent to the first plant are visually inspected before and after the hot functional test to confirm that the internals are functioning correctly. The major features of the reactor internals outlined in subsection 3.9.2.4 are visually inspected for signs of abnormal wear and structural changes.

Prerequisites

The construction testing of the reactor coolant system has been completed. The testing and calibration of the required test instrumentation has been completed. The test instrumentation has been installed on the internals as specified in Table 3.9-4 and the internals pre-test visual inspection has been completed. The internals, test instrumentation, and instrumentation lead wires are installed in the reactor vessel. The reactor vessel head is installed in preparation for the cold hydrostatic test of the reactor coolant system and instrument leads have been properly sealed. The proper operation and calibration of the test instrumentation and recording equipment is verified during the hydrostatic testing of the reactor coolant system.

General Test Method and Acceptance Criteria

Reactor vessel internals testing is performed for the first plant only by measuring and recording strains or accelerations of components in order to determine actual displacements that occur with the reactor coolant pumps operating. This testing is performed at several reactor coolant system temperatures during the system hot functional test. The analysis of data obtained from this testing, combined with a pre-test and post-test visual inspection of the internals, are intended to confirm that the stresses and wear on the AP1000 internals, due to flow induced vibration during plant operation, are acceptably low. The criteria for evaluating testing results are established in the AP1000 reactor internals flow-induced vibration assessment program (see Section 7 of WCAP-15949), and appropriate design specifications.

For the first plant only, the internals are instrumented to obtain data during the following reactor coolant system operating conditions:

a) Background noise in the instrumentation and recording equipment is recorded with no reactor coolant pumps running

b) Data is recorded during the initial startup of the reactor coolant pumps and with all four pumps operating and with the reactor coolant at cold temperature

c) Data is recorded at several increasing coolant temperatures with the pumps operating

d) Data is recorded at the hot functional testing temperature with all four pumps operating

e) Data is recorded at the hot functional testing temperature with the appropriate combinations of reactor coolant pumps operating, including pump start and stop transients

For all plants subsequent to the first plant, visual inspections are performed before and after the hot functional test. When no indications of harmful vibrations or signs of abnormal wear are detected and no structural damage or changes are apparent, the core support structures are considered to be structurally adequate and sound for operation. If such indications are detected, further evaluation is required.

14.2.9.1.10 Containment Isolation and Leak Rate Testing

Purpose

The purpose of the containment isolation and leak rate testing is to demonstrate that the as-installed containment isolation valves, piping and electrical containment penetrations, and hatches, and the containment vessel properly perform the following safety functions as described in Section 6.2:

- Automatic isolation of the piping penetrating containment required to assure containment integrity

- The containment vessel, penetration, and isolation valve leakage is less than the design basis leakage at or near the containment design pressure consistent with 10 CFR 50, Appendix J pressure test requirements.

Prerequisites

The construction testing of the containment, containment hatches/airlocks and containment penetrations including the containment pressure test as specified in subsection 3.8.2.7 has been completed. The construction testing of the piping and isolation valves or electrical wiring through the penetrations, has been completed. The instrumentation to be used in performing the Type A, B, and C testing is calibrated and available, including their associated data processing equipment. The required preoperational testing of the protection and safety monitoring system, plant control system, the Class 1E electrical power uninterruptible power supply, and other interfacing systems required for operation of the containment isolation devices and data collection is available.

General Test Acceptance Criteria and Methods

Containment isolation functions, leak rate, and structural integrity performance are observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the containment functions as described in Section 6.2 and the appropriate design specifications are achieved. The testing is in accordance with the Combined license applicant’s Containment System Leakage Testing Program, which meets the requirements of ANSI/ANS-56.8-1994, as appropriate.

a) Proper operation of safety-related containment isolation valves, listed in Table 6.2.3-1, is verified by the performance of baseline in-service tests as specified in subsection 3.9.6.

b) Proper calibration and operation of safety-related containment isolation instrumentation, controls, actuation signals and interlocks is verified. This testing includes actuation of the containment isolation valves from the main control room, and upon receipt of a containment isolation signal.

c) The appropriate Type C leakage testing is performed for each piping path penetrating the containment boundary, verifying the leakage for each containment isolation valve (listed in Table 6.2.3-1) or set of isolation valves. This testing for individual isolation valves may be performed in conjunction with the associated system test.

d) The appropriate Type B leakage testing is performed for each containment penetration whose design incorporates seals, gaskets, sealants, or bellows. This testing includes door or hatch operating mechanisms and seals.

e) A baseline in-service test/inspection of the accessible interior and exterior surfaces of the containment structure and components is performed as specified in subsection 3.8.2.

f) A Type A integrated leak rate test is performed to verify that the actual containment leak rate does not exceed the design basis leak rate specified in the Technical Specifications.

14.2.9.1.11 Containment Hydrogen Control System Testing

Purpose

The purpose of the containment hydrogen control system testing is to verify that the system properly performs the following safety-related and non-safety defense-in-depth functions described in Section 6.2:

- Prevent the concentration of hydrogen in containment from reaching the flammability limit.
- Prevent the concentration of hydrogen in containment from reaching the detonation limit.
- Monitor the containment hydrogen concentration as required by Regulatory Guide 1.97.

Prerequisites

The construction testing of the containment hydrogen control system is completed. The Class 1E dc electrical power and uninterruptible power supply systems, the non-Class 1E electrical supply system, and other interfacing systems required for operation of the above systems and calibrated data collection instrumentation are available as needed to support the specified testing.

General Test Acceptance Criteria and Methods

Performance of the containment hydrogen control system is observed and recorded during a series of individual component testing. The following testing verifies that the system operates as described in subsection 6.2.4 and as specified in the appropriate design specifications:

a) Proper operation of both the Class 1E safety-related and non Class 1E containment hydrogen concentration instrumentation and alarms is verified.

b) The ability of the passive autocatalytic recombiners to properly respond to a known inlet hydrogen/air mixture is verified by removing and testing one plate or cartridge from each manufacturing lot of catalyst material, contained in each recombiner unit. This verification is performed in accordance with the guidance provided in subsection 6.2.4.5.1 using a manufacturer's standard test device and test procedure. Plate performance is verified to be consistent with the response obtained in manufacturer's tests.

c) Manual actuation and operation of the hydrogen igniters confirm that the igniters are supplied by two power groups from two subsystems of the non-Class 1E dc and UPS system. Operability of the igniters is confirmed by verification that the igniter surface temperature exceeds the temperature specified in subsection 6.2.4.

14.2.9.1.12 Protection and Safety Monitoring System Testing

Purpose

The purpose of the protection and safety monitoring system preoperational testing is to verify that the as-installed components properly perform the following safety-related functions, described in Section 7.1:

- Receive and analyze sensor inputs required for reactor trip and automatically initiate reactor trip signals when plant conditions reach the appropriate setpoints

- Provide actuation signals to the engineered safety features to limit the consequences of design basis accidents

- Provide instrumentation and display systems to monitor the safety-related functions of the plant during and following the occurrence of design basis accidents in accordance with Regulatory Guide 1.97

Preoperational testing is also performed to verify proper operation of the following defense-in-depth functions, described in Section 7.1:

- Provide data from the safety-related sensors to the plant control system
- Provide information to the data display and processing system
- Provide data to the monitor bus for use by other systems within the plant

Prerequisites

Construction and installation testing of the protection and safety monitoring system cabinets has been completed. Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and the initial software diagnostics tests have been completed. Required electrical power supplies and control circuits are energized and operational. Plant systems or components which are to be operated during testing are specifically identified in the preoperational test procedures, are properly aligned, and have proper support systems operating prior to actuation of the particular system or component. Equipment or components which can not be actuated without damage or upsetting the plant are isolated using the test switches provided by the Protection and Safety Monitoring System to block device actuation. Continuity of wiring up to the actuation equipment is verified.

General Test Methods and Acceptance Criteria

Performance of the protection and safety monitoring system is observed and recorded during a series of individual component and integrated tests designed to verify operation of the system components. The following testing verifies that the system operates as described in Section 7.1 and appropriate design specifications:

a) Processing of the analog and digital signals is verified by injecting reference signals and verifying the outputs at various locations in the system.

b) Capability to process sensor data and main control room manual inputs resulting in the initiation of appropriate reactor trip signals is demonstrated by simulating inputs for each of the trip functions. Response times are verified by demonstrating that the applicable trip, actuate, permissive or interlock signal reaches the actuated equipment within the maximum allowable period following a defined step change in the applicable simulated input, above or below the trip, actuate, permissive or interlock setpoint. Operation of the protection cabinet trip/normal/bypass switches and indicators for each of the reactor trip functions is demonstrated by verifying appropriate outputs. Verification that the reactor trip bypass logic satisfies the single failure criteria is demonstrated by operating the bypass switches while simulating channel failures. Proper operation of the reactor trip reset function will be verified.

c) Operation of the reactor trip breakers, including breaker interlock, alarm, and tripping functions and verification that reactor trip response times are less than the specified maximum allowable response times is performed by initiating a manual reactor trip from the main control room. The capability of the undervoltage coil and the shunt trip coil functions to independently trip the reactor trip breakers is verified during this test using the test capabilities provided by the reactor trip switchgear interface.

d) The capability to trip the reactor from the remote shutdown workstation is demonstrated by verifying actuation of the reactor trip breaker undervoltage and shunt trip attachments upon initiation of a reactor trip at the remote shutdown workstation location.

e) The capability of the protection and safety monitoring system to process sensor data and manual inputs, resulting in appropriate engineered safety features actuation at design setpoints, is demonstrated by verifying that injection of simulated inputs for each of the engineered safety features actuation functions results in the proper output as indicated by contact operation, component actuation, or electrical test. Response times associated with the engineered safety features actuation functions are evaluated during these tests to provide verification that the applicable trip, actuate, permissive or interlock signal reaches the actuated equipment within the maximum allowable period following a defined step change in the applicable simulated input above or below the trip, actuate, permissive or interlock setpoint. Operation of the manual actuation/bypass switches and indicators for each of the engineered safety features functions is verified by demonstrating appropriate system outputs. Verification that the engineered safety features bypass logic satisfies the single failure criteria is demonstrated by operating the bypass switches while simulating channel failures. Correct input processing and calculational accuracy of the redundant actuation equipment and operator interface features is verified for each defined engineered safety features actuation function using simulated inputs. Proper operation of the engineered safety features reset functions will be verified.

f) Correct processing of inputs by redundant equipment and operation of the processing, permissive, interlock, display and operator interface features is verified by demonstrating that simulated command inputs result in correct output or actuation functions as indicated by contact operation, component actuation, or electrical test.

g) Accurate processing of component-level manual actuation commands from the main control room to the protection logic cabinets is verified by simulating main control room commands. Processing of component status information is demonstrated by simulating protection logic cabinet outputs to the main control room.

h) Processing of component-level actuation commands from the remote shutdown workstation to the protection logic cabinets is verified by simulating remote shutdown workstation commands. Processing of component status information is verified by simulating protection logic cabinet outputs to the remote shutdown workstation.

i) Operation of the automatic testing features provided in the protection and safety monitoring system is verified by observing the automatic test functions while simulating component failures and utilizing man-machine interface capabilities to evaluate system performance.

j) The capability of the protection and safety monitoring system to provide the plant operator with correct equipment status, component position indication, component control modes and abnormal operating conditions is verified by evaluating system response to simulated inputs representing feedback from actuation devices and position indicators. Communication of information via the plant monitor bus/data display and processing system, such as channel input quality, neutron flux detector high voltage, partial trip/actuation, permissive, interlock, block, reset, bypass, automatic test, reactor trip switchgear and system level actuation status, from the protection and safety monitoring system to external systems is verified by evaluating system response to injected reference signals and operating applicable block and bypass controls.

k) Operation of the qualified data processing equipment is verified by monitoring outputs and qualified display indications generated in response to simulated inputs representing data from the integrated protection cabinets and sensor inputs to the qualified data processing I/O cabinets.

l) Operation of the isolated data links and data highways used for communication between the engineered safety features actuation cabinets, main control room multiplexer cabinets, remote workstation multiplexer cabinets and protection logic cabinets is verified.

m) Preoperational testing of plant sensors used to provide data related to plant equipment monitored by the protection and safety monitoring system is performed in conjunction with testing of the respective systems in which these sensors are located.

n) The capability of the protection and safety monitoring system to provide data from the safety-related sensors to the plant control system is verified by injecting reference signals into the integrated protection cabinets and monitoring the plant control system signal selector outputs.

14.2.9.1.13 Incore Instrumentation System Testing

Purpose

The purpose of the incore instrumentation system preoperational testing is to verify that the as-installed components properly perform the following safety-related functions, described in Section 7.1:

- Provide reactor coolant system pressure boundary integrity for the incore instrumentation thimble assemblies which penetrate the upper head of the reactor vessel

- Provide the protection and safety monitoring system with the core exit temperature signals required for post-accident monitoring

Testing is also performed to verify the following nonsafety-related defense-in-depth functions, described in subsection 4.4.6:

- Provide core exit temperature signals to the diverse actuation system dedicated display in the main control room

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Required electrical power supplies are energized and operational.

General Test Methods and Acceptance Criteria

Performance of the incore instrumentation system is observed and recorded during a series of individual component and integrated tests designed to confirm operation of the system components outside the reactor vessel. The following testing verifies that the system operates as described in Section 7.1 and the appropriate design specifications:

a) Reactor coolant system pressure boundary integrity at the incore instrumentation reactor vessel head penetrations is verified during hydrostatic testing of the reactor coolant system.

b) Processing of the incore thermocouple signals is verified by thermocouple signals at the incore instrumentation thimble assembly connectors and verifying the thermocouple signal paths.

14.2.9.1.14 Class 1E DC Power and Uninterruptible Power Supply Testing

Purpose

The purpose of the Class 1E dc power and uninterruptible power supply testing is to verify that the as-installed components properly perform the following safety-related functions described in Section 8.3:

- Provide the electrical power required for the operation of the plant safety-related equipment, equipment controls, and instrumentation
- Provide the required safety-related electrical power for at least 72 hours following a design basis event, independent of both offsite and onsite ac electrical power supplies
- Provide separation and independence of Class 1E power divisions from other Class 1E divisions and non-Class 1E systems

Testing is also performed to verify proper operation of the following defense-in-depth functions described in subsection 8.3.2:

- The capability to recharge the batteries from the onsite or offsite ac electrical sources is verified so that safety-related functions can be supported for an indefinite time

Prerequisites

The construction testing of the Class 1E dc power and interruptible power supply components has been completed. The necessary permanently installed and test instrumentation is calibrated and operational. The 480V ac electrical power system is in operation and supplying power to the battery chargers and regulating transformers. A test load is available for the performance of battery capacity tests.

General Test Methods and Acceptance Criteria

Performance of the Class 1E dc power and interruptible power supply is observed and recorded during a series of individual component and integrated system tests that characterize the operation of the system. The following testing verifies that this system operates as described in Section 8.3 and appropriate design specifications:

a) The capability of each of the seven Class 1E batteries to provide the required momentary and continuous load is verified by a battery service test performed in accordance with IEEE Standard 450. Following this discharge testing, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

b) The capacity of each of the seven Class 1E batteries is verified to meet or exceed the required ampere-hour rating by a battery performance test performed in accordance with IEEE Standard 450. Following this discharge testing, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

c) The capability of each of the seven battery chargers to charge its associated battery at the required rate is verified. This testing includes verification that the individual voltage of each cell is within the specified limits for a charged battery.

d) The capability of each of the six inverters to provide the required output current, frequency, and voltage is verified.

e) The capability of each of the four regulating transformers to provide the proper ac current to the Class 1E ac distribution panels is verified.

f) The capability of each of the static transfer switches to automatically transfer the electrical loads supplied by each inverter to its associated regulating transformer is verified.

g) The separation and independence of each redundant division of the Class 1E dc power and interruptible power supply is verified by successively powering only one division at a time and verifying power to the proper loads and the absence of voltage at the bus and loads not under test.

h) The proper calibration and operation of instrumentation and alarms, electrical ground detection, and permissive and prohibitive interlocks is verified.

14.2.9.1.15 Fuel Handling and Reactor Component Servicing Equipment Test

Purpose

To verify proper operation of the fuel-handling and reactor component servicing equipment as described in Section 9.1. This includes the refueling machine, fuel handling machine, fuel transfer system, and refueling tools used to lift, transport, or otherwise manipulate fuel, control rods and other incore instruments.

Prerequisites

The construction tests have been completed. Prerequisites of the required interfacing systems are completed to the extent sufficient to support the specified testing. Required electrical power supplies are energized and operational. Compressed air, as required for tool operation, is available. The reactor vessel head has been removed, the reactor vessel and refueling cavity are drained, the refueling cavity gate is open, and the area in which the refueling machine moves is free of structures or components that could interfere with fuel handling operations.

The spent fuel pool and fuel transfer canal are drained, and the area in which the fuel handling machine moves is free of any structures or components that interfere with design fuel handling operations.

The fuel transfer system is operable and capable of transporting a dummy fuel assembly from the spent fuel pool to containment. A dummy fuel assembly, resembling an actual fuel assembly in weight, envelope, and mating hardware, is available for use. The fuel transfer system and new fuel elevator are operable as required to permit testing of fuel handling machine functions.

General Test Methods and Acceptance Criteria

The following tests are performed to verify the refueling machine operation:

a) The refueling machine is operated to simulate actual refueling operations, using a dummy fuel assembly. This testing includes manual and automatic modes of operation, displays, interlocks, and limits. These tests verify:

- The ability to move a fuel assembly from the fuel transfer system to the reactor vessel and back
- The consistency of measured trolley, bridge, and hoist speeds with each mode of operation
- The operability of interlocks limiting motion, speed, and weight, including interlocks with other plant equipment
- The operability of displays indicating position, mode, alarm status, and load
- The adequacy of indexing (by placing the dummy fuel assembly in selected core locations)

b) A known weight or a calibrated spring scale is used to calibrate and set the load limits for the refueling machine load cells. A static load test or the manufacturer’s test results are used to verify the ability of the refueling machine hoists to support 125 percent of their rated loads.

The following tests are performed to verify the operation of the fuel handling machine:

c) The fuel handling machine is operated to simulate actual refueling operations, using a dummy fuel assembly. These tests verify:

- The ability to transfer fuel assemblies between the new fuel elevator, fuel transfer system, fuel storage racks, and other areas of the pool where fuel is serviced or stored
- The consistency of measured trolley, bridge, and hoist speeds with each mode of operation
- The operability of interlocks limiting motion, speed, and weight, including interlocks with other plant equipment
- The operability of displays indicating position, mode, alarm status, and load

d) The fuel handling machine is operated to verify its capability to transfer fuel between the new fuel elevator, fuel transfer system, fuel storage racks, and other areas of the pool where fuel is serviced or stored.

e) A known weight or a calibrated spring scale is used to calibrate and set the load limits for the fuel handling machine load cells. A static load test or the manufacturer's test results are used to verify the ability of the refueling machine hoists to support 125 percent of their rated loads.

The following tests are performed to verify the proper operation of the fuel transfer system and refueling tools:

f) Using appropriate plant operating procedures, the operability of the new fuel elevator is verified. Testing is performed to demonstrate the proper operation of controls, displays, and limit switches, including operation of the interlock that prevents raising the elevator when it contains a fuel assembly.

g) Using appropriate plant operating procedures, the fuel transfer system is operated to simulate actual refueling operations, using a dummy fuel assembly. During these operations, the following items are verified:

- The ability to move fuel assemblies between the fuel building and containment, including proper operation of upenders in both locations
- The operability and setpoints of limit switches and of interlocks between stations and with other plant equipment
- The operability of displays indicating mode of operation and status

h) Tests are performed to verify that the refueling tools operate properly. Included are tools for handling new fuel assemblies, fuel assembly inserts, irradiation specimens, control rod drive shafts, as well as tools for such operations as control rod drive shaft latching and reactor

vessel stud tensioning. As applicable, power is applied to each tool to verify proper operation of controls, limit switches, actuators, and indicators. Stud tensioning equipment is checked when assembling the reactor for hot functional testing. The new fuel handling tool is tested with the dummy fuel assembly during the test of the new fuel elevator.

14.2.9.1.16 Long-Term Safety-Related System Support Testing

Purpose

The purpose of this testing is verify the capability to perform the following functions for maintaining the extended operation of the safety-related systems and components as described in Section 1.9:

- Supply makeup water to the passive containment cooling system.
- Supply makeup water to the spent fuel pool.
- Provide electrical power for post-accident instrumentation, control room lighting and ventilation, division B and C I&C room ventilation, passive containment cooling system pumps, ancillary generator room lights, ancillary generator tank heaters.
- Provide ventilation cooling to the main control room.
- Provide ventilation cooling to the Class 1E cabinets for post-accident instrumentation.

Prerequisites

The construction tests of the safety-related systems and/or components designed for long-term actions have been successfully completed. The preoperational testing of these systems and/or components, including instrument calibrations, has been completed as required for the specified testing, system configurations, and operations. Equipment required for data collection is available and operable. Water used in this testing should be of a quality suitable for filling the specified components. Equipment used to provide the required long-term actions is available.

General Test Method and Acceptance Criteria

The ability to perform the required long-term actions is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the long-term actions can be performed as discussed in Section 1.9 and as specified in appropriate design specifications:

a) The ability to provide makeup water to the passive containment cooling water storage tank as described in subsection 6.2.2 is verified.

b) The ability to provide electrical power to the post-accident monitoring instrumentation, control room lighting and ventilation, division B and C I&C room ventilation, passive containment cooling system pumps, ancillary generator room lights, ancillary generator tank heaters, using the ancillary diesel generators as described in Section 8.3 is verified.

c) The ability to provide main control room ventilation cooling using ancillary fans as described in subsection 9.4.1 is verified.

d) The ability to provide ventilation cooling to post-accident monitoring instrumentation equipment rooms using ancillary fans as described in subsection 9.4.1 is verified.

e) The ability to provide makeup water to the spent fuel pool via the safety-related makeup connection from the passive containment cooling system water storage tank, as described in subsection 9.1.3, is verified.

14.2.9.2 Preoperational Testing of Defense-in-Depth Systems

14.2.9.2.1 Main Steam System Testing

Purpose

The purpose of the main steam system testing is to verify that the as-installed system properly performs the following defense-in-depth function, as described in Section 10.3 and appropriate design specifications:

- Provide backup isolation of the steamlines to prevent blowdown of steam from the steam generators following an event where steamline isolation is required

Prerequisites

The construction tests of the as-installed main steam system have been completed. Prerequisites of the required interfacing systems are completed to the extent sufficient to support the specified testing and the appropriate system configuration.

General Test Method and Acceptance Criteria

Main steam system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the system operates as described in Section 10.4 and appropriate design specifications:

Proper operation of the following system valves is verified.

- Turbine steam stop valves
- Turbine bypass valves
- Auxiliary steam system supply header isolation valve
- Main steam reheat supply steam control valve
- Extraction steam isolation and non-return valves

This testing includes actuation of these valves from the main control room. The ability of these valves to isolate steam flow is verified during hot functional testing.

14.2.9.2.2 Main and Startup Feedwater System

Purpose

The purpose of the main and startup feedwater system testing is to verify that the as-installed system properly performs the following nonsafety-related defense-in-depth function, as described in subsections 10.4.7 and 10.4.9:

- Provide startup feedwater to the steam generators to remove heat from the reactor coolant system following the loss of normal feedwater

Prerequisites

The construction tests have been completed. The component testing of the main and startup feedwater system components and instruments, or specific portion to be tested has been completed. Required interfacing systems are available.

General Test Method and Acceptance Criteria

The main and startup feedwater system performance is observed and recorded during a series of individual component and integrated system testing. The following defense-in-depth testing demonstrates that the system operates as described in subsections 10.4.7 and 10.4.9 and appropriate design specifications:

a) Proper operation of defense-in-depth instrumentation, controls, actuation signals and interlocks is verified. This testing includes actuation of startup feedwater pumps and remotely-operated valves from the main control room including isolation of the main feedwater system.

b) The capability of the startup feedwater pumps to operate properly when performing their defense-in-depth function and main feedwater pumps are verified with the steam generator at normal operating pressure.

c) The capability of the startup feedwater pumps to operate properly with miniflow to the condensate storage tank is verified.

d) The capability to restore normal steam generator water level from the low narrow range water level, without causing unacceptable feedwater or steam generator water hammer, is demonstrated (refer to subsections 14.2.9.1.7 and 14.2.10.4.18).

14.2.9.2.3 Chemical and Volume Control System Testing

Purpose

The purpose of the chemical and volume control system testing is to verify that the as-installed system properly performs the following defense-in-depth functions described in subsection 9.3.6 and appropriate design specifications:

- Provide makeup water to the reactor coolant system
- Provide boration of the reactor coolant system
- Provide auxiliary pressurizer spray

Prerequisites

The construction testing of the as-installed chemical and volume control system is completed. The following interfacing and support systems are available as necessary to support testing: component cooling water system; service water system; reactor coolant system; electrical power and distribution systems. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Chemical and volume control system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies the system properly performs the defense-in-depth functions described in subsection 9.3.6 and appropriate design specifications:

a) Operation of pumps and valves which perform defense-in-depth functions is verified, including:

   - Makeup pumps
   - Boric acid mixing control valve
   - Makeup flow control valve

b) Calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

   - Automatic makeup pump actuation and shutoff
   - Automatic alignment of the boric acid tank
   - Pressurizer auxiliary spray initiation and termination
   - Letdown/purification isolation

   This testing includes actuation of defense-in-depth pumps and remotely-operated valves from the main control room. Pressurizer level control testing is described in subsection 14.2.9.1.1.

c) The capability of the makeup pumps to operate when performing their normal makeup and pressurizer spray functions is verified with the reactor coolant system at normal operating pressure.

d) The capability of the makeup pumps to operate at miniflow and the operation of the miniflow heat exchanger is verified.

e) The proper purification loop flowrate through the demineralizers and filters is verified.

14.2.9.2.4 Normal Residual Heat Removal System Testing

Purpose

The purpose of the normal residual heat removal system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following defense-in-depth functions, as discussed in Section 5.4:

- Remove reactor core decay heat and cool the reactor coolant system during shutdown operations at low pressure and temperature
- Remove reactor core decay heat from the reactor coolant system during reduced reactor coolant inventory operations in Modes 5 and 6
- Following actuation of the automatic depressurization system, provide makeup to the reactor coolant system at low pressure
- Circulate and cool water from the containment after draindown of the in-containment water storage tank
- Provide low temperature overpressure protection for the reactor coolant system
- Remove reactor core decay heat and cool the spent fuel pool during refueling operations when the core is off-loaded from the reactor vessel to the spent fuel pool.

Prerequisites

The construction testing of the normal residual heat removal system is completed. The required preoperational testing of the in-containment refueling water storage tank, reactor coolant system, passive core cooling system, component cooling water system, service water system, ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems and data collection is available as needed to support the specified testing and system configurations. The reactor coolant system and the in-containment refueling water storage tank have an adequate water inventory to support testing.

General Test Acceptance Criteria and Methods

Normal residual heat removal system performance is observed and recorded during a series of individual component and system testing, that characterizes system operation. The following

testing verifies that the normal residual heat removal system performs its defense-in-depth functions as described in subsection 5.4.7.6.1 and appropriate design specifications:

a) Operation of valves to open, to close, or to control flow as required to perform the above defense-in-depth functions is verified.

b) Operation of system controls, alarms, instrumentation, and interlocks associated with performing the above defense-in-depth functions is verified. In addition, the proper operation of the normal residual heat removal system/reactor coolant system isolation valve interlocks specified in Section 7.6 is verified.

c) The normal residual heat removal system pumps testing includes verification that the pump flow rate corresponds to the expected system alignment, proper pump miniflow operation, and verification that adequate net positive suction head is available for the configurations tested. The following system configurations are tested with each pump operating individually and with two pumps operating:

- Recirculation from and to the reactor coolant system with the reactor coolant system at mid-loop hot leg water level and atmospheric pressure

- Makeup to the reactor from the in-containment refueling water storage tank with approximately 4 feet of water in the tank

- Makeup to the reactor from the cask loading pit with water in the pit at a sufficient level to support pump operation

- Recirculation from and to the spent fuel pool with the pool at normal minimum level.

d) During the verifications of normal residual heat removal system flow to the reactor coolant system, verify that the pumped flow provides sufficient back pressure to maintain a water level in the CMT.

e) The capability of the normal residual heat removal heat exchangers to provide the required heat removal rate from the reactor coolant system is verified by testing performed with flow from and to the heated reactor coolant system, with each normal residual heat removal pump/heat exchanger operating individually.

f) The capability of the normal residual heat removal heat exchangers to provide the required heat removal rate from the spent fuel pool is verified. Since the spent fuel pool is not heated during pre-operational testing, this verification can be made based on the flowrate from Item c and heat removal capability from Item e, above.

g) Operation of the normal residual heat removal system relief valve which provides low temperature overpressure protection for the reactor coolant system is verified by the performance of baseline in-service testing, as specified in subsection 3.9.6. The acceptance criteria are based on the valve performance criteria specified in subsection 5.4.9.

h) Operation of the system to facilitate draining the reactor coolant system water level to near the centerline of the hot leg for reduced inventory operations is verified. This test is performed in conjunction with the chemical and volume control system, and is used to demonstrate the performance of the reactor coolant system hot leg level instruments as discussed in subsection 14.2.9.1.1.

14.2.9.2.5 Component Cooling Water System Testing

Purpose

The purpose of the component cooling water system testing is to verify that the as-installed system properly performs the following defense-in-depth functions as described in subsection 9.2.2:

- Provide cooling water to defense-in-depth components and transfer heat to the service water system. In addition, this system provides cooling water to other nonsafety-related components for heat removal.

Prerequisites

The construction testing of the component cooling water system is completed. Preoperational testing of the cooled components has been completed as necessary to support testing of the component cooling water system. Required support systems are available, including applicable portions of the service water system and electrical power and distribution systems. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Component cooling water system performance is observed and recorded during a series of individual component and integrated system testing that characterizes the various modes of system operation. The following testing demonstrates that the system operates as described in subsection 9.2.2 and in appropriate design specifications:

a) Proper operation of the component cooling water pumps is verified.

b) Proper operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

  - Automatic pump actuation if an operating pump stops
  - Pump flow rate
  - Pump discharge pressure
  - Surge tank water level and control
  - Surge tank pressure and control
  - Water flow rate to defense-in-depth components

  This testing includes actuation of the system pumps and remotely-operated valves from the main control room as appropriate.

c) The capability to provide the expected cooling water flow rates to and from the required components with both pumps operating, and with either individual pump and heat exchanger operating as specified in the appropriate design specifications is verified.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during its operating modes.

e) The capability of the heat exchanger(s) to transfer heat properly to the service water system is verified under simulated plant conditions during plant hot functional testing. Testing conditions assume both pumps/heat exchangers in operation and with either one of the pumps/heat exchangers operating.

14.2.9.2.6 Service Water System Testing

Purpose

The purpose of the service water system testing is to verify the capability of the as-installed system to perform the following defense-in-depth function as described in subsection 9.2.1:

- Transfer heat from the component cooling water heat exchangers to the environment

Prerequisites

The construction testing of the service water system is completed. Preoperational testing of the component cooling water heat exchangers so that they can receive service water has been completed, as well as the electrical power and distribution systems, and other interfacing systems required for operation of the service water system. Data collection is available as needed to support the specified testing and system configurations. The component cooling water system and components it cools are functional and hot preoperational testing of the reactor coolant system is in progress in order to confirm the service water system heat removal and heat rejection capability.

General Test Acceptance Criteria and Methods

Service water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the service water system properly performs its defense-in-depth functions, as described in subsection 9.2.1 and appropriate design specifications:

a) Proper operation of the service water pumps, valves, strainers, cooling tower fans, and freeze protection provisions are verified.

b) Proper operation of the defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

  - Automatic pump actuation if an operating pump stops
  - Pump flow rate
  - Pump discharge pressure

- Cooling tower water level and control
- Cooling tower basin water temperature and control
- Water supply and return temperature
- Cooling tower fan control

This testing includes actuation of defense-in-depth pumps and remotely-operated valves from the main control room as appropriate.

c) The capability of the pumps to provide the expected cooling flow rates to and from the component cooling water heat exchangers is verified. Testing conditions include both pumps operating and either individual pump operating.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during appropriate operating modes.

e) The heat removal and heat rejection capability of the service water system during the conditions of the plant hot functional testing is verified. Testing conditions include both pumps/cooling towers cells in operation and with either one of the pumps/cooling tower cells operating.

14.2.9.2.7 Spent Fuel Pool Cooling System Testing

Purpose

The purpose of the spent fuel pool cooling system testing is to verify that the system properly performs the following defense-in-depth function described in subsection 9.1.3:

- Remove heat from the spent fuel stored in the spent fuel pool

- Prevent back flow through refueling canal drain lines when other in-containment compartments have been flooded

Prerequisites

The construction testing of the spent fuel pool cooling system has been completed. The spent fuel pool is filled with water of acceptable quality and chemistry. The ac electrical power and distribution systems and other interfacing systems required for operation of the pumps and for data collection are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Spent fuel pool cooling system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the system properly performs its defense-in-depth function as described in subsection 9.1.3 and appropriate design specifications:

a) Proper operation of the spent fuel pool cooling pumps, valves, and strainers is verified.

b) Proper operation of the instrumentation, controls, actuation signals and interlocks is verified, including:

- Automatic pump actuation if an operating pump stops
- Pump flow rate
- Pump discharge pressure
- Spent fuel pool water level and control
- Spent fuel pool water temperature
- Water return temperature

This testing includes operation of the system pumps from the main control room.

c) The capability of the pumps to provide the expected cooling flow rates to and from the pool is verified; with both pumps operating, with either individual pump operating, and with either heat exchanger operating.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during the appropriate operating modes.

e) The proper operation of the spent fuel pool siphon breakers is verified.

f) The proper operation of the spent fuel pool post-72 hour gravity drain flowpaths from the cask washdown pit and the passive containment cooling water storage tank is verified.

g) The gates, drains, bellows, and gaskets in the refueling canal and fuel storage pool are checked for unacceptable leakage.

14.2.9.2.8 Fire Protection System Testing

Purpose

The purpose of the fire protection system testing is to verify the system properly performs the following defense-in-depth function as described in subsection 9.5.1:

- Provide equipment for manual fire fighting in areas containing safe shutdown equipment
- Provide automatic fire suppression in areas containing selected non-safety-related equipment.
- Provide a nonsafety-related containment spray to reduce offsite dose following a severe accident

Prerequisites

The construction tests of the fire protection system have been completed. Required preoperational testing of the ac power and distribution systems and other interfacing systems required for operation of the fire protection system. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance Criteria

Fire protection system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth function. The following testing demonstrates that the system performs its defense-in-depth functions specified in subsection 9.5.1 and as specified in appropriate design specifications:

a) The capability of the seismic standpipes to supply the required fire water quantity and adequate water pressure for effective hose streams as the required flow rate is verified.

b) The operability of the fire detection equipment is verified to be able to properly detect fires and alert personnel.

c) The proper installation and operation of fire barriers, fire walls, and portions of HVAC systems used for smoke control and exhaust is verified.

d) The proper operation of the fire pumps, fire water storage tank, and fire water supply piping, valves, and instrumentation to provide the as-designed fire water supply is verified.

e) The proper installation and operation of automatic fire suppression equipment is verified.

f) The proper installation and operation of electrical isolation devices for non-safety related equipment in opposite divisional fire areas is verified.

g) Operation of the containment spray remotely operated valve and the continuity of a flow path through the containment spray piping is verified.

14.2.9.2.9 Central Chilled Water System Testing

Purpose

The purpose of the central chilled water system testing is to verify that the as-installed low capacity portion of this system properly performs the following defense-in-depth function, as described in subsection 9.2.7:

- Provide chilled water to cool air used to cool safety-related or defense-in-depth equipment rooms

The proper function of the high capacity portion of this system is also verified.

Prerequisites

The construction testing of the low capacity subsystem of the central chilled water system has been completed. The required preoperational testing of the component cooling and service water systems, ac electrical power and distribution systems, and other interfacing systems required for operation of the central chilled water system has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Central chilled water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the central chilled water system performs its defense-in-depth functions described in subsection 9.2.7 and appropriate design specifications:

a) Proper operation of the low capacity portion of the central chilled water system equipment is verified, including chillers, pumps, and valves.

b) Proper calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks are verified, including:

- Temperature control of the chilled water
- Chiller and chilled water pump actuation
- Chilled water pump flow and discharge pressure
- Chilled water flow control to air handling units

This testing includes actuation of the defense-in-depth pumps and remotely operated valves from the main control room.

c) The proper chilled water flow rate to each of the nuclear island nonradioactive ventilation system air handling units is established, and the capability of each pump to provide this chilled water flow rate is verified.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during the appropriate operating modes.

e) The heat removal capability of the air-cooled chillers is verified when the component areas cooled by the nuclear island nonradioactive ventilation system air handling units are operating.

In addition, the operability of the high capacity portion of the central chilled water system described in subsection 9.2.7 and appropriate design specifications, is verified.

14.2.9.2.10 Nuclear Island Nonradioactive Ventilation System Testing

Purpose

The purpose of the nuclear island nonradioactive ventilation system testing is to verify that the as-installed system properly performs the following defense-in-depth functions, as described in subsection 9.4.1:

- Protect the main control room and technical support center from smoke infiltration

- Provide the capability to remove smoke from the main control room, technical support center, and Class 1E electrical equipment rooms

- Provide heating, ventilation, and cooling for the main control room, technical support center, and Class 1E electrical equipment rooms

- Provide air filtration to limit radioactivity in the main control room and technical support center

- Maintain passive heat sinks at acceptably low initial temperatures

- Maintain the main control room and technical support center at positive pressure

The safety-related functions associated with this system are tested as part of the main control room emergency habitability testing described in subsection 14.2.9.1.6.

Prerequisites

The construction testing of the nuclear island nonradioactive ventilation system has been completed. The required preoperational testing of central chilled water system, the hot water heating system, the ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Nuclear island nonradioactive ventilation system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth functions. The following testing demonstrates that the system performs its defense-in-depth functions as described in subsection 9.4.1 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

   - Smoke detectors and alarms
   - Air handling unit and fan flows, controls, and alarms
   - Differential air pressures and alarms
   - Air and air filtration unit charcoal temperatures, controls, and alarms
   - Air relative humidity measurements, controls, and alarms
   - Isolation/shutoff damper controls
   - Fire/smoke damper controls

   This testing includes operation from the main control room.

c) The proper air flows from and through each air handling unit, as well as to and from the main control room, technical support center, and other equipment rooms is established for each mode of operation.

d) The main control room and technical support center are verified to be maintained at the proper positive pressure.

e) The main control room, technical support center, class 1E equipment rooms, and passive heat sink areas are verified to be maintained at their proper temperature during hot functional testing.

f) Air inleakage into the main control room and technical support center is measured using a tracer gas.

14.2.9.2.11 Radiologically Controlled Area Ventilation System

Purpose

The purpose of the radiologically controlled area ventilation system testing is to verify that the as-installed system properly performs the following defense-in-depth function, as described in subsection 9.4.3:

- In conjunction with the low capacity portion of the central chilled water system, maintain the normal residual heat removal system and chemical and volume control system pump rooms at proper temperature during pump operation

Prerequisites

The construction testing of the radiologically controlled area ventilation system has been completed. The required preoperational testing of the central chilled water system, the ac electrical power and distribution systems, and other interfacing systems required for operation of the radiologically controlled area ventilation system has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Radiologically controlled area ventilation system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth function as described in subsection 9.4.3 and appropriate design specifications:

a) Proper function of the defense-in-depth fans, filters, heaters, and coolers is verified.

b) Proper operation of defense-in-depth instrumentation, controls, actuation signals, alarms, and interlocks is verified. This testing includes operation of the normal residual heat removal and chemical and volume control pump room cooler/fans from the main control room.

c) The proper air flow and cooling capability of the normal residual heat removal and chemical and volume control pump room cooler/fans is verified.

d) The proper actuation of the normal residual heat removal and chemical and volume control pump room cooler fans in response to pump operation or high room temperature is verified.

14.2.9.2.12 Plant Control System Testing

Purpose

The purpose of the plant control system testing is to verify that the as-installed components perform the following nonsafety-related defense-in-depth functions, described in Section 7.1:

- Provide control and coordination of the plant during startup, ascent to power, power operation and shutdown conditions by integrating the automatic and manual control of the reactor, reactor coolant and reactor support processes required for normal and off-normal conditions. This includes rod control, pressurizer pressure and level control, steam generator water level control, steam dump (turbine bypass) control and rapid power reduction.

- Provide control of other defense-in-depth systems and components.

Prerequisites

Construction and installation testing of the plant control system has been completed. Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. The reactor vessel integrated head package is in place, all control rod drive mechanism cables are connected and the integrated head and control rod drive mechanism cooling system is operational. Programming has been completed and the initial software diagnostics tests have been completed. Required electrical power supplies and control circuits are energized and operational. Required plant control system field wiring is electrically isolated to prevent operation of components controlled by the plant control system. Equipment or components that cannot be operated without damage or upsetting the plant are isolated, either by using test switches provided by the Plant Control System or by racking out power circuit breakers, to block device operation. Continuity of wiring up to the equipment is verified.

General Test Methods and Acceptance Criteria

Performance of the plant control system hardware and software is observed and recorded during a series of individual component and integrated tests designed to verify operation of defense-in-depth functions. The following testing demonstrates that the system operates as described in Section 7.1 and applicable design specifications:

a) Processing of analog and digital signals is verified by injecting reference signals and monitoring the outputs of the plant control system.

b) Interfaces with other applicable plant equipment and systems such as reactor power control, feedwater control and turbine control are verified by demonstrating that injection of simulated inputs for each of the control functions provided in the main control room results in the proper output as indicated by contact operation, component actuation, or electrical test.

c) Interfaces with applicable plant equipment and systems are verified by demonstrating that injection of simulated inputs for selected control functions provided at the remote shutdown

workstation results in the proper output as indicated by contact operation, component actuation, or electrical test.

d) Proper operation of defense-in-depth processing, signal selector processing, monitoring, display and operator interface features provided by the plant control system is demonstrated by monitoring system outputs in response to simulated inputs, including simulated device or data highway failures, and utilization of provided self-test functions.

e) Proper functioning of the rod control system is verified by evaluating response to simulated demands from the plant control system and protection and safety monitoring system, including group selection and interlocking functions.

f) Proper calibration and operation of the rod position indication system is demonstrated by evaluating system response to simulated rod control logic inputs, utilizing applicable displays, annunciators and alarms.

g) Proper operation of logic and controls for the pressurizer level and pressure control functions, including interlocks and equipment protective devices, is demonstrated by injecting simulated input signals representing anticipated pressurizer level and pressure transients.

14.2.9.2.13 Data Display and Processing System Testing

Purpose

The purpose of the data display and processing system testing is to verify that the as-installed components properly perform the following nonsafety-related defense-in-depth functions, described in Section 7.1:

- Display plant parameters for normal and emergency operations
- Provide plant alarm functions for normal and emergency plant operations
- Provide operational support for plant personnel, including computerized, interactive plant procedures
- Provide analysis, logging and historical storage and retrieval of plant data
- Provide a redundant communications network for transmission of plant parameters, plant status, displays, alarms and data files

Prerequisites

Construction and installation testing of the data display and processing system has been completed. Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and the initial software diagnostics tests have been determined acceptable. Required electrical power supplies are energized and operational. Required system

interfaces are connected and available or simulated as necessary to support the specified test configurations.

General Test Methods and Acceptance Criteria

Performance of the data display and processing system hardware and software is observed and recorded during a series of individual component and integrated tests designed to verify that the data display and processing system equipment operates as described in Section 7.1 and the applicable design specifications:

a) Initial operation of installed devices is verified by completing the diagnostics tests provided for the components and equipment.

b) Proper operation of the data display and processing system software and hardware is demonstrated by utilizing the data display and processing system to provide the processing, monitoring, display and operator interface features required during preoperational testing of associated plant instrumentation and control systems.

c) Verification that the time periods associated with accessing displays, displaying data after it has been made available on the plant monitor bus and display refresh or update rates are within the maximum allowable times is demonstrated. This verification is performed while utilizing the data display and processing system to provide the processing, monitoring, display and operator interface features required during preoperational testing of associated plant instrumentation and control systems.

14.2.9.2.14 Diverse Actuation System Testing

Purpose

The purpose of the diverse actuation system preoperational testing is to verify that the as-installed components properly perform the following nonsafety-related defense-in-depth functions, described in Section 7.7:

- Provide diverse (from the safety-related protection and safety monitoring system) automatic actuation of the following:
  - Reactor/turbine trip
  - Passive residual heat removal heat exchanger
  - Core makeup tanks/reactor coolant pump trip
  - Passive containment cooling
  - Isolation of selected containment penetrations

- Provide a diverse, alternate means for manual actuation of reactor trip and engineered safety features functions

- Provide a diverse system for monitoring selected plant parameters used to provide guidance for manual operation and confirmation of reactor trip and selected engineered safety features actuation

Prerequisites

Construction and installation testing of the diverse actuation system has been completed to the extent necessary to support preoperational testing. Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and initial system diagnostics tests have been determined acceptable. Required electrical power supplies and control circuits are energized and operational. Required field wiring is electrically isolated to prevent operation of components controlled by the diverse actuation system. Exceptions are specifically identified in the preoperational test procedures if plant systems or components are to be operated during testing and these systems or components are to be properly aligned and have proper support systems operating prior to actuation of the particular system or component. Equipment or components that cannot be actuated without damage or upsetting the plant are isolated using the test switches provided by the Diverse Actuation System to block device actuation. Continuity of wiring up to the actuation equipment is verified.

General Test Methods and Acceptance Criteria

Performance of the diverse actuation system is observed and recorded during a series of individual component and integrated tests designed to verify operation of the system components. The following testing demonstrates that the system operates as described in Section 7.7 and applicable design specifications:

a) Processing of the analog and digital signals is verified by injecting reference signals and verifying the outputs at various locations in the system.

b) Correct outputs or actuation functions, for the automatic actuation logic mode, are verified by demonstrating that injection of simulated inputs for each of the specified actuation functions results in the proper output as indicated by contact operation, component actuation, or electrical test.

c) Correct outputs or actuation functions, for the manual actuation logic mode, are verified by demonstrating that each manual actuation function results in the proper output as indicated by contact operation, component actuation, or electrical test.

d) Proper operation of indications and alarms for the specified inputs, including those which provide reactor trip or engineered safety features actuation status, are verified by injecting simulated input signals.

14.2.9.2.15 Main AC Power System Testing

Purpose

The purpose of the main ac power system testing is to verify that the as-installed components properly perform the following nonsafety-related function:

- Provide ac electrical power to plant nonsafety-related loads as described in subsection 8.3.1; and the following nonsafety-related function:

- Provide onsite power for post-72 hour electrical requirements.

Prerequisites

The construction tests for the individual components associated with the main ac power system have been completed. The required test instrumentation is properly calibrated and operational. Additionally, the plant offsite grid connection is complete and available.

General Test Methods and Acceptance Criteria

The capability of the main ac power system to provide power to plant loads under various plant operating conditions is verified. The system components to be tested include the ancillary diesel generator, the medium and low voltage power system, load centers, motor control centers, and instrumentation and controls. The following tests verify that the main ac power system provides its functions as specified in subsection 8.3.1 and appropriate design specifications:

a) Verify the operability of medium-voltage supply breakers.

b) Energize the diesel-backed buses from their associated onsite standby diesel-generator supplies. Verify the bus voltages are within design limits. This test can be performed in conjunction with the testing of the standby diesel generator.

c) Energize the medium voltage buses from their associated unit auxiliary transformer. Verify the bus voltages are within design limits.

d) Energize each medium voltage bus from the reserve auxiliary transformer. Verify the bus voltages are within design limits.

e) Verify correct operation of the manual controls, annunciation, and instrumentation for the 480 V load centers and their 4160 V feeder breakers.

f) Simulate fault conditions at the 480 V load centers and verify alarms and operation of trip devices and protective relays.

g) Energize the 480 V load centers. Verify the bus voltages are within design limits.

h) Verify the operability of motor control center supply breakers.

i) Simulate fault conditions at the motor control centers and verify alarms and operation of trip devices and protective relays.

j) Energize the motor control centers. Verify the bus voltages are within design limits.

k) Start ancillary diesel generators, energize voltage regulating transformers. Verify the input voltages to the regulating transformers are within design limits.

14.2.9.2.16 Non-Class 1E dc and Uninterruptible Power Supply System Testing

Purpose

The purpose of the non-Class 1E dc and uninterruptible power supply system testing is to verify the ability to provide continuous, reliable power for the non-Class 1E control and instrumentation defense-in-depth loads.

Prerequisites

The construction tests for the individual components associated with the non-Class 1E dc and uninterruptible power supply system have been completed. Permanently installed and test instrumentation are properly calibrated and operational. The 480 V ac system is in operation to supply power to the battery chargers. Additionally, a test load is available for the performance of battery capacity tests.

General Test Methods and Acceptance Criteria

The non-Class 1E dc and uninterruptible power supply system consists of electrical equipment including batteries, battery chargers, inverters, static transfer switches, and associated instrumentation and alarms that is used to supply power for the non-Class 1E control and instrumentation loads. Performance is observed and recorded during a series of individual component and integrated system tests. These tests verify that the non-Class 1E dc and uninterruptible power supply system operates as specified in subsection 8.3.2 and appropriate design specifications:

a) The capability of each of the three non-Class 1E batteries serving defense-in-depth loads is verified to meet or exceed the required ampere-hour rating by a battery performance test in accordance with IEEE 450. Following this discharge, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

b) The capability of each of the three chargers serving defense-in-depth loads to meet the rating specified by Table 8.3.2-6 is verified. This testing includes a verification that the charger output voltage is within design limits.

c) The capability of each inverter to meet the rating specified by Table 8.3.2-6 is verified. This testing includes a verification that the output frequency and voltage to be within the limits specified in Table 8.3.2-6.

d) The proper operation and calibration of instrumentation and alarms, electrical ground detection, and permissive and prohibitive interlocks is verified.

14.2.9.2.17 Standby Diesel Generator Testing

Purpose

The purpose of the standby diesel generator testing is to verify the capability to provide electrical power to plant nonsafety-related loads that enhance an orderly plant shutdown if off-site ac power is not available.

Prerequisites

The construction tests have been completed. The necessary permanently installed instrumentation is properly calibrated and operational. Appropriate electrical power sources and diesel generator building heating and ventilation system are available for use. The plant control system is available for operation as applicable to the diesel generators. Sufficient diesel fuel is available, on site or readily accessible, to perform the tests.

General Test Methods and Acceptance Criteria

Performance is observed and recorded during a series of individual component and integrated tests. These tests verify that the diesel generators operate properly as specified in Sections 8.3 and 9.5 through the following testing:

a) Verify the operability of generator protection features described in subsection 8.3.1.1.2.2.

b) Simulate the loss of ac voltage and verify proper operation of undervoltage relay. Verify sequencer control logic support the description in Tables 8.3.1-1 and 8.3.1-2.

c) Verify the diesel generators fuel transfer pumps start and stop automatically in response to simulated day tank low level and high level signals.

d) Transfer fuel oil from the fuel oil storage tank to the diesel fuel oil day tanks by means of the transfer pumps. Verify flow parameters are within design limits.

e) Verify proper operation of diesel generators building heating and ventilation system fans and dampers, manual and automatic controls, alarms, and indicating instruments, as described in subsection 9.4.10.

f) Verify the air flow in the diesel generator building heating and ventilation system is acceptable.

g) Verify the diesel generator lockout features (turning gear engaged, emergency stop).

h) Verify that the diesel generator air starting system has sufficient capacity for cranking the engine for prescribed number of automatic or manual starts without recharging.

i) Start the diesel generators. Verify voltage and frequency control.

j) Verify the full load-carrying capability for a period of not less than 24 hours, of which 2 hours at are at a load equivalent to the 2-hour (Standby) rating of the diesel generators and 22 hours at a load equivalent to the continuous rating of the diesel generators. Verify the voltage and frequency requirements are maintained. Verify that the diesel generator cooling system functions within design limits.

k) Following the full-load capability test, simulate loss of ac voltage and verify proper automatic startup, sequencing, and operation of the diesel generators. Verify diesel generators bus de-energization and load shedding. Verify diesel generators attain frequency and voltage within design limits within the time described in subsection 8.3.1.1.2.3. Verify sequencer control logic meets the description in Tables 8.3.1-1 and 8.3.1-2. Verify that the diesel generators continuous rating is not exceeded. Verify voltage and frequency requirements are maintained.

l) Verify that the rate of fuel consumption and the operation of the fuel transfer pumps and associated components, while providing power to the load equivalent to those specified in Table 8.3.1-1 or 8.3.1-2, are such that the design capacity of the fuel oil storage tanks meet the subsection 9.5.4 requirement for 7-day storage inventory.

m) With each diesel generator bus supplied only by the diesel generator and supplying loads up to its continuous rating, trip a load equivalent to the largest single load in Table 8.3.1-1 or 8.3.1-2. Verify that the voltage and frequency values are maintained within design limits.

n) With each diesel generator supplying loads up to its continuous rating, trip the generator breaker that supplies power to the diesel generator bus. Verify that the diesel engine continues to run and does not trip on overspeed.

14.2.9.2.18 Radiation Monitoring System Testing

Purpose

The purpose of the radiation monitoring system testing is to verify that the as-installed radiation monitors perform their defense-in-depth function as described in Section 11.5.

Prerequisites

The construction testing of the radiation monitoring system has been completed. The radiation monitors have been calibrated and the monitor check sources are installed, as appropriate. The required preoperational testing of the protection and safety monitoring system, plant control system, the electrical power and distribution systems, and other interfacing systems required for operation and data collection is available as needed to support the specified testing.

General Test Acceptance Criteria and Methods

Radiation monitoring system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth

functions. The following testing demonstrates that the system operates as specified in Section 11.5 and as specified in appropriate design specifications:

a) The proper calibration and operation of each radiation detector assembly and associated equipment using a standard radiation source or portable calibration unit are verified.

b) Proper operation of the monitoring equipment and controls required for manually initiated operation of the monitor check sources is verified.

c) Proper operation of the local processors that process and transmit radiation monitoring data to the protection and safety monitoring system or plant control system, as appropriate, is verified.

d) Proper actuation of alarms and signals for actuation of equipment responses following receipt of a high radiation signal is verified.

14.2.9.2.19 Plant Lighting System Testing

Purpose

The purpose of plant lighting system testing is to verify that the system can perform its defense-in-depth function of providing emergency lighting in the main control room and remote shutdown workstation area to illuminate these areas for emergency operations upon loss of normal lighting, as described in subsection 9.5.3. In addition, the operability of lighting for emergency ingress and egress is verified.

Prerequisites

The construction testing of the plant lighting system is completed. The required preoperational testing of the interfacing and support systems required for testing the emergency lighting function is available as needed to support the specified testing and system configurations including the Class 1E dc and uninterruptible power supply system, and the main ac power system.

General Test Acceptance Criteria and Methods

Plant lighting system performance is observed during a series of individual component and integrated system testing to verify the system capability to perform its defense-in-depth functions. The following testing verifies that the system operates as described in subsection 9.5.3 and in appropriate design specifications:

a) The proper operation of the plant lighting system emergency lighting is verified when powered from the Class 1E dc and uninterruptible power supply system.

b) Self-contained emergency lighting units are verified to be operable and installed into the proper ingress and egress paths, standby diesel generator rooms, switchgear rooms (annex and turbine buildings), fire pump rooms, access route between the main control room and remote shutdown workstation, and appropriate connecting corridors and stairwells.

14.2.9.2.20 Primary Sampling System Testing

Purpose

The purpose of the primary sampling system testing is to verify that the as installed components properly perform the following nonsafety-related defense-in-depth functions described in subsection 9.3.3:

- Provide the capability to obtain samples of the reactor coolant, passive core cooling system, containment sump water, and containment atmosphere
- Provide the capability to analyze and measure samples.

Prerequisites

Construction testing of the primary sampling system has been completed. Component cooling water is being provided to the sample cooler when samples are taken from the reactor coolant system when it is at elevated temperature. The systems/components to be sampled are filled and at their normal pressure and temperature. The liquid radwaste system is available to receive discharged sample fluid. Electrical power is available for operation of the system components and a source of compressed gas is available for operation of the gas sample eductor.

General Test Method and Acceptance Criteria

The performance of the primary sampling system is observed and recorded during a series of individual component tests and testing in conjunction with the reactor coolant system and passive core cooling system operation. The following testing demonstrates that the primary sampling system performs its defense-in-depth functions as described in subsection 9.3.3 and appropriate design specifications.

a) Proper operation of the system’s remotely-operated valves and eductor supply pump is verified.

b) Proper calibration and operation of instrumentation, controls, actuation signals, and interlocks are verified.

c) Verify the capability to obtain samples from the reactor coolant system, core makeup tanks, accumulators, containment sump, and containment atmosphere.

d) Verify the ability to return the sample stream fluid to the containment sump or liquid radwaste system, as appropriate.

e) Verify the capability to route sample streams to the laboratory.

f) Verify the operability of the test laboratory equipment used to analyze or measure radiation levels and radioactivity concentrations.

14.2.9.2.21 Annex/Auxiliary Building Non-radioactive HVAC System

Purpose

The purpose of the annex/auxiliary non-radioactive HVAC system testing is to verify that the as installed system properly performs the defense-in-depth function, as described in subsection 9.4.2, to provide conditioned air to maintain the diesel bus switchgear rooms and battery charger rooms (containing DC switchgear) within their design temperature range during operation of the onsite standby power system.

Prerequisites

The construction testing of the annex/auxiliary building HVAC system has been successfully completed. The required preoperational testing of the interfacing systems required for the operation of the above system is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

The annex/auxiliary building non-radioactive HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.2 and appropriate design specifications:

a) Proper function of the fans, filters, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

   - Air handling unit and fan flows, controls, and alarms
   - Air temperatures, alarms, and controls
   - Damper open, close and modulate control in response to monitored parameters

   This testing includes operation from the main control room.

c) The ventilated areas are verified to be maintained at a slightly positive pressure relative to the outside air pressure and other areas of the auxiliary building.

d) The switchgear and equipment room subsystem air handling unit supply and return fans are verified to be automatically connected to the onsite standby power supplies on a loss of power to the buses powered by the standby diesels.

14.2.9.3 Preoperational Testing of Nonsafety-Related Radioactive Systems

14.2.9.3.1 Liquid Radwaste System Testing

Purpose

The purpose of the liquid radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following safety-related function described in subsection 11.2.1.1:

- Drain the passive core cooling system compartments to the containment sump to prevent flooding of these compartments and possible immersion of safety-related components

- Prevent back flow through the drain lines from the containment sump to the chemical and volume control system compartment and the passive core cooling system compartments, in order to prevent cross flooding of these compartments

The liquid radwaste system testing is performed to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the nonsafety-related functions described in subsection 11.2.1.2, including receiving and processing reactor coolant system effluents, radioactive equipment and floor drains, and other radioactive liquid wastes from the plant.

Prerequisites

The construction testing of the liquid radwaste system is completed. The required preoperational testing of the interfacing and support systems required for testing has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Liquid radwaste system performance is observed and recorded during a series of individual component and system testing that characterizes system operation. This testing verifies that the system operates as specified in Section 11.2 and appropriate design specifications.

a) The drain lines from the passive core cooling system compartments and the refueling cavity are verified to provide a flow path to the reactor compartment.

b) Proper operation of the backflow prevention check valves is verified by the performance of baseline in-service tests, as specified in subsection 3.9.6.

c) Proper operation of the system pumps and valves is verified, including:

  - Effluent holdup tank pumps
  - Waste holdup tank pumps
  - Degasifier separator pumps
  - Chemical waste tank pump

- Monitor tank pumps
- Reactor coolant drain tank pumps

d) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified, including:

- Pump controls and alarms
- Tank level control and alarms
- Valve and pump responses to safeguards signals
- Valve and pump responses to high radiation isolation signals

e) In conjunction with the gaseous radwaste system testing in subsection 14.2.9.3.2, the proper operation of the degasifier is verified.

f) The proper operation of the liquid radwaste filters and ion exchangers is verified.

14.2.9.3.2 Gaseous Radwaste System Testing

Purpose

The purpose of the gaseous radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following nonsafety-related functions described in Section 11.3.

- Collect waste gases that contain radioactivity or hydrogen
- Provide holdup for radioactive waste gases as appropriate

Prerequisites

The construction testing of the gaseous radwaste system is completed. The required preoperational testing of the interfacing and support systems required for testing is completed, and data collection is available as needed to support the specified testing and system configurations. In addition, a source of hydrogen and calibration gases is available.

General Test Acceptance Criteria and Methods

The performance of the gaseous radwaste system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation. This testing verifies that the gaseous radwaste system operates as described in Section 11.3 and appropriate design specifications:

a) System and component control circuits, including response to normal control, interlock, and alarm signals are verified. The gaseous radwaste system instrumentation, controls, valves, and interlocks are verified to respond to various inputs and provide proper isolation and alarm signals. Appropriate automatic control functions are verified in response to abnormal conditions inputs.

b) Nitrogen, hydrogen, and calibration gases are routed through the system. Performance characteristics of the instrumentation and control systems are verified, and the delay bed operation is verified.

c) Moist test gas is routed through the system to verify proper moisture removal and detection.

d) The degasifer vacuum pump is verified to operate properly. Manual override of the automatic control functions of the drainpot and moisture separator drain control valves is verified.

e) Sample pumps are operated and the sample flow meter indication is observed.

f) The proper operation of the degasifier moisture separator is demonstrated.

14.2.9.3.3 Solid Radwaste System Testing

Purpose

The purpose of the solid radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to prepare waste generated during the normal operation of the plant for processing, packaging, and shipment as described in subsection 11.4.1.2.

Prerequisites

The construction testing of the solid radwaste system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance Criteria

The performance of the solid radwaste system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation. This testing verifies that the solid radwaste system operates as described in Section 11.4 and in appropriate design specifications:

a) Tests are performed to verify that manual and automatic system controls, alarms, and instruments are functional; the system instrumentation, controls, valves, and interlocks respond properly to various inputs and provide proper isolation and alarm signals; and appropriate automatic control functions occur in response to abnormal condition inputs.

b) Tests are performed to verify proper system process rates as described in Section 11.4, and that no free liquids are present in packaged waste.

c) The capability to properly transfer and retain spent resins is verified.

d) The capability to properly handle filter cartridges in a manner that minimizes personnel radiation exposure is demonstrated.

14.2.9.3.4 Radioactive Waste Drain System Testing

Purpose

The purpose of the radioactive waste drain system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following functions, described in Section 11.2 and subsection 9.3.5:

- Drain floor and equipment compartments
- Collect drainage and transfer drainage to the liquid radwaste system

Prerequisites

The construction testing of the radioactive waste drain system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations, including the liquid radwaste system and compressed air supply.

General Test Method and Acceptance Criteria

The performance of the radioactive drain system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation. This testing verifies that the system operates as described in Section 11.2, subsection 9.3.5, and in appropriate design specifications:

a) Proper operation of system instrumentation, controls, alarms, and interlocks is verified.

b) Proper operation of the system pumps and valves is verified.

c) Proper system and component flowpaths and flowrates, including pump capacities and sump tank volumes, is verified.

d) Flow water in each drain path to verify that the drains discharge to their designated destination and that proper drain path segregation is maintained.

14.2.9.3.5 Steam Generator Blowdown System Testing

Purpose

The purpose of the steam generator blowdown system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to provide an isolatable flowpath for the controlled removal of water from the secondary side of the steam generators as described in Section 10.4.

Prerequisites

The construction testing of the steam generator blowdown system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations. A portion of this testing is performed during the hot functional testing of the plant, when the steam generators are at or near normal operating pressure and temperature.

General Test Method and Acceptance Criteria

The performance of the steam generator blowdown system is observed and recorded during a series of individual component and system tests that characterize the various modes of system operation. This testing demonstrates that the system operates as described in Section 10.4 and in appropriate design specifications:

a) Proper operation of system instrumentation, controls, alarms, and interlocks is verified.

b) Proper operation of the system pump and valves is verified.

d) The proper operation of the electrodeionization units is verified.

e) The heat transfer capability of each blowdown heat exchanger is verified.

f) The automatic isolation of steam generator blowdown on low steam generator level is verified.

14.2.9.3.6 Waste Water System Testing

Purpose

The purpose of the waste water system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to collect and perform appropriate processing of normally non-radioactive drains, as described in Section 11.2 and subsection 9.2.9.

Prerequisites

The construction testing of the waste water system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

Waste water system performance is observed and recorded during a series of individual component and system testing that characterizes system operation. This testing verifies that the system operates as described in Section 11.2 and subsection 9.2.9 and appropriate design specifications.

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

c) Proper system and component flowpaths and flowrates, including pump capacities and sump tank volumes is verified.

d) Verify the ability of the waste water system radiation alarm to trip the drain tank pumps and the waste water retention basin pumps, as appropriate.

14.2.9.4 Preoperational Tests of Additional Nonsafety-Related Systems

14.2.9.4.1 Condensate System Testing

Purpose

The purpose of the condensate system testing is to verify that the as-installed components properly perform the system functions, described in subsection 10.4.7, of delivering the required flow of heated water from the condenser hotwell to the feedwater system.

Prerequisites

The construction testing of the condensate system has been completed. The construction testing of the condenser is completed and a source of water of appropriate quality is available for filling the condenser hotwell. The steam generator feedwater system is available to receive flow from the condensate system. Required electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Condensate system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the condensate system can perform its functions as described in subsection 10.4.7 and appropriate design specifications:

a) Proper operation of the condensate pumps and system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Proper operation of the heater drains is verified.

d) During the plant hot functional testing, the integrated operation of the condensate system in conjunction with the feedwater system is verified with the condenser and circulating water system in operation.

14.2.9.4.2 Condenser Air Removal System Testing

Purpose

The purpose of the condenser air removal system testing is to verify that the as-installed components properly perform the system functions to establish and maintain the required vacuum in the main condenser, as described in subsection 10.4.2.

Prerequisites

The construction testing of the condenser air removal system has been completed. The construction testing of the condenser has been completed and a source of water of appropriate quality is available for filling the condenser hotwell. The turbine gland sealing system and exhaust blower are in operation. A source of steam such as the auxiliary boiler is available. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Condenser air removal system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the condensate system can perform its functions as described in subsection 10.4.2 and appropriate design specifications:

a) Proper operation of the vacuum pumps and system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) The capability of the vacuum pumps to establish the required vacuum in the main condenser is verified.

14.2.9.4.3 Main Turbine System and Auxiliaries Testing

Purpose

The purpose of the main turbine system testing is to verify that the as-installed main turbine and its auxiliary components properly perform their functions, described in Sections 10.2 and 10.4. This testing includes testing of the turbine gland sealing system, lube oil system, turning gear, turbine controls and protective functions, and moisture separator reheater.

Prerequisites

The construction testing of the main turbine and its auxiliaries has been completed. The construction testing of the condenser is completed and a source of water of appropriate quality is available for filling the condenser hotwell. The main turbine is on turning gear and the condenser air removal system is operable. A source of steam such as the auxiliary boiler is available. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Because this testing is performed using a temporary steam source, the extent to which the turbine can be tested in preoperational testing is limited. However, the proper function of the turbine auxiliaries is verified to assure the turbine will operate properly when a greater amount of steam is provided.

Main turbine system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the turbine and its auxiliaries function as described in Sections 10.2 and 10.4 and in appropriate design specifications:

a) Proper operation of the turbine lube oil pump and turning gear motor, gland seal exhaust blower, and moisture separator and gland seal valves is verified.

b) Proper operation of system valves including the turbine control and intercept valves is verified.

c) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

d) Proper turbine operation during the turning gear testing is verified. The turning gear engagement and disengagement functions are verified to operate properly.

e) Proper performance of the turbine trip functions is verified.

14.2.9.4.4 Main Generator System and Auxiliaries Testing

Purpose

The purpose of the main generator system testing is to verify that the as-installed main generator and its auxiliary components properly perform their functions, described in Sections 8.2 and 10.2. This testing includes testing of the generator cooling systems, lube oil system, controls, and protective functions.

Prerequisites

The construction testing of the main generator and its auxiliaries has been completed. The construction testing of the condenser is completed. The turbine cooling water system is operable, and required support systems, electrical power supplies, and control circuits are operational.

General Test Method and Acceptance Criteria

Performance is observed and recorded during a series of individual component and integrated tests. These tests verify that the generator operated as specified in Sections 8.2 and 10.2 through the following testing:

a) Verify the operability of the generator protection features.
b) Verify proper cooling of the generator stator and rotor.
c) Verify MW, MVAR, and frequency control.

14.2.9.4.5 Turbine Building Closed Cooling Water System Testing

Purpose

The purpose of the turbine building closed cooling water system testing is to verify that the as-installed components properly perform their functions of supplying adequate cooling water to the designated turbine building components, as described in subsection 9.2.8.

Prerequisites

The construction testing of the turbine building closed cooling water system has been completed. The cooled components are operational and operating to the extent possible, especially for verifying the heat exchanger capability. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Turbine building closed cooling water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.2.8 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

14.2.9.4.6 Circulating Water System Testing

Purpose

The purpose of the circulating water system testing is to verify that the as-installed components properly perform the functions of cooling and circulating adequate cooling water to the main condenser and turbine building closed cooling water system heat exchangers as described in subsection 10.4.5.

Prerequisites

The construction testing of the circulating water system has been completed. The main condenser and turbine building closed cooling water heat exchangers are operational. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Since there will be little, if any, heat rejected to the circulating water system, verification of the heat removal capability of the ultimate heat sink is performed during the startup testing of the plant when the reactor is producing power.

Circulating water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 10.4.5 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

The proper operation of the system freeze protection equipment is verified, as applicable.

14.2.9.4.7 Turbine Island Chemical Feed System Testing

Purpose

The purpose of the turbine island chemical feed system testing is to verify that the as-installed components properly perform the functions of adding appropriate chemicals to the condensate, circulating water, service water, and auxiliary boiler in a controlled manner, as described in subsection 10.4.11.

Prerequisites

The construction testing of the chemical feed system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Turbine island chemical feed system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 10.4.11 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.8 Condensate Polishing System Testing

Purpose

The purpose of the condensate polishing system testing is to verify that the as-installed components properly perform the functions of removing corrosion products, dissolved solids, and other impurities from the condensate system, as described in subsection 10.4.6.

Prerequisites

The construction testing of the condensate polishing system has been completed. The ultimate heat sink water reservoir is filled with water of appropriate quality and the condensate and feedwater systems are operational. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Condensate polishing system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 10.4.6 and appropriate design specifications:

a) Proper operation of the system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.9 Demineralized Water Transfer and Storage System Testing

Purpose

The purpose of the demineralized water transfer and storage system testing is to verify that the as-installed components properly perform the function of providing reservoirs of demineralized water and deliver deoxygenated, demineralized water to various plant users, as described in subsection 9.2.4.

Prerequisites

The construction testing of the demineralized water transfer and storage system has been completed. The demineralized water treatment system is operational and the equipment which uses demineralized water are able to accept water. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Demineralized water transfer and storage system performance is observed and recorded during a series of individual component and integrated system testing. The following defense-in-depth testing verifies that the system functions as described in subsection 9.2.4 and appropriate design specifications:

a) Proper operation of the system pumps, valves, blower, and is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.10 Compressed and Instrument Air System Testing

Purpose

The purpose of the compressed and instrument air system testing is to verify that the as-installed components properly perform the functions of providing compressed air at the required pressures to various plant users, as described in the Compressed and Instrument Air portion of Section 9.3.

Prerequisites

The construction testing of the compressed and instrument air system has been completed. The component cooling water system is operational and providing cooling for the compressor units. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Compressed and instrument air system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system and its plant users, where applicable, function as described in subsection 9.3.1.4 and appropriate design specifications:

a) Proper operation of the system compressors, receivers, prefilters, air dryers, afterfilters, purifiers, and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Integral testing is performed to verify that the instrument air subsystem can provide sufficient air pressure to accommodate the maximum number of air-operated valves expected to operate simultaneously.

d) Testing is performed to verify the fail-safe positioning of safety-related air-operated valves for sudden loss of instrument air or gradual loss of pressure as described in subsection 9.3.1.4.

e) Proper calibration is verified for system relief valves that protect the system from overpressure conditions.

14.2.9.4.11 Containment Recirculation Cooling System Testing

Purpose

The purpose of the containment recirculation cooling system testing is to verify that the as-installed components properly perform the functions of maintaining the proper containment air temperature during normal plant operation and during refueling and maintenance operations, as described in subsection 9.4.6.

Prerequisites

The construction testing of the containment recirculation cooling system has been completed. The central chilled water system and hot water heating system are operational. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Containment recirculation cooling system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.6 and appropriate design specifications:

a) Proper operation of the system fans and dampers is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.12 Containment Air Filtration System Testing

Purpose

The purpose of the containment air filtration system testing is to verify that the as-installed components properly perform the functions of supplying and exhausting air to maintain the proper containment air pressure, and filter exhaust air to minimize radiation release, as described in subsection 9.4.7.

Prerequisites

The construction testing of the containment air filtration system has been completed. The portions of the radiologically controlled area ventilation system connected to the air filtration system are operational. The hot water heating and chilled water systems are required for verification of the air filtration heating and cooling functions. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Containment air filtration system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.7 and appropriate design specifications:

a) Proper operation of the system fans and dampers is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Proper operation of the containment air filtration filters is verified.

14.2.9.4.13 Plant Communications System Testing

Purpose

The purpose of the plant communications system testing is to verify that the as-installed components properly perform the functions of verifying the proper operation and adequacy of the plant communication systems used during normal and abnormal operations, as described in Section 9.5.

Prerequisites

The construction testing of the communication system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Plant communications system performance is observed and recorded during a series of individual component and integrated system testing. The inplant communications system includes the following subsystems:

- Wireless telephone system
- Telephone/page system
- Private Automatic Branch Exchange (PABX) System
- Sound Powered Phone System
- Emergency Offsite Communication System
- Security Communication System

The following testing verifies that the system functions as described in Section 9.5 and appropriate design specifications:

a) Transmitters and receivers are verified to operate without excessive interference.

b) Proper operation of controls, switches, and interfaces is verified.

c) Proper operation of the public address, including the plant emergency alarms, is verified.

d) The proper operation of equipment expected to function under abnormal conditions such as a loss of electrical power, shutdown from outside the control room, or execution of the plant emergency plan is verified. This functional testing will be performed under conditions that simulate the maximum plant noise levels being generated during the various operating conditions, including fire and accident conditions, to demonstrate system capabilities.

14.2.9.4.14 Mechanical Handling System Crane Testing

Purpose

The purpose of the mechanical handling system crane testing is to verify that the as-installed components properly perform their functions. The test ensures operation and adequacy of the containment polar crane, which is used to lift and relocate components providing access to the reactor fuel, vessel internals, and reactor components during refueling and servicing operations.

In addition, the following load handling systems described in subsection 9.1.5 are tested; the equipment hatch hoist, maintenance hatch hoist, and the spent fuel shipping cask crane.

Prerequisites

The construction testing of the heavy lift cranes has been completed. Required support systems, electrical power supplies and control circuits are operational. The heavy load analysis, defining the load paths, has been completed.

General Test Method and Acceptance Criteria

Heavy load crane performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the crane systems function as described in subsection 9.1.5 and in appropriate design specifications:

a) Proper operation and assembly of the various cables, grapples, and hoists including brakes, limit switches, load cells, and other equipment protective devices are verified.

b) Proper operation of control, instrumentation, interlocks, and alarms is verified.

c) Dynamic and static load testing of cranes and hoists, and associated lifting and rigging equipment are performed including a static load test at 125 percent of rated load and full operational test at 100 percent of rated load.

14.2.9.4.15 Seismic Monitoring System Testing

Purpose

The purpose of the seismic monitoring system testing is to verify that the as-installed components properly perform the functions of verifying proper operation in response to a seismic event, as described in Section 3.7.

Prerequisites

The construction testing of the seismic monitoring system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance Criteria

Seismic monitoring system instrumentation performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Section 3.7 and appropriate design specifications:

a) Proper calibration and response of seismic instrumentation are verified, including verification of alarm and initiation setpoints.

b) Proper operation of internal calibration and test features are verified.

c) Proper integrated system response, including actuations, alarms, and annunciations, is verified.

d) Verify the proper operation of the recording and analysis functions on a loss of AC power sourced.

14.2.9.4.16 Special Monitoring System Testing

Purpose

The purpose of the special monitoring system testing is to verify that the as-installed components properly perform the following nonsafety-related functions, described in subsection 4.4.6:

- Detect the presence of metallic debris in the reactor coolant system
- Obtain baseline data for metal impact monitoring prior to power operations

Prerequisites

Construction and installation testing of the special monitoring system has been completed to the extent necessary to support preoperational testing. Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and initial system diagnostics tests have been determined acceptable. Required electrical power supplies are energized and operational.

General Test Methods and Acceptance Criteria

Performance of the special monitoring system is observed and recorded during a series of individual component and integrated tests designed to verify system operation in response to specified input conditions. The following testing demonstrates that the system operates as described in subsection 4.4.6 and the applicable design specifications:

a) Proper calibration and response of digital metal impact monitoring instrumentation are verified.

b) Proper operation of the digital metal impact monitoring system is verified by evaluating system response to simulated input signals representing the anticipated signal range.

c) Baseline response data is obtained for the metal impact monitoring system to serve as a reference for monitoring degradation of sensor response.

14.2.9.4.17 Secondary Sampling System Testing

Purpose

The purpose of the secondary sampling system testing is to verify that the as-installed components properly perform the following nonsafety-related functions, described in subsection 9.3.4:

- Provide the capability to continuously monitor selected secondary water and steam process streams in order to establish and maintain proper water chemistry during plant operation

- Provide the capability to manually analyze additional secondary water and steam process streams

Prerequisites

Construction testing of the secondary sampling system has been completed. Cooling water is being provided to the sample coolers when samples are taken from sample points with fluid temperatures exceeding 125°F. The systems/components to be sampled are filled and operating at their normal pressure and temperature. Electrical power is available for operation of the on-line chemistry analyzers.

General Test Method and Acceptance Criteria

The performance of the secondary sampling system is observed and recorded during a series of individual component tests and testing in conjunction with the plant in operation at normal pressure and temperature. The following testing verifies that the secondary sampling system operates as described in subsection 9.3.4 and appropriate design specifications.

a) Proper calibration and operation of on-line continuous analyzers, data collection and display, controls, and actuation signals to the turbine island chemical feed system are verified.

b) Proper calibration and operation of the portable analyzer are verified.

c) Proper operation of the sample coolers is verified.

d) Capability to obtain grab samples from the sample points is verified.

14.2.9.4.18 Turbine Building Ventilation System

Purpose

The purpose of the turbine building ventilation system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in subsection 9.4.9.

Prerequisites

The construction testing of the turbine building ventilation system has been successfully completed. The required preoperational testing of the central chilled water and hot water heating systems, and other interfacing systems required for the operation of the above systems and data collection is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

The turbine building ventilation system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.9 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Air handling unit and fan flows, controls, and alarms
- Damper open, close and modulate control

This testing includes operation from the main control room.

14.2.9.4.19 Health Physics and Hot Machine Shop HVAC System

Purpose

The purpose of the health physics and hot machine shop HVAC system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in subsection 9.4.11.

Prerequisites

The construction testing of the health physics and hot machine shop HVAC system has been successfully completed. The required preoperational testing of the central chilled water and hot

water heating systems, and other interfacing systems required for the operation of the above systems is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

The health physics and hot machine shop HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.11 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

   - Radiation detectors and alarms
   - Air handling unit and fan flows, controls, and alarms
   - Air temperatures, alarms, and controls
   - Differential air pressure and alarms
   - Damper open, close and modulate control

   This testing includes operation from the main control room.

c) The health physics and hot machine shop HVAC system is verified to maintain the access control area and hot machine shop at a slightly negative pressure with respect to outdoors and clean areas of the annex building to prevent unmonitored releases of radioactive contaminants.

14.2.9.4.20 Radwaste Building HVAC System

Purpose

The purpose of the radwaste building HVAC system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in subsection 9.4.8, as required for personnel and equipment in serviced areas; and provides the proper filtration of air from potentially contaminated areas.

Prerequisites

The construction testing of the radwaste building HVAC system has been successfully completed. The required preoperational testing of the central chilled water and hot water heating systems, the ac electrical power and distribution systems, and other interfacing systems required for the operation of the above systems is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Acceptance Criteria and Methods

The radwaste building HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in subsection 9.4.8 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Radiation detectors and alarms
- Air handling unit and fan flows, controls, and alarms
- Air temperatures, alarms, and controls
- Differential air pressures and alarms
- Damper open, close and modulate control in response to monitored parameters

This testing includes operation from the main control room.

c) The radwaste building is verified to be maintained at a slightly negative pressure with respect to outdoors to prevent unmonitored releases of radioactive contaminants.

14.2.9.4.21 Main, Unit Auxiliary and Reserve Auxiliary Transformer Test

Purpose

The purpose of the main, unit auxiliary and reserve auxiliary transformer testing is to demonstrate the energization of the transformers and the proper operation of associated protective relaying, alarms, and control devices.

Prerequisites

The construction tests for the individual components associated with the main, unit auxiliary and reserve auxiliary transformers have been completed. The required test instrumentation is properly calibrated and operational. Additionally, the plant offsite grid connection is complete and available.

General Test Methods and Acceptance Criteria

The following tests demonstrate proper energization of the main, unit auxiliary and reserve auxiliary transformers and proper operation of protective relaying, alarms, and control devices associated with the transformers:

a) Energize the unit auxiliary transformers. Verify phase rotation. Verify phase voltages are within design limits.

b) Energize the reserve auxiliary transformer. Verify phase rotation. Verify phase voltages are within design limits.

c) Simulate fault conditions and verify alarms and operation of protective relaying circuits.

14.2.10 Startup Test Procedures

Those tests comprising the startup test phase are discussed in this subsection. For each test a general description is provided for test objective, test prerequisites, test description, and test performance criteria, where applicable. In describing a test, the operating and safety-related characteristics of the plant to be tested and evaluated are identified.

Where applicable, the relevant performance criteria for the test are discussed. Some of the criteria relate to the value of process variables assigned in the design or analysis of the plant, component systems, and associated equipment. Other criteria may be associated with expectations relating to the performance of systems.

The specifics of the startup tests relating to test methodology, plant prerequisites, initial conditions, performance criteria, and analysis techniques are developed by the Combined License applicant/holder in the form of plant, system and component performance and testing procedures.

14.2.10.1 Initial Fuel Loading and Precritical Tests

Tests performed after preoperational testing is complete but prior to initial criticality are described in this section. These tests include those performed prior to core load to verify the plant is ready for core loading, the loading of the core and the tests performed under hot conditions after the core has been loaded but prior to initial criticality.

Tests to be performed prior to and during initial core loading are described in subsections 14.2.10.1.1 through 14.2.10.1.5. These tests verify the systems necessary to monitor the fuel loading process are operational and that the core loading is conducted properly.

After core load, tests are performed at hot conditions to bring the plant to a final state of readiness prior to initial criticality.

14.2.10.1.1 Fuel Loading Prerequisites and Periodic Checks

Objectives

- Specify the prerequisites for initial fuel loading, including the status of required systems, plant conditions, and special equipment
- Provide a checklist for periodic verification that the conditions required for fuel loading are being maintained

Prerequisites

- Plant systems required for initial fuel loading have been satisfactorily tested and turned over to the plant operating staff, and are in the status specified
- Plant conditions required for initial core loading are as specified
- Special equipment required for initial fuel loading is available and operable

Test Method

- Prior to the beginning of fuel loading, verify and document the required status of test prerequisites
- Throughout fuel loading, verify through periodic checks that conditions required for safe fuel loading are being maintained

Performance Criterion

The required status of prerequisites for initial fuel loading is verified and documented prior to fuel loading and maintained throughout the loading process.

14.2.10.1.2 Reactor Systems Sampling for Fuel Loading

Objective

- Verify that the dissolved boron concentration in the reactor coolant system and directly connected portions of associated auxiliary systems is uniform and equals or exceeds the value required by the plant Technical Specifications for fuel loading.

Prerequisites

- Plant Technical Specifications for fuel loading are complete and verified
- Boric acid storage tanks, transfer pumps, and associated piping and equipment are filled and operable
- The reactor vessel is filled with borated water to a level approximately equal to the centerline of the outlet nozzles
- The water in the reactor vessel and reactor coolant system piping, including all directly connected auxiliary systems, is borated to a value that equals or exceeds the value specified in the plant Technical Specifications for fuel loading, and that water is circulating through the normal residual heat removal system at a rate that provides reasonable assurance of a uniform concentration.

Test Method

- Obtain and analyze samples from at least one representative point in each auxiliary system and at four equidistant depths in the reactor vessel for boron concentration

- Periodically repeat sampling until the performance criteria are met

Performance Criteria

- The minimum boron concentration of all samples equals or exceeds the value specified in the plant Technical Specifications for fuel loading. If the minimum boron concentration criteria is not met, the chemical and volume control system is used to increase the boron concentration to above the specified limit.

- The boron concentrations of the samples obtained in the reactor vessel and operating residual heat removal loop are within the specified range of each other. The normal residual heat removal system continues to operate until a uniform concentration is established.

14.2.10.1.3 Fuel Loading Instrumentation and Neutron Source Requirements

Objectives

- Verify alignment, calibration, and neutron response of the temporary core loading instrumentation prior to the start of fuel loading

- Verify the neutron response of the nuclear instrumentation system source range channels prior to the start of fuel loading

- Verify the neutron response of the temporary and nuclear instrumentation system source range instrumentation prior to resumption of fuel loading following any delay of 8 hours or more

Prerequisites

- The following special equipment is available:

  - The temporary core loading package consisting of three complete counting channels, including preshipment alignment and calibration data

  - A portable neutron source with sufficient strength to verify detector response

- Preoperational testing of the nuclear instrumentation system source range channels is completed

Test Method

- Prior to the start of fuel loading, verify the response of temporary and nuclear instrumentation system source range channels to neutrons by using a portable neutron source

- Verify proper alignment and calibration of the temporary channels by comparing the neutron response data to the data obtained during preshipment testing

- Prior to resumption of fuel loading following a delay of 8 hours or more, verify proper operation of the temporary and nuclear instrumentation system source range channels by performing a neutron response check (using the portable neutron source or by moving a fuel assembly containing a primary neutron source) or by statistical analysis of the count rate data

Performance Criterion

Equipment used for neutron monitoring during fuel loading is operating correctly and is responsive to changes in neutron flux levels. Minimum count rates of 1/2 counts per second, attributable to core neutrons, are required on at least two of the available pulse-type nuclear channels at all times following installation of the initial nucleus of fuel assemblies (approximately eight fuel assemblies, one of which contains a neutron source), which permits meaningful inverse count-rate monitoring.

14.2.10.1.4 Inverse Count Rate Ratio Monitoring for Fuel Loading

Objective

Verify the neutron monitoring data obtained during initial fuel loading is consistent with calculations showing the predicted response and, for plants subsequent to the first plant, with data obtained during a previous similar fuel loading.

Prerequisites

- Temporary and plant source range nuclear instrumentation has been operational for a minimum of 60 minutes to allow the equipment to attain stable operating conditions

- The plant is prepared for initial fuel loading

- Neutron monitoring data from a previous similar initial fuel loading or calculations showing the predicted response of monitoring channels are available for evaluating monitoring data

Test Method

- Prior to inserting the first fuel assembly into the reactor vessel, obtain background count rates for each temporary and plant source range channel

- During the insertion of each fuel assembly, continuously observe the response of at least one channel for unexpected changes in count rate

- Construct a plot of inverse count rate ratio, versus fuel loading step number, from monitoring data obtained after each fuel assembly is loaded and used to assess the safety with which fuel loading may continue

Performance Criterion

Monitoring data are consistent with calculations showing the predicted response and, for plants subsequent to the first plant, with data obtained during a previous similar fuel loading. Each subsequent fuel addition will be accompanied by detailed neutron count rate monitoring to determine that the just loaded fuel assembly does not excessively increase the count rate and that the extrapolated ICRR is behaving as expected and not decreasing for unexplained reasons.

14.2.10.1.5 Initial Fuel Loading

Objectives

- Establish the conditions under which the initial fuel loading is to be accomplished
- Accomplish initial fuel loading in a safe manner

Prerequisites

- The nuclear design of the initial reactor core specifying the final core configuration of fuel assemblies and inserts is completed.

- Preoperational testing is completed on systems specified as required for initial fuel loading.

- Preoperational testing is completed on required fuel handling tools. Tools are available, operational, and calibrated, including indexing of the manipulator crane with a dummy fuel element.

- Containment integrity is established.

- The reactor vessel is filled with water to a level approximately equal to the center of the vessel outlet nozzles. The water is being circulated at a rate to provide uniform mixing.

- The boron concentration in the reactor coolant equals or exceeds the concentration required by the plant Technical Specifications for refueling. Core moderator chemistry conditions (particularly boron concentration) are prescribed in the core loading procedure document and are verified periodically by chemical analysis of moderator samples taken prior to and periodically during core loading operations.

- Sources of unborated water to the reactor coolant are isolated.

- Temporary and plant source range channels are operable as required to monitor changes in core reactivity.

- A surveillance program verifies that the conditions for fuel loading are maintained throughout the fuel loading program.

- Auxiliary system status is in accordance with Technical Specification requirements.

- The overall process of initial fuel loading will be supervised by a licensed senior reactor operator with no other concurrent duties.

Test Method

- Place fuel assemblies, together with inserted components (control rods, burnable poison elements, primary and secondary neutron sources), in the reactor vessel one at a time according to an established and approved sequence

- During and following the insertion of each fuel assembly and until the last fuel assembly has been loaded, the response of the neutron detectors is observed and compared to previous fuel loading data, or calculations, to verify that the observed changes in response are as expected

- Check sheets are completed at prescribed intervals verifying that the conditions required for initial fuel loading are being maintained

- Fuel assemblies, together with inserted components (control rod assemblies, burnable poison inserts, source spider, or thimble plugging devices) are placed in the reactor vessel one at a time according to a previously established and approved sequence, which was developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The core loading procedure documents include detailed tabular check sheets that prescribe and verify the successive movements of each fuel assembly and its specified inserts from its initial position in the storage racks to its final position and orientation in the core. Multiple checks are made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitutions of components, and fuel assembly status boards are maintained throughout the core loading operation. The results of each loading step will be reviewed and evaluated before the next prescribed step is started.

- The criteria for safe loading require that loading operations stop immediately if:

  – An unanticipated increase in the neutron count rate by a factor of two occurs in all responding nuclear channels during any single loading step after the initial nucleus of fuel assemblies is loaded.

  – An unanticipated increase in the count rate by a factor of five occurs on any individual responding nuclear channel during any single loading step after the initial nucleus of fuel assemblies is loading.

  – A decrease in boron concentration greater than 20 ppm is determined from two successive samples of reactor coolant system water until the decrease is explained.

Performance Criteria

All fuel assemblies have been loaded into the vessel in the correct location and orientation consistent with the prespecified configuration for the initial reactor core. All fuel loading steps are documented, including the final core configuration.

14.2.10.1.6 Post-Fuel Loading Precritical Test Sequence

Objective

Specify the sequence of events constituting the precritical test program.

Prerequisites

- Plant system conditions are established as required by the individual test instructions within the precritical test sequence, as described in subsections 14.2.10.1.7 through 14.2.10.1.20.
- The systems, structures, and components required by Technical Specifications shall be operable as required for the specified plant operational mode prior to initiation of precritical testing. Preoperational and precritical tests shall be completed to confirm the operability of required plant safety systems to support precritical testing prior to the initiation of the precritical tests.

Test Method

The instructions establish the sequence for required testing after core loading, until the plant has completed precritical testing.

Performance Criteria

Performance criteria are contained in the various individual tests conducted during this time (subsections 14.2.10.1.7 through 14.2.10.1.23).

14.2.10.1.7 Incore Instrumentation System Precritical Verification

Objectives

- Verify that the incore instrumentation thimbles have been installed correctly following initial fuel loading
- Verify proper operation of the incore thermocouples prior to plant heatup

Prerequisites

- Initial fuel loading has been completed, all incore instrumentation thimble assemblies have been installed, and all mechanical and electrical connections have been completed.
- The plant is at ambient temperature and pressure prior to heatup for initial criticality.

- Incore instrumentation system signal processing software has been installed and is operational.

Test Method

- With the plant at ambient conditions following initial fuel loading and prior to heatup for initial criticality, make electrical continuity checks at the incore instrumentation system panel to verify proper installation and connection of the incore sensor strings.

- Obtain incore thermocouple data and compare with the measured reactor coolant system temperature to verify proper operation of the incore thermocouples and signal processing.

Performance Criteria

- Prior to plant heatup, proper connections to the incore instrumentation thimbles are verified and outputs from the incore thermocouple system are consistent with existing plant conditions, and are consistent with design requirements specified in subsection 4.4.6 and Section 7.5 and applicable design specification.

- Data required for calibration of other plant instrumentation are obtained.

14.2.10.1.8 Resistance Temperature Detectors-Incore Thermocouple Cross Calibration

Objectives

- Verify calibration coefficients for the resistance temperature detectors installed in the reactor coolant system.

- Determine calibration coefficients for resistance temperature detectors replaced in the reactor coolant system following hot functional testing as required.

- Determine calibration coefficients for the incore thermocouples that are part of the incore instrumentation system.

Prerequisites

- Initial fuel loading has been completed and the reactor coolant system is filled and vented prior to heatup for initial criticality.

- Reactor coolant system resistance temperature detectors that were replaced as a result of preoperational testing are operational, and an initial alignment has been completed according to the manufacturer’s calibration data.

- The incore instrumentation system, including signal processing software, has been installed and is operational, and the preoperational testing has been completed.

- Instrumentation and data collection equipment is operational and available for logging plant data.

Test Method

- With the reactor coolant system at ambient temperature, and at isothermal conditions at specified temperature plateaus during heatup to normal operating temperature, measure the resistance of each resistance temperature detector installed in the reactor coolant system and the output from each installed incore thermocouple, along with supplemental plant data.
- Using the calibration coefficients determined during hot functional testing and the manufacturer's resistance versus temperature calibration data for the replaced resistance temperature detectors, determine the best-estimate temperature of each temperature plateau from the average of the derived resistance temperature detectors temperatures.
- On an iterative basis, recompute the best-estimate plateau temperature after removing from the average calculation the data from resistance temperature detectors whose temperature differs from the average by a predetermined amount.
- Verify or recompute calibration coefficients for each resistance temperature detector, as required, based on the final plateau average temperatures.
- Compute calibration coefficients for each incore thermocouple based on the final plateau average temperatures and supplemental data obtained during heatup.

Performance Criteria

- For each resistance temperature detector, the adequacy of the final calibration coefficients is verified when the temperature derived from the resistance temperature detector resistance agrees with the plateau average temperatures within predetermined limits as described in Sections 7.2 and 7.3.
- For each incore thermocouple, the adequacy of the final calibration coefficients is verified when the temperature derived from the thermocouple output agrees with the plateau average temperatures within predetermined limits, as described in subsection 4.4.6, Section 7.2 (Table 7.2-1) and Section 7.3 (Table 7.3-4).

14.2.10.1.9 Nuclear Instrumentation System Precritical Verification

Objective

Establish and determine voltage settings, trip settings, operational settings, alarm settings, and overlap of channels on source range instrumentation prior to initial criticality.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms.

- Set operational modes of the source range channels for their proper functions, in accordance with the test instructions.

Performance Criterion

The nuclear instrumentation system operates in accordance with the design basis functional requirements, as discussed in subsection 4.4.6.

14.2.10.1.10 Setpoint Precritical Verification

Objectives

- Prior to initial criticality, verify that initial values of instrumentation setpoints assumed in the design, operation, and safety analysis of the nuclear steam supply system have been installed correctly, and identify which of these are expected to be readjusted based on the results of startup testing and initial operations.

- Prior to initial criticality, document final values of instrumentation setpoints assumed in the design, operation, and safety analysis of the plant and as modified by initial startup testing, operations, or reanalysis to serve as a basis for future plant operations.

Prerequisites

- Initial alignment and calibration of plant instrumentation has been completed, and initial set points are installed per applicable design documentation.

- Preoperational and startup testing of affected plant instrumentation has been completed, and test results are documented.

Test Method

- Review applicable design documentation and generate a list of the instrumentation setpoints assumed in the design, operation, and safety analysis of the plant. Identify setpoints expected to be modified based on the results of initial startup tests and operations.

- Prior to initial criticality, the results of preoperational and startup tests, as applicable, are reviewed to verify that initial setpoints have been installed correctly. Document the results of this review for future use.

- Prior to initial criticality, summarize and document the setpoint values for future plant operations.

Performance Criterion

Prior to initial criticality, installed setpoint values are verified to be consistent with Technical Specifications.

14.2.10.1.11 Rod Control System

Objective

Demonstrate and document that the rod control system performs the required control and indication functions just prior to initial criticality.

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure
- The nuclear instrumentation system source range channels are aligned and operable

Test Method

- With the reactor at no-load temperature and pressure, just prior to initial criticality, verify the operation of the rod control system in various modes including tests of control rod block and inhibit functions.
- Verify the operation of status lights, alarms, and indicators

Performance Criteria

- The performance of the rod control system as described in subsection 7.7.1.2.
- The rod control system withdraws and inserts each rod bank
- The rod position and indication system tracks each rod bank as it is being moved
- The control banks overlap system starts and stops rod movement at the designated bank positions

14.2.10.1.12 Rod Position Indication System

Objective

Verify that the rod position indication system satisfactorily performs required indication and alarm functions for each individual rod and that each rod operates satisfactorily over its entire range of travel.

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure

- At least one reactor coolant pump is in service, with reactor coolant boron concentration not less than specified in the Technical Specifications for refueling shutdown

Test Method

Individually withdraw rod banks from the core and reinsert them, according to the test procedure. Record rod position sensor output voltages, and rod position readouts and group step counters in the main control room.

Performance Criterion

The rod position indication system performs the required indication and alarm functions as discussed in subsection 7.7.1.3, and each rod operates over its entire range of travel.

14.2.10.1.13 Control Rod Drive Mechanisms

Objectives

- Demonstrate operation of each control rod drive mechanism under both cold and hot standby conditions

- Provide verification of slave cycler timing

Prerequisites

- The reactor coolant system is filled and vented at cold shutdown
- Rods are fully inserted
- Nuclear instrumentation channels are available
- A fast-speed oscillograph, or equivalent, to monitor test parameters is available

Test Method

- With the reactor core installed and the reactor in the cold shutdown condition, confirm that the slave cycler devices supply operating signals to the control rod drive mechanism stepping magnet coils.

- Verify operation of all control rod drive mechanisms under both cold and hot standby conditions. Record the control rod drive mechanism magnet coil currents.

Performance Criterion

The control rod drive mechanisms conform to the requirements for proper mechanism operation and timing including control rod withdrawal and insertion speeds as described in the applicable design specifications.

14.2.10.1.14 Rod Drop Time Measurement

Objectives

- Determine the rod drop time of each rod cluster control assembly under cold no-flow and hot full-flow conditions, with the reactor at normal operating temperature and pressure.

- Verify the operability of the control rod deceleration device.

Prerequisites

- Initial core loading is completed
- Source range channels are in operation
- Rods are fully inserted
- Reactor coolant pumps are operational

Test Method

- Withdraw each rod cluster control assembly

- Interrupt the electrical power to the associated control rod drive mechanism

- Measure and record the rod drop time, and verify control rod deceleration

- Perform a minimum of three additional drops for each control rod whose drop time falls outside the two-sigma limit, as determined from the drop times obtained for each test condition

Performance Criteria

- Measured rod drop times are consistent with the design basis functional requirements and the applicable plant Technical Specifications

- The control rod is slowed by the control rod deceleration device during rod drop testing

14.2.10.1.15 Rapid Power Reduction System

Objective

Verify proper operation of the rapid power reduction system prior to power operations.

Prerequisites

- The following systems are operable to the extent necessary to support the test: rod control system, rod position indication system, reactor trip breakers, and reactor protection system.

- The reactor is shut down, the reactor coolant system boron concentration is such that Technical Specifications requirements for shutdown margin will be met with required rod withdrawal, and all control banks are near their fully inserted positions.

Test Method

- Input signals simulating operation at the full power condition to the reactor control and protection system. Close the reactor trip breakers.

- Input signals simulating a rapid loss of load exceeding 50 percent power are input to the rapid power reduction system. Verify the response of the system.

- Demonstrate procedures for returning the plant to power following a partial trip.

Performance Criteria

- Performance of the rapid power reduction system is in accordance with subsection 7.7.1.10.

- In response to the simulated loss of load, gripper power is interrupted to a preselected grouping of control rods, so that rods drop freely into the core.

- Gripper power to only those control rods selected for drop is interrupted.

- Procedures for returning the plant to power operations without a reactor trip are verified.

14.2.10.1.16 Process Instrumentation Alignment

Objective

Align ΔT and T_{avg} process instrumentation under isothermal conditions prior to initial criticality.

Prerequisites

- Reactor coolant pumps are operating
- The reactor coolant system average temperature is at the hot no-load average temperature

Test Method

- Align ΔT and T_{avg} according to test instructions at isothermal conditions prior to criticality

Performance Criterion

The indicated values for reactor coolant system T_{hot}, T_{cold}, T_{avg}, and ΔT under isothermal conditions are within the limits of the applicable design requirements as discussed in Section 7.2 (Table 7.2-1) and Section 7.3 (Table 7.3-4).

14.2.10.1.17 Reactor Coolant System Flow Measurement

Objectives

- Prior to initial criticality, verify that the reactor coolant system flow rate is sufficient to permit operation at power.

Prerequisites

- The core is installed and the plant is at normal operating temperature and pressure.
- Special instrumentation is installed and calibrated for obtaining reactor coolant flow data.

Test Method

- Prior to initial criticality, measure the reactor coolant flow measurement parameters with all four coolant pumps in operation. Estimate the reactor coolant flow rate using these data.

Performance Criterion

The estimated reactor coolant flow rate from data taken prior to initial criticality equals or exceeds 90 percent of the minimum value required by the plant Technical Specifications for full power operation.

14.2.10.1.18 Reactor Coolant System Flow Coastdown

Objectives

- Measure the rate at which reactor coolant loop flow and pump speed changes, subsequent to tripping all reactor coolant pumps.

- Measure the rate at which reactor coolant loop flow and pump speed changes, subsequent to tripping two of four reactor coolant pumps.

Prerequisites

- Required component testing and instrument calibration are complete

- Required electrical power supplies and control circuits are operational

- The reactor core is installed, and the plant is at normal operating temperature and pressure with all reactor coolant pumps running

Test Method

- Record loop flow, pump speeds following the trip of all reactor coolant pumps
- Record loop flows, pump speeds following the trip of two of four reactor coolant pumps

Performance Criterion

The loop flows and pump speed data are obtained for verification of the loss of flow analyses in subsections 15.3.1 and 15.3.2.

14.2.10.1.19 Pressurizer Spray Capability and Continuous Spray Flow Verification

Objectives

- Establish the optimum continuous spray flow rate
- Determine the effectiveness of the normal control spray

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure.
- All reactor coolant pumps are operating.

Test Method

- While maintaining constant pressurizer level, adjust spray bypass valves until a minimum flow is achieved that maintains the temperature difference between the spray line and the pressurizer within acceptable limits.

- With the pressurizer heaters de-energized, fully open both spray valves, and record the time to lower the pressurizer pressure a specified amount.

Performance Criteria

- The spray bypass valves are throttled so that the minimum flow necessary to keep the spray line warm is achieved.

- The pressurizer pressure response to the opening of the pressurizer spray valves is within design basis functional limits as specified in subsection 7.7.1.6 and the appropriate pressure control system design specification documentation.

14.2.10.1.20 Feedwater Valve Stroke Test

Objective

Verify proper operation of the main and startup feedwater control valves prior to the start of power operations.

Prerequisites

- Preoperational testing of the feedwater control systems has been completed
- Main and startup feedwater pumps are off
- Initial fuel loading has been completed prior to initial criticality.

Test Method

For each main and startup feedwater flow control valve, the following tests are performed:

- Using simulated signals for several valve demand positions covering the range from fully closed to fully open, verify the actual valve position to be consistent with the demand signal.

- For selected valve position changes, measure the time required from the initiation of the demand signal until the valve reaches the final position. Typical demands changes are the following: fully closed to fully open, fully open to fully closed, 25 percent open to 75 percent open, and 75 percent open to 25 percent open.

Performance Criteria

The main and startup feedwater valves operate as described in subsection 7.7.1.8 and appropriate design specifications including:

- The differences between the measured actual and demand valve positions, over the range of travel, are less than prespecified tolerances.

- The time between the initiation of the demand signal and the final valve position for each of the demand changes is within specified ranges as discussed in applicable design specifications.

- For demand changes to intermediate valve positions, the amount of overshoot is less than specified limits as discussed in applicable design specifications.

14.2.10.2 Initial Criticality Tests

Initial criticality testing is described in this section. Following completion of the core loading and precriticality testing, the plant is brought to initial criticality, according to the test procedures in subsection 14.2.10.2.1.

14.2.10.2.1 Initial Criticality Test Sequence

Objective

Define the sequence of tests and operations to bring the core to initial criticality.

Prerequisite

Plant system conditions are established as required by the individual test instructions within this sequence.

Test Method

An individual test instruction will establish the plant conditions required for initial criticality.

Performance Criteria

Relevant performance criteria are provided in each of the test procedure abstracts.

14.2.10.2.2 Initial Criticality

Objective

Achieve initial criticality in a controlled manner.

Prerequisites

- The nuclear instrumentation is verified to be operating properly (See 14.2.10.2.3)
- The reactor coolant system temperature and pressure are stable at the normal hot no-load values
- Control rod banks are inserted, and shutdown rod banks are withdrawn
- The reactor coolant system boron concentration is sufficiently high so the reactor is shut down by at least 1000 pcm with all banks withdrawn

Test Method

- Accomplish initial criticality by the controlled withdrawal of the rods using the same rod withdrawal sequence used for normal plant startup, followed by the dilution of the reactor coolant system boron concentration.
- At preselected points during rod withdrawal and/or boron dilution, gather data to plot the inverse count rate ratio to monitor the approach to critical evolution for reactivity monitoring.
- As criticality is approached, slow or stop dilution rate to allow criticality to occur during mixing or by withdrawal of rods that have been slightly inserted for control.

Performance Criterion

The reactor is critical.

14.2.10.2.3 Nuclear Instrumentation System Verification

Objective

Establish and determine voltage settings, trip settings, operational settings, alarm settings, and overlap of channels on source and intermediate range instrumentation, from prior to initial criticality and during initial criticality.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms.
- Set operational modes of the source and intermediate range channels for their proper functions, in accordance with the test instructions.

Performance Criteria

- The nuclear instrumentation system operates in accordance with the design basis functional requirements, as discussed in subsection 4.4.6.
- The nuclear instrumentation system demonstrates an overlap of indication between the source and intermediate range instrumentation.
- The nuclear instrumentation minimum neutron count rate and noise to signal ratio are within appropriate design specifications.

14.2.10.2.4 Post-Critical Reactivity Computer Checkout

Objective

Demonstrate proper operation of the reactivity computer through a dynamic test using neutron flux signals.

Prerequisites

- The reactor is critical with the neutron flux level within the range for low-power physics testing
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- The reactivity computer is installed, checked out, and operational, and input flux signals are representative of the core average neutron flux level
- The controlling rod bank is positioned in such a way that the required reactivity insertion can be made by rod motion alone
- The systems, structures, and components required by Technical Specifications shall be operable as required for the specified plant operational mode prior to initiation of precritical, low power physics, and power ascension testing. Verification of proper operation of

source-range and intermediate-range excore nuclear instrumentation and associated alarms and protective functions in Startup Test 14.2.10.2.3 shall be completed prior to initiation of this startup test.

Test Method

- By control rod motion, add positive reactivity to the core in accordance with design requirements as discussed in Section 7.7.
- During the resultant increase in flux level, make two independent measurements of core reactivity; one using the reactivity computer, and one using an analysis of the rate of change of flux level (for example, reactor period or doubling time).

Performance Criterion

Each measurement deviation between the two independent sources of reactivity is within design tolerances. Adjustment and recalibration or repair of the reactivity computer may be required if the deviation between the two independent sources of reactivity is not within design tolerances.

14.2.10.3 Low Power Tests

Following successful completion of the initial criticality tests, low power tests are conducted, typically at power levels less than 5 percent, to measure physics characteristics of the reactor system and to verify the operability of the plant systems at low power levels.

14.2.10.3.1 Low-Power Test Sequence

Objective

Define the sequence of tests and operations that constitutes the low-power testing program.

Prerequisite

Plant system conditions are established as required by the individual test instructions within this sequence.

Test Method

Individual test instruction will establish the plant conditions required for and during the low-power testing program following initial criticality.

Performance Criteria

Relevant performance criteria are provided in each of the test procedure abstracts.

14.2.10.3.2 Determination of Physics Testing Range

Objectives

- Determine the reactor power level at which the effects from fuel heating are detectable
- Establish the range of neutron flux in which zero power reactivity measurements are to be performed

Prerequisites

- The reactor is critical, and the neutron flux level is below the expected level of nuclear heating
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- The reactivity computer is installed, checked out, and operational, and input flux signals are representative of the core average neutron flux level
- The controlling rod bank is positioned in such a way that the required reactivity insertion can be made by rod motion alone

Test Method

- Withdraw the control rod bank and allow the neutron flux level to increase until nuclear heating effects are indicated by the reactivity computer
- Record the reactivity flux level and the corresponding intermediate range channel currents at which nuclear heating occurs
- Multiply the measured reactivity flux level by 0.3 to determine the maximum value for the zero power testing range

Performance Criterion

The zero power testing range is determined.

14.2.10.3.3 Boron Endpoint Determination

Objective

Determine the critical reactor coolant system boron concentration appropriate to an endpoint rod configuration.

Prerequisites

- The reactor is critical, and the neutron flux level is within the range for low-power physics testing

- The reactor coolant system temperature and pressure are stable at the normal no-load values

- The neutron flux level and reactor coolant system boron concentration are stable

- Instrumentation and equipment used to measure and compute reactivity is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level

- The controlling rod bank is positioned in such a way that limited reactivity insertion will be required to achieve the endpoint condition

Test Method

- Move the rods to the desired endpoint configuration without boron concentration adjustment

- Directly measure the just-critical boron concentration by chemical analysis

- Measure and convert the change in reactivity and the reactor coolant temperature difference from program to an equivalent change in boron concentration

- Add the changes to the just-critical boron concentration to yield the endpoint for the given rod configuration

Performance Criterion

The measured value for the boron endpoint is consistent with the design value within design limits as specified in the Technical Specifications.

14.2.10.3.4 Isothermal Temperature Coefficient Measurement

Objectives

- Determine the isothermal temperature coefficient
- Calculate the moderator temperature coefficient

Prerequisites

- The reactor is critical, and the neutron flux level is within the range for low-power physics testing

- The reactor coolant system temperature and pressure are stable at the normal no-load values

- The neutron flux level and reactor coolant system boron concentration are stable

- Instrumentation and equipment used to measure and compute reactivity is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level

- The controlling rod bank is positioned near fully withdrawn

Test Method

- Vary reactor coolant system temperature (heatup/cooldown) while maintaining rods and boron concentration constant

- Monitor reactivity results and determine the isothermal temperature coefficient

- Calculate the moderator temperature coefficient using the isothermal temperature coefficient and design values

Performance Criterion

- The measured value for the moderator temperature coefficient is more negative than the Technical Specification limit

14.2.10.3.5 Bank Worth Measurement

Objective

Validate design calculations of the reactivity worth of the rod cluster control banks.

Prerequisites

- The reactor is critical and the neutron flux level is within the range for low-power physics testing

- The reactor coolant system temperature and pressure are stable at the normal no-load values

- The neutron flux level and reactor coolant system boron concentration are stable

- Instrumentation and equipment used to measure and compute reactivity is installed and operational, with input flux signals representative of the core average neutron flux level

Test Method

- One of the following methods will be used to measure the worth of all of the individual control rod banks:

  – A bank is stepwise inserted into the core from fully withdrawn and the worth is measured using the reactivity computer

– Exchange bank with another bank measured as above, with the worth determined from the critical positions and the worth of the reference bank

Performance Criteria

- The measured value for the individual bank worth is consistent with the design value within specified limits as discussed in subsection 4.3.2.5.

- The sum of the measured bank worth is consistent with the design value within the assumed uncertainty used in the shutdown margin calculation

14.2.10.3.6 Natural Circulation (First Plant Only)

Objective

Demonstrate that core decay heat can be removed by the steam generators under the conditions of natural circulation (no reactor coolant pumps operating).

Prerequisites

- The reactor is critical, and the neutron flux level is within the range for low-power physics testing

- The neutron flux level and reactor coolant system boron concentration and temperature are stable, and the controlling rod bank is positioned in such a way that an increase in core power level to approximately 3 percent can be achieved by rod motion alone

- Reactor coolant pumps are operating

- The reactivity computer is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level

- Instrumentation and data collection equipment is operational and available for logging plant data

- Special instrumentation is available to measure vessel ΔT with high precision at low-power levels

Test Method

- Because this test is performed at beginning of life when the core fission product density is low, decay heat is simulated by reactor power

- By control rod motion, increase reactor power to approximately 3 percent of full power based on predictions of vessel ΔT at full power

- With reactor coolant pumps running, obtain data for correlating nuclear flux level and loop temperatures with power

- Trip all reactor coolant pumps. Maintain core power at approximately 3 percent by control rod motion while cold leg temperatures remain relatively constant.

- Verify natural circulation by observing the response of the hot leg temperature in each loop. The plant is stable under natural circulation at this power level when hot leg temperature is constant.

- Obtain data characterizing the plant under natural circulation conditions

- Restart reactor coolant pumps only after the reactor is shut down and isothermal conditions are re-established

Performance Criterion

The measured average vessel ΔT under natural circulation conditions is equal to or less than limiting design predictions for the measured reactor power level as specified in the applicable design specifications.

14.2.10.3.7 Passive Residual Heat Removal Heat Exchanger (First Plant Only)

Objective

[*Demonstrate the heat removal capability of the passive residual heat removal heat exchanger with the reactor coolant system at prototypic temperatures and natural circulation conditions.*]* Note that this test is performed in conjunction with the reactor coolant system natural circulation test with heat removal via the steam generators described in subsection 14.2.10.3.6.

Prerequisites

As described in subsection 14.2.10.3.6, the following prerequisites have been met in preparation for the natural circulation test with heat removal via the steam generators:

- The reactor is critical and the neutron flux level is within the range for low power physics testing.

- The neutron flux level and reactor coolant system boron concentration and temperature are stable, and the controlling rod bank is positioned in such a way that an increase in core power level to approximately 5 percent can be achieved by rod motion only.

- Reactor coolant pumps are running.

- The reactivity computer is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level.

- Instrumentation and data collection equipment is operational and available for logging plant data.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Special instrumentation is available to measure the reactor vessel ΔT with high precision at low power levels.

- The passive residual heat removal heat exchanger inlet and outlet temperature instrumentation and heat exchanger flow instrumentation are calibrated and operational.

- The passive residual heat exchanger inlet isolation valve is operational and in its open position, and the heat exchanger outlet isolation valves are operational and in their closed position.

- The startup feedwater system and controls are operating properly to maintain the steam generator secondary side water levels.

- The steam generator steam dump system is operating properly to maintain steam generator pressure so that the reactor coolant system cold leg fluid is at its expected temperature.

- The chemical volume control system auxiliary spray and letdown flow path are operable for controlling the pressurizer pressure and level, respectively after the reactor coolant pumps are shutoff.

Test Method

[*Note that the following test steps are to be performed at the conclusion of the natural circulation test with heat removal via the steam generators.*

- *Verify that the natural circulation test with core power being removed by dumping steam from the steam generators has been completed.*

- *Initiate flow through the passive residual heat removal heat exchanger by slowly opening one of the two parallel heat exchanger outlet isolation valves until it is fully open.*

- *The steam generator steam dump will automatically reduce heat removal by the steam generators in response to passive residual heat exchanger operation. Manual operation of the control rods may be required to maintain core power at approximately 3 percent.*

- *Obtain heat exchanger flow and inlet/outlet temperature data to characterize the heat removal capability of the heat exchanger and heatup of the in-containment refueling water storage tank water with one of two parallel isolation valves open.*

- *Close the open heat exchanger isolation valve to terminate the heat exchanger test. The steam generator steam dump should automatically maintain the reactor coolant system fluid average temperature constant. Note that operation of the passive residual heat exchanger should be terminated before the in-containment refueling water storage tank average water temperature exceeds 150°F.*

- *Shutdown the reactor by inserting the control rods. Restart reactor coolant pumps only after the reactor is shutdown and isothermal conditions are re-established.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Performance Criteria

[*The measured passive residual heat exchanger heat removal rate is equal to or greater than the heat removal rate predicted by the methodology used in the safety analyses at the measured hot leg and in-containment refueling water temperatures.*]*

14.2.10.4 Power Ascension Tests

After low power testing is completed, testing is performed at specified elevated power levels to demonstrate the facility operates in accordance with design during normal steady-state operations, and to the extent practical, during and following anticipated transients. During power ascension, tests are performed to obtain operational data and to demonstrate the operational capabilities of the plant.

14.2.10.4.1 Test Sequence

Objective

Define the sequence of operations, beginning at approximately 5 percent rated thermal power, that constitutes the power ascension testing program.

Prerequisite

Plant system conditions are established, as required, by the individual test instruction within this sequence.

Test Method

Present the sequence of operations and tests, along with instructions, specific plant conditions, and test procedures.

Performance Criteria

Relevant performance criteria are provided in each of the test procedures.

14.2.10.4.2 Incore Instrumentation System

Objectives

- Obtain data for incore thermocouple and flux maps at various power levels during ascension to full power determine flux distributions and verify proper core loading and fuel enrichments.

Prerequisites

- Incore instrumentation system signal processing software is installed and operational

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- For incore thermocouple and flux mapping, the plant is at various power levels greater than approximately 20 percent of rated thermal power

Test Method

- With the plant at approximate power levels of 25, 50, 75 and 100 percent of rated thermal power, obtain data from the incore instrumentation system and process to produce incore thermocouple and flux maps. (Actual power levels will be specified in the power ascension program test sequence.)

- Use data from the incore maps to verify that core power distribution is consistent with design predictions and the limits imposed by the plant Technical Specifications, including detection of potential fuel loading errors, and to calibrate other plant instrumentation. Refer to Technical Specifications Section 3.2, Power Distribution Limits.

Performance Criteria

- Core power peaking factors derived from the incore data are consistent with design predictions and the limitations of the plant Technical Specifications

- Data required for calibration of other plant instrumentation are obtained

14.2.10.4.3 Nuclear Instrumentation System

Objective

Establish and determine voltage settings, trip settings, operational settings, alarm settings, and overlap of channels on intermediate range and power range instrumentation from zero power to at or near full rated thermal power.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms

- Set operational modes of the intermediate range and power range channels for their proper functions, in accordance with the test instructions

Performance Criteria

- The nuclear instrumentation system operates in accordance with the design basis functional requirements as discussed in subsection 4.4.6.

- The nuclear instrumentation system demonstrates an overlap of indication between the intermediate and power range instrumentation.

14.2.10.4.4 Setpoint Verification

Objective

During power ascension, document final values of instrumentation setpoints as modified by initial startup testing, operations, or reanalysis to serve as a basis for future plant operations.

Prerequisites

- Initial alignment and calibration of plant instrumentation have been completed, and initial set points are installed per applicable design documentation

- Preoperational and startup testing of affected plant instrumentation has been completed, and test results are documented

- The results of the precritical verification of the instrument setpoints are completed and documented

Test Method

- Identify setpoints modified based on the results of initial startup tests and operations

- During power ascension testing, readjust specific setpoints noted for readjustment on the data sheets if required. Record final setpoint values.

Performance Criterion

Setpoint changes based on initial startup testing and operations are documented for future reference.

14.2.10.4.5 Startup Adjustments of Reactor Control Systems

Objectives

- Determine the adequacy of the reactor coolant system programmed T_{avg}

- Obtain plant data during power ascension which would provide the basis for any required changes to the T_{avg} program

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure
- The reactor coolant system temperature is being controlled by the steam dump valves

Test Method

- Obtain system temperature and steam pressure data at steady-state conditions for zero rated thermal power and at hold points during power escalations

- At approximately 75 percent rated thermal power, modify the T_{avg} program as required to achieve design steam generator pressure at full power, based on extrapolation of the data to the full power condition.

- Reevaluate the T_{avg} program as above at approximately 90 and 100 percent rated thermal power making modifications to the T_{avg} program as required.

Performance Criterion

The reactor coolant system T_{avg} program is established such that steam generator pressure at the full rated thermal power condition is within design functional requirements as discussed in Section 5.1.

14.2.10.4.6 Rod Cluster Control Assembly Out of Bank Measurements (First Plant Only)

Objectives

- Demonstrate the sensitivity of the incore and excore instrumentation system to rod cluster control assembly (RCCA) misalignments

- Demonstrate the design conservatism for predicted power distributions with a fully misaligned rod cluster control assembly

- Monitor the power distribution following the recovery of a misaligned rod cluster control assembly

Prerequisites

- The reactor is operating between 30 and 50 percent of full licensed power and has been at that power for a sufficient time to reach xenon equilibrium.

- The reactor power level, reactor coolant system boron concentration, and temperature are stable.

- The control and shutdown banks are positioned as required for the specific measurement, near fully withdrawn for rod cluster control assembly insertion, and at their respective insertion limits for rod cluster control assembly withdrawal.

Test Method

- For the rod cluster control assembly insertion, insert a group of selected rod cluster control assemblies, one at a time, first to the limit of misalignment specified in subsection 15.0.5,

then fully inserted, and finally restored to the bank position. Compensate for reactivity changes by dilution and boration as required.

- For the rod cluster control assembly withdrawal, withdraw one or more selected rod cluster control assemblies, one at a time, to the fully withdrawn position. Compensate for reactivity changes by boration and dilution as required.

- Record incore and excore instrumentation signals to determine their response and to determine the power distribution and power peaking factors prior to rod cluster control assembly misalignment, at partial misalignment, at full misalignment, and periodically after restoration to normal.

Performance Criteria

- Measured power distributions and power peaking factors are within Technical Specification limits and are consistent with the predictions.

- The sensitivity of the incore and excore instrumentation to rod cluster control assembly misalignment is demonstrated by examination of the power distribution and power peaking factors measured for each misalignment.

14.2.10.4.7 Axial Flux Difference Instrumentation Calibration

Objectives

- Calibrate the power range nuclear instrumentation signals used as axial flux difference (delta flux) input to the reactor protection system

- Calibrate instrumentation used to display and monitor axial flux difference

Prerequisites

- The reactor is at a power level greater than 50 percent of rated thermal power
- The incore instrumentation system is available for obtaining incore power distribution data
- A preliminary calibration of the axial flux difference indication instrumentation is completed

Test Method

- Using control rod movement, xenon redistribution, or a combination of both, vary the axial power distribution of the core over a specified range of interest. At selected values of indicated axial flux difference, obtain reactor thermal power data along with the outputs from the nuclear instrumentation power range channels and the incore instrumentation system. (For the first plant, a minimum of three data sets will be taken; subsequent cores may require less.)

- Calibrate signals from the nuclear instrumentation power range channels based on incore power distribution and thermal power data.

Performance Criterion

Axial flux difference signals, derived from the nuclear instrumentation power range detectors and input to the reactor protection system, display, and monitoring instrumentation, reflect actual incore power distribution within specified limits, as discussed in subsection 7.7.1.1.

14.2.10.4.8 Primary and Secondary Chemistry

Objective

Verify proper water quality in the reactor coolant system and secondary coolant system.

Prerequisite

The plant is at the steady-state condition at approximately 0, 25, 50, 75, and 100 percent rated thermal power.

Test Method

Analyze samples to determine the chemical and radiochemical concentrations.

Performance Criterion

The chemical and radiochemical control systems maintain the water chemistry within the applicable guidelines as discussed in subsections 5.2.3.2 and 10.3.5.

14.2.10.4.9 Process Measurement Accuracy Verification

Objectives

- Measure the temperature variation in the reactor coolant loops resulting from non-uniform flow effects such as streaming
- Measure the sensitivity of the excore detectors to variations in control bank position and reactor coolant loop cold leg temperature

Prerequisites

- For the reactor coolant loop temperature measurements:
  - Special temperature measuring equipment, including recording and indicating instrumentation, is installed, as required, on the reactor coolant loops hot and cold leg piping
  - The reactor is at a stable power level of approximately 0, 50, 75 and 100 percent of rated thermal power

- For the excore detector measurements:
  - The reactor is at a stable power level of approximately 25, 50 and 100 percent of rated thermal power

Test Method

- For the reactor coolant loop temperature measurements, at each power level:
  - Measure reactor power level, using calorimetric data
  - Simultaneously, measure the hot and cold leg temperatures, using normal plant instrumentation and any other required instrumentation
- For the excore detector tests, with the reactor at constant power level:
  - Measure the response of the excore detectors as selected control banks are moved over prescribed ranges of travel
  - Measure excore detector response as the reactor coolant cold leg temperature is varied over a prescribed range
  - Simultaneously, for each of the preceding measurements, obtain calorimetric data to verify reactor power level

Performance Criteria

- Uncertainties in reactor coolant loop temperature measurements resulting from non-uniform flow effects such as streaming are consistent with allowances used in the plant safety analyses.
- Uncertainties in excore detector response resulting from control rod motion and reactor coolant loop cold leg temperature changes are consistent with allowances used in the plant safety analyses.

14.2.10.4.10 Process Instrumentation Alignment at Power Conditions

Objective

Align ΔT and T_{avg} process instrumentation at power conditions.

Prerequisites

- Reactor coolant pumps are operating.
- The reactor system is operating at the required power level.

Test Method

- Align ΔT and T_{avg} according to test instructions at approximately 75 percent rated thermal power. Extrapolate the 75 percent data to determine ΔT and T_{avg} values for the 100 percent plateau.

- At or near 100 percent rated thermal power, check the alignment of the ΔT and T_{avg} channels for agreement with the results of the thermal power measurement.

Performance Criterion

The indicated values for reactor coolant system T_{hot}, T_{cold}, T_{avg}, and ΔT at or near full thermal power are within the limits of the applicable design requirements, as discussed in Section 5.1.

14.2.10.4.11 Reactor Coolant System Flow Measurement at Power Conditions

Objective

At power, verify that the reactor coolant flow equals or exceeds the minimum value required by the plant Technical Specifications.

Prerequisites

- The reactor is at power levels greater than 75 percent and up to and including 100 percent of rated thermal power

- Special instrumentation required for measuring reactor thermal power and reactor coolant inlet and outlet temperatures is installed and calibrated

Test Method

With the reactor at steady-state power greater than 75 percent and up to and including 100 percent of rated thermal power, measure the reactor thermal power and coolant inlet and outlet temperatures. Determine the reactor coolant flow rate using the data in conjunction with hydraulic analysis of differential pressures at different locations in the reactor coolant system.

Performance Criterion

The reactor coolant system flow determined from the measurements at approximately 100 percent rated thermal power equals or exceeds the minimum value required by the plant Technical Specifications.

14.2.10.4.12 Steam Dump Control System

Objective

Verify automatic operation of the T_{avg} steam dump control system, demonstrate controller setpoint adequacy, and obtain final settings from steam pressure control of the condenser dump valves.

Prerequisites

- Steam dump control system is aligned and calibrated to initial settings
- Plant is at no-load temperature and pressure
- Condenser vacuum is established
- Reactor is critical

Test Method

- Increase reactor power to less than 10 percent rated thermal power by rod withdrawal and steam dump to condenser to demonstrate setpoint adequacy

- Increase pressure controller setpoint prior to switching to T_{avg} control, which rapidly modulates open condenser dump valves

- Simulate turbine operating conditions with reactor at power, then simulate a turbine trip resulting in the rapid opening of the steam dump valves

Performance Criteria

- The plant trip controller responds to maintain a stable T_{avg}. After steady-state power is achieved, no divergent oscillations in temperature occur

- The loss of load controller responds properly to maintain a specified stable T_{avg}. After steady-state power is achieved, no divergent oscillations in temperature occur

- The steam header pressure controller responds to maintain a stable pressure at normal no-load pressure

14.2.10.4.13 Steam Generator Level Control System

Objective

Verify the stability of the automatic steam generator level control system by introducing simulated transients at various power levels during escalation to full power.

Prerequisites

- The reactor is critical and stable at various power levels during the power escalation test program. (Typical power levels are 30, 75 and 90 percent of full rated thermal power)

- The steam generator level control system is checked and calibrated

- Steam generator alarm setpoints are set for each generator

Test Method

- At each power level, with the steam generator control system in manual mode, simulate level transients by changing the level setpoint. Verify the steam generator level control response when the control system is returned to automatic control.

- Verify the variable speed features of the main feedwater pumps by manipulating controllers and test input signals.

Performance Criteria

- During recovery from a simulated steam generator level transient, steam generator level control response is consistent with the design for the following: overshoot or undershoot to the new level, time required to achieve the new level, and error between the actual level and control setpoint.

- Feedwater pump discharge pressure oscillations are less than design test limits

- The main feedwater control valves open and stabilize in response to various steam flow conditions in accordance with design requirements discussed in subsection 7.7.1.8.

14.2.10.4.14 Radiation and Effluent Monitoring System

Objectives

- For monitors that:
  - Are used for establishing conformance within the safety limits or limiting conditions for operation that are included in the Technical Specifications, or
  - Are classified as engineered safety features, or are relied on to support operation of the engineered safety features within design limits, or
  - Are assumed to function or for which credit is taken in the accident analysis of the facility, and
  - Are used to process, store, control, or limit the release of radioactive materials

- The objectives are:
  - Verify the calibration of the process and effluent radiation monitor against an acceptable standard
  - Establish baseline activity and background levels
  - Demonstrate that process and effluent radiation monitoring systems respond correctly by performing independent analyses

Prerequisites

- The plant is stable at the desired power level
- The sampling systems for the process and effluent radiation monitoring systems are operable

Test Method

- Perform calibrations with the use of radioactive sources to verify proper operation of the monitors and detectors

- Collect and analyze samples with laboratory instruments, and compare the results from the process and effluent monitor to verify proper monitor operation

- Establish background levels at low power (less than 5 percent rated thermal power)

- Establish background levels and baseline activity levels determined by sampling at 100 percent rated thermal power to monitor the buildup of activity

Performance Criteria

- Radiation monitors are calibrated against radioactive standards

- Baseline activities are established

- Laboratory analyses agree, given sensitivity and energy response, with the process and effluent radiation monitors

14.2.10.4.15 Ventilation Capability

Objective

Verify that heating, ventilation, and air conditioning systems for the containment and areas housing engineered safety features continue to maintain design temperatures.

Prerequisite

The plant is operating at or near the desired power (0, 50, and 100 percent of rated power).

Test Method

- Record temperature readings in specified areas while operating with normal ventilation lineups

- Record temperature readings in specified areas while operating the designed minimum number of heating ventilation and air conditioning components consistent with existing plant conditions

- Record surface concrete temperatures adjacent to the high temperature piping penetrations and at selected locations on the concrete shielding (at 100 percent rated thermal power only)

Performance Criterion

The heating, ventilation and air conditioning systems for the containment and areas housing engineered safeguards features perform as designed in accordance with subsections 9.4.1 and 9.4.6.

14.2.10.4.16 Biological Shield Survey

Objectives

- Document the radiation levels in accessible locations of the plant outside of the biological shield while at power

- Obtain baseline radiation levels for comparison with future measurements of level buildup with operation

Prerequisites

- Radiation survey instruments are calibrated
- Background radiation levels are measured in designated locations prior to initial criticality
- The plant is stable at the applicable power level

Test Method

Measure gamma and neutron radiation dose rates at designated locations at approximately 25, 50, 75, and 100 percent rated thermal power.

Performance Criterion

Radiation levels are acceptable for full-power operation and consistent with design expectations.

14.2.10.4.17 Thermal Power Measurement and Statepoint Data Collection

Objective

Obtain thermal power measurement and statepoint data at selected power levels during the power ascension testing program, typically at 25, 50, 75, and 100 percent of rated thermal power.

Prerequisites

- The following equipment is installed and is operational: sensors for measuring steam generator feedwater temperature, differential pressure measuring devices for determining feedwater flow to each steam generator, and pressure gauges to measure steam pressure at steam generator outlets.

- The pressurizer pressure and level control system, and the steam generator level control system are in automatic mode.

- Instrumentation and data collection equipment is available for logging supplemental plant data.

- Reactor power is stable at the required level.

Test Method

The required data are obtained using installed plant equipment, special test equipment, and the plant data processing equipment. These data are subsequently used to determine reactor thermal power and assess the performance of the plant.

Performance Criterion

Reactor thermal power is stable at each power level and at the rated level at full power conditions. Operability of the pressurizer pressure and level control systems not previously verified as part of reactor coolant system preoperational testing (subsection 14.2.9.2.1) is demonstrated.

14.2.10.4.18 Dynamic Response

Objectives

Demonstrate during power range testing that the stress analysis for selected systems and components, under transient conditions is within design functional requirements. Portions of systems that meet the selection criteria for subsection 14.2.9.1.7 for dynamic effects testing, but were not tested because system conditions during hot functional testing are not conducive to prototypical systems conditions, are tested.

Prerequisites

- Temporary instrumentation is installed, as required, to monitor the deflections of components under test and the occurrence of water hammer noise and vibration.

- Points are monitored and baseline data are established.

Test Method

- Record deflection measurements during various plant transients.
- Monitor for the occurrence of water hammer noise and vibration.

Performance Criteria

- The movements due to flow-induced loads do not exceed the stress analysis of the monitored points. See subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to vibration.

- Flow-induced movements and loads do not cause malfunctions of plant equipment or instrumentation.
- No effects due to water hammer are detected.

14.2.10.4.19 Reactor Power Control System

Objective

Demonstrate the capability of the reactor power control system to respond to input signals.

Prerequisites

- The reactor is at equilibrium at the power level specified by the startup test program reference document.
- Setpoints and controls for the pressurizer, steam generator steam dump, and feedwater pump are checked and are set to proper values.

Test Method

Vary T_{avg} from the T_{ref} setpoint to verify the transient recovery capabilities of the automatic reactor power control system.

Performance Criterion

T_{avg} returns to the T_{ref} setpoint, within pre-specified limits and without manual intervention.

14.2.10.4.20 Load Swing Test

Objective

Verify nuclear plant transient response, including automatic control system performance, when 10 percent step-load changes are introduced to the turbine-generator at 30, 75, and 100 percent rated thermal power levels.

Prerequisite

The plant is operating in a steady-state condition at the desired thermal power level.

Test Method

Change the turbine-generator output as rapidly as possible to achieve a step 10 percent load increase or decrease. Monitor and record plant parameters of reactor power, reactor coolant system temperature, pressurizer pressure and level, and steam generator pressure and level during the load transients. Core power should not exceed 100-percent power as indicated by the excore nuclear instrumentation.

Performance Criterion

The primary and secondary control systems, with no manual intervention, maintain reactor power, reactor coolant system temperatures, pressurizer pressure and level, and steam generator levels and pressures within acceptable ranges during and following the transient. Control system response is reviewed and compared to the control system setpoint and performance analysis, and adjustments to the control systems are made, if necessary, prior to proceeding to the next power plateau.

14.2.10.4.21 100 Percent Load Rejection

Objective

Demonstrate the ability of the AP1000 plant to accept a 100 percent load rejection from full power.

Prerequisites

- The plant is operating at a stable power level of approximately 100 percent rated thermal power. Reactor and turbine control systems are in the automatic mode of operation. Plant temperatures, pressures, levels, and flow rates are within their normal range for full-power operation.

- Startup testing of the reactor and turbine control and protection systems is completed, and final setpoints are installed according to applicable plant technical manuals.

- The incore instrumentation system, including signal processing software, is operational, and all preoperational and startup testing is completed.

- Instrumentation and data collection equipment is operational and available for logging plant data.

- Special test instrumentation is installed and operational as required to augment normal data logging ability.

Test Method

- With the plant at nominal full-power steady-state conditions, to effect a rejection of 100 percent load, manually place the main step-up transformer high side breaker in the trip position.

- Prior to the load rejection, and until the plant stabilizes at the lower power level, record key plant parameters using the plant computer and special test instrumentation. The key plant parameters include plant temperatures, pressures, levels and flow rates for the primary and secondary systems.

Performance Criteria

- The plant is capable of accepting a 100 percent load rejection from full rated thermal power without reactor trip or operation of the steam generator relief valves or pressurizer safety valves.

- The turbine is capable of continued stable operation at the minimum house loads.

14.2.10.4.22 Load Follow Demonstration (First Plant Only)

Objective

- Demonstrate the ability of the AP1000 plant to follow a design basis daily load follow cycle.

- Demonstrate the ability of the plant to respond to grid frequency changes while in the load follow cycle.

Prerequisites

- The plant is operating at a stable power level of approximately 100 percent power and has been at that power for a sufficient length of time to have reached an equilibrium xenon condition.

- Startup testing of the reactor and turbine control and protection systems are completed, and final setpoints are installed.

- The incore instrumentation system, including signal processing software, is operational. All preoperational and startup testing is completed.

- Instrumentation and data collection equipment is operational and available for logging plant data.

Test Method

- Prior to any load reduction, obtain thermal power measurement and statepoint data along with incore power distribution maps to serve as the reference plant condition.

- Using normal plant procedures, reduce turbine load at a rate such that a reactor thermal power level of approximately 50 percent is achieved linearly in 2 hours.

- After remaining at 50 percent rated thermal power for more than 2 hours but less than 10 hours, increase turbine load at a rate such that a reactor power level of approximately 100 percent rated thermal power is achieved linearly in 2 hours.

- At selected times during the power decrease, while at reduced power, during the power increase, and after reaching approximately full rated thermal power, obtain data from both incore and excore instrumentation to monitor plant performance.

- While within the load-follow maneuver, demonstrate the ability to respond to grid frequency changes by increasing and decreasing load by as much as 10 percent, at a rate of 2 percent per minute.

Performance Criteria

- Core power distribution limits, as specified in the plant Technical Specifications, are not exceeded when the plant power is varied according to the design basis load-follow cycle, or while in the cycle, responding to load changes simulating grid frequency changes.

- Load follow maneuvers, including response to grid frequency changes, can be accomplished without changes to the reactor coolant boron concentration.

14.2.10.4.23 Hot Full Power Boron Endpoint

Objective

Measure the reactor coolant system critical boron concentration at beginning of cycle life for the all rods out, hot full power, xenon equilibrium condition.

Prerequisites

- The reactor is operating at approximately 100 percent of full licensed power and has been at that power for a sufficient time to reach xenon equilibrium.

- The reactor power level and reactor coolant system boron concentration and temperature are stable, and control and shutdown rod banks are in the near fully withdrawn position.

- Current core burnup data are available.

Test Method

- During the power ascension test program, and, as soon as practicable after achieving xenon equilibrium at full licensed power, obtain and analyze samples of reactor coolant for dissolved boron content.

- Using plant calorimetric and statepoint data obtained at the same time as coolant sampling, correct the measured boron concentration, as required, for control rod insertion, xenon nonequilibrium, and any difference between T_{avg} and T_{ref}.

- The resultant boron value, corresponding to the measured critical boron concentration for all rods out, hot full power, and xenon equilibrium, is compared with design predictions for the current accumulated core burnup (Figure 4.3-3).

- As permitted by the plant Technical Specifications, use the corrected measured boron concentration to renormalize the predicted curve of boron concentration as a function of core burnup.

Performance Criterion

The reactivity equivalent of the difference between measured and predicted boron concentrations (Table 4.3-2) is less than the design limit shown in subsection 4.3.3.3.

14.2.10.4.24 Plant Trip from 100 Percent Power

Objectives

- Verify the ability of the plant automatic control systems to sustain a trip from 100 percent rated thermal power and bring the plant to stable conditions following the transient.
- Assess the dynamic response of the plant for the event that subjects the turbine to its maximum credible overspeed condition.
- Determine the overall response time of the hot leg resistance temperature detector.
- Optimize the control systems setpoints, if necessary.

Prerequisite

The plant is operating in a steady-state condition at full rated thermal power.

Test Method

- Trip the plant by opening the main generator breaker.
- Monitor and record selected plant parameters.
- If necessary, adjust the control systems setpoints to obtain optimal response.

Performance Criteria

- Following the opening of the main generator breaker while at 100 percent rated thermal power, primary and secondary control systems and operator actions can stabilize reactor coolant system temperature, pressurizer pressure and level, and steam generator levels to no-load operating temperature and pressure.
- The steam dump control system operates to prevent opening of primary and secondary safety valves.
- The hot leg resistance temperature detector (RTD) time responses are verified to be less than or equal to values used in the safety analysis.

14.2.10.4.25 Thermal Expansion

Objective

Demonstrate that essential nuclear steam supply system and balance-of-plant components can expand without obstruction and that the expansion is in accordance with design. Also, during

cooldown, the components return to their approximate baseline cold position. Testing is conducted to resolve discrepancies from hot functional testing as in subsection 14.2.9.1.1, and to test modifications made since hot functional testing was completed. Portions of systems that meet the selection criteria for subsection 14.2.9.1.7 for thermal dynamic testing, but were not tested because system conditions during hot functional testing are not conducive to prototypical system conditions are tested.

Prerequisite

Temporary instrumentation is installed, as required, to monitor the deflections for the components under test.

Test Method

For the components tested, the following apply:

- During plant heatup and cooldown, record deflection data.
- Verify support movements by recording hot and cold positions.

Performance Criteria

Thermal expansion testing is performed in accordance with ASME OM Standard, Part 7 as discussed in subsection 3.9.2.1.2. For the components tested, the following apply:

- There is no evidence of blocking of the thermal expansion of piping or component, other than by installed supports, restraints, and hangers.

- Spring hanger movements must remain within the hot and cold setpoints and supports must not become fully retracted or extended.

- Piping and components return to their approximate baseline cold position.

14.2.10.4.26 Loss of Offsite Power

Objective

Demonstrate plant response following a plant trip with no offsite power available.

Prerequisites

- The plant is at minimum power level supplying normal house loads through the unit auxiliary transformers.

- The unit is disconnected from the electrical grid.

Test Method

- The turbine is tripped and the generator output breaker opens, removing ac power from the unit auxiliary transformers.

Performance Criteria

- The reactor trips.
- Both standby diesel generators start and pick up the required loads in the proper sequence.
- Class 1E dc and non-1E dc loads are uninterrupted and are provided by the battery subsystems.
- The primary plant is placed in a stable condition.

14.2.10.4.27 Feedwater Heater Loss and Out of Service Test

Objective

Demonstrate the plant response to the loss of one of the feedwater heaters during power operation due to single failure or operator error. Demonstrate the plant response to a pair of feedwater heaters taken out of service during power operation. Verify the ability of operators to manually reduce steam flow and place a pair of feedwater heaters out of service while maintaining reactor power operation.

Prerequisites

The plant is operating in a steady-state condition at the rated thermal powers described.

Test Method

LOSS OF FEEDWATER HEATER

- With the plant operating at 50% power, isolate the extraction steam supply to one of the main feedwater heaters.
- With the plant operating at 90% power, isolate the extraction steam supply to one of the main feedwater heaters.

FEEDWATER OUT OF SERVICE TEST

- The operators calculate the appropriate steam flow reduction which will maintain the plant at the desired thermal load after the heaters have been taken out of service.
- Reduce steam flow by the appropriate amount and allow plant conditions to reach a new steady-state (approximately 10 minutes).
- Take a pair of feedwater heaters out of service.

Performance Criteria

The plant control systems properly respond to the loss of a main feedwater heater, without reactor or turbine trip.

The operator successfully removes a pair of feedwater heaters from service without causing a reactor trip.

14.2.10.4.28 Remote Shutdown Workstation

Objective

Demonstrate the ability of the operators to conduct a remote shutdown of the plant during a simulated main control room evacuation.

Prerequisites

Approved operation procedures for performing a remote shutdown is available. Communication exists between the control room and the remote shutdown room. Procedures for transferring control back to the main control room are available if an emergency or unsafe condition develops during the testing that cannot be managed by the shutdown crew.

The plant is operating in a steady-state condition at 10-20 percent of power.

Test Method

- Using the appropriate operating procedures, the operators transfer control of the plant from the main control room to the remote shutdown workstation.
- From the remote shutdown workstation, the operators bring the plant to hot standby, and maintain hot standby conditions for at least 30 minutes.
- From the remote shutdown workstation, the operators lower the reactor coolant system pressure and temperature to the appropriate conditions, and place the normal residual heat removal system into service. The normal residual heat removal system, in conjunction with the component cooling water system and service water system are used to cool the plant at least 50°F without exceeding prescribed cooldown limits.

Performance Criteria

The operators successfully demonstrate the ability transfer control of the plant to the remote shutdown workstation, shut down the reactor, maintain hot standby, and then demonstrate the ability to transition to cold shutdown conditions, while performing these operations from the remote shutdown workstation.

14.3 Certified Design Material

This section provides the selection criteria and processes used to develop the AP1000 Certified Design Material (CDM). This document provides the principal design bases and design characteristics that are certified by the 10 CFR Part 52 rulemaking process and included in the design certification rule.

The top-level design information in the Certified Design Material is extracted directly from the AP1000 design information. Limiting the certified design contents to top-level information reflects the tiered approach to design certification endorsed by the U.S. Nuclear Regulatory Commission (see References 1 through 5).

The objective of this section is to define the bases and methods that were used to develop the Certified Design Material for the AP1000. This section contains no new technical information regarding the AP1000 design.

The AP1000 Certified Design Material consists of the following:

- An introduction section which defines terms used in the Certified Design Material and lists general provisions that are applicable to all Certified Design Material entries. Also included is a list of acronyms and legends used in the Certified Design Material. (Because this material is self-explanatory, it is not discussed in this section.)

- Design descriptions for selected systems that are within the scope of the AP1000 design certification, and the applicable portions of those selected systems that are only partially within the scope of the AP1000 design certification. The Certified Design Material design descriptions delineate the principal design bases and principal design characteristics that are referenced in the design certification rule. The design descriptions are accompanied by the inspections, tests, analyses, and acceptance criteria (ITAAC) required by 10 CFR 52.47(a)(1)(vi) to be part of the design certification application. The ITAAC define verification activities that are to be performed for a facility with the objective of confirming that the plant is built and will operate in accordance with the design certification. Completion of these certified design ITAAC, together with the Combined License applicant's ITAAC for the site-specific portions of the plant, will be the basis for NRC authorization to load fuel per the provisions of 10 CFR Part 52.103.

- Design descriptions and their associated ITAAC for design and construction activities that are applicable to more than one system. Design-related processes have been included in the Certified Design Material for:

  – Aspects of the AP1000 design likely to undergo rapid, beneficial technological developments in the lifetime of the design certification. Certifying the design processes associated with these areas of the design, rather than specific design details, permits future license applicants referencing the AP1000 design certification to take advantage of the best technology available at the time of combined license application and facility construction.

- Aspects of the design dependant upon characteristics of as-procured, as-installed systems, structures, and components. These characteristics are not available at the time of certification and, therefore, cannot be used to develop and certify design details.

- Aspects of the seismic, structural and piping design for which detailed design has not been developed. These details are not available at the time of certification and, therefore, cannot be used to certify design details. Certifying the design processes associated with these design details provides the basis for future license applicants referencing the AP1000 design certification to establish and implement seismic, structural and piping design details as part of the COL application process.

- Interface requirements as defined by 10 CFR Part 52.47(a)(1)(vii). Interface requirements are defined as those which must be met by the site-specific portions of the complete nuclear power plant that are not within the scope of the certified design. These requirements define characteristics of the site-specific features that must be provided for the certified design to comply with certification commitments. AP1000 has no interfaces meeting this definition. The Certified Design Material does not include ITAAC or a requirement for COL developed ITAAC for interface requirements.

- Site parameters used as the basis for AP1000 design presented in the Tier 2 Material. These parameters represent a bounding envelope of site conditions for any license application referencing the AP1000 design certification. No ITAAC are necessary for the site parameters entries because compliance with site parameters will be verified as part of issuance of a license for a plant that references the AP1000 design certification.

The following is a description of the criteria and methods used to select specific technical entries for the Certified Design Material. The structure of the description is based on the Certified Design Material report structure.

The criteria and methods discussed in the following sections are guidelines only. For some matters, the contents of the Certified Design Material may not directly correspond to these guidelines because special considerations related to the matters may warrant a different approach. For such matters, a case-by-case determination is made regarding how or whether the matters should be addressed in the Certified Design Material. These determinations are based upon the principles inherent in Part 52.

14.3.1 CDM Section 1.0, Introduction

This section provides definitions, general provisions, a figure legend, and a list of acronyms used in the AP1000 Certified Design Material.

Selection Criteria – Section 1.1 is used to define terms used throughout the Certified Design Material. Selection of entries is based on a judgment that a particular word/phrase merits definition – with particular emphasis on terms associated with implementation of the ITAAC. Section 1.2 contains a mixture of provisions that is selected on the basis that the provision is necessary to either define technical requirements applicable to multiple systems in the Certified

Design Material or to provide clarification and guidance for future users of the Certified Design Material.

Selection Methodology – Entries in the Definition section are made on the basis of a self-evident need for a term to be defined. These terms are accumulated during the preparation and review of the Certified Design Material. Entries in the General Provisions section also are developed as part of the Certified Design Material selection and review process. Each entry has a unique background, but the overall intent is to state the broad guidelines and interpretations that are used to prepare Certified Design Material for the AP1000.

14.3.2 CDM Section 2.0, System Based Design Descriptions and ITAAC

This section of the Certified Design Material has the design description and ITAAC material for the selected AP1000 systems. The intent of this list of AP1000 systems is to define at the Certified Design Material level the full scope of the certified design.

14.3.2.1 Design Descriptions

The certified design descriptions for selected AP1000 systems address the top-level design features and performance standards that pertain to the safety of the plant and include descriptive text and supporting figures. The intent of the Certified Design Material design descriptions is to define the AP1000 design characteristics referenced in the design certification rule as a result of the certification provisions of 10 CFR Part 52.

Selection Criteria – The following criteria are considered in determining the information included in the certified design descriptions:

- The information in the certified design descriptions is selected from the technical information presented in the Tier 2 Material. This reflects the approach that the Certified Design Material contains top-level design information and is based on the NRC directive in Reference 2 that there "be less detail in a certification than in an application for certification." In this context, the certification is the Certified Design Material and the application for certification includes the Tier 2 Material.

- The certified design descriptions contain only the information from the Tier 2 Material that is most significant to safety. The Tier 2 Material contains a wide spectrum of information on various aspects of the AP1000 design. Not all of this information is included in the certified design descriptions. This selection criterion reflects the NRC directive in Reference 2 that the certified design should "encompass roughly the same design features that Section 50.59 prohibits changing without prior NRC approval." In determining those structures, systems, or components for which certified design descriptions and ITAAC must be prepared, the following questions are considered for each structure, system, or component:

  – Are there any features or functions classified as Class A, B, or C?

  – Are there any defense–in–depth features or functions provided?

– For nonsafety–related systems, are there any features or functions credited for mitigation of design basis events?

– For nonsafety–related systems, are there any features or functions that have been identified in Section 16.3 as candidates for additional regulatory oversight?

If the answer to the first question is yes, then a certified design description and ITAAC are prepared using the safety function stated in the Tier 2 Material and the parameters from the safety analysis.

If the answer to either of the next two questions is yes, then a certified design description and ITAAC are prepared using the functions stated in the Tier 2 Material and the parameters from the system design calculations.

If the answer to the last question is yes and the feature or function is not a programmatic requirement related to operations, maintenance or other programs, then a certified design description and ITAAC are prepared using the functions stated in the Tier 2 Material and the parameters from system design calculations.

In addition, the following questions were considered for each structure, system, or component not already selected for ITAAC using the above selection criteria:

– Are any features or functions necessary to satisfy the NRC's regulations in Parts 20, 50, 52, 73 and 100?

– Are there any features or functions that represent an important assumption for probabilistic risk assessment?

– Are any features or functions important in preventing or mitigating severe accidents?

– Are there any features or functions that have a significant impact on the safety and operation of the plant?

– Are any features or functions the subject of a provision in the Technical Specifications?

If the answer to any of the above questions is yes, then a design description and ITAAC are prepared using the appropriate functions stated in the Tier 2 material and the parameters from the system design calculations.

A summary of the AP1000 structures, systems, or components considered for selection is given in Table 14.3-1.

- In general, safety-related and defense-in-depth features and functions of structures, systems, and components are discussed in the certified design descriptions. Structures, systems, and components that are not classified as safety-related or defense-in-depth are discussed in the certified design descriptions to the extent that they have features or functions that mitigate a design basis event.

- The certified design descriptions for structures, systems, and components are limited to a discussion of design features and functions. The design bases of structures, systems, and components, and explanations of their importance to safety, are provided in the Tier 2 Material and are not included in the certified design descriptions. The Certified Design Material design descriptions define the certified design. Justification that the design meets regulatory requirements is presented in the Tier 2 Material.

- The certified design descriptions focus on the physical characteristics of the facility. The certified design descriptions do not contain programmatic requirements related to operating conditions or to operations, maintenance, or other programs. These matters are controlled by other means such as the technical specifications.

- The certified design descriptions in Section 2.0 of the Certified Design Material discuss the functional arrangement and performance characteristics that the structures, systems, and components should have after construction is completed. In general, the certified design descriptions do not address the processes that will be used for designing and constructing a plant that references the AP1000 design certification. This is acceptable because the safety-function of a structure, system, or component is dependent upon its final as-built condition and not the processes used to achieve that condition. Exceptions to this criterion are the selected design and qualification processes defined in the instrumentation and control portions and piping portions of Section 2 and the piping, seismic, structural and human factors portion of Section 3.

  The programmatic aspects of the design and construction processes (training, qualification of welders, and the like) are part of the licensee's programs and are subject to commitments made at the time of combined license issuance. Consequently, these issues are not addressed in the AP1000 Certified Design Material.

- The certified design descriptions address fixed design features expected to be in place for the lifetime of the facility. Portable equipment and replaceable items are controlled through operational related programs.

- The certified AP1000 design descriptions do not discuss component types (for example, valve and instrument types), component internals, or component manufacturers. This approach is based on the premise that the safety function of a particular design element can be performed by a variety of component types from different manufacturers.

- The certified design descriptions do not contain proprietary information.

- For the applicant or licensee of a plant that references the AP1000 design certification to take advantage of improvements in technology, the certified design descriptions in general do not prescribe design features that are the subject of rapidly evolving technology.

- The Certified Design Material design description is intended to be self-contained and does not make direct reference to the Tier 2 Material, industrial standards, regulatory requirements, or other documents. (There are some exceptions involving the ASME Code and the Code of Federal Regulations.) If these sources contain technical information of

sufficient safety significance to warrant Certified Design Material treatment, the information is extracted from the source and included directly in the appropriate system design description.

This approach is appropriate because it is unambiguous and it avoids potential questions regarding how much of a referenced document is encompassed in, and becomes part of, the Certified Design Material.

- Selection of the technical terminology to be used in the Certified Design Material is guided by the principle that the terminology should be as consistent as possible with that used in the Tier 2 Material and the body of regulatory requirements and industrial standards applicable to the nuclear industry. This approach is intended to minimize problems in interpreting Certified Design Material commitments.

A review of those sections of the AP1000 Tier 2 Material that document plant safety evaluations was conducted. Specifically, reviews were conducted of the following chapters of the AP1000 Tier 2 Material; the flooding analysis in Chapter 5, the analysis of overpressure protection in Chapter 5, containment analysis in Chapter 6, the core cooling analysis in Chapters 6 and 15, the analysis of fire protection in Chapter 9, the safety analysis of transients in Chapter 15, the analysis of anticipated transients without scram (ATWS) in Chapters 7 and 15, the radiological analysis in Chapter 15, the resolution of unresolved or generic safety issues and Three Mile Island issues in Chapter 1, and the PRA and severe accident information in Chapter 19. These reviews were important in identifying safety-related system design information warranting consideration in the design descriptions and the accompanying design commitments.

Selection Methodology – The Certified Design Material uses a system report structure. The certified design description entry for any system is based on review of the multiple sources having technical information related to that system. Using the selection criteria listed, design description material is developed for each system by reviewing the Tier 2 Material, safety analysis, test programs, and design documents relating to that system.

Application of the criteria listed results in a graded treatment of the systems. This leads to variation in the scope of the design description entries. The following lists the types of AP1000 systems and is a summary of this graded treatment:

System Type	Scope of Design Description
Systems with safety-related functions that contribute to plant performance during design basis accidents	Major safety-related features and performance characteristics
Systems with defense-in-depth functions that contribute to plant performance during design basis accidents	Major defense-in-depth features and performance characteristics

System Type	Scope of Design Description
Nonsafety-related systems potentially impacting safety	Brief discussion of design features that prevent or mitigate the potential safety concern
Nonsafety-related systems with no relationship to safety	No discussion

For safety-related systems, application of this criteria results in design description entries that include the following information, as applicable:

- System name and scope
- System purpose
- Summary of the system's safety-significant components (usually shown by a figure)
- Equipment seismic and ASME classifications
- Piping ASME classification and Leak-Before-Break criteria
- Type of electrical power provided for the system
- System's important instruments, controls, and alarms to the extent located in the main control room or remote shutdown workstation
- Equipment to be qualified for harsh environments
- Motor-operated valves within the system that have an active safety-related function
- Other features or functions that are significant to safety

The certified design descriptions for nonsafety-related systems include the information listed to the extent that the information is relevant to the system and is significant to safety. Since much of this information is not relevant to nonsafety-related systems, the certified design descriptions for nonsafety-related systems are less extensive than the descriptions for safety-related systems.

14.3.2.2 Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

A table of ITAAC entries is provided for each system that has design description entries. The intent of these ITAAC is to define activities that will be undertaken to verify the as-built system conforms with the design features and characteristics defined in the design description. ITAAC are provided in tables with the following three-column format:

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria

Each design commitment in the left-hand column of the ITAAC tables has an associated inspections, tests, or analyses (ITA) requirement specified in the middle column. The acceptance criteria for the ITA are defined in the right-hand column.

Selection Criteria – The following are considered when determining what information is included in the Certified Design Material ITAAC entries:

- The scope and content of the ITAAC correspond to the scope and content of the certified design descriptions. There are no ITAAC for aspects of the design not addressed in the design description. This is appropriate because the objective of the ITAAC design certification entries is to verify that the as-built facility has the design features and performance characteristics defined in the Certified Design Material descriptions.

  Each AP1000 system with a design description has an ITAAC table. This reflects the assessment that a design feature meriting a Certified Design Material description also merits an ITAAC entry to verify that the feature has been included in the as-built facility.

- One inspection, test, or analysis may verify one or more provisions in the certified design description. An ITAAC that specifies a system functional test or an inspection may verify a number of provisions in the design description. There is not necessarily a one-to-one correspondence between the ITAAC and the design descriptions.

- As required by 10 CFR 52.103, the inspections, tests, and analyses must be completed (and the acceptance criteria satisfied) prior to fuel loading. Therefore, the ITAAC do not include any inspections, tests, or analyses that are dependent upon conditions that exist only after fuel load.

- Because the design descriptions are limited to fixed design features expected to be in place for the lifetime of the facility, the ITAAC are limited to a verification of fixtures in the plant. There are no ITAAC for nuclear fuel, fuel channels, and control rods because they are changed by a licensee.

- The ITAAC verify the as-built configuration and performance characteristics of structures, systems, and components as identified in the Certified Design Material design descriptions.

Selection Methodology – Using the selection criteria, ITAAC table entries are developed for each selected system. This is achieved by evaluating the design features and performance characteristics defined in the Certified Design Material design description and preparing an ITAAC table entry for the design description criteria that satisfied the selection criteria. There is a close correlation between the left-hand column of the ITAAC table and the corresponding design description entries.

The ITAAC table is completed by selecting the method to be used for verification (either a test, an inspection, or an analysis [ITA]) and the acceptance criteria for the as-built feature.

The selection of the ITAs is guided by the following:

ITA Approach	Application
Inspection	To be used when verification can be accomplished by visual observations, physical examinations, review of records based on visual observations, or physical examinations that compare the as-built structure, system, or component condition to one or more design description commitments.
Test	To be used when verification can be accomplished by the actuation or operation, or establishment of specified conditions, to evaluate the performance or integrity of the as-built structures, systems, or components. The type of tests identified in the ITAAC tables includes activities such as factory testing, special test facility programs, and laboratory testing.
Analysis	To be used when verification can be accomplished by calculation, mathematical computation, or engineering or technical evaluations of the as-built structures, systems, or components.

The proposed verification activity is identified in the middle column of the ITAAC table. Where appropriate, the Tier 2 Material provides details regarding implementation of the verification activity. This Tier 2 Material is not referenced in the Certified Design Material and is not part of the Certified Design Material; Tier 2 Material is considered as providing one of potentially several acceptable methods for completing the ITA.

Selection of acceptance criteria is dependent upon the design characteristic being verified by the ITAAC table entry: in most cases, the appropriate acceptance criteria is self-evident and is based upon the Certified Design Material design description. For many of the AP1000 ITAAC, the acceptance criteria is a statement that the as-built facility has the design feature or performance characteristic identified in the design description. A guiding principle for acceptance criteria preparation is the recognition that the criteria should be objective and unambiguous. The use of objective and unambiguous terms for the acceptance criteria will minimize opportunities for multiple, subjective (and potentially conflicting) interpretations as to whether an acceptance criteria has, or has not, been met. In some cases, the ITAAC acceptance criteria contain numerical parameters from the Tier 2 Material that are not specifically identified in the Certified Design Material design description or the design commitment column of the ITAAC table. This is acceptable because the design description defines the important design feature/performance that merits Certified Design Material treatment. The acceptance criterion defines a measurement standard for determining if the as-built facility is in compliance with the Certified Design Material design description commitment. Where appropriate, the Tier 2 Material identifies criteria applicable to the same design feature or function that is the subject of more general acceptance criteria in the ITAAC table.

For numerical acceptance criteria, ranges and/or tolerances are included. This is necessary and acceptable because of the following:

- Specification of a single-value acceptance criteria is impractical because trivial deviations will represent unnecessary noncompliances.
- Tolerances recognize that legitimate site variations can occur in complex construction projects.
- Minor variations in plant parameters within the tolerance bounds have no impact on plant safety.

14.3.3 CDM Section 3.0, Non-System Based Design Descriptions and ITAAC

Entries in this section of the Certified Design Material have the same structure as the system material discussed in Section 14.3.2; that is, design description text and figures and a table of ITAAC entries. The objective of this Certified Design Material is to address selected design and construction activities which are applicable to more than one system. There are six entries in Section 3.0 of the Certified Design Material: nuclear island buildings, initial test program, emergency response facilities, human factors engineering, Design Reliability Assurance Program, and radiation protection.

14.3.4 Certified Design Material Section 4.0, Interface Requirements

AP1000 is a plant design incorporating the nuclear island, the annex building and associated equipment, the diesel/generator building and associated equipment, the turbine/generator building, the turbine/generator equipment, and the radwaste facilities. As a result, no interfaces need to be identified between or among these portions of the plant. There are no safety-related interfaces between the AP1000 certified design and other portions of a facility with a combined license under 10 CFR Part 52.

The combined license applicant is responsible for initial testing of interfacing non-safety systems in portions of the plant outside the scope of design certification. Section 1.8, Table 1.8-1, lists the interfacing systems and structures. Those systems that meet the requirements of 10 CFR 52.47(a)(1)(viii) are tabulated in subsection 14.4.5.

14.3.5 CDM Section 5.0, Site Parameters

This section of the Certified Design Material defines the site parameters used as a basis for the design defined in the AP1000 certification application. These entries respond to the 10 CFR 52.47(a)(1)(iii) requirement that the design certification documentation include site parameter information. It is intended that applicants referencing the AP1000 design certification demonstrate that these parameters for the selected site are within the certification envelope or provide additional analysis to show acceptability of deviations from the interface envelope.

Site-specific external events that relate to the acceptability of the design (and not to the acceptability of the site) are not considered site parameters and are addressed as interface requirements in the appropriate system entry in Section 4 of the Certified Design Material.

Section 5.0 of the Certified Design Material does not include any ITAAC and is limited to defining the AP1000 site parameters. This is an appropriate approach because compliance of the site with these parameters is demonstrated by a license applicant prior to issuance of the license.

Selection Criteria – Section 2.0, Table 2.0-1, provides the envelope of site design parameters used for the AP1000 design. The corresponding Certified Design Material Section 5.0 is based on using Table 2.0-1. Section 5.0 is limited to a tabular entry; no supporting text material is required.

14.3.6 Initial Test Program

The AP1000 Initial Test Program defines testing activities that will be conducted following completion of construction and construction-related inspections and tests. The Initial Test Program extends through the start of commercial operation of the facility. This program is discussed in Chapter 14.

A summary of the Initial Test Program is included in Certified Design Material Section 3.4. This summary includes an overview of the Initial Test Program structure. This information is included in the Certified Design Material because of the importance of the Initial Test Program defining pre- and post-fuel load testing for the as-built facility. Key pre-fuel load Initial Test Program testing for individual systems is defined in the system ITAAC in Certified Design Material Sections 2 and 3.

No ITAAC entries have been included in the Certified Design Material for the Initial Test Program. This is acceptable because of the following:

- The Initial Test Program activities involve testing with the reactor at various power levels and thus cannot be completed prior to fuel load (Part 52 requires ITAAC to be completed prior to fuel load).

- Testing activities specified as part of the ITAAC in Certified Design Material Sections 2 and 3 must be performed prior to fuel load. Because these ITAAC testing activities address the design features and characteristics of safety significance, additional ITAAC for the Initial Test Program are not necessary to ensure that the as-built plant conforms with the certified design.

14.3.7 Elements of AP1000 Design Material Incorporated into the Certified Design Material

Tables 14.3-2 through 14.3-8 summarize the design material that has been incorporated into the CDM in the areas of 1) Design Basis Accident Analysis, 2) Anticipated Transients Without Scram (ATWS), 3) Fire Protection, 4) Flood Protection, 5) Probabilistic Risk Assessment, 6) Radiological Analysis, and 7) Severe Accident Analysis. PRA assumptions incorporated into these tables encompass elements of the system design and assumptions that were expressly included in Tier 1 due to their importance. Both types of PRA assumptions were included for completeness, but are not distinguished in the tables. CDM falling outside of the seven subject areas are intentionally not incorporated in these tables. However, the referenced AP1000 DCD sections may contain more information than encompassed by these seven subject areas. Each table may also include design information (certified or non-certified) that is not directly related to the

particular subject area. Further, these tables are not intended to include all system-specific CDM information that is provided in the AP1000 Tier 2 system descriptions.

14.3.8 Summary

An element of the design certification processes deriving from 10 CFR Part 52 is the selection and documentation of the technical information to be included in the design certification rule as the certified design. The certified design material is a subset of the design information presented in the Tier 2 Material. It includes the following:

- Key, important safety-significant aspects of the design described in the certification application
- Inspections, tests, analyses, and acceptance criteria (ITAAC) that will be used to verify that the as-built facility conforms with the certified design
- Interface requirements and site parameters

The information presented in the AP1000 Certified Design Material is prepared using the selection criteria and methodology described in this section and is intended to satisfy the above Part 52 requirements for design certification. The ITAAC entries in Sections 2.0 and 3.0 confirm that key design performance characteristics and design features are implemented in the as-built facility.

14.3.9 References

1. SECY-90-377, "Requirements for Design Certification under 10 CFR Part 52," February 15, 1991.
2. 10 CFR, Part 52, "Statement of Considerations," (54 Federal Regulations 15372, 154377 [1989]).
3. SECY-90-241, "Level of Detail Required for Design Certification under Part 52," August 31, 1990.
4. SECY-90-377, "Requirements for Design Certification Under 10 CFR Part 52," November 8, 1990.
5. SECY-91-178, "Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) for Design Certifications and Combined Licenses," June 12, 1991.

Table 14.3-1 (Sheet 1 of 4)

ITAAC SCREENING SUMMARY

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
ADS	Automatic Depressurization System	X
ASS	Auxiliary Steam Supply System	X
BDS	Steam Generator Blowdown System	X
CAS	Compressed Air System	X
CCS	Component Cooling Water System	X
CDS	Condensate System	X
CES	Condenser Tube Cleaning System	X
CFS	Turbine Island Chemical Feed System	X
CMS	Condenser Air Removal System	X
CNS	Containment System	X
CPS	Condensate Polishing System	X
CVS	Chemical and Volume Control System	X
CWS	Circulating Water System	
DAS	Diverse Actuation System	X
DDS	Data Display Processing System	X
DOS	Standby Diesel and Auxiliary Boiler Fuel Oil System	X
DRS	Storm Drain System	
DTS	Demineralized Water Treatment System	X
DWS	Demineralized Water Transfer and Storage System	X
ECS	Main AC Power System	X
EDS	Non Class 1E DC and UPS System	X
EFS	Communication System	X
EGS	Grounding and Lightning Protection System	X

Table 14.3-1 (Sheet 2 of 4)

ITAAC SCREENING SUMMARY

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
EHS	Special Process Heat Tracing System	<u>X</u>
ELS	Plant Lighting System	X
EQS	Cathodic Protection System	<u>X</u>
FHS	Fuel Handling System	X
FPS	Fire Protection System	X
FWS	Main and Startup Feedwater System	X
GSS	Gland Seal System	<u>X</u>
HCS	Generator Hydrogen and CO_2 Systems	<u>X</u>
HDS	Heater Drain System	<u>X</u>
HSS	Hydrogen Seal Oil System	<u>X</u>
IDS	Class 1E DC and UPS System	X
IIS	Incore Instrumentation System	X
LOS	Main Turbine and Generator Lube Oil System	<u>X</u>
MES	Meteorological and Environmental Monitoring System	
MHS	Mechanical Handling System	X
MSS	Main Steam System	<u>X</u>
MTS	Main Turbine System	X
OCS	Operations and Control Centers	X
PCS	Passive Containment Cooling System	X
PGS	Plant Gas System	<u>X</u>
PLS	Plant Control System	X
PMS	Protection and Safety Monitoring System	X
PSS	Primary Sampling System	X

Table 14.3-1 (Sheet 3 of 4)

ITAAC SCREENING SUMMARY

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
PWS	Potable Water System	X
PXS	Passive Core Cooling System	X
RCS	Reactor Coolant System	X
RDS	Gravity and Roof Drain Collection System	X
RMS	Radiation Monitoring System	X
RNS	Normal Residual Heat Removal System	X
RWS	Raw Water System	
RXS	Reactor System	X
SDS	Sanitary Drainage System	X
SES	Plant Security System	X
SFS	Spent Fuel Cooling System	X
SGS	Steam Generator System	X
SJS	Seismic Monitoring System	X
SMS	Special Monitoring System	X
SSS	Secondary Sampling System	X
SWS	Service Water System	X
TCS	Turbine Building Closed Cooling Water System	X
TDS	Turbine Island Vents, Drains and Relief Systems	X
TOS	Main Turbine Control and Diagnostics System	X
TVS	Closed Circuit TV System	
VAS	Radiologically Controlled Area Ventilation System	X
VBS	Nuclear Island Nonradioactive Ventilation System	X
VCS	Containment Recirculation Cooling System	X
VES	Main Control Room Emergency Habitability System	X

Table 14.3-1 (Sheet 4 of 4)

ITAAC SCREENING SUMMARY

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
VFS	Containment Air Filtration System	X
VHS	Health Physics and Hot Machine Shop HVAC System	X
VLS	Containment Hydrogen Control System	X
VPS	Pump House Building Ventilation System	
VRS	Radwaste Building HVAC System	X
VTS	Turbine Island Building Ventilation System	<u>X</u>
VUS	Containment Leak Rate Test System	<u>X</u>
VWS	Central Chilled Water System	X
VXS	Annex/Auxiliary Nonradioactive Ventilation System	X
VYS	Hot Water Heating System	<u>X</u>
VZS	Diesel Generator Building Ventilation System	X
WGS	Gaseous Radwaste System	X
WLS	Liquid Radwaste System	X
WRS	Radioactive Waste Drain System	
WSS	Solid Radwaste System	X
WWS	Waste Water System	<u>X</u>
ZAS	Main Generator System	<u>X</u>
ZBS	Transmission Switchyard and Offsite Power System	
ZOS	Onsite Standby Power System	X
ZVS	Excitation and Voltage Regulation System	<u>X</u>

Legend: X = Selected for ITAAC
<u>X</u> = Selected for ITAAC - title only, no entry for Design Certification
Blank = Not selected for ITAAC

Table 14.3-2 (Sheet 1 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
Section	3.10	The protection and safety monitoring system equipment is seismically qualified to meet safe shutdown earthquake levels.	
Section	3.11.2.1	The design of the protection and safety monitoring system equipment has margin to accommodate a loss of the normal HVAC.	
Section	5.1.2	Safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system.	
Section	5.1.2	The RCS has two hot legs and four cold legs.	
Section	5.1.2	The RCS has two steam generators and four reactor coolant pumps.	
Section	5.1.2	The RCS contains a pressurizer and a surge line connected to one hot leg.	
Section	5.1.3.3	Rotating inertia needed for flow coast-down, is provided.	
Table	5.1-3	Minimum measured flow rate with 10% tube plugging (gpm/loop)	150,835
Table	5.1-3	Initial rated reactor core thermal power (MWt)	3400
Section	5.2.2	Reactor coolant system and steam system overpressure protection during power operation are provided by the pressurizer safety valves and the steam generator safety valves, in conjunction with the action of the PMS.	
Section	5.2.2.1	Safety valve capacity exists to prevent exceeding 110 percent of system design pressure for the following events: - Loss of electrical load and/or turbine trip - Uncontrolled rod withdrawal at power - Loss of reactor coolant flow - Loss of normal feedwater - Loss of offsite power to the station auxiliaries	
Section	5.2.2.1	Overpressure protection for the steam system is provided by steam generator safety valves	
Section	5.3.2.3	Non-destructive examination (NDE) of the reactor vessel and its appurtenances is conducted in accordance with ASME Code Section III requirements.	

Table 14.3-2 (Sheet 2 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 5.3.2.5	The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline base metal traverse direction and welds are 75 foot-pounds, as required by Appendix G of 10 CFR 50.	
Section 5.4.1.2.1	Resistance temperature detectors (RTDs) monitor motor cooling circuit water temperature. These detectors provide indication of anomalous bearing or motor operation. They also provide a system for automatic shutdown in the event of a prolonged loss of component cooling water.	
Section 5.4.1.3.4	It is important to reactor protection that the reactor coolant continues to flow for a time after reactor trip and loss of electrical power. To provide this flow, each reactor coolant pump has a high-inertia rotor.	
Section 5.4.1.3.4	A safety-related pump trip occurs on high bearing water temperature.	
Section 5.4.5.2.3	Power to the pressurizer heaters is blocked when the core makeup tanks are actuated.	
Section 5.4.6	Automatic depressurization system stage 1, 2 and 3 valves are connected to the pressurizer and discharge via the spargers to the in-containment refueling water storage tank.	
Section 5.4.6	Automatic depressurization system stage 4 valves are connected to each hot leg.	
Section 5.4.9.3	In the analysis of overpressure events, the pressurizer safety valves are assumed to actuate at 2500 psia. The safety valve flowrate assumed is based on full flow at 2575 psia, assuming 3 percent accumulation.	
Section 5.4.9.3	The pressurizer safety valves prevent reactor coolant system pressure from exceeding 110% of system design pressure.	
Section 5.4.12.2	The reactor head vent valves can be operated from the main control room to provide an emergency letdown path.	
Table 5.4-1	Minimum reactor coolant motor/pump moment of inertia ($lb\text{-}ft^2$).	≥ 16,500
Table 5.4-11	Reactor Coolant System Design Pressure Settings: - Safety valves begin to open (psig)	 2485

Table 14.3-2 (Sheet 3 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
Table	5.4-17	Pressurizer Safety Valves - Design Parameters: - Number - Minimum required relieving capacity per valve (lbm/hr) - Set pressure (psig)	 2 ≥ 750,000 2485 ± 25
Table	6.1-2	The exterior of the containment vessel (above plant elevation 135′ 3″) and the interior of the containment vessel (above 7′ above the operating deck) is coated with an inorganic zinc coating.	
Section	6.1.2.1.5	The nonsafety-related coatings used inside containment on walls, floors, ceilings, structural steel which is part of the building structure, and on the polar crane have a minimum dry film density (lb/ft^3).	≥ 100
Section	6.2.1.1.3	Internal containment structures, both metallic and concrete, act as passive internal heat sinks during a LOCA or a MSLB.	
Figure	6.2.2-1	The passive containment cooling system consists of a water storage tank, cooling water flow discharge path to the containment shell, a water distribution system for the containment shell, and a cooling air flow path.	
Figure	6.2.2-1	The minimum duration the PCS cooling water flow is provided from the PCCWST (hours).	≥ 72
Table	6.2.2-1	The water coverage of the containment shell exceeds the amount used in the safety analysis.	
Table	6.2.2-1	The minimum drain flow rate capacity of the upper annulus drain (gpm).	≥ 525
Table	6.2.2-1	The minimum makeup flow rate capability from an external source to the PCS water storage tank (gpm).	≥ 100
Table	6.2.2-1	The minimum makeup flow rate capability from the PCS water storage tank to the spent fuel pit (gpm).	≥ 118
Table	6.2.2-1	The minimum PCS water storage tank volume for makeup to the spent fuel pit (non-coincident with PCS operation) (gallons).	≥ 756,700
Table	6.2.2-1	The minimum long term makeup capability from the PCCAWST to the PCCWST (days).	≥ 4
Table	6.2.2-1	The minimum long term makeup flow capability from the PCCAWST to the PCCWST (gpm).	≥ 100

Table 14.3-2 (Sheet 4 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Table 6.2.2-1	The minimum long term makeup flow capability from the PCCAWST to the spent fuel pool (gpm).	> 35
Table 6.2.2-2	The first (i.e., tallest) standpipe's elevation above the tank floor (feet).	24.1 ± 0.2
Table 6.2.2-2	The second tallest standpipe's elevation above the tank floor (feet).	20.3 ± 0.2
Table 6.2.2-2	The third tallest standpipe's elevation above the tank floor (feet).	16.8 ± 0.2
Table 6.2.2-1	The minimum passive containment cooling water flow rate at a PCCWST water level 4.0 ft. (± 0.2 ft.) above the tank floor. (This supports analysis that ensures that delivered flow at 72 hours will be greater than 100.7 gpm.) (gpm).	≥ 109.6
Table 6.2.2-1	The minimum passive containment cooling water flow rate when the PCCWST water level uncovers the third tallest standpipe (gpm).	≥ 151.4
Table 6.2.2-1	The minimum passive containment cooling water flow rate when the PCCWST water level uncovers the second tallest standpipe (gpm).	≥ 184.0
Table 6.2.2-1	The minimum passive containment cooling water flow rate when the PCCWST water level uncovers the first (i.e., tallest) standpipe (gpm).	≥ 238.4
Table 6.2.2-1	The minimum passive containment cooling water flow rate with water inventory at a level of 27.4 ft + 0.2, -0.0 ft above the tank floor (gpm).	≥ 471.1
Section 6.3	The passive core cooling system provides core decay heat removal during design basis events.	
Section 6.3	The passive core cooling system provides RCS makeup, boration, and safety injection during design basis events.	
Section 6.3	The passive core cooling system provides pH adjustment of water flooding the containment following design bases events.	
Section 6.3.1.1	The passive core cooling system is designed to provide emergency core cooling during events involving increases and decreases in secondary side heat removal and decreases in reactor coolant system inventory.	

Table 14.3-2 (Sheet 5 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 6.3.2.1.1	The heat exchanger consists of a bank of C-tubes, connected to a tubesheet and channel heat arrangement at the top (inlet) and bottom (outlet). The passive exchanger connects to the reactor coolant system through an inlet line from one reactor coolant system hot leg and an outlet line to the associated steam generator cold leg plenum (reactor coolant pump suction).	
Section 6.3.2.1.1	For the passive residual heat removal heat exchanger, the normal water temperature in the inlet line will be hotter than the discharge line.	
Section 6.3.2.1.2	The actuation of the core makeup tanks following a steam line break provides injection of borated water via water recirculation to mitigate the reactivity transient and provide the required shutdown margin.	
Section 6.3.2.2.1	The CMT inlet diffuser has a minimum flow area (in^2).	≥ 165
Section 6.3.2.2.3	The in-containment refueling water storage tank contains one passive residual heat removal heat exchanger.	
Section 6.3.2.2.6	The connection of the sparger branch arms to the sparger hub are submerged below the in-containment refueling water storage tank overflow level (ft).	≤ 11.5
Section 6.3.2.2.6	Automatic depressurization system stage 1, 2 and 3 valves are connected to the pressurizer and discharge via the spargers to the in-containment refueling water storage tank.	
Section 6.3.2.2.7	The containment recirculation screens have plates located above them that are no more than 10 feet above the top of the screens and extend out at least 7 feet to the side of the screens to prevent coating debris from reaching the screens.	
Section 6.3.2.2.7	The type of insulation used on ASME Class 1 lines inside containment and on the reactor vessel, reactor coolant pumps, pressurizer and steam generators is a metal reflective or suitable equivalent insulation.	
Section 6.3.2.2.7	The surface materials used in the vicinity of the containment recirculation screens are stainless steel. In the vicinity of the containment recirculation screens includes surfaces located above the bottom of the recirculation screens up to and including the bottom surface of the plate discussed in subsection 6.3.2.2.7, and the surfaces 10 feet in front and 7 feet to the sides of the screen face.	

Table 14.3-2 (Sheet 6 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 6.3.2.2.7	The bottom of the containment recirculation screens are located above the loop compartment floor (ft).	≥ 2
Section 6.3.3.2.1	For a loss of main feedwater event, the passive residual heat removal heat exchanger is actuated. If the core makeup tanks are not initially actuated, they actuate later when passive residual heat exchanger cooling sufficiently reduces pressurizer level.	
Section 6.3.3.2.2	For a feedwater system pipe failure event, the passive residual heat removal heat exchanger and the core makeup tanks are actuated.	
Section 6.3.3.3.1	For a steam generator tube rupture event, the nonsafety-related makeup pumps are automatically actuated when reactor coolant system inventory decreases and a reactor trip occurs, followed by actuation of the startup feedwater pumps. Makeup pumps automatically function to maintain the programmed pressurizer level. The core makeup tanks subsequently actuate on low pressurizer level, if they are not already actuated. Actuation of the core makeup tanks automatically actuates the passive residual heat removal system heat exchanger.	
Section 6.3.6.1	The piping resistances connecting the following PXS components and the RCS are bounded by the resistances assumed in the Chapter 15 safety analysis: - Core makeup tanks - Accumulators - In-containment refueling water storage tank injection - Containment recirculation - Automatic depressurization system valves	
Section 6.3.6.1.3	The bottom of the core makeup tanks are located above the reactor vessel direct vessel injection nozzle centerline (ft).	≥ 7.5
Section 6.3.6.1.3	The bottom of the in-containment refueling water storage tank is located above the direct vessel injection nozzle centerline (ft).	≥ 3.4
Section 6.3.6.1.3	The pH baskets are located below plant elevation 107′ 2″.	
Figure 6.3-1	The passive core cooling system has two direct vessel injection lines.	
Table 6.3-2	The passive core cooling system has two core makeup tanks, each with a minimum required volume (ft^3).	2487

Table 14.3-2 (Sheet 7 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
Table	6.3-2	The passive core cooling system has two accumulators, each with a minimum required volume (ft^3)	2,000
Table	6.3-2	The passive core cooling system has an in-containment refueling water storage tank with a minimum required water volume (ft^3)	73,900
Section	6.3.2.2.3	The containment floodup volume for a LOCA in PXS room B has a maximum volume (ft^3) (excluding the IRWST) below a containment elevation of 108 feet.	73,500
Table	6.3-2	Each sparger has a minimum discharge flow area (in^2).	≥ 274
Table	6.3-2	The passive core cooling system has two pH adjustment baskets each with a minimum required volume (ft^3).	280
Section	14.2.9.1.3f	The passive residual heat removal heat exchanger minimum natural circulation heat transfer rate (Btu/hr) - With 520°F hot leg and 80°F IRWST - With 420°F hot leg and 80°F IRWST	 ≥ 1.78 E+08 ≥ 1.11 E+08
Section	6.3.6.1.3	The centerline of the HX's upper channel head is located above the HL centerline (ft).	≥ 26.3
Figure	6.3-1	The CMT level sensors (PXS-11A/B/C/D, -12A/B/C/D, -13A/B/C/D, and -14A/B/C/D) upper level tap centerlines are located below the centerline of the upper level tap connection to the CMTs (in).	1″ ± 1″
Figure	6.3-1	The CMT inlet lines (cold leg to high point) have no downward sloping sections.	
Figure	6.3-1	The maximum elevation of the CMT injection lines between the connection to the CMT and the reactor vessel is the connection to the CMTs.	
Figure	6.3-2	The PRHR inlet line (hot leg to high point) has no downward sloping sections.	
Figure	6.3-2	The maximum elevation of the IRWST injection lines (from the connection to the IRWST to the reactor vessel) and the containment recirculation lines (from the containment to the IRWST injection lines) is less that the bottom inside surface of the IRWST.	
Figure	6.3-2	The maximum elevation of the PRHR outlet line (from the PRHR to the SG) is less than the PRHR lower channel head top inside surface.	

Table 14.3-2 (Sheet 8 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 7.1.2.10	Isolation devices are used to maintain the electrical independence of divisions and to see that no interaction occurs between nonsafety-related systems and the safety-related system. Isolation devices serve to prevent credible faults in circuit from propagating to another circuit.	
Section 7.1.4.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire, flooding, explosions, missiles, electrical faults and pipe whip.	
Section 7.1.2	The flexibility of the protection and safety monitoring system enables physical separation of redundant divisions.	
Section 7.2.2.2.1	The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level.	
Section 7.2.2.2.8	The reactor is tripped by actuating one of two manual reactor trip controls from the main control room.	
Section 7.3.1.2.2	The in-containment refueling water storage tank is aligned for injection upon actuation of the fourth stage automatic depressurization system via the protection and safety monitoring system.	
Section 7.3.1.2.3	The core makeup tanks are aligned for operation on a safeguards actuation signal or on a low-2 pressurizer level signal via the protection and safety monitoring system.	
Section 7.3.1.2.4	The fourth stage valves of the automatic depressurization system receive a signal to open upon the coincidence of a low-2 core makeup tank water level in either core makeup tank and low reactor coolant system pressure following a preset time delay after the third stage depressurization valves receive a signal to open via the protection and safety monitoring system.	
Section 7.3.1.2.4	The first stage valves of the automatic depressurization system open upon receipt of a signal generated from a core makeup tank injection alignment signal coincident with core makeup tank water level less than the Low-1 setpoint in either core makeup tank via the protection and safety monitoring system.	

Table 14.3-2 (Sheet 9 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 7.3.1.2.4	The second and third stage valves open on time delays following generation of the first stage actuation signal via the protection and safety monitoring system.	
Section 7.3.1.2.5	The reactor coolant pumps are tripped upon generation of a safeguards actuation signal or upon generation of a low-2 pressurizer water level signal.	
Section 7.3.1.2.7	The passive residual heat removal heat exchanger control valves are opened on low steam generator water level or on a CMT actuation signal via the protection and safety monitoring system.	
Section 7.3.1.2.9	The containment recirculation isolation valves are opened on a safeguards actuation signal in coincidence with low-3 in-containment refueling water storage tank water level via the protection and safety monitoring system.	
Section 7.3.1.2.14	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, or low input voltage to the 1E dc and uninterruptible power supply battery chargers.	
Section 7.3.1.2.15	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protection and monitoring system derived from either a high-2 pressurizer level, high-2 steam generator level signal, a safeguards signal coincident with high-1 pressurizer level, or high-2 containment radioactivity.	
Section 7.3.2.2.1	The protection and monitoring system automatically generate an actuation signal for an engineered safety feature whenever a monitored condition reaches a preset level.	
Section 7.3.2.2.9	Manual initiation at the system-level exists for the engineered safety features actuation.	
Section 7.4.3.1	If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation.	

Table 14.3-2 (Sheet 10 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 7.4.3.1.1	The remote shutdown workstation equipment is similar to the operator workstations in the main control room and is designed to the same standards. One remote shutdown workstation is provided.	
Section 7.4.3.1.3	The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.	
Section 7.5.4	The protection and safety monitoring system provides signal conditioning, communications, and display functions for Category 1 variables and for Category 2 variables that are energized from the Class 1E uninterruptible power supply system.	
Section 7.6.1.1	An interlock is provided for the normally closed motor-operated normal residual heat removal system inner and outer suction isolation valves. Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure.	
Section 8.2.2	Following a turbine trip during power operation, the reverse-power relay will be blocked for a minimum time period (sec).	≥ 15
Section 8.3.2.1.2	The non-Class 1E dc and UPS system (EDS) consists of the electric power supply and distribution equipment that provides dc and uninterruptible ac power to nonsafety-related loads.	
Section 9.1.1.2.1	In the unlikely event of a dropping of an unirradiated fuel assembly, accidental deformation of the fuel rack will be determined and evaluated in the criticality analysis to demonstrate that it does not cause criticality criterion to be violated.	
Section 9.1.3.5	The spent fuel pool is designed such that a water level is maintained above the spent fuel assemblies for at least 7 days following a loss of the spent fuel cooling system using only on-site makeup water sources (See Table 9.1-4).	
Section 9.1.3.5	The spent fuel pool cooling system includes safety-related connections to establish safety-related makeup to the spent fuel pool following a design basis event including a seismic event.	

Table 14.3-2 (Sheet 11 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 9.1.4.1.1	In the event of a safe shutdown earthquake (SSE), handling equipment cannot fail in such a manner as to prevent required function of seismic Category 1 equipment.	
Section 9.3.6.3.7	The chemical and volume control system contains two redundant safety-related valves to isolate the demineralized water system from the makeup pump suction.	
Section 9.3.6.3.7	The chemical and volume control system contains two safety-related valves to isolate the makeup flow to the reactor coolant system.	
Section 9.3.6.4.5	The chemical and volume control system contains two safety-related valves to isolate the makeup flow to the reactor coolant system.	
Section 9.3.6.4.5.1	The chemical and volume control system contains two redundant safety-related valves to isolate the demineralized water system from the makeup pump suction.	
Section 9.3.6.7	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, low input voltage to the 1E dc and uninterruptible power supply battery chargers, or a safety injection signal.	
Section 9.3.6.7	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protecttion and safety monitoring system derived from either a high-2 pressurizer level, high steam generator level signal, or a safeguards signal coincident with high-1 pressurizer level.	
Section 10.1.2	Safety valves are provided on both main steam lines.	
Section 10.2.2.4.3	The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. The stop valves are closed by actuation of the emergency trip system devices.	
Section 10.3.1.1	The main steam supply system is provided with a main steam isolation valve and associated MSIV bypass valve on each main steam line from its respective steam generator.	
Section 10.3.1.1	A main steam isolation valve (MSIV) on each main steam line prevents the uncontrolled blowdown of more than one steam generator and isolates nonsafety-related portions of the system.	

Table 14.3-2 (Sheet 12 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
Section	10.3.1.2	Power-operated atmospheric relief valves are provided to allow controlled cooldown of the steam generator and the reactor coolant system when the condenser is not available.	
Section	10.3.2.1	The main steam supply system includes: - One main steam isolation valve and one main steam isolation valve bypass valve per main steam line. - Main steam safety valves. - Power-operated atmospheric relief valves and upstream isolation valves.	
Section	10.3.2.3.2	In the event that a design basis accident occurs, which results in a large steam line break, the main steam isolation valves with associated main steam isolation bypass valves automatically close.	
Figure	10.3.2-1	The steam generator system consists of two main steam, two main feedwater, and two startup feedwater lines.	
Table	10.3.2-2	Design data for main steam supply safety system valves: - Number per main steam line - Minimum relieving capacity per valve at 110% of design pressure (lb/hr)	 6 1,390,000
Table	10.3.2-2	The minimum flow capacity of the steam generator safety valves (lbm/hr).	≥ 8,340,000
Table	10.3.2-2	The maximum set pressure of the steam generator safety valves (psig).	≤ 1,220
Section	10.4.8.3	The safety-related portions of the steam generator blowdown system are located in the containment and auxiliary buildings and are designed to remain functional after a safe shutdown earthquake.	
Section	10.4.7.1.1	Double valve main feedwater isolation is provided via the main feedwater control valve and main feedwater isolation valve. Both valves close automatically on main feedwater isolation signals, an appropriate engineered safety features isolation signal, within the time established with the Technical Specifications, Section 16.1. The startup feedwater control valve also serves as a containment isolation valve.	

Table 14.3-2 (Sheet 13 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 10.4.7.1.1	The condensate and feedwater system provides redundant isolation valves for the main feedwater lines routed into containment.	
Section 10.4.7.1.1	For a main feedwater or main steam line break (MSLB) inside the containment, the condensate and feedwater system is designed to limit high energy fluid to the broken loop.	
Section 10.4.7.1.2	The booster/main feedwater pumps are tripped simultaneously with the feedwater isolation signal to close the main feedwater isolation valves.	
Section 10.4.7.2.1	The main feedwater pumps and booster pumps are tripped with the feedwater isolation signal that closes the main feedwater isolation valves. The same isolation signal closes the isolation valve in the cross connect line between the main feedwater pump discharge header and the startup feedwater pump discharge header.	
Section 10.4.7.2.2	One MFIV is installed in each of the two main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from the steam generators in the event of a feedwater pipe rupture. The main feedwater check valve provides backup isolation. In the event of a secondary side pipe rupture inside the containment, the MFIVs limit the quantity of high energy fluid that enters the containment through the broken loop and limit cooldown. The MFCV provides backup isolation to limit cooldown and high energy fluid addition.	
Section 10.4.7.2.2	In the event of a secondary side pipe rupture inside the containment, the main feedwater control valves provide a redundant isolation to the MFIVs to limit the quantity of high energy fluid that enters the containment through the broken loop.	
Section 10.4.7.3	For a main feedwater line break inside the containment or a main steam line break, the MFIVs and the main feedwater control valves automatically close upon receipt of a feedwater isolation signal.	
Section 10.4.7.3	For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater (MFIV and MFCV) with isolation signals generated by the protection and safety monitoring system (PMS).	

Table 14.3-2 (Sheet 14 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 10.4.8.2.2.7	Blowdown system isolation is actuated on low steam generator water levels. The isolation of steam generator blowdown provides for a continued availability of the steam generator as a heat sink for decay heat removal in conjunction with operation of the passive residual heat removal system and the startup feedwater system.	
Section 10.4.8.3	The safety-related portions of the steam generator blowdown system located in the containment and auxiliary buildings are designed to remain functional after a safe shutdown earthquake.	
Section 10.4.9.1.1	Double valve startup feedwater isolation is provided by the startup feedwater control valve and the startup feedwater isolation valve. Both valves close on a startup feedwater isolation signal, an appropriate engineered safeguards features signal, within the time established within the Technical Specifications, Section 16.1.	
Section 10.4.9.1.1	For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation signal and startup feedwater control valve), with isolation signals generated by the protection and safety monitoring system.	
Section 10.4.9.2.2	In the event of a steam generator tube rupture, the startup feedwater isolation valve and startup feedwater control valve limit overfill of the steam generator by terminating startup feed flow.	
Section 10.4.9.2.2	In the event of a secondary pipe rupture inside containment, the startup feedwater isolation valve and startup feedwater control valve provide isolation to limit the quantity of high energy fluid that enters the containment.	
Section 10.4.9.2.2	The startup feedwater isolation valve is provided to prevent the uncontrolled blowdown from more than one steam generator in the event of startup feedwater line rupture. The startup feedwater isolation valve provides backup isolation.	
Table 15.0-1	Initial core thermal power (MWt).	3400
Table 15.0-3	Nominal values of pertinent plant parameters used in accident analysis with 10% steam generator tube plugging - Reactor coolant flow (gpm)	296,000

Table 14.3-2 (Sheet 15 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 15.1.2.1	Continuous addition of excessive feedwater is prevented by the steam generator high-2 water level signal trip, which closes the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps and reactor.	
Section 15.1.4.1	For an inadvertent opening of a steam generator relief or safety valve, core makeup tank actuation occurs from one of four sources: - Two out of four low pressurizer pressure signals - Two out of four low pressurizer level signals - Two out of four low T_{cold} signals in any one loop - Two out of four low steam line pressure signals in any one loop	
Section 15.1.4.1	After an inadvertent opening of a steam generator relief or safety valve, redundant isolation of the main feedwater lines closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.	
Section 15.1.5.1	Following a steam line rupture, core makeup tank actuation occurs from one of five sources: - Two out of four low pressurizer pressure signals - Two out of four high-2 containment pressure signals - Two out of four low steam line pressure signals in any loop - Two out of four low T_{cold} signals in any one loop - Two out of four low pressurizer level signals	
Section 15.1.5.1	After a steam line rupture, redundant isolation of the main feedwater lines closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.	
Section 15.1.5.2.1	Core makeup tanks and the accumulators are the portions of the passive core cooling system used in mitigating a steam line rupture.	
Section 15.1.6.1	The heat sink for the PRHR heat exchanger is provided by the IRWST, in which the PRHR heat exchanger is submerged.	
Section 15.2.6.2.1	Following a loss of ac power, the PRHR heat exchanger is actuated by the low steam generator water level (wide range).	

Table 14.3-2 (Sheet 16 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 15.2.8.2.1	Receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal that closes all main steam line and feed line isolation valves. This signal also gives a safeguards signal that initiates flow of cold borated water from the core makeup tanks to the reactor coolant system.	
Section 15.3.3.2.2	The pressurizer safety valves are fully open at 2575 psia. Their capacity for steam relief is described in Section 5.4.	
Section 15.4.6.2.2	A safety signal from the protection and safety monitoring system automatically isolates the potentially unborated water from the demineralized water transfer and storage system and thereby terminates the dilution.	
Section 15.5.1.1	Following inadvertent operation of the core makeup tanks during power operation, the high-3 pressurizer level signal actuates the PRHR heat exchanger and blocks the pressurizer heaters.	
Section 15.5.2.1	The pressurizer heaters are blocked, and the main feedwater lines, steam lines, and chemical and volume control system are isolated.	
Table 15.6.5-10	ADS Valve Flow Areas (in^2) - ADS Stage 1 Control Valve - ADS Stage 2 Control Valve - ADS Stage 3 Control Valve - ADS Stage 4A Valve - ADS Stage 4B Valve	 ≥ 4.6 ≥ 21 ≥ 21 ≥ 67 ≥ 67
Table 15.6.5-10	ADS Valve Opening Times (sec) - ADS Stage 1 Control Valve - ADS Stage 1 Isolation Valve - ADS Stage 2 Control Valve - ADS Stage 2 Isolation Valve - ADS Stage 3 Control Valve - ADS Stage 3 Isolation Valve	 ≤ 30 ≤ 30 ≤ 80 ≤ 80 ≤ 80 ≤ 80
Section 18.8.3.2	The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel information system.	

Table 14.3-2 (Sheet 17 of 17)

DESIGN BASIS ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 18.8.3.2	The human system interface resources available at each workstation are the plant information system displays, the control displays (soft controls), the alarm system support displays, procedure system, and the screen and component selector.	

Table 14.3-3

ANTICIPATED TRANSIENT WITHOUT SCRAM

Reference	Design Feature	Value
Section 7.7.1.11	The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection and safety monitoring system.	
Section 7.7.1.11	The diverse actuation system trips the reactor control rods and the turbine on low wide range steam generator water level and on low pressurizer water level.	
Section 7.7.1.11	The diverse actuation system initiates passive residual heat removal on low wide range steam generator water level or high hot leg temperature; actuates core makeup tanks and trips the reactor coolant pumps on low pressurizer water level; and isolates selected containment penetrations and starts passive containment cooling on high containment temperature.	
Section 7.7.1.11	The manual actuation function of the diverse actuation system is implemented by wiring the controls located in the main control room directly to the final loads in a way that bypasses the normal path through the control room multiplexers, the protection and safety monitoring system cabinets, and the diverse actuation system logic.	
Section 7.7.1.11	The diverse actuation system uses a microprocessor board different from those used in the protection and safety monitoring system.	
Section 7.7.1.11	The diverse actuation system hardware implementation is different from that of the protection and safety monitoring system.	
Section 7.7.1.11	The operating system and programming language of the diverse actuation system is different from that of the protection and safety monitoring system.	

Table 14.3-4 (Sheet 1 of 2)

FIRE PROTECTION

Reference	Design Feature	Value
Section 3.4.1.1.2	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 3.4.1.1.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section 3.8.4.1.1	The conical roof supports the passive containment cooling system tank, which is constructed with a stainless steel liner on reinforced concrete walls.	
Section 7.1.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	
Section 7.4.3.1	If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation.	
Section 7.4.3.1.1	The remote shutdown workstation equipment is similar to the operator workstations in the main control room and is designed to the same standards. One remote shutdown workstation is provided.	
Section 7.4.3.1.3	The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.	
Section 8.3.2.2	The four divisions of Class 1E battery chargers and Class 1E voltage regulating transformers are independent, located in separate rooms, cannot be interconnected, and their circuits are routed in dedicated, physically separated raceways.	
Section 8.3.2.3	Each safety-related circuit and raceway is given a unique identification number to distinguish between circuits and raceways of different voltage level or separation groups.	

Table 14.3-4 (Sheet 2 of 2)

FIRE PROTECTION

Reference	Design Feature	Value
Section 8.3.2.4.2	Cables of one separation group are run in separate raceway and physically separated from cables of other separation groups. Group N raceways are separated from safety-related groups A, B, C, and D. Non-class 1E circuits are electrically isolated by isolation devices, shielding and wiring techniques, physical separation, or an appropriate combination thereof.	
Section 9.5.1.2.1.1	Separation is maintained between redundant safe shutdown components, including equipment, electrical cables, and instrumentation controls, in accordance with the fire areas.	
Section 9.5.1.2.1.5	The standpipe system is supplied with water from the safety-related passive containment cooling system storage tank and normally operates independently of the rest of the fire protection system. The supply line draws water from a portion of the storage tank, using water allocated for fire protection.	
Section 9.5.1.2.1.5	The standpipe system serving areas containing equipment required for safe shutdown following a safe shutdown earthquake is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional.	
Section 9.5.1.2.1.5	The volume of the water in the PCS tank is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for two hours (gal).	≥ 18,000
Table 9.5.1-2	Each fire pump is rated: - Flow rate (gpm) - Total head (ft)	 ≥ 2000 ≥ 300
Section 18.8.3.2	The human system interface resources available at each workstation are the plant information system displays, the control displays (soft controls), the alarm system support displays, procedure system, and the screen and component selector.	
Section 18.8.3.4	The mission of the remote shutdown workstation is to provide the resources to bring the plant to a safe shutdown condition after an evacuation of the main control room.	
Section 18.12.3	The controls, displays, and alarms listed in Table 18.12.2-1 are retrievable from the remote shutdown workstation.	

Table 14.3-5 (Sheet 1 of 2)

FLOOD PROTECTION

Reference		Design Feature	Value
Section	Appendix 1-A RG 1.143 Section C.1.1.3 Clarification	The lowest level of the auxiliary building, elevation 66′-6″, contains the components of the radwaste system within a common flood zone with watertight floors and walls. This volume of this enclosed flood zone is sufficient to contain the contents of the radwaste system.	
Table	2-1	Plant elevation for maximum flood level (ft).	≤ 100
Section	3.4.1.1.1	The seismic category I structures below grade are protected against flooding by waterstops and a waterproofing system.	
Section	3.4.1.1.2	The boundaries between mechanical equipment rooms and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section	3.4.1.2.2	The boundaries between mechanical equipment rooms inside containment and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section	3.4.1.2.2	Boundaries exist to prevent flooding between the following rooms which contain safety-related equipment: PXS valve/accumulator room A, PXS valve/accumulator room B, and chemical and volume control room.	
Section	3.4.1.2.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section	3.4.1.2.2	The safety-related components available for safety shutdown are located in the auxiliary building and inside containment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.	
Section	3.4.1.2.2.1	The PXS-A compartment, PXS-B compartment and the chemical and volume control system compartment are physically separated and isolated from each other by structural walls such that flooding in any one of these compartments cannot cause flooding in any of the other compartments at elevations up to the top of these compartments.	

Table 14.3-5 (Sheet 2 of 2)

FLOOD PROTECTION

Reference	Design Feature	Value
Section 3.6	In the event of a high- or moderate-energy pipe failure within the plant, adequate protection is provided so that essential structures, systems, or components are not impacted by the adverse effects of postulated pipe failure.	
Section 7.1.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	

Table 14.3-6 (Sheet 1 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Table 3.2-2	The Nuclear Island structures include the containment and the shield and auxiliary buildings. These structures are seismic Category I.	
Table 3.2-3	The components identified under Reactor Systems in Table 3.2-3, as ASME Code Section III are designed and constructed in accordance with ASME Code Section III Requirements.	
Table 3.2-3	The Nuclear Island structures include the containment and the Shield and Auxiliary Buildings. These structures are seismic Category I.	
Section 3.4.1.1.2	The boundaries between mechanical equipment rooms and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section 3.4.1.1.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section 3.4.1.1.2	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 3.4.1.2.2	Boundaries exist to prevent flooding between the following rooms which contain safety-related equipment: PXS valve/accumulator room A, PXS valve/accumulator room B, and chemical and volume control room.	
Section 3.4.1.2.2	The boundaries between mechanical equipment rooms inside containment and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section 3.4.1.2.2	The safety-related components available for safety shutdown are located in the auxiliary building and inside containment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.	

Table 14.3-6 (Sheet 2 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 3.4.1.2.2.1	The PXS-A compartment, PXS-B compartment and the chemical and volume control system compartment are physically separated and isolated from each other by structural walls such that flooding in any one of these compartments or in the reactor coolant system compartment cannot cause flooding in any of the other compartments.	
Section 3.11.2.1	The design of the protection and safety monitoring system equipment has margin to accommodate a loss of the normal HVAC.	
Section 3D.6	RXS equipment in Appendix 3D is seismically qualified.	
Section 5.1.3.7	ADS has four stages. Each stage is arranged into two separate groups of valves and lines. - Stages 1, 2, and 3 discharge from the top of the pressurizer to the IRWST. - Each stage 4 discharges from a hot leg to the RCS loop compartment.	
Section 5.3.1.1	The reactor vessel provides a high integrity pressure boundary to contain the reactor coolant, heat generating reactor core, and fuel fission products. The reactor vessel is the primary boundary for the reactor coolant and the secondary barrier against the release of radioactive fission products.	
Section 5.4.6	ADS has four stages. Each stage is arranged into two separate groups of valves and lines. - Stages 1, 2, and 3 discharge from the top of the pressurizer to the IRWST. - Each stage 4 discharges from a hot leg to the RCS loop compartment.	
Section 5.4.6.2	Each ADS stage 1, 2, and 3 line contains two normally closed motor-operated valves (MOVs).	
Section 5.4.6.2	Each ADS stage 4 line contains a normally open MOV valve and a normally closed squib valve.	
Section 5.4.7	The RNS removes heat from the core and reactor coolant system at reduced RCS pressure and temperature conditions after shutdown.	

Table 14.3-6 (Sheet 3 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 5.4.7	The normal residual heat removal system (RNS) provides a safety-related means of performing the following functions: - Containment isolation for the RNS lines that penetrate the containment - Long-term, post-accident makeup water to the RCS	
Section 5.4.7.1.1	The RNS containment isolation and pressure boundary valves are safety-related. The motor-operated valves are powered by Class 1E dc power.	
Section 5.4.7.1.2.1	The component cooling water system (CCS) provides cooling to the RNS heat exchanger.	
Section 6.2.4	The containment hydrogen control system provides nonsafety-related hydrogen igniters for control of the containment hydrogen concentration for beyond design basis accidents.	
Section 6.2.4.2.3	At least 64 hydrogen igniters are provided.	
Section 6.3.1.1.3	The automatic depressurization system provides a safety-related means of depressurizing the RCS.	
Section 6.3	The in-containment refueling water storage tank subsystem provides a safety-related means of performing the following functions: - Low-pressure safety injection - Core decay heat sink during design basis events - Flooding of the lower containment, the reactor cavity and the loop compartment by draining the IRWST into the containment. - Borated water	
Section 6.3.1	The core makeup tanks provide safety-related means of safety injection of borated water to the RCS.	
Section 6.3.1	Passive residual heat removal (PRHR) provides a safety-related means of removing core decay heat during design basis events.	
Section 6.3.2	The ADS valves are powered from Class 1E dc power.	

Table 14.3-6 (Sheet 4 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 6.3.2	There are two CMTs, each with an injection line to the reactor vessel/DVI nozzle. - Each CMT has a pressure balance line from an RCS cold leg. - Each injection line is isolated with a parallel set of air-operated valves (AOVs). - These AOVs open on loss of air. - The injection line for each CMT also has two check valves in series.	
Section 6.3.2	The IRWST subsystem has the following flowpaths: - Two (redundant) injection lines from the IRWST to the reactor vessel/DVI nozzle. Each line is isolated with a parallel set of valves; each set with a check valve in series with a squib valve. - Two (redundant) recirculation lines from the containment to the IRWST injection line. Each recirculation line has two paths: one path contains a squib valve and an MOV, the other path contains a squib valve and a check valve. - The two MOV/squib valve lines also provide the capability to flood the reactor cavity.	
Section 6.3.2	There are screens for each IRWST injection line and recirculation line.	
Section 6.3.2	PRHR is actuated by opening redundant, parallel air-operated valves. These air-operated valves open on loss of air.	
Section 6.3.2.2	The passive core cooling system (PXS) is composed of the following: - Accumulator subsystem - Core makeup tank (CMT) subsystem - In-containment refueling water storage tank (IRWST) subsystem - Passive residual heat removal (PRHR) subsystem. - The automatic depressurization system (ADS), which is a subsystem of the reactor coolant system (RCS), also supports passive core cooling functions.	
Section 6.3.2.2.2	There are two accumulators, each with an injection line to the reactor vessel/direct vessel injection (DVI) nozzle. Each injection line has two check valves in series.	

Table 14.3-6 (Sheet 5 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 6.3.2.2.2	The accumulators provide a safety-related means of safety injection of borated water to the RCS.	
Section 6.3.2.2.8.7	The accumulator discharge check valves are of a different type than the CMT discharge check valves.	
Section 6.3.3	IRWST squib valves and MOVs are powered by Class 1E dc power.	
Section 6.3.3	The CMT AOVs are automatically and manually actuated from PMS and DAS.	
Section 6.3.3	The PRHR air-operated valves are automatically actuated and manually actuated from the control room by either PMS or DAS.	
Section 6.3.3	The squib valves and MOVs for injection and recirculation are automatically and manually actuated via PMS, and manually actuated via DAS.	
Section 6.3.3	The squib valves and MOVs for and reactor cavity flooding are manually actuated via PMS and DAS from the control room.	
Section 6.3.7	The positions of the containment recirculation isolation MOVs are indicated in the control room.	
Section 6.3.7	The position of the inlet PRHR valve is indicated in the control room.	
Section 6.3.7.6.1	The ADS first-, second-, and third-stage valve positions are indicated in the control room.	
Section 7.1.1	The diverse actuation system provides a nonsafety-related means of performing the following functions: - Initiates automatic and manual reactor trip - Automatic and manual actuation of selected engineered safety features - Main control room display of selected plant parameters.	
Section 7.1.1	The protection and safety monitoring system provides a safety-related means of performing the following functions: - Automatic and manual reactor trip - Automatic and manual actuation of engineered safety features (ESF).	

Table 14.3-6 (Sheet 6 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 7.1.1	PMS provides for the minimum inventory of fixed position controls and displays in the control room.	
Section 7.1.2	Each PMS division is powered from its respective Class 1E dc division.	
Section 7.1.2	PMS has four divisions of reactor trip and ESF actuation.	
Section 7.1.2.5	PMS has two divisions of safety-related post-accident parameter display.	
Section 7.1.2.9	PMS automatically blocks an attempt to bypass more than one channel of a function that uses 2-out-of-4 logic.	
Section 7.1.2.14	The PMS hardware and software are developed using a planned design process which provides for specific design documentation and reviews during the design requirement, system definition, development, test and installation phases.	
Section 7.1.4.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	
Section 7.1.2	The flexibility of the protection and safety monitoring system enables physical separation of redundant divisions.	
Section 7.2.2.2.1	The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level.	
Section 7.4.3 18.12.2	The PMS allows for the transfer of control capability from the main control room to the remote shutdown workstation. The minimum inventory of displays and controls in the remote shutdown workstation is provided.	
Section 7.3.1 8.3.2.1.1	The ADS valves are powered from Class 1E dc power.	
Section 7.7.1.11 7.3.1.2.4	The ADS valves are automatically and manually actuated via the protection and safety monitoring system (PMS), and manually actuated via the diverse actuation system (DAS).	
Section 7.3.1.2.3 7.7.1.11	The CMT AOVs are automatically and manually actuated from PMS and DAS.	
Section 7.3.1.2.2 7.3.1.2.9 7.7.1.11	The squib valves and MOVs for injection and recirculation are automatically and manually actuated via PMS, and manually actuated via DAS.	

Table 14.3-6 (Sheet 7 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference		Design Feature	Value
Figure	7.2-1 (Sheets 16 and 20)	The squib valves and MOVs for reactor cavity flooding are manually actuated via PMS and DAS from the control room.	
Section	7.3.1.2.7 7.7.1.11	The PRHR air-operated valves are automatically actuated and manually actuated from the control room by either PMS or DAS.	
Section	7.3.1.2.20	The RNS containment isolation MOVs are actuated via PMS.	
Section	7.5.4	PMS has two divisions of safety-related post-accident parameter display.	
Section	7.6.1.1	An interlock is provided for the normally closed motor-operated normal residual heat removal system inner and outer suction isolation valves. Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure.	
Section	7.7.1.11	The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection and safety monitoring system.	
Section	7.7.1.11	The diverse actuation system trips the reactor control rods and the turbine on low wide range steam generator water level and on low pressurizer water level.	
Section	7.7.1.11	DAS manual initiation functions are implemented in a manner that bypasses the signal processing equipment of the DAS.	
Section	7.7.1.11	The DAS automatic actuation signals are generated in a functionally diverse manner from the PMS signals. Diversity between DAS and PMS is achieved by the use of different architecture, different hardware implementations, and different software.	
Section	8.3.1.1.1	On loss of power to a 6900V diesel-backed bus, the associated diesel generator automatically starts and produces ac power. The source circuit breakers and bus load circuit breakers are opened, and the generator is connected to the bus. Each generator has an automatic load sequencer to enable controlled loading on the associated buses.	

Table 14.3-6 (Sheet 8 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 8.3.1.1.2.1	Two onsite standby diesel generator units provide power to the selected nonsafety-related ac loads.	
Section 8.3.1.1.3	The main ac power system distributes non-Class 1E power from onsite sources to selected nonsafety-related loads.	
Section 8.3.2.1	The Class 1E dc and uninterruptible power supply (UPS) system (IDS) provides dc and uninterruptible ac power for the safety-related equipment.	
Section 8.3.2.1.1.1	There are four independent, Class 1E 125 Vdc divisions. Divisions A and D are each composed of one battery bank, one switchboard, and one battery charger. Divisions B and C are each composed of two battery banks, two switchboards, and two battery chargers. The first battery bank in the four divisions is designated as the 24-hour battery bank. The second battery bank in Divisions B and C is designated as the 72-hour battery bank.	
Section 8.3.2.1.1.1	Battery chargers are connected to dc switchboard buses. The input ac power for the Class 1E dc battery chargers is supplied from onsite diesel-generator-backed low-voltage ac power supplies.	
Section 8.3.2.1.1.1	The 24-hour battery banks provide power to the loads for a period of 24 hours without recharging. The 72-hour battery banks supply a dc switchboard bus load for a period of 72 hours without recharging.	
Section 8.3.2.1.2	The non-Class 1E dc and UPS system (EDS) consists of the electric power supply and distribution equipment that provides dc and uninterruptible ac power to nonsafety-related loads.	
Section 8.3.2.1.2	EDS load groups 1, 2, and 3 provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E uninterruptible power supply ac system.	
Section 8.3.2.1.2	Battery chargers are connected to dc switchboard buses. The input ac power for the non-Class 1E dc battery chargers is supplied from onsite diesel-generator-backed low-voltage ac power supplies.	
Section 8.3.2.1.2	The onsite standby diesel-generator-backed low-voltage ac power supply provides the normal ac power to the battery chargers.	

Table 14.3-6 (Sheet 9 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 8.3.2.1.3	Separation is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E cables.	
Section 9.2.1	The service water system is a nonsafety-related system that transfers heat from the component cooling water heat exchangers to the atmosphere.	
Section 9.2.1.2.1	The SWS is arranged into two trains. Each train includes one pump and one cooling tower cell.	
Section 9.2.2	The component cooling water system is a nonsafety-related system that removes heat from various components and transfers the heat to the service water system (SWS).	
Section 9.2.2.2	The CCS is arranged into two trains. Each train includes one pump and one heat exchanger.	
Section 9.3.6	The CVS provides a nonsafety-related means to perform the following functions: - Makeup water to the RCS during normal plant operation - Boration following a failure of reactor trip - Coolant to the pressurizer auxiliary spray line.	
Section 9.3.6.1.1	The chemical and volume control system (CVS) provides a safety-related means to terminate inadvertent RCS boron dilution.	
Section 9.4.1	The main control room has its own ventilation system and is pressurized. The ventilation system for the remote shutdown room is independent of the ventilation system for the main control room.	
Section 9.5.1.2.1.1	The PMS allows for the transfer of control capability from the main control room to the remote shutdown workstation. The minimum inventory of displays and controls at the remote shutdown workstation is provided.	
Section 9.5.1.2.1.1	Class 1E divisional cables are routed in their respective divisional raceways.	
Section 9.5.1.2.1.1	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 17.4.1	D-RAP provides reasonable assurance that the design of risk-significant SSCs is consistent with their PRA assumptions.	

Table 14.3-6 (Sheet 10 of 10)

PROBABILISTIC RISK ASSESSMENT

Reference	Design Feature	Value
Section 18.8.3.2	The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel information system.	
Section 18.12.2	The minimum inventory of instrumentation includes those displays, controls, and alarms that are used to monitor the status of the critical safety functions and to manually actuate the safety-related systems that achieve the critical safety functions. The minimum inventory resulting from the implementation of the selection criteria is provided in Table 18.12.2-1.	

Table 14.3-7 (Sheet 1 of 3)

RADIOLOGICAL ANALYSIS

Reference		Design Feature	Value
Table	2-1	Plant elevation for maximum flood level (ft)	≤ 100
Section	2.3.4	Atmospheric dispersion factors - X/Q (sec/m^3) - Site Boundary X/Q 0 - 2 hour time interval - Low Population Zone Boundary X/Q 0 - 8 hours 8 - 24 hours 24 - 96 hours 96 - 720 hours	 $\leq 8.0 \times 10^{-4}$ $\leq 5.0 \times 10^{-4}$ $\leq 3.0 \times 10^{-4}$ $\leq 1.5 \times 10^{-5}$ $\leq 8.0 \times 10^{-5}$
Table	6.2.3-1	Containment penetration isolation features are configured as in Table 6.2.3-1	
Table	6.2.3-1	Maximum closure time for remotely operated containment purge valves (seconds)	≤ 10
Table	6.2.3-1	Maximum closure time for all other remotely operated containment isolation valves (seconds)	≤ 60
Section	6.4.2.3	The minimum storage capacity of all storage tanks in the VES (scf)	≤ 314,132
Section	6.4.3.2	The maximum temperature rise in the main control room pressure boundary following a loss on the nuclear island nonradioactive ventilation system over a 72-hour period (°F)	+ 10.8
Section	6.4.4	The maximum temperature in the instrumentation and control rooms and dc equipment rooms following a loss of the nuclear island nonradioactive ventilation system remains over a 72-hour period (°F).	≤ 120
Section	6.4.4	The main control emergency habitability system nominally provides 65 scfm of ventilation air to the main control room from the compressed air storage tanks.	65 ± 5
Section	6.4.4	Sixty-five ± five scfm of ventilation flow is sufficient to pressurize the control room to $1/8^{th}$ inch water gauge differential pressure (WIC).	$1/8^{th}$
Figure	6.4-2	The main control room emergency habitability system consists of two sets of emergency air storage tanks and an air delivery system to the main control room.	
Section	6.5.3	The passive heat removal process and the limited leakage from the containment result in offsite doses less than the regulatory guideline limits.	

Table 14.3-7 (Sheet 2 of 3)

RADIOLOGICAL ANALYSIS

Reference	Design Feature	Value
Section 8.3.1.1.6	Electrical penetrations through the containment can withstand the maximum short-circuit currents available either continuously without exceeding their thermal limit, or at least longer than the field cables of the circuits so that the fault or overload currents are interrupted by the protective devices prior to a potential failure of a penetration.	
Section 9.4.1.1.1	The VBS isolates the HVAC ductwork that penetrates the main control room boundary on high particulate or iodine concentrations in the main control room supply air or on extended loss of ac power to support operation of the main control room emergency habitability system.	
Section 12.3.2.2.1	During reactor operation, the shield building protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete shield building wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the shield building to less than 0.25 mrem/hr from sources inside containment. The shield building completely surrounds the reactor components.	
Section 12.3.2.2.2	The reactor vessel is shielded by the concrete primary shield and by the concrete secondary shield which also surrounds other primary loop components. The secondary shield is a structural module filled with concrete surrounding the reactor coolant system equipment, including piping, pumps and steam generators. Extensive shielding is provided for areas surrounding the refueling cavity and the fuel transfer canal to limit the radiation levels.	
Section 12.3.2.2.3	Shielding is provided for the liquid radwaste, gaseous radwaste and spent resin handling systems consistent with the maximum postulated activity. Corridors are generally shielded to allow Zone II access, and operator areas for valve modules are generally Zone II or III for access. Shielding is provided to attenuate radiation from normal residual heat removal equipment during shutdown cooling operations to levels consistent with radiation zoning requirements of adjacent areas.	

Table 14.3-7 (Sheet 3 of 3)

RADIOLOGICAL ANALYSIS

Reference	Design Feature	Value
Section 12.3.2.2.4	The concrete shield walls surrounding the spent fuel cask loading and decontamination areas, and the shield walls surrounding the fuel transfer and storage are sufficiently thick to limit radiation levels outside the shield walls in accessible areas to Zone II. The building walls are sufficient to shield external plant areas which are not controlled to Zone II.	
Section 12.3.2.2.5	Shielding is provided as necessary for the waste storage areas in the radwaste building to meet the radiation zone and access requirements.	
Section 12.3.2.2.7	Shielding combined with other engineered safety features is provided to permit access and occupancy of the control room following a postulated loss-of-coolant accident, so that radiation doses are limited to five rem whole body from contributing modes of exposure for the duration of the accident, in accordance with General Design Criteria 19.	
Section 12.3.2.2.9	The spent fuel transfer tube is shielded to within adjacent area radiation limits, is completely enclosed in concrete, and there is no unshielded portion of the spent fuel transfer tube during the refueling operation.	

Table 14.3-8

SEVERE ACCIDENT ANALYSIS

Reference	Design Feature	Value
Section 1.2	The discharge from the IRWST vents located in the roof of the IRWST next to the containment vessel are oriented away from the containment vessel.	
Section 5.3.1.2	There are no penetrations in the reactor vessel below the core.	
Section 5.3.5	The reflective reactor vessel insulation provides an engineered flow path to allow the ingression of water and venting of steam for externally cooling the vessel. - A flow path exists from the loop compartment to the reactor vessel cavity (ft^2). - A flow path area to vent steam exists between the vessel insulation and the reactor vessel (ft^2).	 ≥ 6 ≥ 12
Section 6.2.4.2.3	The hydrogen ignition subsystem consists of 64 hydrogen igniters strategically distributed throughout the containment.	
Table 6.2.4-3	The minimum surface temperature of the hydrogen igniters (°F).	≥ 1,700
Section 6.3	The ADS provides a safety-related means of depressurizing the RCS.	
Section 6.3	The PXS provides a safety-related means of flooding the reactor cavity by draining the IRWST into the containment.	
Section 7.3.1.2.9	Signals to align the IRWST containment recirculation isolation valves are generated by manual initiation.	
Section 7.7.1.11	Initiation of containment recirculation is a diverse manual function.	

14.4 Combined License Applicant Responsibilities

This section describes the Combined License applicant's and holder's responsibilities required to perform the AP1000 plant initial test program.

14.4.1 Organization and Staffing

The specific staff, staff responsibilities, authorities, and personnel qualifications for performing the AP1000 initial test program are the responsibility of the Combined License applicant. This test organization is responsible for the planning, executing, and documenting of the plant initial testing and related activities that occur between the completion of plant/system/component construction and commencement of plant commercial operation. Transfer and retention of experience and knowledge gained during initial testing for the subsequent commercial operation of the plant is an objective of the test program.

14.4.2 Test Specifications and Procedures

The Combined License applicant is responsible for providing test specifications and test procedures for the preoperational and startup tests, as identified in subsection 14.2.3, for review by the NRC.

14.4.3 Conduct of Test Program

The Combined License applicant is responsible for a startup administration manual (procedure) which contains the administration procedures and requirements that govern the activities associated with the plant initial test program, as identified in subsection 14.2.3.

14.4.4 Review and Evaluation of Test Results

The Combined License applicant or holder is responsible for review and evaluation of individual test results. Test exceptions or results which do not meet acceptance criteria are identified to the affected and responsible design organizations, and corrective actions and retests, as required, are performed.

14.4.5 Interface Requirements

The combined license applicant is responsible for testing that may be required of structures and systems which are outside the scope of this design certification. Test Specifications and acceptance criteria are provided by the responsible design organizations as identified in subsection 14.2.3. The interfacing systems to be considered for testing are taken from Table 1.8-1 and include as a minimum, the following:

- storm drains
- site specific seismic sensors
- offsite ac power systems
- circulating water heat sink
- raw and sanitary water systems

- individual equipment associated with the fire brigade
- portable personnel monitors and radiation survey instruments
- equipment associated with the physical security plan

14.4.6 First-Plant-Only and Three-Plant-Only Tests

[*The COL applicant or holder for the first plant and the first three plants will perform the tests listed in subsection 14.2.5. For subsequent plants, the COL applicant or licensee shall either perform the tests listed in subsection 14.2.5, or shall provide a justification that the results of the first-plant-only tests or first-three-plant tests are applicable to the subsequent plant.*]*

* NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

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CHAPTER 15

ACCIDENT ANALYSES

15.0.1 Classification of Plant Conditions

The ANSI 18.2 (Reference 1) classification divides plant conditions into four categories according to anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

- Condition I: Normal operation and operational transients
- Condition II: Faults of moderate frequency
- Condition III: Infrequent faults
- Condition IV: Limiting faults

The basic principle applied in relating design requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk, and those extreme situations having the potential for the greatest risk should be those least likely to occur. Where applicable, reactor trip and engineered safeguards functioning are assumed to the extent allowed by considerations such as the single failure criterion in fulfilling this principle.

15.0.1.1 Condition I: Normal Operation and Operational Transients

Condition I occurrences are those that are expected to occur frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between a plant parameter and the value of that parameter requiring either automatic or manual protective action.

Because Condition I events occur frequently, they must be considered from the point of view of their effect on the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to adverse conditions that can occur during Condition I operation.

A typical list of Condition I events follows.

Steady-state and Shutdown Operations

See Table 1.1-1 of Chapter 16.

Operation with Permissible Deviations

Various deviations that occur during continued operation as permitted by the plant Technical Specifications are considered in conjunction with other operational modes. These deviations include the following:

- Operation with components or systems out of service (such as an inoperable rod cluster control assembly [RCCA])

- Leakage from fuel with limited cladding defects
- Excessive radioactivity in the reactor coolant:
  - Fission products
  - Corrosion products
  - Tritium
- Operation with steam generator tube leaks
- Testing

Operational Transients

- Plant heatup and cooldown
- Step load changes (up to ±10 percent)
- Ramp load changes (up to 5 percent/minute)
- Load rejection up to and including design full-load rejection transient

15.0.1.2 Condition II: Faults of Moderate Frequency

These faults, at worst, result in a reactor trip with the plant being capable of returning to operation. By definition, these faults (or events) do not propagate to cause a more serious fault (Condition III or IV events). In addition, Condition II events are not expected to result in fuel rod failures, reactor coolant system failures, or secondary system overpressurization. The following faults are included in this category:

- Feedwater system malfunctions that result in a decrease in feedwater temperature (see subsection 15.1.1)
- Feedwater system malfunctions that result in an increase in feedwater flow (see subsection 15.1.2)
- Excessive increase in secondary steam flow (see subsection 15.1.3)
- Inadvertent opening of a steam generator relief or safety valve (see subsection 15.1.4)
- Inadvertent operation of the passive residual heat removal heat exchanger (see subsection 15.1.6)
- Loss of external electrical load (see subsection 15.2.2)
- Turbine trip (see subsection 15.2.3)
- Inadvertent closure of main steam isolation valves (see subsection 15.2.4)
- Loss of condenser vacuum and other events resulting in turbine trip (see subsection 15.2.5)

- Loss of ac power to the station auxiliaries (see subsection 15.2.6)
- Loss of normal feedwater flow (see subsection 15.2.7)
- Partial loss of forced reactor coolant flow (see subsection 15.3.1)
- Uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition (see subsection 15.4.1)
- Uncontrolled RCCA bank withdrawal at power (see subsection 15.4.2)
- RCCA misalignment (dropped full-length assembly, dropped full-length assembly bank, or statically misaligned assembly) (see subsection 15.4.3)
- Startup of an inactive reactor coolant pump at an incorrect temperature (see subsection 15.4.4)
- Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant (see subsection 15.4.6)
- Inadvertent operation of the passive core cooling system during power operation (see subsection 15.5.1)
- Chemical and volume control system malfunction that increased reactor coolant inventory (see subsection 15.5.2)
- Inadvertent opening of a pressurizer safety valve (see subsection 15.6.1)
- Break in instrument line or other lines from the reactor coolant pressure boundary that penetrate containment (see subsection 15.6.2)

15.0.1.3 Condition III: Infrequent Faults

Condition III events are faults that may occur infrequently during the life of the plant. They may result in the failure of only a small fraction of the fuel rods. The release of radioactivity is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary, in accordance with the guidelines of 10 CFR 100. By definition, a Condition III event alone does not generate a Condition IV event or result in a consequential loss of function of the reactor coolant system or containment barriers. The following faults are included in this category:

- Steam system piping failure (minor) (see subsection 15.1.5)
- Complete loss of forced reactor coolant flow (see subsection 15.3.2)
- RCCA misalignment (single RCCA withdrawal at full power) (see subsection 15.4.3)

- Inadvertent loading and operation of a fuel assembly in an improper position (see subsection 15.4.7)
- Inadvertent operation of automatic depressurization system (see subsection 15.6.1)
- Loss-of-coolant accidents (LOCAs) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (small break) (see subsection 15.6.5)
- Gas waste management system leak or failure (see subsection 15.7.1)
- Liquid waste management system leak or failure (see subsection 15.7.2)
- Release of radioactivity to the environment due to a liquid tank failure (see subsection 15.7.3)
- Spent fuel cask drop accidents (see subsection 15.7.5)

15.0.1.4 Condition IV: Limiting Faults

Condition IV events are faults that are not expected to take place, but are postulated because their consequences include the potential of the release of significant amounts of radioactive material. They are the faults that must be designed against, and they represent limiting design cases. Condition IV faults are not to cause a fission product release to the environment resulting in doses in excess of the guideline values of 10 CFR 100. A single Condition IV event is not to cause a consequential loss of required functions of systems needed to cope with the fault, including those of the emergency core cooling system and the containment. The following faults are classified in this category:

- Steam system piping failure (major) (see subsection 15.1.5)
- Feedwater system pipe break (see subsection 15.2.8)
- Reactor coolant pump shaft seizure (locked rotor) (see subsection 15.3.3)
- Reactor coolant pump shaft break (see subsection 15.3.4)
- Spectrum of RCCA ejection accidents (see subsection 15.4.8)
- Steam generator tube rupture (see subsection 15.6.3)
- LOCAs resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (large break) (see subsection 15.6.5)
- Design basis fuel handling accidents (see subsection 15.7.4)

15.0.2 Optimization of Control Systems

A control system setpoint study is performed prior to plant operation to simulate performance of the primary plant control systems and overall plant performance. In this study, emphasis is placed on the development of the overall plant control systems that automatically maintain conditions in the plant within the allowed operating window and with optimum control system response and stability over the entire range of anticipated plant operating conditions. The control system setpoints are developed using the nominal protection and safety monitoring system setpoints implemented in the plant. Where appropriate (such as in margin to reactor trip analyses), instrumentation errors are considered and are applied in an adverse direction with respect to maintaining system stability and transient performance. The accident analysis and plant control system setpoint study in combination show that the plant can be operated and meet both safety and operability requirements throughout the core life and for various levels of power operation.

The plant control system setpoint study is comprised of analyses of the following control systems: plant control, axial offset control, rapid power reduction, steam dump (turbine bypass), steam generator level, pressurizer pressure, and pressurizer level.

15.0.3 Plant Characteristics and Initial Conditions Assumed in the Accident Analyses

15.0.3.1 Design Plant Conditions

Table 15.0-1 lists the principal power rating values assumed in the analyses performed. The thermal power output includes the effective thermal power generated by the reactor coolant pumps. Selected AP1000 loop layout elevations are shown in Figure 15.0.3-2 to aid in interpreting plots shown in other Chapter 15 subsections.

The values of other pertinent plant parameters used in the accident analyses are given in Table 15.0-3.

15.0.3.2 Initial Conditions

For most accidents that are departure from nucleate boiling (DNB) limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the departure from nucleate boiling ratio (DNBR) design limit values (see subsection 4.4), as described in WCAP-11397-P-A (Reference 2). This procedure is known as the Revised Thermal Design Procedure (RTDP) and is discussed more fully in Section 4.4.

For accidents that are not DNB limited, or for which the revised thermal design procedure is not used, the initial conditions are obtained by adding the maximum steady-state errors to rated values. The following conservative steady-state errors are assumed in the analysis:

Core power	$\pm$ 2 percent allowance for calorimetric error
Average reactor coolant system temperature	+6.5 or -7.0°F allowance for controller deadband and measurement errors

Pressurizer pressure	± 50 psi allowance for steady-state fluctuations and measurement errors

Initial values for core power, average reactor coolant system temperature, and pressurizer pressure are selected to minimize the initial DNBR unless otherwise stated in the sections describing the specific accidents. Table 15.0-2 summarizes the initial conditions and computer codes used in the accident analyses.

15.0.3.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of fuel assemblies and control rods. Power distribution may be characterized by the nuclear enthalpy rise hot channel factor ($F_{\Delta H}$) and the total peaking factor (F_q). Unless specifically noted otherwise, the peaking factors used in the accident analyses are those presented in Chapter 4.

For transients that may be DNB limited, the radial peaking factor is important. The radial peaking factor increases with decreasing power level due to control rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 15.0.3-1. Transients that may be departure from nucleate boiling limited are assumed to begin with an $F_{\Delta H}$, consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is the 1.55 chopped cosine, as discussed in subsection 4.4, for transients analyzed at full power and the most limiting power shape calculated or allowed for accidents initiated at nonfull power or asymmetric RCCA conditions.

The radial and axial power distributions just described are input to the VIPRE-01 code as described in subsection 4.4.

For transients that may be overpower-limited, the total peaking factor (F_q) is important. Transients that may be overpower-limited are assumed to begin with plant conditions, including power distributions, which are consistent with reactor operation as defined in the Technical Specifications.

For overpower transients that are slow with respect to the fuel rod thermal time constant (for example, the chemical and volume control system malfunction that results in a slow decrease in the boron concentration in the reactor coolant system as well as an excessive increase in secondary steam flow) and that may reach equilibrium without causing a reactor trip, the fuel rod thermal evaluations are performed as discussed in subsection 4.4.

For overpower transients that are fast with respect to the fuel rod thermal time constant (for example, the uncontrolled RCCA bank withdrawal from subcritical or lower power startup and RCCA ejection incident, both of which result in a large power rise over a few seconds), a detailed fuel transient heat transfer calculation is performed.

15.0.4 Reactivity Coefficients Assumed in the Accident Analysis

The transient response of the reactor system is dependent on reactivity feedback effects, in particular, the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients are discussed in subsection 4.3.2.3.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values. The values used are given in Figure 15.0.4-1, which shows the upper and lower bound Doppler power coefficients as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values is treated on an event-by-event basis. In some cases, conservative combinations of parameters are used to bound the effects of core life, although these combinations may not represent possible realistic situations.

15.0.5 Rod Cluster Control Assembly Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs as a function of time and the variation in rod worth as a function of rod position. For accident analyses, the critical parameter is the time of insertion up to the dashpot entry, or approximately 85 percent of the rod cluster travel. In analyses where all of the reactor coolant pumps are coasting down prior to, or simultaneous, with RCCA insertion, a time of 2.09 seconds is used for insertion time to dashpot entry.

In Figure 15.0.5-1, the curve labeled “complete loss of flow transients” shows the RCCA position versus time normalized to 2.09 seconds assumed in accident analyses where all reactor coolant pumps are coasting down. In analyses where some or all of the reactor coolant pumps are running, the RCCA insertion time to dashpot is conservatively taken as 2.47 seconds. The RCCA position versus time normalized to 2.47 seconds is also shown in Figure 15.0.5-1.

The use of such a long insertion time provides conservative results for accidents and is intended to apply to all types of RCCAs, which may be used throughout plant life. Drop time testing requirements are specified in the Technical Specifications.

Figure 15.0.5-2 shows the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip, which is input to the point kinetics core models used in transient analyses. The bottom-skewed power distribution itself is not an input into the point kinetics core model.

There is inherent conservatism in the use of Figure 15.0.5-2 in that it is based on a skewed flux distribution, which would exist relatively infrequently. For cases other than those associated with unbalanced xenon distributions, significantly more negative reactivity is inserted than that shown in the curve, due to the more favorable axial distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown in Figure 15.0.5-3. The curves shown in this figure were obtained from Figures 15.0.5-1 and 15.0.5-2. A total negative reactivity insertion following a trip of 4 percent Δk is assumed in the transient analyses except

where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Table 4.3-3.

The normalized RCCA negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure 15.0.5-3) is used in those transient analyses for which a point kinetics core model is used. Where special analyses require use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. In this case, the RCCA position versus time of Figure 15.0.5-1 is used as code input.

15.0.6 Protection and Safety Monitoring System Setpoints and Time Delays to Trip Assumed in Accident Analyses

A reactor trip signal acts to open two trip breaker sets connected in series, feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the RCCAs, which then fall by gravity into the core. There are various instrumentation delays associated with each trip function including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.0-4a. Reference is made in that table to overtemperature and overpower ΔT trip shown in Figure 15.0.3-1.

Table 15.0-4a also summarizes the setpoints and the instrumentation delay for engineered safety features (ESF) functions used in accident analyses. Time delays associated with equipment actuated (such as valve stroke times) by ESF functions are summarized in Table 15.0-4b.

The difference between the limiting setpoint assumed for the analysis and the nominal setpoint represents an allowance for instrumentation channel error and setpoint error. Nominal setpoints are specified in the plant Technical Specifications. During plant startup tests, it is demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times are determined periodically in accordance with the plant Technical Specifications.

15.0.7 Instrumentation Drift and Calorimetric Errors, Power Range Neutron Flux

Examples of the instrumentation uncertainties and calorimetric uncertainties used in establishing the power range high neutron flux setpoint are presented in Table 15.0-5.

The calorimetric uncertainty is the uncertainty assumed in the determination of core thermal power as obtained from secondary plant measurements. The total ion chamber current (sum of the top and bottom sections) is calibrated (set equal) to this measured power on a daily basis.

The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generators, and steam pressure. Installed plant instrumentation is used for these measurements.

15.0.8 Plant Systems and Components Available for Mitigation of Accident Effects

The plant is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions, and dynamic effects of the postulated accidents. In addition, the design incorporates features that minimize the probability and effects of fires and explosions.

Chapter 17 discusses the quality assurance program that is implemented to provide confidence that the plant systems satisfactorily perform their assigned safety functions. The incorporation of these features in the plant, coupled with the reliability of the design, provides confidence that the normally operating systems and components listed in Table 15.0-6 are available for mitigation of the events discussed in Chapter 15.

In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI N18.2-1973 (Reference 1) is used. The design of safety-related systems (including protection systems) is consistent with IEEE Standard 379-2000 and Regulatory Guide 1.53 in the application of the single-failure criterion. Conformance to Regulatory Guide 1.53 is summarized in subsection 1.9.1.

Table 15.0-8 summarizes the nonsafety-related systems assumed in the analyses to mitigate the consequences of events. Except for the cases listed in Table 15.0-8, control system action is not used for mitigation of accidents.

15.0.9 Fission Product Inventories

The sources of radioactivity for release are dependent on the specific accident. Activity may be released from the primary coolant, from the secondary coolant, and from the reactor core if the accident involves fuel damage. The radiological consequences analyses use the conservative design basis source terms identified in Appendix 15A.

15.0.10 Residual Decay Heat

15.0.10.1 Total Residual Heat

Residual heat in a subcritical core is calculated for the LOCA according to the requirements of 10 CFR 50.46, as described in WCAP-10054-P-A and WCAP-12945-P (References 3 and 4). The large-break LOCA methodology considers uncertainty in the decay power level. The small-break LOCA events and post-LOCA long-term cooling analyses use 10 CFR 50, Appendix K, decay heat, which assumes infinite irradiation time before the core goes subcritical to determine fission product decay energy. For all other accidents, the same models are used, except that fission product decay energy is based on core average exposure at the end of an equilibrium cycle.

15.0.10.2 Distribution of Decay Heat Following a Loss-of-Coolant Accident

During a LOCA, the core is rapidly shut down by void formation, RCCA insertion, or both, and a large fraction of the heat generation considered comes from fission product decay gamma rays. This heat is not distributed in the same manner as steady-state fission power. Local peaking effects, which are important for the neutron-dependent part of the heat generation, do not apply to

the gamma ray contribution. The steady-state factor, which represents the fraction of heat generated within the cladding and pellet, drops to 95 percent or less for the hot rod in a LOCA.

For example, consider the transient resulting from the postulated double-ended break of the largest reactor coolant system pipe; one-half second after the rupture, about 30 percent of the heat generated in the fuel rods is from gamma ray absorption. The gamma power shape is less peaked than the steady-state fission power shape, reducing the energy deposited in the hot rod at the expense of adjacent colder rods. A conservative estimate of this effect on the hot rod is a reduction of 10 percent of the gamma ray contribution or 3 percent of the total heat. Because the water density is considerably reduced at this time, an average of 98 percent of the available heat is deposited in the fuel rods; the remaining 2 percent is absorbed by water, thimbles, sleeves, and grids. Combining the 3 percent total heat reduction from gamma redistribution with this 2 percent absorption produce as the net effect a factor of 0.95, which exceeds the actual heat production in the hot rod. The actual hot rod heat generation is computed during the AP1000 large-break LOCA transient as a function of core fluid conditions.

15.0.11 Computer Codes Used

Summaries of some of the principal computer codes used in transient analyses are given as follows. Other codes – in particular, specialized codes in which the modeling has been developed to simulate one given accident, such as those used in the analysis of the reactor coolant system pipe rupture (see subsection 15.6.5) – are summarized in their respective accident analyses sections. The codes used in the analyses of each transient are listed in Table 15.0-2. WCAP-15644 (Reference 11) provides the basis for use of analysis codes.

15.0.11.1 FACTRAN Computer Code

FACTRAN (Reference 5) calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the transient heat flux at the surface of the cladding using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which simultaneously exhibits the following features:

- A sufficiently large number of radial space increments to handle fast transients such as rod ejection accidents
- Material properties which are functions of temperature and a sophisticated fuel-to-clad gap heat transfer calculation
- The necessary calculations to handle post-DNB transients: film boiling heat transfer correlations, zircaloy-water reaction, and partial melting of the materials

FACTRAN is further discussed in WCAP-7908-A (Reference 5).

15.0.11.2 LOFTRAN Computer Code

The LOFTRAN (Reference 6) program is used for studies of transient response of a pressurized water reactor system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by a model containing reactor vessel, hot and cold leg piping, steam generator

(tube and shell sides), and pressurizer. The pressurizer heaters, spray, and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The protection and safety monitoring system is simulated to include reactor trips on high neutron flux, overtemperature ΔT, high and low pressure, low flow, and high pressurizer level. Control systems are also simulated, including rod control, steam dump, feedwater control, and pressurizer level and pressure control. The emergency core cooling system, including the accumulators, is also modeled.

LOFTRAN is a versatile program suited to both accident evaluation and control studies as well as parameter sizing.

LOFTRAN also has the capability of calculating the transient value of DNBR based on the input from the core limits illustrated in Figure 15.0.3-1. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

The LOFTRAN code is modified to allow the simulation of the passive residual heat removal (PRHR) heat exchanger, core makeup tanks, and associated protection and safety monitoring system actuation logic. A discussion of these models and additional validation is presented in WCAP-14234 (Reference 10).

LOFTTR2 (Reference 8) is a modified version of LOFTRAN with a more realistic break flow model, a two-region steam generator secondary side, and an improved capability to simulate operator actions during a steam generator tube rupture (SGTR) event.

The LOFTTR2 code is modified to allow the simulation of the PRHR heat exchanger, core makeup tanks, and associated protection system actuation logic. The modifications are identical to those made to the LOFTRAN code. A discussion of these models is presented in WCAP-14234 (Reference 10).

15.0.11.3 TWINKLE Computer Code

The TWINKLE (Reference 7) program is a multidimensional spatial neutron kinetics code, which is patterned after steady-state codes currently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multiregion fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points and performs its own steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions, such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided (for example, channelwise power, axial offset, enthalpy, volumetric surge, point-wise power, and fuel temperatures).

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

15.0.11.4 VIPRE-01 Computer Code

The VIPRE-01 code is described in subsection 4.4.4.5.2.

15.0.11.5 COAST Computer Program

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in the hot or cold legs. The program is described in Reference 13 and was referenced in Reference 12. The program was approved in Reference 14.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.12 Component Failures

15.0.12.1 Active Failures

SECY-77-439 (Reference 9) provides a description of active failures. An active failure results in the inability of a component to perform its intended function.

An active failure is defined differently for different components. For valves, an active failure is the failure of a component to mechanically complete the movement required to perform its function. This includes the failure of a remotely operated valve to change position on demand. The spurious, unintended movement of the valve is also considered as an active failure. Failure of a manual valve to change position under local operator action is included.

Spring-loaded safety or relief valves that are designed for and operate under single-phase fluid conditions are not considered for active failures to close when pressure is reduced below the valve set point. However, when valves designed for single-phase flow are challenged with two-phase flow, such as a steam generator or pressurizer safety valve, the failure to reseat is considered as an active failure.

For other active equipment – such as pumps, fans, and rotating mechanical components – an active failure is the failure of the component to start or to remain operating.

For electrical equipment, the loss of power, such as the loss of offsite power or the loss of a diesel generator, is considered as a single failure. In addition, the failure to generate an actuation signal, either for a single component actuation or for a system-level actuation, is also considered as an active failure.

Spurious actuation of an active component is considered as an active failure for active components in safety-related passive systems. An exception is made for active components if specific design

features or operating restrictions are provided that can preclude such failures (such as power lockout, confirmatory open signals, or continuous position alarms).

A single incorrect or omitted operator action in response to an initiating event is also considered as an active failure. The error is limited to manipulation of safety-related equipment and does not include thought-process errors or similar errors that could potentially lead to common cause or multiple errors.

15.0.12.2 Passive Failures

SECY-77-439 also provides a description of passive failures. A passive failure is the structural failure of a static component that limits the effectiveness of the component in carrying out its design function. A passive failure is applied to fluid systems and consists of a breach in the fluid system boundary. Examples include cracking of pipes, sprung flanges, or valve packing leaks.

Passive failures are not assumed to occur until 24 hours after the start of the event. Consequential effects of a pipe leak – such as flooding, jet impingement, and failure of a valve with a packing leak – must be considered.

Where piping is significantly overdesigned or installed in a system where the pressure and temperature conditions are relatively low, passive leakage is not considered a credible failure mechanism. Line blockage is also not considered as a passive failure mechanism.

15.0.12.3 Limiting Single Failures

The most limiting single active failure (where one exists), as described in Section 3.1, of safety-related equipment, is identified in each analysis description. The consequences of this failure are described therein. In some instances, because of redundancy in protection equipment, no single failure that could adversely affect the consequences of the transient is identified. The failure assumed in each analysis is listed in Table 15.0-7.

15.0.13 Operator Actions

For events where the PRHR heat exchanger is actuated, the plant automatically cools down to the safe shutdown condition. Where a stabilized condition is reached automatically following a reactor trip, it is expected that the operator may, following event recognition, take manual control and proceed with orderly shutdown of the reactor in accordance with the normal, abnormal, or emergency operating procedures. The exact actions taken and the time at which these actions occur depend on what systems are available and the plans for further plant operation.

However, for these events, operator actions are not required to maintain the plant in a safe and stable condition. Operator actions typical of normal operation are credited for the inadvertent actuations of equipment in response to a Condition II event.

15.0.14 Loss of Offsite ac Power

As required in GDC 17 of 10 CFR Part 50, Appendix A, anticipated operational occurrences and postulated accidents are analyzed assuming a loss of offsite ac power. The loss of offsite power is

not considered as a single failure, and the analysis is performed without changing the event category. In the analyses, the loss of offsite ac power is considered to be a potential consequence of the event.

A loss of offsite ac power will be considered a consequence of an event due to disruption of the grid following a turbine trip during the event. Event analyses that do not result in a possible consequential disruption of offsite ac power do not assume offsite power is lost.

For those events where offsite ac power is lost, an appropriate time delay between turbine trip and the postulated loss of offsite ac power is assumed in the analyses. A time delay of 3 seconds is used. This time delay is based on the inherent stability of the offsite power grid as discussed in Section 8.2. Following the time delay, the effect of the loss of offsite ac power on plant auxiliary equipment – such as reactor coolant pumps, main feedwater pumps, condenser, startup feedwater pumps, and RCCAs – is considered in the analyses. Turbine trip occurs 5 seconds following a reactor trip condition being reached. This delay is part of the AP1000 reactor trip system.

Design basis LOCA analyses are governed by the GDC-17 requirement to consider the loss of offsite power. For the AP1000 design, in which all the safety-related systems are passive, the availability of offsite power is significant only regarding reactor coolant pump operation for LOCA events. A sensitivity study for AP1000 has shown that for large-break LOCAs, assuming the loss of offsite power coincident with the inception of the LOCA event is nonlimiting relative to assuming continued reactor coolant pump operation until the automatic reactor coolant pump trip occurs following an “S” signal less than 10 seconds into the transient. For small-break LOCA events, the AP1000 automatic reactor coolant pump trip feature prevents continued operation of the reactor coolant pumps from mixing the liquid and vapor present within a two-phase reactor coolant system inventory to increase the liquid break flow and deplete the reactor coolant system mass inventory rapidly. The automatic reactor coolant pump trip occurs early enough during AP1000 small-break LOCA transients that emergency core cooling system performance is not affected by the loss of offsite power assumption because the total break flow is approximately equivalent for reactor coolant pump trip occurring either at time zero or as a result of the “S” signal. Whether a loss of offsite power is postulated at the inception of the LOCA event or occurs automatically later on is unimportant in the subsection 15.6.5.4C long-term cooling analyses because with either assumption, the reactor coolant pumps are tripped long before the long-term cooling timeframe.

The AP1000 protection and safety monitoring system and passive safeguards systems are not dependent on offsite power or on any backup diesel generators. Following a loss of ac power, the protection and safety monitoring system and passive safeguards are able to perform the safety functions and there are no additional time delays for these functions to be completed.

15.0.15 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.0.16 References

1. American National Standards Institute N18.2, “Nuclear Safety Criteria for the Design of Stationary PWR Plants,” 1973.

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11. "AP1000 Code Applicability Report," WCAP-15644-P (Proprietary) and WCAP-15644-NP (Non-Proprietary), Revision 2, March 2004.

12. “Combustion Engineering Standard Safety Analysis Report,” CESSAR Docket No. STN-50-470, December 1975.

13. “COAST Code Description,” CENPD-98-A, April 1973, Proprietary Information.

14. CENPD-98-A, “COAST Code Description,” April 1973 (NRC Approval Letter dated December 4, 1974).

Table 15.0-1

NUCLEAR STEAM SUPPLY SYSTEM POWER RATINGS

Thermal power output (MWt)	3415
Effective thermal power generated by the reactor coolant pumps (MWt)	15
Core thermal power (MWt)	3400

Table 15.0-2 (Sheet 1 of 5)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.1	Increase in heat removal from the primary system					
	Feedwater system malfunctions causing a reduction in feedwater temperature	Bounded by excessive increase in secondary steam flow	–	–	–	–
	Feedwater system malfunctions that result in an increase in feedwater flow	LOFTRAN, FACTRAN, VIPRE-01	0.470	–	Upper curve of Figure 15.0.4-1	0 and 3415
	Excessive increase in secondary steam flow	LOFTRAN, FACTRAN, VIPRE-01	0.0 and 0.470	–	Upper and lower curves of Figure 15.0.4-1	3415
	Inadvertent opening of a steam generator relief or safety valve	LOFTRAN, VIPRE-01	Function of moderator density (see Figure 15.1.4-1)	–	See subsection 15.1.4.	0 (subcritical)
	Steam system piping failure	LOFTRAN, VIPRE-01	Function of moderator density (see Figure 15.1.4-1)	–	See subsection 15.1.5	0 (subcritical)
	Inadvertent operation of the PRHR heat exchanger	LOFTRAN, FACTRAN, VIPRE-01	See subsection 15.1.6.2.1	–	Upper curve of Figure 15.0.4-1	3415

Table 15.0-2 (Sheet 2 of 5)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.2	Decrease in heat removal by the secondary system					
	Loss of external electrical load and/or turbine trip	LOFTRAN, FACTRAN, VIPRE-01	0.0 and 0.470	–	Lower and upper curves of Figure 15.0.4-1	3415 and 3483.3 (a)
	Inadvertent closure of main steam isolation valves	Bounded by turbine trip event	–	–	–	–
	Loss of condenser vacuum and other events resulting in turbine trip	Bounded by turbine trip event	–	–	–	–
	Loss of nonemergency ac power to the plant auxiliaries	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3483.3 (a)
	Loss of normal feedwater flow	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3483.3 (a)
	Feedwater system pipe break	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3483.3 (a)
15.3	Decrease in reactor coolant system flow rate					

Table 15.0-2 (Sheet 3 of 5)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.3	Partial and complete loss of forced reactor coolant flow	LOFTRAN, FACTRAN, COAST, VIPRE-01	0.0	–	Lower curve of Figure 15.0.4-1	3415
	Reactor coolant pump shaft seizure (locked rotor) and reactor coolant pump shaft break	LOFTRAN, FACTRAN, COAST, VIPRE-01	0.0	–	Lower curve of Figure 15.0.4-1	3483.3 (a)
15.4	Reactivity and power distribution anomalies					
	Uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition	TWINKLE, FACTRAN, VIPRE-01	–	0.0	Coefficient is consistent with a Doppler defect of -0.67%Δk	0
	Uncontrolled RCCA bank withdrawal at power	LOFTRAN, FACTRAN, VIPRE-01	0.0 and 0.470	–	Upper and lower curves of Figure 15.0.4-1	10%, 60%, and 100% of 3415
	RCCA misalignment	LOFTRAN, VIPRE-01	NA	–	NA	3415
	Startup of an inactive reactor coolant pump at an incorrect temperature	NA	NA	–	NA	NA

Table 15.0-2 (Sheet 4 of 5)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.4	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant	NA	NA	–	NA	0 and 3415
	Inadvertent loading and operation of a fuel assembly in an improper position	ANC	NA	–	NA	3415
	Spectrum of RCCA ejection accidents	TWINKLE, FACTRAN	Refer to subsection 15.4.8	Refer to subsection 15.4.8	Coefficient consistent with a Doppler defect of -0.90% ΔK at BOC(b) and –0.87% ΔK at EOC (b)	0 and 3483.3 (a)
15.5	Increase in reactor coolant inventory					
	Inadvertent operation of the emergency core cooling system during power operation	LOFTRAN	0.0	–	Upper curve of Figure 15.04-1	3483.3 (a)
	Chemical and volume control system malfunction that increases reactor coolant inventory	LOFTRAN	0.0	–	Upper curve of Figure 15.04-1	3483.3 (a)

Table 15.0-2 (Sheet 5 of 5)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.6	Decrease in reactor coolant inventory					
	Inadvertent opening of a pressurizer safety valve and inadvertent operation of ADS	LOFTRAN, FACTRAN, VIPRE-01	0.0	–	Lower curve of Figure 15.0.4-1	3415
	Steam generator tube failure	LOFTTR2	0.0	–	Lower curve of Figure 15.0.4-1	3483.3 (a)
	A break in an instrument line or other lines from the reactor coolant pressure boundary that penetrate containment	NA	NA	–	NA	NA
	LOCAs resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	NOTRUMP WCOBRA/ TRAC	See subsection 15.6.5 references	–	See subsection 15.6.5 references	3468.0

Notes:

a. 102% of rated thermal power

b. BOC – Beginning of core cycle
EOC – End of core cycle

Table 15.0-3

NOMINAL VALUES OF PERTINENT PLANT PARAMETERS USED IN ACCIDENT ANALYSES

	RTDP With 10% Steam Generator Tube Plugging	Without RTDP[a]	
		Without Steam Generator Tube Plugging	With 10% Steam Generator Tube Plugging
Thermal output of NSSS (MWt)	3415	3415	3415
Core inlet temperature (°F)	535.8	535.5	535.0
Vessel average temperature (°F)	573.6	573.6	573.6
Reactor coolant system pressure (psia)	2250.0	2250.0	2250.0
Reactor coolant flow per loop (gpm)	15.08 E+04	14.99 E+04	14.8 E+04
Steam flow from NSSS (lbm/hr)	14.96 E+06	14.96 E+06	14.95 E+06
Steam pressure at steam generator outlet (psia)	802.2	814.0	796.0
Assumed feedwater temperature at steam generator inlet (°F)	440.0	440.0	440.0
Average core heat flux (Btu/-hr-ft^2)	1.99 E+05	1.99 E+05	1.99 E+05

Note:

a. Steady-state errors discussed in subsection 15.0.3 are added to these values to obtain initial conditions for transient analyses.

Table 15.0-4a (Sheet 1 of 2)

PROTECTION AND SAFETY MONITORING SYSTEM SETPOINTS AND TIME DELAY ASSUMED IN ACCIDENT ANALYSES

Function	Limiting Setpoint Assumed in Analyses	Time Delays (seconds)
Reactor trip on power range high neutron flux, high setting	118%	0.9
Reactor trip on power range high neutron flux, low setting	35%	0.9
High neutron flux, P-8	84%	0.9
Reactor trip on source range neutron flux reactor trip	Not applicable	0.9
Overtemperature ΔT	Variable (see Figure 15.0.3-1)	2.0
Overpower ΔT	Variable (see Figure 15.0.3-1)	2.0
Reactor trip on high pressurizer pressure	2460 psia	2.0
Reactor trip on low pressurizer pressure	1800 psia	2.0
Reactor trip on low reactor coolant flow in either hot leg	87% loop flow	1.45
Reactor trip on reactor coolant pump under speed	90%	0.767
Reactor trip on low steam generator narrow range level	95,000 lbm	2.0
High-2 steam generator level	100% of narrow range level span	2.0 (reactor trip) 0.0 (turbine trip) 2.0 (feedwater isolation)
Reactor trip on high-3 pressurizer water level	80% of span	2.0
PRHR actuation on low steam generator wide range level	55,000 lbm	2.0
"S" signal and steamline isolation on low T_{cold}	500°F	2.0
"S" signal and steamline isolation on low steamline pressure	405 psia (with an adverse environment assumed) 535 psia (without an adverse environment assumed)	2.0
"S" signal on low pressurizer pressure	1700 psia	2.0

Table 15.0-4a (Sheet 2 of 2)

PROTECTION AND SAFETY MONITORING SYSTEM SETPOINTS AND TIME DELAY ASSUMED IN ACCIDENT ANALYSES

Function	Limiting Setpoint Assumed in Analyses	Time Delays (seconds)
“S” signal on high-1 containment pressure	8 psig	2.0
Reactor coolant pump trip following “S”	–	15.0
PRHR actuation of high-3 pressurizer water level	80% of span	2.0 (plus 15.0-second timer delay)
Chemical and volume control system isolation on high-2 pressurizer water level	67% of span	2.0
Chemical and volume control system isolation on high-1 pressurizer water level coincident with “S” signal	30% of span	2.0
Boron dilution block on source range flux multiplication	1.6 over 50 minutes	10.0
ADS Stage 1 actuation on core makeup tank low level signal	67.5% of tank volume	20.0 seconds for control valve to begin to open)
ADS Stage 4 actuation on core makeup tank low-low level signal	20% of tank volume	30.0 seconds for squib valve to begin to open)

Table 15.0-4b

LIMITING DELAY TIMES FOR EQUIPMENT ASSUMED IN ACCIDENT ANALYSES

Component	Time Delays (seconds)
Feedwater isolation valve closure, feedwater control valve closure, or feedwater pump trip	10 (maximum value for non-LOCA) 5 (maximum value for mass/energy)
Steamline isolation valve closure	5
Core makeup tank discharge valve opening time	15 (maximum) 10 (nominal value for best-estimate LOCA)
Chemical and volume control system isolation valve closure	10
PRHR discharge valve opening time	15 (maximum) 10 (nominal value for best-estimate LOCA) 1.0 second (small-break LOCA value: follows a 15-second interval of no valve movement)
Demineralized water transfer and storage system isolation valve closure time	20
Steam generator power-operated relief valve block valve closure	44
Automatic depressurization system (ADS) valve opening times	See Table 15.6.5-13

Table 15.0-5

DETERMINATION OF MAXIMUM POWER RANGE NEUTRON FLUX CHANNEL TRIP SETPOINT, BASED ON NOMINAL SETPOINT AND INHERENT TYPICAL INSTRUMENTATION UNCERTAINTIES

Nominal setpoint (% of rated power)		109
Calorimetric errors in the measurement of secondary system thermal power:		
Variable	**Accuracy of Measurement of Variable**	**Effect on Thermal Power Determination (% of Rated Power)**
Feedwater temperature	$\pm$3°F	
Steam pressure (small correction on enthalpy)	$\pm$6 psi	
Feedwater flow	$\pm$0.5% ΔP instrument span (two channels per steam generator)	
Assumed calorimetric error		2.0 (a)*
Radial power distribution effects on total ion chamber current		7.8 (b)*
Allowed mismatch between power range neutron flux channel and calorimetric measurement		2.0 (c)*
Instrumentation channel drift and setpoint reproducibility	0.4% of instrument span (120% power span)	0.84(d)*
Instrumentation channel temperature effects		0.48(e)*
*Total assumed error in setpoint (% of rated power): $[(a)^2 + (b)^2 + (c)^2 + (d)^2 + (e)^2]^{1/2}$		$\pm$8.4
Maximum power range neutron flux trip setpoint assuming a statistical combination of individual uncertainties (% of rated power)		118

Table 15.0-6 (Sheet 1 of 4)

PLANT SYSTEMS AND EQUIPMENT AVAILABLE FOR TRANSIENT AND ACCIDENT CONDITIONS

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.1			
Increase in heat removal from the primary system			
Feedwater system malfunctions that result in an increase in feedwater flow	High-2 Steam Generator Level, Power range high flux, overtemperature	High-2 steam generator level produced feedwater isolation and turbine trip	Feedwater isolation valves
Excessive increase in secondary steam flow	Power range high flux, overtemperature ΔT, overpower ΔT, manual	–	–
Inadvertent opening of a steam generator safety valve	Power range high flux, overtemperature ΔT, overpower ΔT, Low pressurizer pressure, “S”, manual	Low pressurizer pressure, low compensated steam line pressure, low T_{cold}, low-2 pressurizer level	Core makeup tank, feedwater isolation valves, steam line stop valves
Steam system piping failure	Power range high flux, overtemperature ΔT, overpower ΔT, Low pressurizer pressure, “S”, manual	Low pressurizer pressure, low compensated steam line pressure, high-1 containment pressure, low T_{cold}, manual	Core makeup tank, feedwater isolation valves, main steam line isolation valves (MSIVs), accumulators
Inadvertent operation of the PRHR	Power range high flux, overtemperature ΔT, overpower ΔT, Low pressurizer pressure, “S”, manual	Low pressurizer pressure, low T_{cold}, low-2 pressurizer level	Core makeup tank
Section 15.2			
Decrease in heat removal by the secondary system			
Loss of external load/turbine trip	High pressurizer pressure, high pressurizer water level, overtemperature ΔT, overpower ΔT, Steam generator low narrow range level, low RCP speed, manual	–	Pressurizer safety valves, steam generator safety valves

Table 15.0-6 (Sheet 2 of 4)

PLANT SYSTEMS AND EQUIPMENT AVAILABLE FOR TRANSIENT AND ACCIDENT CONDITIONS

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.2 (Cont.)			
Loss of nonemergency ac power to the station auxiliaries	Steam generator low narrow range level, high pressurizer pressure, high pressurizer level, manual	Steam generator low narrow range level coincident with low startup water flow, steam generator low wide range level	PRHR, steam generator safety valves, pressurizer safety valves
Loss of normal feedwater flow	Steam generator low narrow range level, high pressurizer pressure, high pressurizer level, manual	Steam generator low narrow range level coincident with low startup water flow, steam generator low wide range level	PRHR, steam generator safety valves, pressurizer safety valves
Feedwater system pipe break	Steam generator low narrow range level, high pressurizer pressure, high pressurizer level, manual	Steam generator low narrow range level coincident with low startup feedwater flow, Steam generator low wide range level, low steam line pressure, high-1 containment pressure	PRHR, core makeup tank, MSIVs, feedline isolation, pressurizer safety valves, steam generator safety valves
Section 15.3			
Decrease in reactor coolant system flow rate			
Partial and complete loss of forced reactor coolant flow	Low flow, underspeed, manual	–	Steam generator safety valves, pressurizer safety valves
Reactor coolant pump shaft seizure (locked rotor)	Low flow, high pressurizer pressure, manual	–	Pressurizer safety valves, steam generator safety valves
Section 15.4			
Reactivity and power distribution anomalies			
Uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition	Source range high neutron flux, intermediate range high neutron flux, power range high neutron flux (low setting), power range high neutron flux (high setting), high nuclear flux rate, manual	–	–

Table 15.0-6 (Sheet 3 of 4)

PLANT SYSTEMS AND EQUIPMENT AVAILABLE FOR TRANSIENT AND ACCIDENT CONDITIONS

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.4 (Cont.)			
Uncontrolled RCCA bank withdrawal at power	Power range high neutron flux, high power range positive neutron flux rate, overtemperature ΔT, over-power ΔT, high pressurizer pressure, high pressurizer water level, manual	–	Pressurizer safety valves, steam generator safety valves
RCCA misalignment	Overtemperature ΔT, manual	–	–
Startup of an inactive reactor coolant pump at an incorrect temperature	Power range high flux, low flow (P-8 interlock), manual	–	–
Chemical and volume control system malfunction that results in a decrease in boron concentration in the reactor coolant	Source range high flux, overtemperature ΔT, manual	Source range flux doubling	Low insertion limit annunciators
Spectrum of RCCA ejection accidents	Power range high flux, high positive flux rate, manual	–	Pressurizer safety valves
Section 15.5			
Increase in reactor coolant inventory			
Inadvertent operation of the ECCS during power operation	High pressurizer pressure, manual, “safeguards” trip, high pressurizer level	High pressurizer level, low T_{cold}	Core makeup tank, pressurizer safety valves, chemical and volume control system isolation, PRHR
Chemical and volume control system malfunction that increases reactor coolant inventory	High pressurizer pressure, “safeguards” trip, high pressurizer level, manual	High pressurizer level, low T_{cold}	Core makeup tank, pressurizer safety valves, chemical and volume control system isolation, PRHR

Table 15.0-6 (Sheet 4 of 4)

PLANT SYSTEMS AND EQUIPMENT AVAILABLE FOR TRANSIENT AND ACCIDENT CONDITIONS

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.6			
Decrease in reactor coolant inventory			
Inadvertent opening of a pressurizer safety valve or ADS path	Low pressurizer pressure, overtemperature ΔT, manual	Low pressurizer pressure	Core makeup tank, ADS, accumulator
Failure of small lines carrying primary coolant outside containment	–	Manual isolation of the Sample System or CVS discharge lines	Sample System isolation valves, Chemical and volume control system discharge line isolation valves
Steam generator tube rupture	Low pressurizer pressure, overtemperature ΔT, safeguards (“S”), manual	Low pressurizer pressure, high steam generator level, low steam line pressure	Core makeup tank, PRHR, steam generator safety and/or relief valves, MSIVs, radiation monitors (air removal, steamline, and steam generator blowdown), startup feedwater isolation, chemical and volume control system pump isolation, pressurizer heater isolation, steam generator power-operated relief valve isolation
LOCAs resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	Low pressurizer pressure, safeguards (“S”), manual	High-1 containment pressure, low pressurizer pressure	Core makeup tank, accumulator, ADS, steam generator safety and/or relief valves, PRHR, in-containment water storage tank (IRWST)

Table 15.0-7 (Sheet 1 of 2)

SINGLE FAILURES ASSUMED IN ACCIDENT ANALYSES

Event Description	Failure
Feedwater temperature reduction[(a)]	–
Excessive feedwater flow	One protection division
Excessive steam flow	One protection division
Inadvertent secondary depressurization	One core makeup tank discharge valve
Steam system piping failure	One core makeup tank discharge valve
Inadvertent operation of the PRHR	One protection division
Steam pressure regulator malfunction[(b)]	–
Loss of external load	One protection division
Turbine trip	One protection division
Inadvertent closure of main steam isolation valve	One protection division
Loss of condenser vacuum	One protection division
Loss of ac power	One PRHR discharge valve
Loss of normal feedwater	One PRHR discharge valve
Feedwater system pipe break	One PRHR discharge valve
Partial loss of forced reactor coolant flow	One protection division
Complete loss of forced reactor coolant flow	One protection division
Reactor coolant pump locked rotor	One protection division
Reactor coolant pump shaft break	One protection division
RCCA bank withdrawal from subcritical	One protection division
RCCA bank withdrawal at power	One protection division
Dropped RCCA, dropped RCCA bank	One protection division
Statically misaligned RCCA[(c)]	–
Single RCCA withdrawal	One protection division

Notes:

a. No protection action required
b. Not applicable to AP1000
c. No transient analysis

Table 15.0-7 (Sheet 2 of 2)

SINGLE FAILURES ASSUMED IN ACCIDENT ANALYSES

Event Description	Failure
Flow controller malfunction[b]	–
Uncontrolled boron dilution	One protection division
Improper fuel loading[c]	–
RCCA ejection	One protection division
Inadvertent emergency core cooling system operation at power	One PRHR discharge valve
Increase in reactor coolant system inventory	One PRHR discharge valve
Inadvertent reactor coolant system depressurization	One protection division
Failure of small lines carrying primary coolant outside containment[c]	–
Steam generator tube rupture	Faulted steam generator power-operated relief valve fails open
Spectrum of LOCA Small breaks Large breaks	 One ADS Stage 4 valve None
Long-term cooling	One ADS Stage 4 valve

Notes:

a. No protection action required
b. Not applicable to AP1000
c. No transient analysis

Table 15.0-8

NONSAFETY-RELATED SYSTEM AND EQUIPMENT USED FOR MITIGATION OF ACCIDENTS

Event	Nonsafety-related System and Equipment
15.1.5 Feedwater system malfunctions that result in an increase in feedwater flow	Main feedwater pump trip
15.1.4 Inadvertent opening of a steam generator relief or safety valve	MSIV backup valves[1] Main steam branch isolation valves
15.1.5 Steam system piping failure	MSIV backup valves[1] Main steam branch isolation valves
15.2.7 Loss of normal feedwater	Pressurizer heater block
15.5.1 Inadvertent operation of the core makeup tanks during power operation	Pressurizer heater block
15.5.2 Chemical and volume control system malfunction that increases reactor coolant inventory	Pressurizer heater block
15.6.3 Steam generator tube rupture	Pressurizer heater block MSIV backup valves[1] Main steam branch isolation valves
15.6.5 Small-break LOCA	Pressurizer heater block

Note:

1. These include the turbine stop or control valves, the turbine bypass valves, and the moisture separator reheat steam supply control valve.

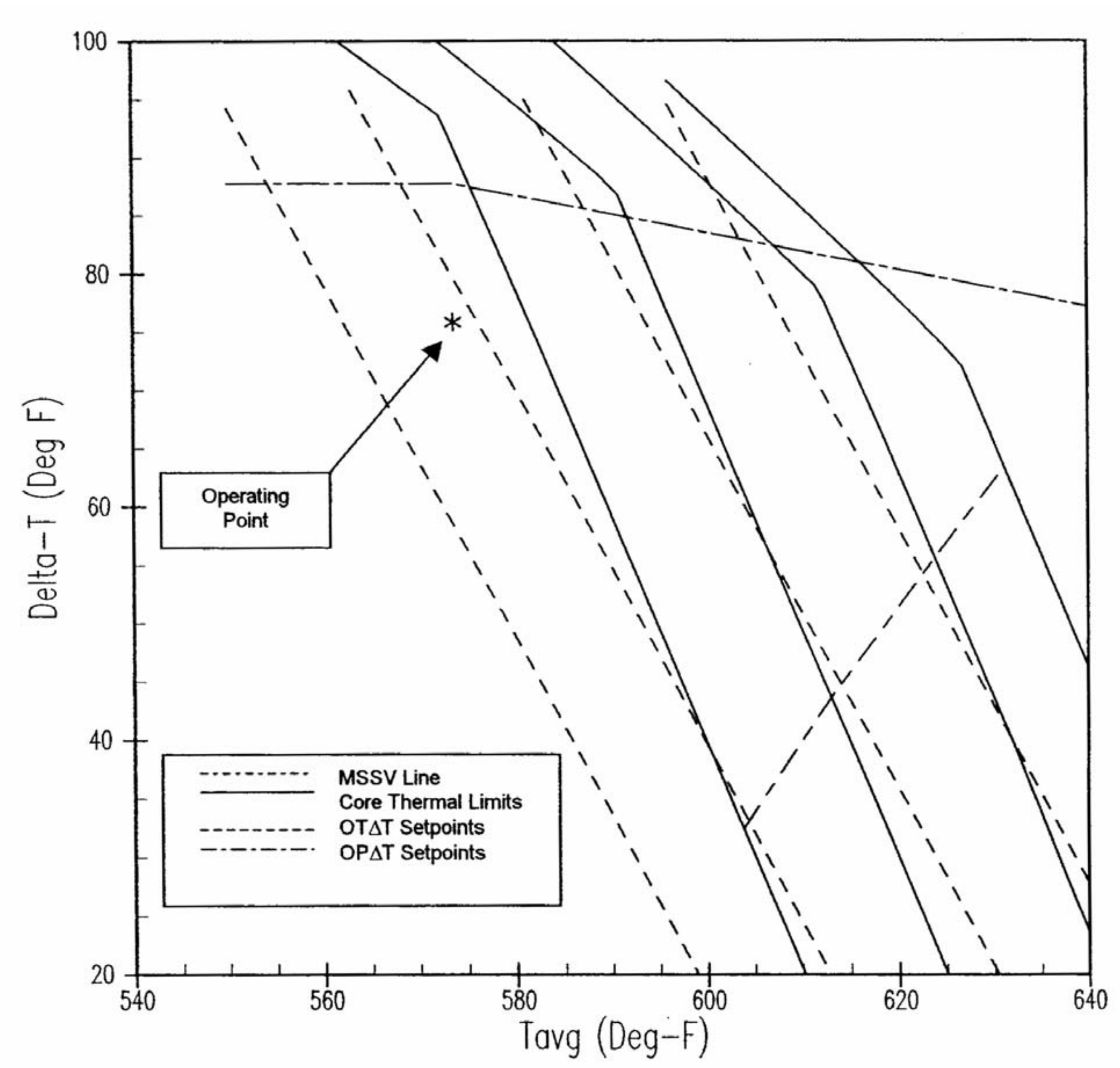

Figure 15.0.3-1

Overpower and Overtemperature ΔT Protection

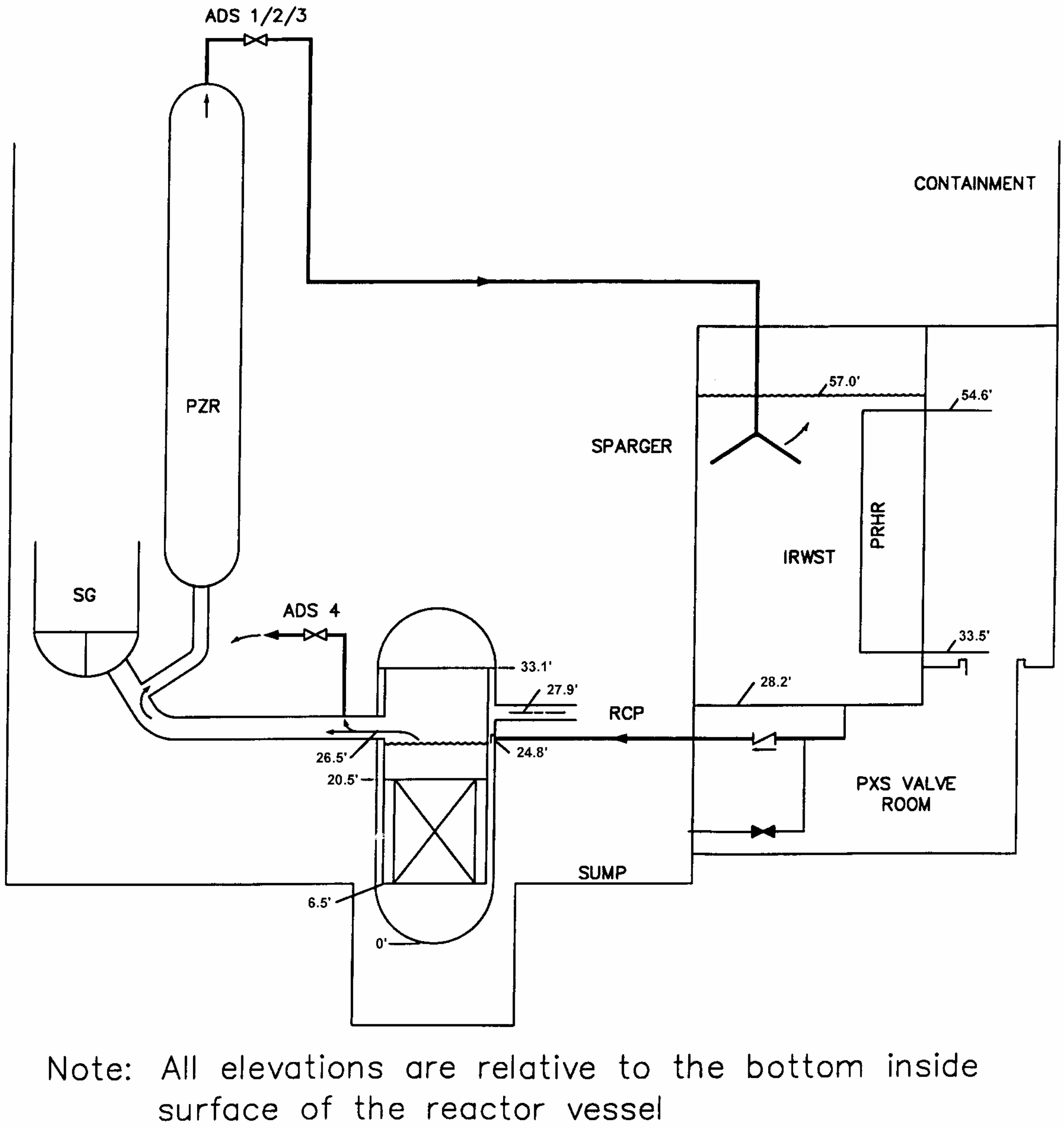

Figure 15.0.3-2

AP1000 Loop Layout

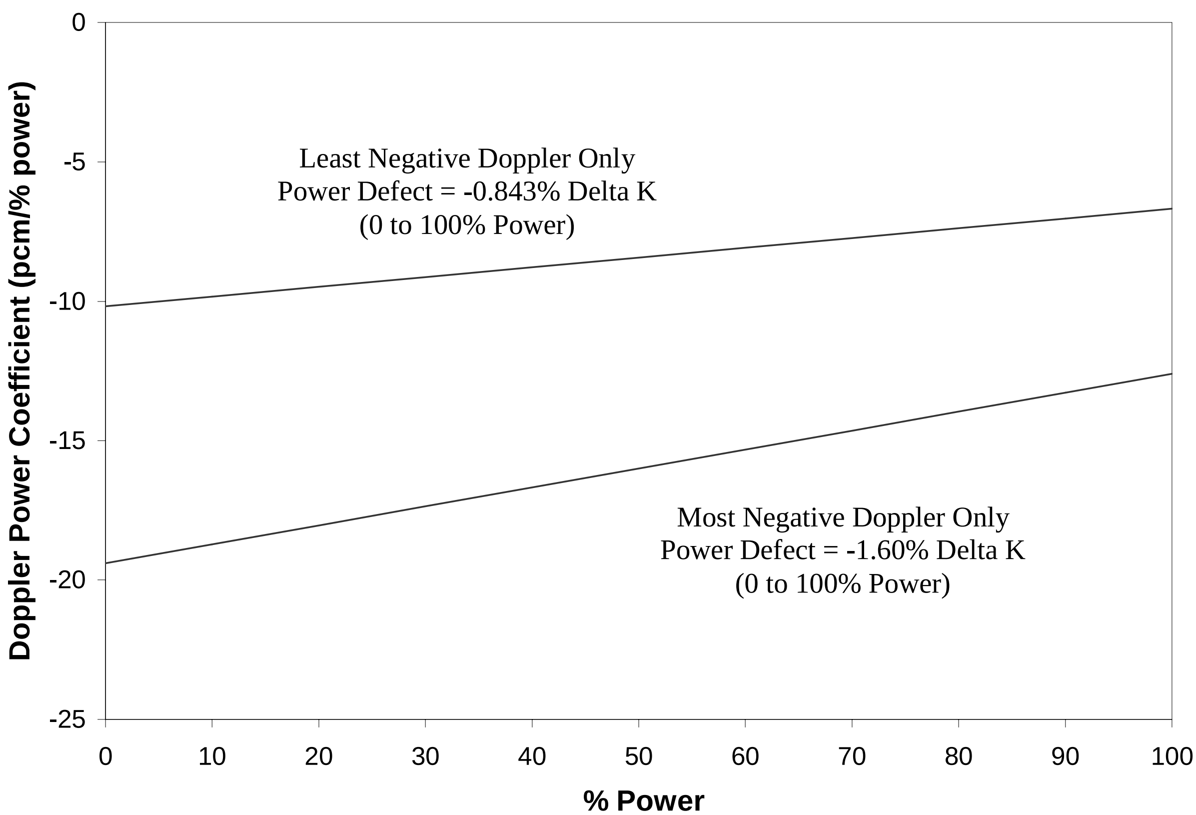

Figure 15.0.4-1

Doppler Power Coefficient used in Accident Analysis

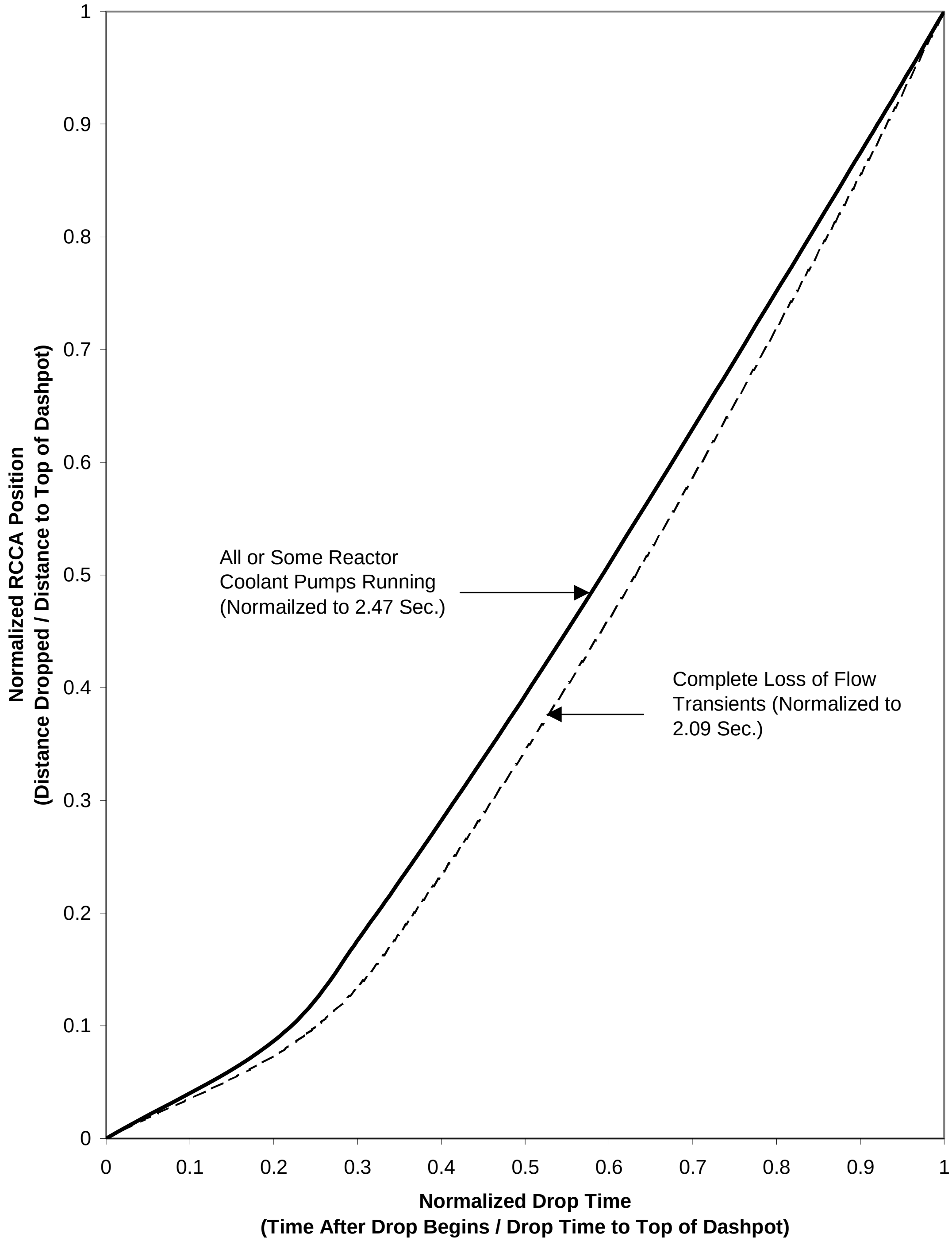

Figure 15.0.5-1

RCCA Position Versus Time to Dashpot

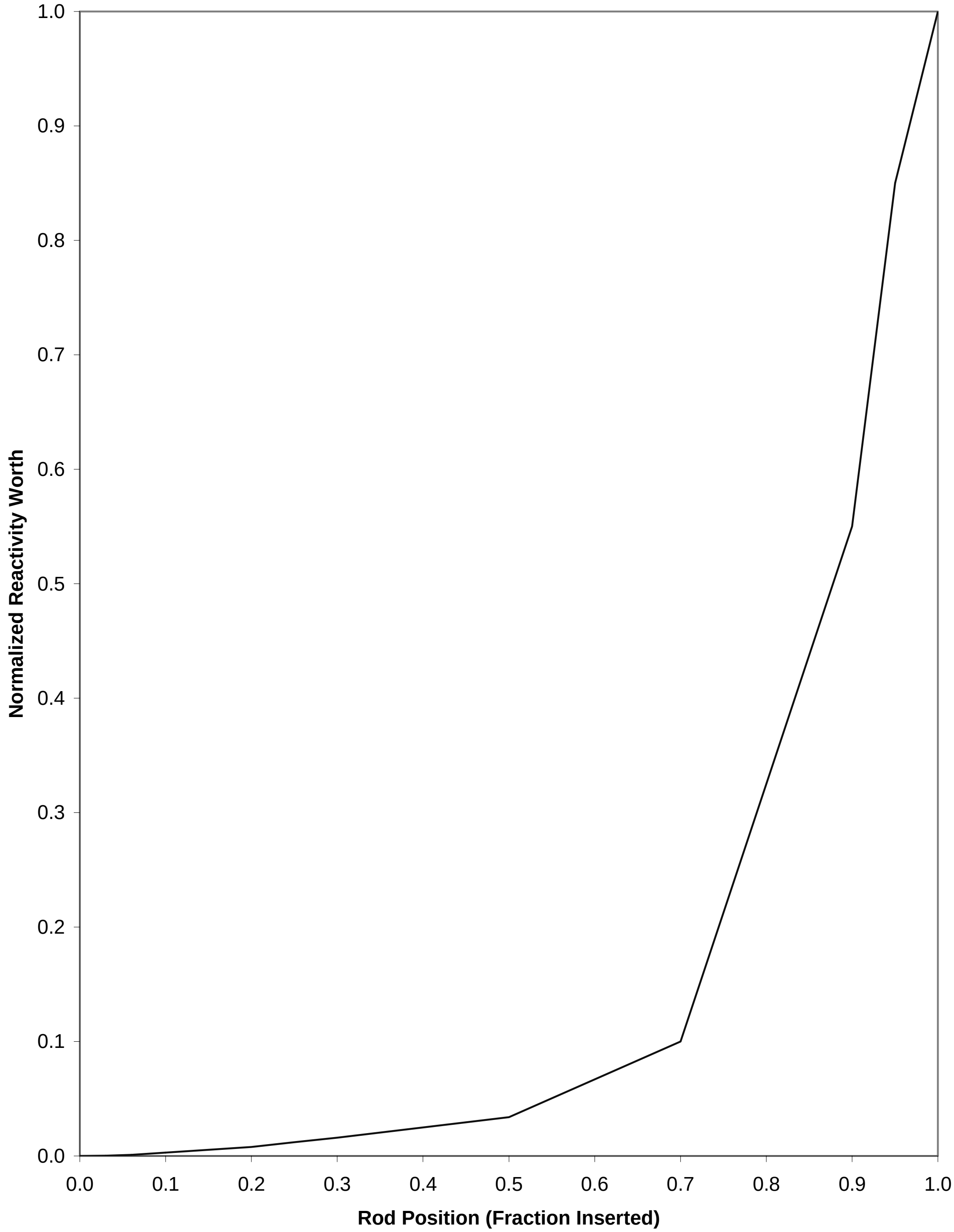

Figure 15.0.5-2

Normalized Rod Worth Versus Position

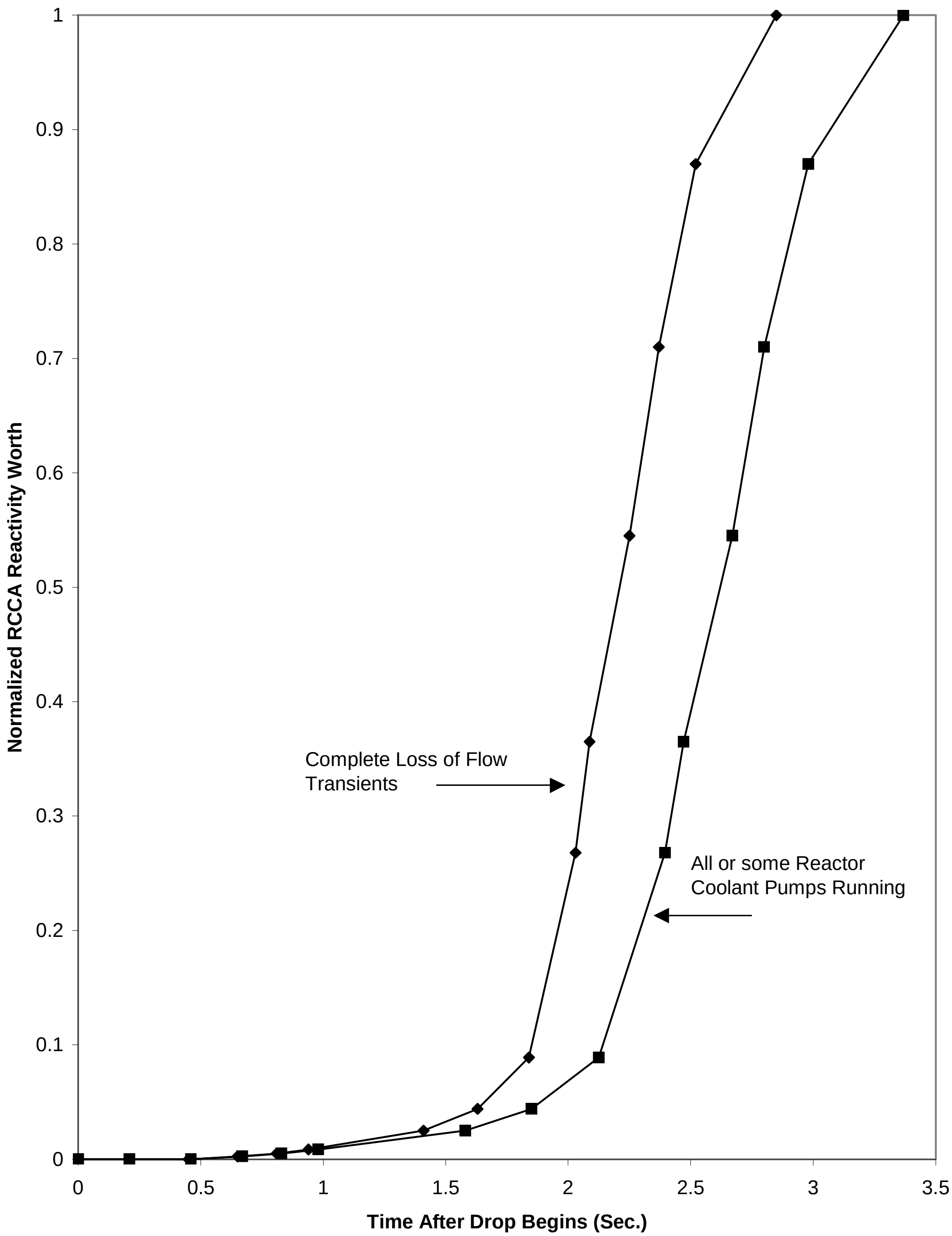

Figure 15.0.5-3

Normalized RCCA Bank Reactivity Worth Versus Drop Time

15.1 Increase in Heat Removal From the Primary System

A number of events that could result in an increase in heat removal from the reactor coolant system are postulated. Detailed analyses are presented for the events that have been identified as limiting cases.

Discussions of the following reactor coolant system cooldown events are presented in this section:

- Feedwater system malfunctions causing a reduction in feedwater temperature
- Feedwater system malfunctions causing an increase in feedwater flow
- Excessive increase in secondary steam flow
- Inadvertent opening of a steam generator relief or safety valve
- Steam system piping failure
- Inadvertent operation of the passive residual heat removal (PRHR) heat exchanger

The preceding events are Condition II events, with the exception of small steam system piping failures, which are considered to be Condition III, and large steam system piping failure Condition IV events. Subsection 15.0.1 contains a discussion of classifications and applicable criteria.

The accidents in this section are analyzed. The most severe radiological consequences result from the main steam line break accident discussed in subsection 15.1.5. The radiological consequences are reported only for that limiting case.

15.1.1 Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature

15.1.1.1 Identification of Causes and Accident Description

Reductions in feedwater temperature cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the reactor coolant system. The overpower/overtemperature protection (neutron overpower, overtemperature, and overpower ΔT trips) prevents a power increase that could lead to a departure from nucleate boiling ratio (DNBR) that is less than the design limit values.

A reduction in feedwater temperature may be caused by a low-pressure heater train or a high-pressure heater train out of service or bypassed. At power, this increased subcooling creates an increased load demand on the reactor coolant system.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flows decrease, so the no-load transient is less severe than the full-power case. The net effect on the reactor coolant system due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow; that is, the reactor reaches a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

A decrease in normal feedwater temperature is classified as a Condition II event, an incident of moderate frequency.

The protection available to mitigate the consequences of a decrease in feedwater temperature is the same as that for an excessive steam flow increase, as discussed in subsection 15.0.8 and listed in Table 15.0-6.

15.1.1.2 Analysis of Effects and Consequences

15.1.1.2.1 Method of Analysis

This transient is analyzed by calculating conditions at the feedwater pump inlet following the removal of a low-pressure feedwater heater train from service. These feedwater conditions are then used to recalculate a heat balance through the high-pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

- Initial plant power level corresponding to 100-percent nuclear steam supply system thermal output.
- The worst single failure in the pre-heating section of the Main Feedwater System, resulting in the maximum reduction in feedwater temperature, occurs.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

15.1.1.2.2 Results

A fault in the feedwater heaters section of the Feedwater System causes a reduction in feedwater temperature that increases the thermal load on the primary system. The maximum reduction in feedwater temperature, due to a single failure in the feedwater system, is lower than 79.5°F. This reduction results in an increase in heat load on the primary system of less than 10-percent full power.

15.1.1.3 Conclusions

The decrease in feedwater temperature transient is less severe than the increase in feedwater flow event or the increase in secondary steam flow event (see subsections 15.1.2 and 15.1.3). Based on the results presented in subsections 15.1.2 and 15.1.3, the applicable Standard Review Plan subsection 15.1.1 evaluation criteria for the decrease in feedwater temperature event are met.

15.1.2 Feedwater System Malfunctions that Result in an Increase in Feedwater Flow

15.1.2.1 Identification of Causes and Accident Description

Addition of excessive feedwater causes an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and the reactor coolant system. The overpower/overtemperature protection (neutron overpower,

overtemperature, and overpower ΔT trips) prevents a power increase that leads to a DNBR less than the safety analysis limit value.

An example of excessive feedwater flow is a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes an increased load demand on the reactor coolant system due to increased subcooling in the steam generator.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity.

Continuous addition of excessive feedwater is prevented by the steam generator high-2 water level signal trip, which closes the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps, and reactor.

An increase in normal feedwater flow is classified as a Condition II event, fault of moderate frequency.

Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of the turbine trip for the excessive feedwater flow case initiated from full-power conditions. As discussed in subsection 15.0.14, an excessive feedwater flow transient initiated with the plant at no-load conditions need not consider a consequential loss of offsite power. With the plant initially at zero-load, the turbine would not have been connected to the grid, so any subsequent reactor or turbine trip would not disrupt the grid and produce a consequential loss of offsite ac power.

15.1.2.2 Analysis of Effects and Consequences

15.1.2.2.1 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient primarily is analyzed by using the LOFTRAN computer code (Reference 1). LOFTRAN simulates a multiloop system, neutron kinetics, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level.

For that portion of the feedwater malfunction transient that includes a primary coolant flow coastdown caused by the consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analysis. First the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 5) is then used to calculate the heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

The transient is analyzed to demonstrate plant behavior if excessive feedwater addition occurs because of system malfunction or operator error that allows a feedwater control valve to open fully. The following two cases are analyzed assuming a conservatively large negative moderator temperature coefficient:

- Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions.
- Accidental opening of one feedwater control valve with the reactor in automatic control at full power.

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

- For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 120 percent of nominal feedwater flow to one steam generator.
- For the feedwater control valve accident at zero-load condition, a feedwater control valve malfunction occurs, which results in a step increase in flow to one steam generator from 0 in 120 percent of the nominal full-load value for one steam generator.
- For the zero-load condition, feedwater temperature is at a conservatively low value of 40°F.
- No credit is taken for the heat capacity of the reactor coolant system and steam generator thick metal in attenuating the resulting plant cooldown.
- The feedwater flow resulting from a fully open control valve is terminated by a steam generator high-2 level trip signal, which closes feedwater control and isolation valves and trips the main feedwater pumps, the turbine, and the reactor.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

Normal reactor control systems are not required to function. The protection and safety monitoring system may function to trip the reactor because of overpower or high-2 steam generator water level conditions. No single active failure prevents operation of the protection and safety monitoring system. A discussion of anticipated transients without trip considerations is presented in Section 15.8.

The analysis assumes that the turbine trip during the case initiated from full power results in a consequential loss of offsite power that produces the coastdown of the reactor coolant pumps. As described in subsection 15.0.14, the loss of offsite power is modeled to occur 3.0 seconds after the turbine trip. The excessive feedwater flow analysis conservatively delays the start of rod insertion until 2.0 seconds after the reactor trip signal is generated, while assuming that the turbine trip occurs with a zero time delay following the generation of the turbine trip signal. The interaction of these assumptions produces maximum core power with minimum core coolant flow during the period of reactor coolant pump coastdown and thereby minimizes the predicted DNBRs.

15.1.2.2.2 Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the preceding assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate analyzed in subsection 15.4.1 for an uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition. Therefore, the results of the analysis are not presented here. If the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25-percent nominal full power.

The full-power case (maximum reactivity feedback coefficients, automatic rod control) results in the greatest power increase. Assuming the rod control system to be in the manual control mode results in a slightly less severe transient.

When the steam generator water level in the faulted loop reaches the high-2 level setpoint, the feedwater control valves and feedwater isolation valves are automatically closed and the main feedwater pumps are tripped. This prevents continuous addition of the feedwater. In addition, a turbine trip and a reactor trip are initiated.

Transient results show the increase in nuclear power and ΔT associated with the increased thermal load on the reactor (see Figures 15.1.2-1 and 15.1.2-2). A new equilibrium condition is reached and all the plant parameters, except for the SG water level, remain almost constant. Following the turbine trip, the consequential loss of offsite power produces the reactor coolant system flow coastdown shown in Figure 15.1.2-3. The minimum DNBR is predicted to occur before the reactor trip and the reactor coolant pump coastdown caused by the loss of offsite power. The minimum DNBR predicted is 2.14 using the WRB-2 equation, which is well above the design limit described in Section 4.4. Following the reactor trip, the plant approaches a stabilized and safe condition; standard plant shutdown procedures may then be followed to further cool down the plant.

Because the power level rises by a maximum of about 12 percent above nominal during the excessive feedwater flow incident, the fuel temperature also rises until after reactor trip occurs. The core heat flux lags behind the neutron flux response because of the fuel rod thermal time constant. Therefore, the peak value does not exceed 118 percent of its nominal value (the assumed high neutron flux trip setpoint). The peak fuel temperature thus remains well below the fuel melting temperature.

The transient results show that departure from nucleate boiling (DNB) does not occur at any time during the excessive feedwater flow incident. Thus, the capability of the primary coolant to remove heat from the fuel rods is not reduced and the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.1.2-1.

15.1.2.3 Conclusions

The results of the analysis show that the minimum DNBR encountered for an excessive feedwater addition at power is above the design limit value. The DNBR design basis is described in Section 4.4.

Additionally, the reactivity insertion rate that occurs at no-load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from subcritical condition analysis (see subsection 15.4.1).

15.1.3 Excessive Increase in Secondary Steam Flow

15.1.3.1 Identification of Causes and Accident Description

An excessive increase in secondary system steam flow (excessive load increase incident) results in a power mismatch between the reactor core power and the steam generator load demand. The plant control system is designed to accommodate a 10-percent step load increase or a 5-percent-per-minute ramp load increase in the range of 25- to 100-percent full power. Any loading rate in excess of these values may cause a reactor trip actuated by the protection and safety monitoring system. Steam flow increases greater than 10 percent are analyzed in subsections 15.1.4 and 15.1.5.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, turbine bypass to the condenser is controlled by reactor coolant condition signals. A high reactor coolant temperature indicates a need for turbine bypass. A single controller malfunction does not cause turbine bypass. An interlock blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following protection and safety monitoring system signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux

An excessive load increase incident is considered to be a Condition II event, as described in subsection 15.0.1.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, an analysis has been performed to evaluate the effects produced by a possible consequential loss of offsite power during the excessive load increase event. As discussed in subsection 15.0.14, the loss of offsite power need be considered only as a direct consequence of a turbine trip occurring while the plant is operating at power. For the four excessive load increase cases presented, reactor and turbine trips are not predicted to occur. However, to address the loss of offsite power issue, analysis has been performed that conservatively assumes a reactor trip and an associated turbine trip occur at the time of peak power. Consistent with the discussion in subsection 15.0.14, the analysis then

models a loss of offsite power occurring 3.0 seconds after the turbine trip. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

15.1.3.2 Analysis of Effects and Consequences

15.1.3.2.1 Method of Analysis

This accident is primarily analyzed using the LOFTRAN computer code (Reference 1). LOFTRAN simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

For the excessive load increase analysis that includes a primary coolant flow coastdown caused by the consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analysis. First the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 5) is then used to calculate the heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

Four cases are analyzed to demonstrate plant behavior following a 10-percent step load increase from rated load. These cases are as follows:

- Reactor control in manual with minimum moderator reactivity feedback
- Reactor control in manual with maximum moderator reactivity feedback
- Reactor control in automatic with minimum moderator reactivity feedback
- Reactor control in automatic with maximum moderator reactivity feedback

For the minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity; therefore, reductions in coolant temperature have the least impact on core power. For the maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value. This results in the largest amount of reactivity feedback due to changes in coolant temperature. For all the cases analyzed both with and without automatic rod control, no credit is taken for ΔT trips on overtemperature or overpower in order to demonstrate the inherent transient capability of the plant. Under actual operating conditions, such a trip may occur, after which the plant quickly stabilizes.

A 10-percent step increase in steam demand is assumed, and each case is analyzed without credit being taken for pressurizer heaters. At initial reactor power, reactor coolant system pressure and temperature are assumed to be at their full power values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-11397-P-A (Reference 2). Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

In addressing the consequential loss of offsite power, limiting cases are analyzed that model a reactor trip and an associated turbine trip occurring at the time of peak power during the limiting excessive load increase transient. The analysis has been performed conservatively assuming a

reactor trip with a coincident turbine trip followed by a loss of offsite power 3.0 seconds later, as discussed in subsection 15.0.14. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

Normal reactor control systems and engineered safety systems are not required to function.

15.1.3.2.2 Results

Figures 15.1.3-1 through 15.1.3-10 show the transient with the reactor in the manual control mode and no reactor trip signals occur. For the minimum moderator feedback case, there is a slight power increase and the average core temperature shows a large decrease. This results in a DNBR that increases above its initial value. For the maximum moderator feedback manually controlled case, there is a much faster increase in reactor power due to the moderator feedback. A reduction in the DNBR occurs, but the DNBR remains above the design limit (see Section 4.4).

Figures 15.1.3-11 through 15.1.3-20 show the transient assuming the reactor is in the automatic control mode. A reactor trip signal setpoint is reached but, conservatively, reactor trip is not credited. Both the minimum and maximum moderator feedback cases show that core power increases and thereby reduces the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the design limit (see Section 4.4).

For the cases with no reactor trip signal, the plant power stabilizes at an increased power level. Normal plant operating procedures are followed to reduce power. Because of the measurement errors assumed in the setpoints, it is possible that reactor trip could actually occur for the automatic control and maximum feedback cases. The plant reaches a stabilized condition following the trip.

For the analysis performed modeling a loss of offsite power and the subsequent reactor coolant pump coastdown, the results show that the minimum DNBRs predicted during the excessive load increase cases occur prior to the time the flow coastdown begins. Therefore, the DNB ratio results provided in Figures 15.1.3-5, 15.1.3-10, 15.1.3-15, and 15.1.3-20 are bounding, and the minimum DNBR during the flow coastdown remains well above the design limit defined in Section 4.4. Since the loss of offsite power is delayed for 3.0 seconds after the turbine trip, the RCCAs are inserted well into the core before the reactor coolant system flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once power to the reactor coolant pumps is lost.

The excessive load increase incident is an overpower transient for which the fuel temperature rises. Reactor trip may not occur for some of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Because DNB does not occur during the excessive load increase transients, the capability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for the excessive load increase cases with no reactor trip are shown in Table 15.1.2-1.

15.1.3.3 Conclusions

The analysis presented in this subsection demonstrates that for a 10-percent step load increase, the DNBR remains above the design limit. The design basis for DNB is described in Section 4.4. The plant rapidly reaches a stabilized condition following the load increase.

15.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

15.1.4.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in subsection 15.1.5.

The steam release, as a consequence of this accident, results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

The analysis is performed to demonstrate that the following Standard Review Plan subsection 15.1.4 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA, with offsite power available, and assuming a single failure in the engineered safety features system, there will be no consequential damage to the fuel or reactor coolant system after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve. This criterion is met by showing the DNB design basis is not exceeded.

Accidental depressurization of the secondary system is classified as a Condition II event as described in Section 15.1.

The following systems provide the necessary protection against an accidental depressurization of the main steam system:

- Core makeup tank actuation from one of the following signals:
  - Safeguards (“S”) signal
    - Two out of four low pressurizer pressure signals
    - Two out of four high-2 containment pressure signals
    - Two out of four low T_{cold} signals in any one loop
    - Two out of four low steam line pressure signals in any one loop
  - Two out of four low pressurizer level signals

- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the “S” signal

- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater valves following reactor trip, an "S" signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.

- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the low T_{cold} signal closes the startup feedwater control and isolation valves.

- Trip of the fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on one of the following signals:

  – Two out of four low steam line pressure signals in any one loop (above permissive P-11)
  – Two out of four high negative steam pressure rates in any loop (below permissive P-11)
  – Two out of four low T_{cold} signals in any one loop

  Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0.6.

15.1.4.2 Analysis of Effects and Consequences

15.1.4.2.1 Method of Analysis

The following analyses of a secondary system steam release are performed:

- A full plant digital computer simulation using the LOFTRAN code (Reference 1) to determine reactor coolant system temperature and pressure during cooldown, and the effect of core makeup tank injection

- Analyses to determine that there is no damage to the fuel or reactor coolant system

The following conditions are assumed to exist at the time of a secondary steam system release:

- End-of-life shutdown margin at no-load, equilibrium xenon conditions, and with the most reactive RCCA stuck in its fully withdrawn position. Operation of RCCA mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

- The most negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is modeled as a function of core mass flow, core boron concentration, and core inlet temperature.

- Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the passive core cooling system. Low-concentration boric acid must be swept from the core makeup tank lines downstream of isolation valves before delivery of boric acid (3400 ppm) to the reactor coolant loops. This effect has been accounted for in the analysis.

- The case studied is a steam flow of 520 pounds per second at 1200 psia with offsite power available. This conservatively models the maximum capacity of any single steam dump, relief, or safety valve. Initial hot shutdown conditions at time zero are assumed because this represents the most conservative initial conditions.

Should the reactor be just critical or operating at power at the time of a steam release, the reactor is tripped by the normal overpower protection when power level reaches a trip point. Following a trip at power, the reactor coolant system contains more stored energy than at no-load. This is because the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. The additional stored energy is removed via the cooldown caused by the steam release before the no-load conditions of the reactor coolant system temperature and shutdown margin assumed in the analyses are reached.

After the additional stored energy is removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no-load condition at time zero. However, because the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the reactor coolant system cooldown are less for steam line release occurring at power:

- In computing the steam flow, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

- Perfect moisture separation occurs in the steam generator.

- Offsite power is available, because this maximizes the cooldown.

- Maximum cold startup feedwater flow is assumed.

- Four reactor coolant pumps are initially operating.

- Manual actuation of the PRHR system at time zero is conservatively assumed to maximize the cooldown.

15.1.4.2.2 Results

The results presented conservatively indicate the events that would occur assuming a secondary system steam release because it is postulated that the conditions just described occur simultaneously.

Figures 15.1.4-2 through 15.1.4-12 show the transient results for a steam flow of 520 pounds per second at 1200 psia.

The assumed steam release is typical of the capacity of any single steam dump, relief, or safety valve. Core makeup tank injection and the associated tripping of the reactor coolant pumps are

initiated automatically by the low T_{cold} "S" signal. Boron solution at 3400 ppm enters the reactor coolant system, providing enough negative reactivity to prevent a significant return to power and core damage. Later in the transient, as the reactor coolant pressure continues to fall, the accumulators actuate and inject boron solution at 2600 ppm.

The transient is conservative with respect to cooldown, because no credit is taken for the energy stored in the system metal other than that of the fuel elements and steam generator tubes, and the PRHR system is assumed to be actuated at time zero. Because the limiting portion of the transient occurs over a period of about 5 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

The calculated time sequence of events for this accident is listed in Table 15.1.2-1.

15.1.4.3 Margin to Critical Heat Flux

The analysis demonstrates that the DNB design basis, as described in Section 4.4, is met for the inadvertent opening of a steam generator relief or safety valve. As shown in Figure 15.1.4-2, no significant return to power occurs and, therefore, DNB does not occur. The minimum DNBR is conservatively calculated and is above the 95/95 limit.

15.1.4.4 Conclusions

The analysis shows that the criterion stated in this subsection is satisfied. For an inadvertent opening of any single steam dump or a steam generator relief or safety valve, the DNB design basis is met.

15.1.5 Steam System Piping Failure

15.1.5.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line results in an initial increase in steam flow, which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core becomes critical and returns to power. A return to power following a steam line rupture is a potential problem mainly because of the existing high-power peaking factors, assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid solution delivered by the passive core cooling system.

The analysis of a main steam line rupture is performed to demonstrate that the following Standard Review Plan subsection 15.1.5 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA with or without offsite power and assuming a single failure in the engineered safety features system, the core cooling capability is maintained. As shown in subsection 15.1.5.4, radiation doses are within the guidelines.

DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable. The following analysis shows that the DNB design basis is not exceeded for any steamline rupture, assuming the most reactive assembly stuck in its fully withdrawn position.

A major steam line rupture is classified as a Condition IV event.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events, as described in subsection 15.0.1.3.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat retards the cooldown and thereby reduces the likelihood that the reactor returns to power. A detailed analysis of this transient with the most limiting break size, a double-ended rupture, is presented here.

Certain assumptions used in this analysis are discussed in WCAP-9226 (Reference 4). WCAP-9226 also contains a discussion of the spectrum of break sizes and power levels analyzed.

The following functions provide the protection for a steam line rupture (see subsection 7.2.1.1.2):

- Core makeup tank actuation from any of the following:
  - Two out of four low pressurizer pressure signals
  - Two out of four high-2 containment pressure signals
  - Two out of four low steam line pressure signals in any loop
  - Two out of four low T_{cold} signals in any one loop
  - Two out of four low pressurizer level signals

- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the "S" signal

- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater control valves, the "S" signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.

- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the low T_{cold} signal closes the startup feedwater control and isolation valves.

- Fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on any of the following:
  - Two out of four high-1 containment pressure
  - Two out of the four low steam line pressure signals in any one loop (above permissive P-11)
  - Two out of four high negative steam pressure rates in any one loop (below permissive P-11)
  - Two out of four low T_{cold} signals in any one loop

A fast-acting main steam isolation valve is provided in each steam line. These valves are assumed to fully close within 10 seconds of actuation following a large break in the steam line. For breaks downstream of the main steam line isolation valves, closure of at least one valve in each line terminates the blowdown.

For any break in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the main steam line isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Flow restrictors are installed in the steam generator outlet nozzle, as an integral part of the steam generator. The effective throat area of the nozzles is 1.4 ft^2, which is considerably less than the main steam pipe area; thus, the flow restrictors serve to limit the maximum steam flow for a break at any location.

Design criteria and methods of protection of safety-related equipment from the dynamic effects of postulated piping ruptures are provided in Section 3.6.

15.1.5.2 Analysis of Effects and Consequences

15.1.5.2.1 Method of Analysis

The analysis of the steam pipe rupture is performed to determine the following:

- The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN code (Reference 1) is used to model the system transient.
- The thermal-hydraulic behavior of the core following a steam line break. A detailed thermal-hydraulic digital computer code, VIPRE-01, is used to determine if DNB occurs for the core transient conditions computed by the LOFTRAN code.

The following conditions are assumed to exist at the time of a main steam line break accident:

- End-of-cycle shutdown margin at no-load, equilibrium xenon conditions, and the most reactive rod control assembly stuck in its fully withdrawn position. Operation of the control

rod mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is modeled as a function of core mass flow, core boron concentration, and core inlet temperature.

The core properties used in the LOFTRAN mode for feedback calculations are generated by combining those in the sector nearest the affected steam generator with those associated with the remaining sector. The resultant properties reflect a combination process that accounts for inlet plenum fluid mixing and a conservative weighing of the fluid properties from the coldest core sector.

In verifying the conservatism of this method, the power predictions of the LOFTRAN modeling are confirmed by comparison with detailed core analysis for the limiting conditions of the cases considered. This core analysis conservatively models the hypothetical core configuration (that is, stuck RCCA, nonuniform inlet temperatures, pressure, flow, and boron concentration) and directly evaluates the total reactivity feedback including power, boron, and density redistribution in an integral fashion. The effect of void formation is also included.

Comparison of the results from the detailed core analysis with the LOFTRAN predictions verify the overall conservatism of the methodology. That is, the specific power, temperature, and flow conditions used to perform the DNB analysis are conservative.

- The core makeup tanks and the accumulators are the portions of the passive core cooling system used in mitigating a steam line rupture. There are no single failures that prevent core makeup tank injection. In modeling the core makeup tanks and the accumulators, conservative assumptions are used that minimize the capability to add borated water. Specifically, the core makeup tank injection line characteristics modeled reflect the failure of one core makeup tank discharge valve.

- The maximum overall fuel-to-coolant heat transfer coefficient is used to maximize the rate of cooldown.

- Because the steam generators are provided with integral flow restrictors with a 1.4-ft^2 throat area, any rupture in a steam line with a break area greater than 1.4 ft^2, regardless of location, has the same effect on the primary plant as the 1.4-ft^2 double-ended rupture. The limiting case considered in determining the core power and reactor coolant system transient is the complete severance of a pipe, with the plant initially at no-load conditions and full reactor coolant flow with offsite power available. The results of this case bound the loss of offsite power case for the following reasons:

  – Loss of offsite power results in an immediate reactor coolant pump coastdown at the initiation of the transient. This reduces the severity of the reactor coolant system

cooldown by reducing primary-to-secondary heat transfer. The lessening of the cooldown, in turn, reduces the magnitude of the return to power.

- Following actuation, the core makeup tank provides borated water that injects into the reactor coolant system. Flow from the core makeup tank increases if the reactor coolant pumps have coasted down. Therefore, the analysis performed with offsite power and continued reactor coolant pump operation reduces the rate of boron injection into the core and is conservative.

- The protection system automatically provides a safety-related signal that initiates the coastdown of the reactor coolant pumps in parallel with core makeup tank actuation. Because this reactor coolant pump trip function is actuated early during the steam line break event (right after core makeup tank actuation), there is very little difference in the predicted DNBR between cases with and without offsite power.

- Because of the passive nature of the safety injection system, the loss of offsite power does not delay the actuation of the safety injection system.

- Power peaking factors corresponding to one stuck RCCA are determined at the end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck RCCA during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow and, therefore, may differ for each case studied.

The analysis assumes initial hot standby conditions at time zero in order to present a representative case which will yield limiting post-trip DNBR results for this transient. If the reactor is just critical or operating at power at the time of a steam line break, the reactor is tripped by the overpower protection system when power level reaches a trip point.

Following a trip at power, the reactor coolant system contains more stored energy than at no-load because the average coolant temperature is higher than at no-load, and there is energy stored in the fuel. The additional stored energy reduces the cooldown caused by the steam line break before the no-load conditions of reactor coolant system temperature and shutdown margin assumed in the analyses are reached.

After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis that assumes a no-load condition at time zero.

- In computing the steam flow during a steam line break, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

- Perfect moisture separation occurs in the steam generator.

- Maximum cold startup feedwater flow plus nominal 100 percent main feedwater flow is assumed.

- Four reactor coolant pumps are initially operating.
- Manual actuation of the PRHR system at time zero is conservatively assumed to maximize the cooldown.

15.1.5.2.2 Results

The calculated sequence of events for the analyzed case is shown in Table 15.1.2-1. The results presented conservatively indicate the events that would occur assuming a steam line rupture because it is postulated that the conditions described occur simultaneously.

15.1.5.2.3 Core Power and Reactor Coolant System Transient

Figures 15.1.5-1 through 15.1.5-13 show the reactor coolant system transient and core heat flux following a main steam line rupture (complete severance of a pipe) at initial no-load condition.

Offsite power is assumed available so that, initially, full reactor coolant flow exists. During the course of the event, the reactor protection system initiates a trip of the reactor coolant pumps in conjunction with actuation of the core makeup tanks. The transient shown assumes an uncontrolled steam release from only one steam generator. Steam release from more than one steam generator is prevented by automatic trip of the main steam isolation valves in the steam lines by high containment pressure signals or by low steam line pressure signals. Even with the failure of one valve, release is limited to approximately 10 seconds for the other steam generator while the one generator blows down. The main steam isolation valves fully close in less than 10 seconds from receipt of a closure signal.

As shown in Figure 15.1.5-1, the core attains criticality with the RCCAs inserted (with the design shutdown assuming the most reactive RCCA stuck) before boron solution at 3400 ppm (from core makeup tanks) or 2600 ppm (from accumulators) enters the reactor coolant system. A peak core power significantly lower than the nominal full-power value is attained.

The calculation assumes that the boric acid is mixed with and diluted by the water flowing in the reactor coolant system before entering the reactor core. The concentration after mixing depends upon the relative flow rates in the reactor coolant system and from the core makeup tanks or accumulators (or both). The variation of mass flow rate in the reactor coolant system due to water density changes is included in the calculation. The variation of flow rate from the core makeup tanks or accumulators (or both) due to changes in the reactor coolant system pressure and temperature and the pressurizer level is also included. The reactor coolant system and passive injection flow calculations include line losses.

At no time during the analyzed steam line break event does the core makeup tank level approach the setpoint for actuation of the automatic depressurization system. During non-LOCA events, the core makeup tanks remain filled with water. The volume of injection flow leaving the core makeup tank is offset by an equal volume of recirculation flow that enters the core makeup tanks via the reactor coolant system cold leg balance lines.

The PRHR system provides a passive, long-term means of removing the core decay and stored heat by transferring the energy via the PRHR heat exchanger to the in-containment refueling water

storage tank (IRWST). The PRHR heat exchanger is normally actuated automatically when the steam generator level falls below the low wide-range level. For the main steam line rupture case analyzed, the PRHR exchanger is conservatively actuated at time zero to maximize the cooldown.

15.1.5.2.4 Margin to Critical Heat Flux

The case presented in subsection 15.1.5.2.2 conservatively models the expected behavior of the plant during a steam system piping failure. This includes the tripping of the reactor coolant pumps coincident with core makeup tank actuation. A DNB analysis is performed using limiting assumptions that bound those of subsection 15.1.5.2.2.

Under the low flow (natural circulation) conditions present in the AP1000 transient, the return to power is severely limited by the large negative feedback due to flow and power. The minimum DNBR is conservatively calculated and is above the 95/95 limit.

15.1.5.3 Conclusions

The analysis shows that the DNB design basis is met for the steam system piping failure event. DNB and possible cladding perforation following a steam pipe rupture are not precluded by the criteria. The preceding analysis shows that no DNB occurs for the main steam line rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

15.1.5.4 Radiological Consequences

The evaluation of the radiological consequences of a postulated main steam line break outside containment assumes that the reactor has been operating with the design basis fuel defect level (0.25 percent of power produced by fuel rods containing cladding defects) and that leaking steam generator tubes have resulted in a buildup of activity in the secondary coolant.

Following the rupture, startup feedwater to the faulted loop is isolated and the steam generator is allowed to steam dry. Any radioiodines carried from the primary coolant into the faulted steam generator via leaking tubes are assumed to be released directly to the environment. It is conservatively assumed that the reactor is cooled by steaming from the intact loop.

15.1.5.4.1 Source Term

The only significant radionuclide releases due to the main steam line break are the iodines and alkali metals that become airborne and are released to the environment as a result of the accident. Noble gases are also released to the environment. Their impact is secondary because any noble gases entering the secondary side during normal operation are rapidly released to the environment.

The analysis considers two different reactor coolant iodine source terms, both of which consider the iodine spiking phenomenon. In one case, the initial iodine concentrations are assumed to be those associated with equilibrium operating limits for primary coolant iodine activity. The iodine spike is assumed to be initiated by the accident with the spike causing an increasing level of iodine in the reactor coolant.

The second case assumes that the iodine spike occurs prior to the accident and that the maximum resulting reactor coolant iodine concentration exists at the time the accident occurs.

The reactor coolant noble gas and alkali metal concentrations are assumed to be those associated with the design basis fuel defect level.

The secondary coolant is assumed to have an iodine source term of 0.1 μCi/g dose equivalent I-131. This is 10 percent of the maximum primary coolant activity at equilibrium operating conditions. The secondary coolant alkali metal concentration is also assumed to be 10 percent of the primary concentration.

15.1.5.4.2 Release Pathways

There are three components to the accident releases:

- The secondary coolant in the steam generator of the faulted loop is assumed to be released out the break as steam. Any iodine and alkali metal activity contained in the coolant is assumed to be released.
- The reactor coolant leaking into the steam generator of the faulted loop is assumed to be released to the environment without any credit for partitioning or plateout onto the interior of the steam generator.
- The reactor coolant leaking into the steam generator of the intact loop would mix with the secondary coolant and thus raise the activity concentrations in the secondary water. While the steam release from the intact loop would have partitioning of non-gaseous activity, this analysis conservatively assumes that any activity entering the secondary side is released.

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.1.5.4.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.1.5.4.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.1.5-1.

15.1.5.4.5 Identification of Conservatisms

The assumptions and parameters used in the analysis contain a number of significant conservatisms:

- The reactor coolant activities are based on a fuel defect level of 0.25 percent. The expected fuel defect level is far less than this (see Section 11.1).

- The assumed leakage of 150 gallons of reactor coolant per day into each steam generator is conservative. The leakage is expected to be a small fraction of this during normal operation.

- The conservatively selected meteorological conditions are present only rarely.

15.1.5.4.6 Doses

Using the assumptions from Table 15.1.5-1, the calculated total effective dose equivalent (TEDE) doses for the case with accident-initiated iodine spike are determined to be less than 0.9 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 2.0 rem at the low population zone outer boundary. These doses are small fractions of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A “small fraction” is defined, consistent with the Standard Review Plan, as being 10 percent or less. The TEDE doses for the case with pre-existing iodine spike are determined to be less than 0.8 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 0.8 rem at the low population zone outer boundary. These doses are within the dose guidelines of 10 CFR Part 50.34.

At the time the main steam line break occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE. When this is added to the dose calculated for the main steam line break, the resulting total dose remains less than the values reported above.

15.1.6 Inadvertent Operation of the PRHR Heat Exchanger

15.1.6.1 Identification of Causes and Accident Description

The inadvertent actuation of the PRHR heat exchanger causes an injection of relatively cold water into the reactor coolant system. This produces a reactivity insertion in the presence of a negative moderator temperature coefficient. The overpower/overtemperature protection functions (neutron overpower, overtemperature, and overpower ΔT trips) are intended to prevent a power increase which could lead to a DNBR less than the safety analysis limit. In addition, because the cold leg temperature is reduced which depressurizes the reactor coolant system during this event, the low cold leg temperature or low pressurizer pressure protection functions could generate a reactor trip. These protection functions do not terminate operation of the PRHR heat exchanger.

The inadvertent actuation of the PRHR heat exchanger could be caused by operator error or a false actuation signal. Actuation of the PRHR heat exchanger involves opening one of the isolation valves, which establishes a flow path from one reactor coolant system hot leg, through the PRHR heat exchanger, and back into its associated steam generator cold leg plenum.

The PRHR heat exchanger is located above the core to promote natural circulation flow when the reactor coolant pumps are not operating. With the reactor coolant pumps in operation, flow through the PRHR heat exchanger is enhanced. The heat sink for the PRHR heat exchanger is provided by the IRWST, in which the PRHR heat exchanger is submerged. Because the fluid in

the heat exchanger is in thermal equilibrium with water in the tank, the initial flow out of the PRHR heat exchanger is significantly colder than the reactor coolant system fluid. Following this initial insurge, the reduction in cold leg temperature is limited by the cooling capability of the PRHR heat exchanger. Because the PRHR heat exchanger is connected to only one reactor coolant system loop, the cooldown resulting from its actuation is asymmetric with respect to the core.

The response of the plant to an inadvertent PRHR heat exchanger actuation with the plant at no-load conditions is bounded by the analyses performed for the inadvertent opening of a steam generator relief or safety valve event (subsection 15.1.4) and the steam system piping failure event (subsection 15.1.5). Both of these events are conservatively analyzed assuming PRHR heat exchanger actuation coincident with the steam line depressurization. Therefore, only the response of the plant to an inadvertent PRHR initiation with the core at power is considered.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, an analysis has been performed to evaluate the effects produced by a possible consequential loss of offsite power during the inadvertent PRHR heat exchanger actuation event. For the limiting case presented, reactor and turbine trips have been conservatively ignored. However, to address the loss of offsite power issue, an analysis has also been performed that assumes a reactor trip and an associated turbine trip occur at the time of peak power. This is conservative with respect to assessing the flow coastdown. Consistent with the discussion in subsection 15.0.14, the analysis then models a loss of offsite power occurring 3.0 seconds after the turbine trip. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

The inadvertent actuation of the PRHR heat exchanger event is a Condition II event, a fault of moderate frequency. Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0.6. The following reactor protection system functions are available to provide protection in the event of an inadvertent PRHR heat exchanger actuation:

- The overpower/overtemperature reactor trips (neutron flux and ΔT)
- Two out of four low pressurizer pressure signals
- Two out of four low T_{cold} signals in any one loop
- Two out of four low pressurizer level signals

15.1.6.2 Analysis of Effects and Consequences

15.1.6.2.1 Method of Analysis

The excessive heat removal due to an inadvertent PRHR heat exchanger actuation is primarily analyzed by using the digital computer code LOFTRAN (References 1 and 6). This code simulates a multiloop system, neutron kinetics, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Analysis performed for inadvertent PRHR heat exchanger actuation including a primary coolant flow coastdown caused by the consequential loss of offsite power uses a combination of three

computer codes for the DNBR analysis. First the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 5) is then used to calculate heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

The system is analyzed to demonstrate plant behavior for an inadvertent PRHR heat exchanger actuation due to an operator error or a false actuation signal that opens the valves that normally isolate the PRHR heat exchanger from the remainder of the reactor coolant system. Both full-power and zero-load conditions are considered. The analyses for the inadvertent opening of a steam generator relief or safety valve event (subsection 15.1.4) and the steam system piping failure event (subsection 15.1.5) bound the results for the zero-power inadvertent PRHR heat exchanger actuation transient.

The case considered in this section is the response of the plant to an inadvertent PRHR heat exchanger initiation with the core initially operating at full power. The reactivity insertion transient arising from the inadvertent actuation of the PRHR heat exchanger is calculated, including the following assumptions:

- With the core at full power, the inadvertent PRHR heat exchanger actuation occurs at 10 seconds. The LOFTRAN code explicitly models the performance of the PRHR heat exchanger and the resulting cooldown transient experienced by the reactor coolant system.

- A conservative model is used to predict the power excursion experienced by the core.

  This includes the use of a negative moderator coefficient corresponding to the end-of-life rodded core. The variation of the coefficient with temperature and pressure is included in conjunction with a low level of power feedback.

  The core properties used in the LOFTRAN code for feedback calculations are generated by combining those in the sector nearest the loop with the PRHR system with those associated with the remaining sector. The resultant properties reflect a combination process that accounts for inlet plenum fluid mixing and a conservative weighing of the fluid properties from the coldest core sector.

  To verify the conservatism of this method, the power predictions of the LOFTRAN point kinetics modeling are confirmed by comparison with detailed core analysis for the limiting conditions of the cases considered. This core analysis explicitly models the hypothetical core configuration (that is, nonuniform inlet temperatures, pressure, flow. and boron) and directly evaluates the total reactivity feedback including power, boron, and density redistribution in an integral fashion.

  Comparison of the results from the detailed core analysis with the LOFTRAN predictions verify the overall conservatism of the methodology. The specific power, temperature, and flow conditions used to perform the DNB analysis are conservative.

- The reactor trips on high neutron flux, overtemperature, and overpower ΔT trips are conservatively ignored for the case presented in Figures 15.1.6-1 through 15.1.6-8. The analysis demonstrates that the applicable safety analysis limits are met without a reactor trip being generated.
- No credit is taken for the heat capacity of the reactor coolant system and steam generator thick metal in attenuating the resulting plant cooldown.
- Control systems are assumed to function only if their operation results in more severe accident results. For the inadvertent PRHR heat exchanger actuation event, both cases with and without automatic rod control are considered.

In addressing the consequential loss of offsite power, a limiting case is analyzed that models a reactor trip and an associated turbine trip occurring at the time of peak power. Consistent with the discussion in subsection 15.0.14, the loss of offsite power then occurs 3.0 seconds after the turbine trip. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3. No single active failure prevents operation of the reactor protection system functions assumed in the analysis. A discussion of anticipated transients without scram considerations is presented in Section 15.8.

15.1.6.2.2 Results

The system responses to an inadvertent PRHR heat exchanger actuation at power event, with manual rod control and no reactor trip, are shown in Figures 15.1.6-1 through 15.1.6-8. The full-power case with manual rod control results in the greatest power increase.

The inadvertent operation of the PRHR heat exchanger incident is an overpower transient for which the fuel temperature rises. Assuming a reactor trip does not occur, the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in power demanded by the system. In the limiting case analyzed, the plant power stabilizes at about 108 percent of its nominal value.

Assuming the rod control system to be in automatic control results in a slightly less limiting transient because the control rods are inserted in response to a primary-to-secondary power mismatch. The results show the increase in nuclear power and ΔT associated with the inadvertent PRHR system actuation at full power. The DNBR does not drop below the design limit value (see Section 4.4).

Because the power level rises during the inadvertent PRHR heat exchanger initiation, the fuel temperatures will also rise until after reactor trip. The core heat flux lags behind the neutron flux response because of the fuel rod thermal time constant. The peak fuel temperature remains below the fuel melting temperature.

The transient results show that DNB does not occur at any time during the inadvertent PRHR heat exchanger actuation event. The ability of the primary coolant to remove heat from the fuel rods is therefore not reduced. The calculated sequence of events for this accident is shown in Table 15.1.2-1.

For the analysis performed modeling a loss of offsite power and the subsequent reactor coolant pump coastdown, the results show that the minimum DBNR is predicted to occur during the time period of the inadvertent PRHR heat exchanger actuation event prior to the time the flow coastdown begins. Therefore, the DNBR results provided in Figure 15.1.6-6 are bounding and the minimum DNBR during the flow coastdown remains well above the design limit defined in Section 4.4. Because the loss of offsite power is delayed for 3.0 seconds after the turbine trip signal, the RCCAs are inserted well into the core before the reactor coolant system flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once ac power to the reactor coolant pumps is lost.

Inadvertent operation of the PRHR heat exchanger is not included among the design overpower transients considered in subsection 4.3. The conservative safety analysis assumptions applied to this event do not credit a reactor trip to preclude the core power from rising above 118 percent of rated thermal power. The nature of this excessive cooldown transient dictates that the predicted power excursion is associated with very low core inlet temperatures, which partially offsets the penalties associated with the high power.

15.1.6.3 Conclusions

The results of the analysis show that the DNBRs encountered for an inadvertent actuation of the PRHR heat exchanger at power are above the design limit values. (The DNB design basis is described in Section 4.4.) The results for an inadvertent PRHR heat exchanger actuation initiated from zero load conditions are bounded by the inadvertent opening of a steam generator relief or safety valve event (subsection 15.1.4) and the steam system piping failure event (subsection 15.1.5).

15.1.7 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.1.8 References

1. Burnett, T. W. T., et al., “LOFTRAN Code Description,” WCAP-7907-P-A (Proprietary), and WCAP-7907-A (Nonproprietary), April 1984.

2. Friedland, A. J., and Ray, S., “Revised Thermal Design Procedure,” WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

3. Moody, F. S., “Transactions of the ASME, Journal of Heat Transfer,” Figure 3, page 134, February 1965.

4. Wood, D. C., and Hollingsworth, S. D., “Reactor Core Response to Excessive Secondary Steam Releases,” WCAP-9226 (Proprietary) and WCAP-9227 (Nonproprietary), January 1978.

5. Hargrove, H. G., “FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod,” WCAP-7908-A, December 1989.

Table 15.1.2-1 (Sheet 1 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN AN INCREASE IN HEAT REMOVAL FROM THE PRIMARY SYSTEM

Accident	Event	Time (seconds)
Excessive increase in secondary system		
– Manual reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	250.0
– Manual reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	70.0
– Automatic reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	125.0
– Automatic reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	50.0
Feedwater system malfunctions that result in an increase in feedwater flow	One main feedwater control valve fails fully open	0.0
	Turbine trip/feedwater isolation and reactor trip on high steam generator level	201.9
	Rod motion begins	203.9
	Loss of offsite power occurs	204.9
	Minimum DNBR occurs	205.8
Inadvertent operation of the PRHR	Inadvertent actuation of PRHR	10.0
	Minimum DNBR occurs	~22.0
	Equilibrium conditions reached (approximate time only)	100.0

Table 15.1.2-1 (Sheet 2 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN AN INCREASE IN HEAT REMOVAL FROM THE PRIMARY SYSTEM

Accident	Event	Time (seconds)
Inadvertent opening of a steam generator relief or safety valve	Inadvertent opening of one main steam safety or relief valve	0.0
	"S" actuation signal on safeguards low T_{cold}	120.3
	Core makeup tank actuation	137.3
	Boron reaches core	152.6
Steam system piping failure	Steam line ruptures	0.0
	"S" actuation signal on safeguards low steam line pressure	1.4
	Criticality attained	28.0
	Pressurizer empty	58.2
	Boron reaches core	33.2

Table 15.1.5-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A MAIN STEAM LINE BREAK

Reactor coolant iodine activity	
– Accident-initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Appendix 15A). Duration of spike is 3.6 hours.
– Preaccident spike	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	10% of reactor coolant concentrations at maximum equilibrium conditions
Duration of accident (hr)	72
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in Appendix 15A
Steam generator in faulted loop	
– Initial water mass (lb)	3.03 E+05
– Primary to secondary leak rate (lb/hr)	52.14[a]
– Iodine partition coefficient	1.0
– Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.03 E+05 1.225 E+04
Steam generator in intact loop	
– Primary to secondary leak rate (lb/hr)	52.14[a]
– Iodine partition coefficient	1.0
– Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.0335 E+05 1.225 E+04
Nuclide data	See Table 15A-4

Note:
a. Equivalent to 150 gpd cooled liquid at 62.4 lb/ft^3.

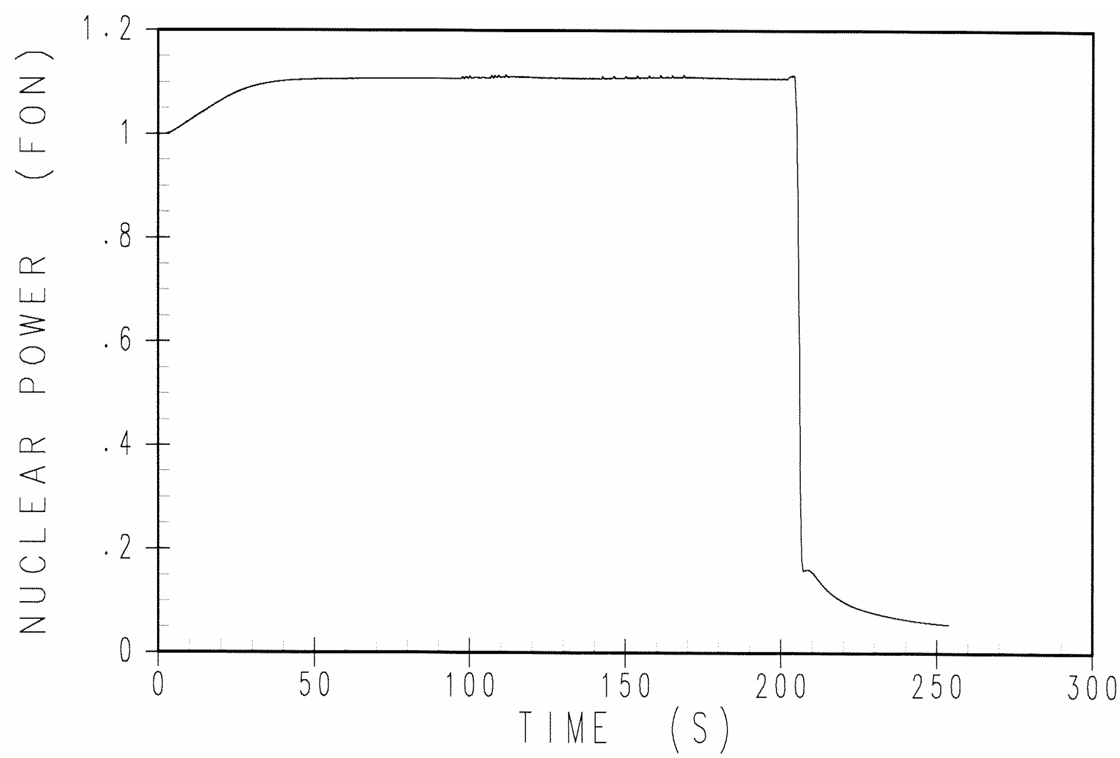

Figure 15.1.2-1

Feedwater Control Valve Malfunction Nuclear Power

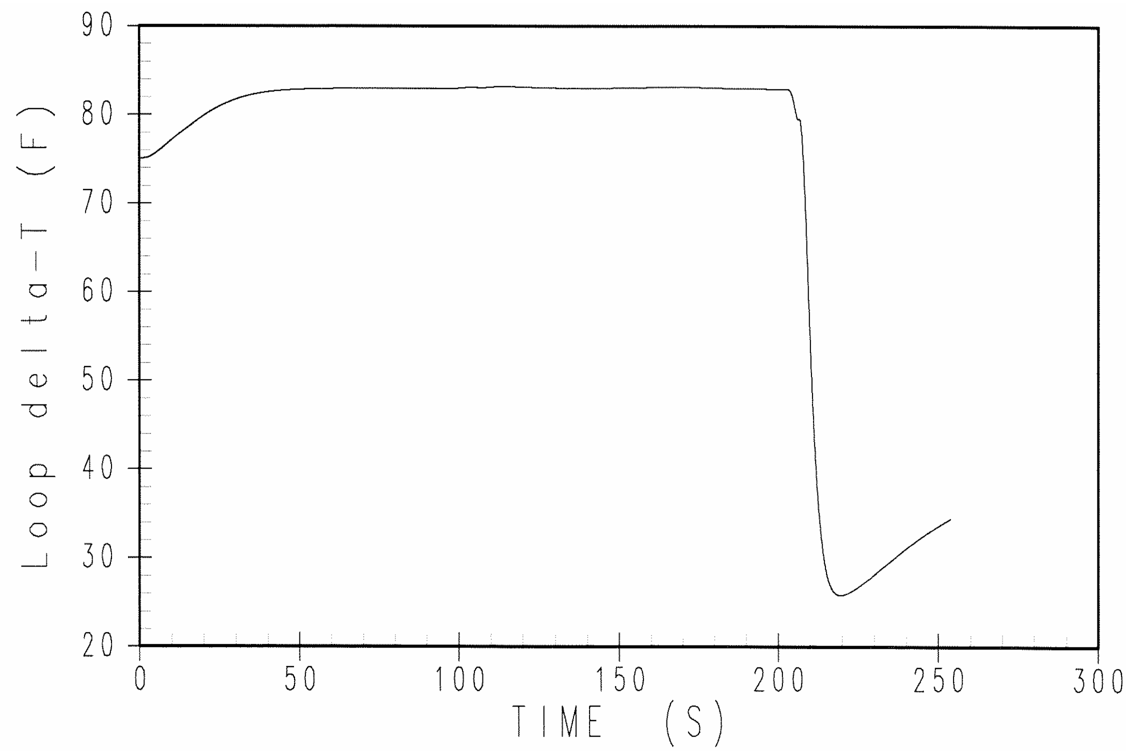

Figure 15.1.2-2

Feedwater Control Valve Malfunction Loop ΔT

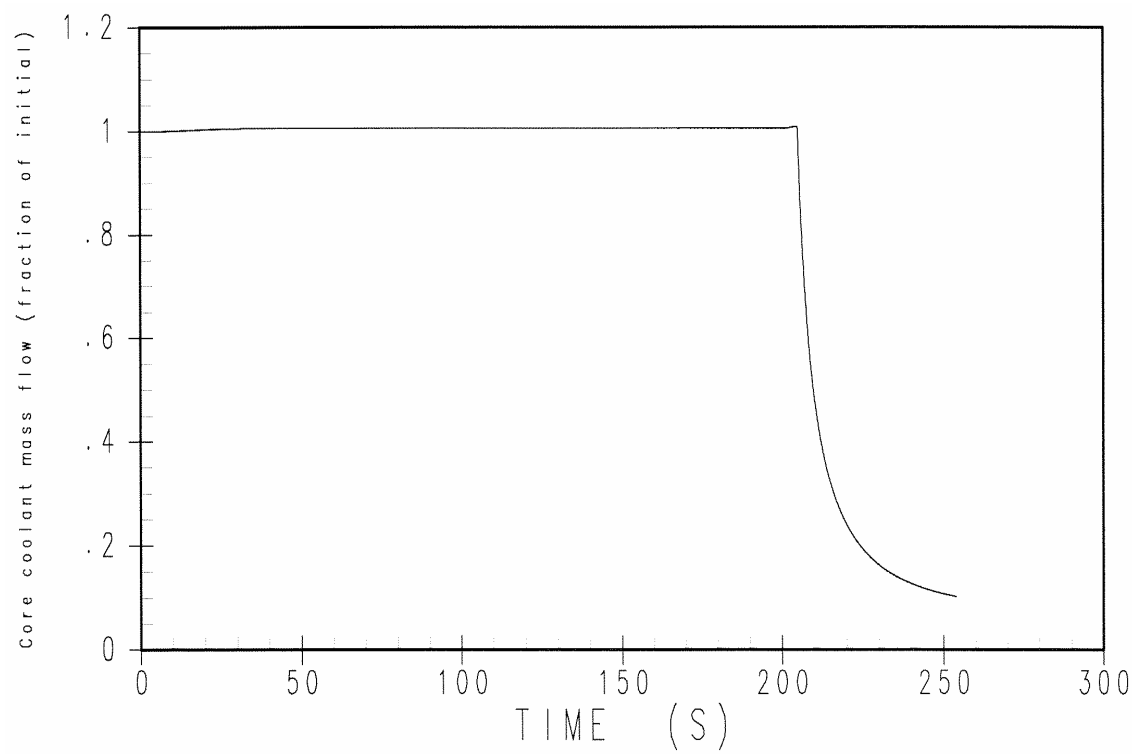

Figure 15.1.2-3

Feedwater Control Valve Malfunction Core Coolant Mass Flow

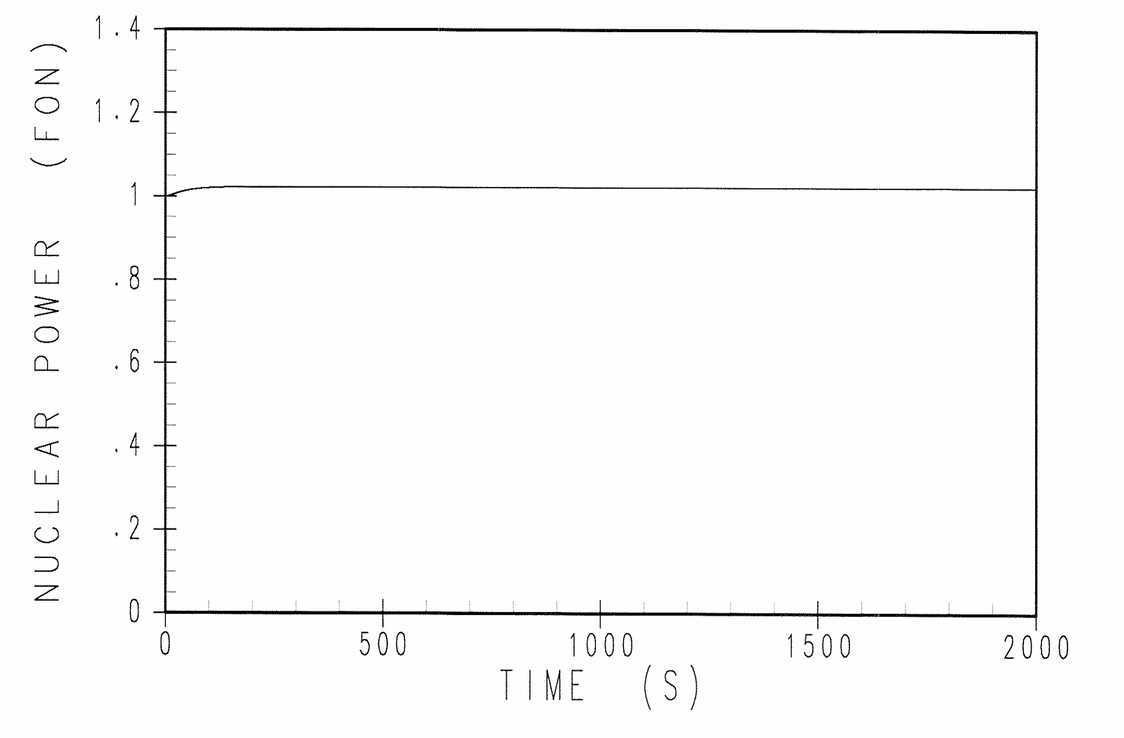

Figure 15.1.3-1

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

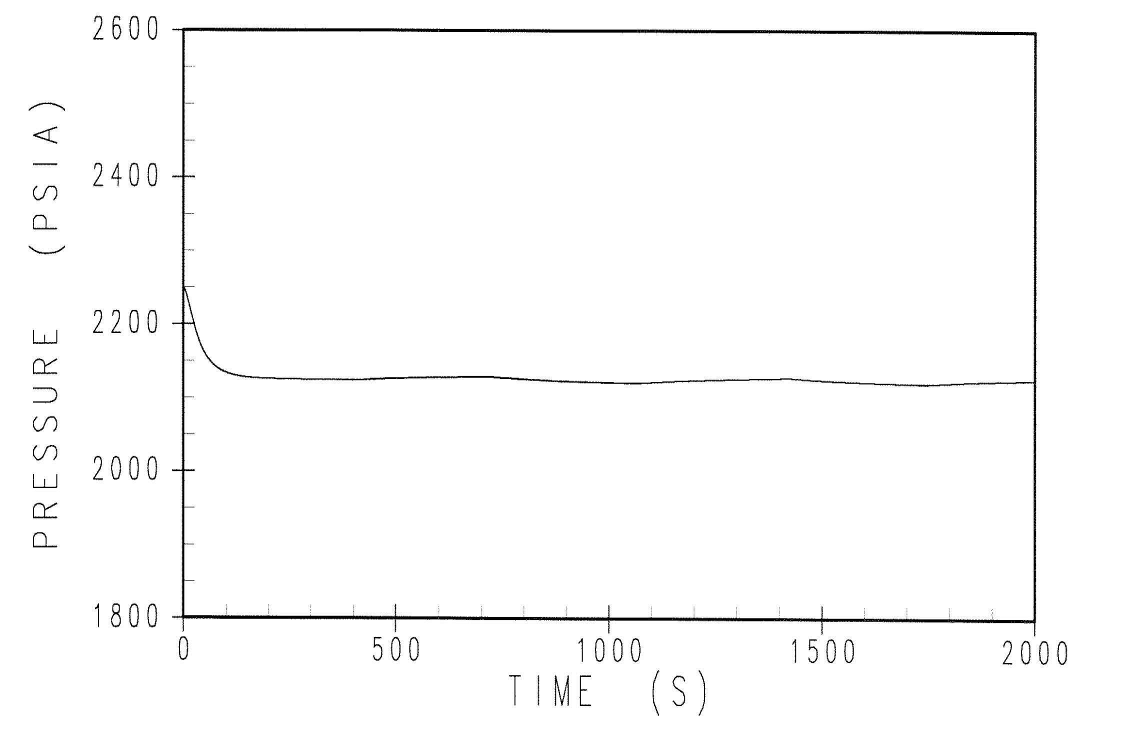

Figure 15.1.3-2

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

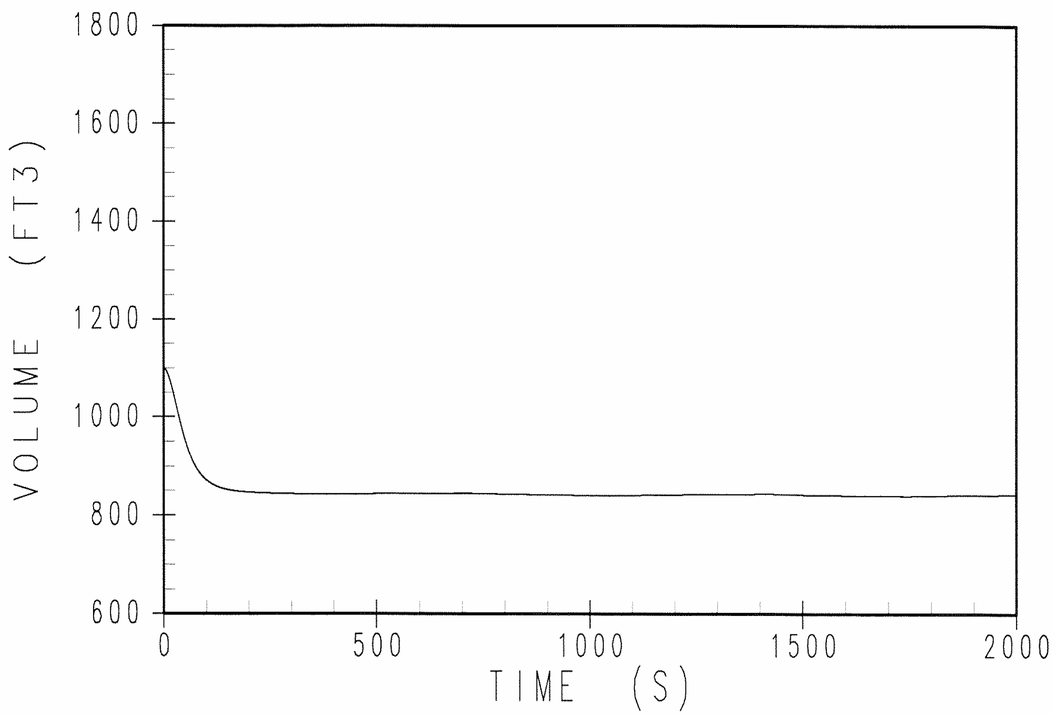

Figure 15.1.3-3

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

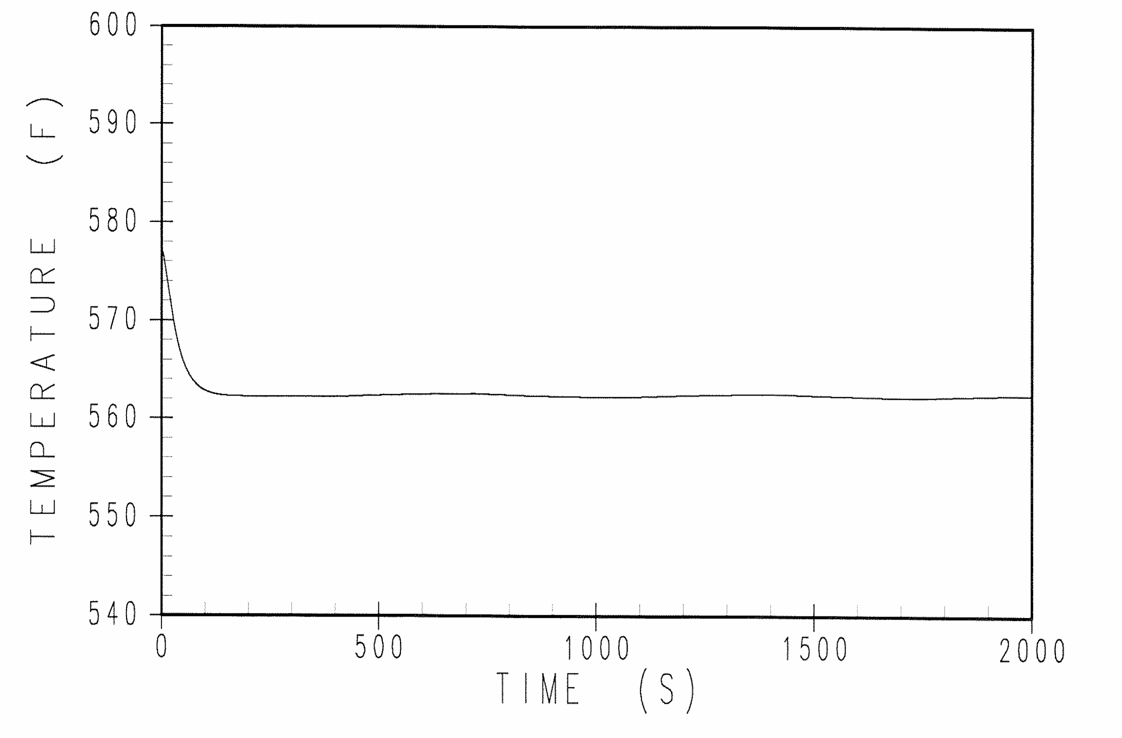

Figure 15.1.3-4

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

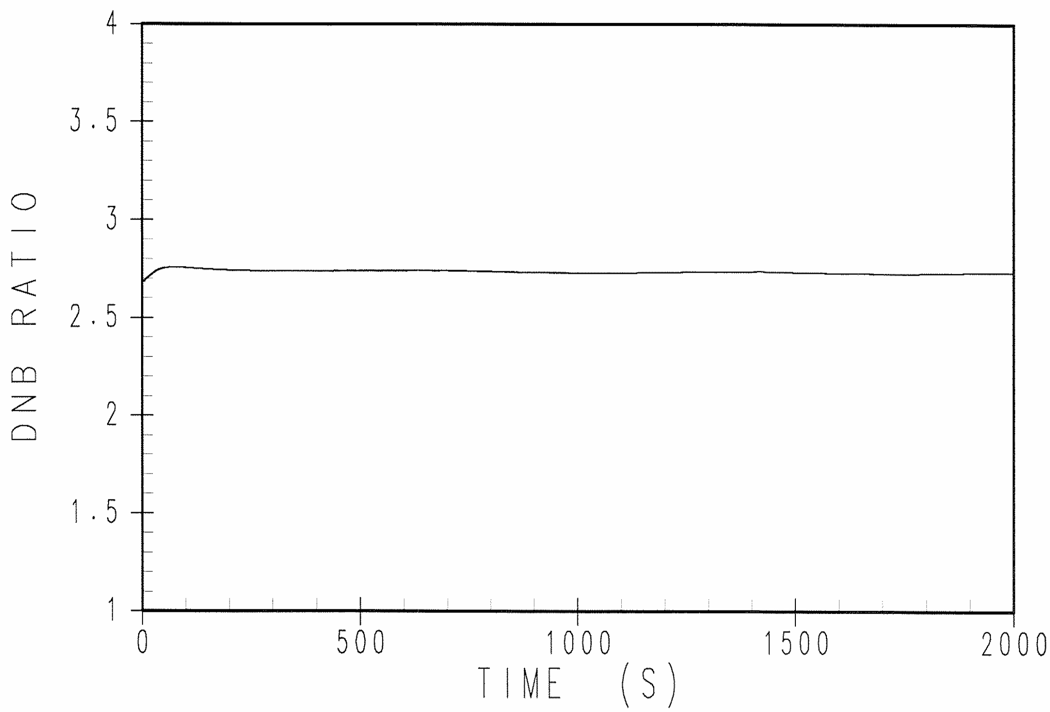

Figure 15.1.3-5

DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

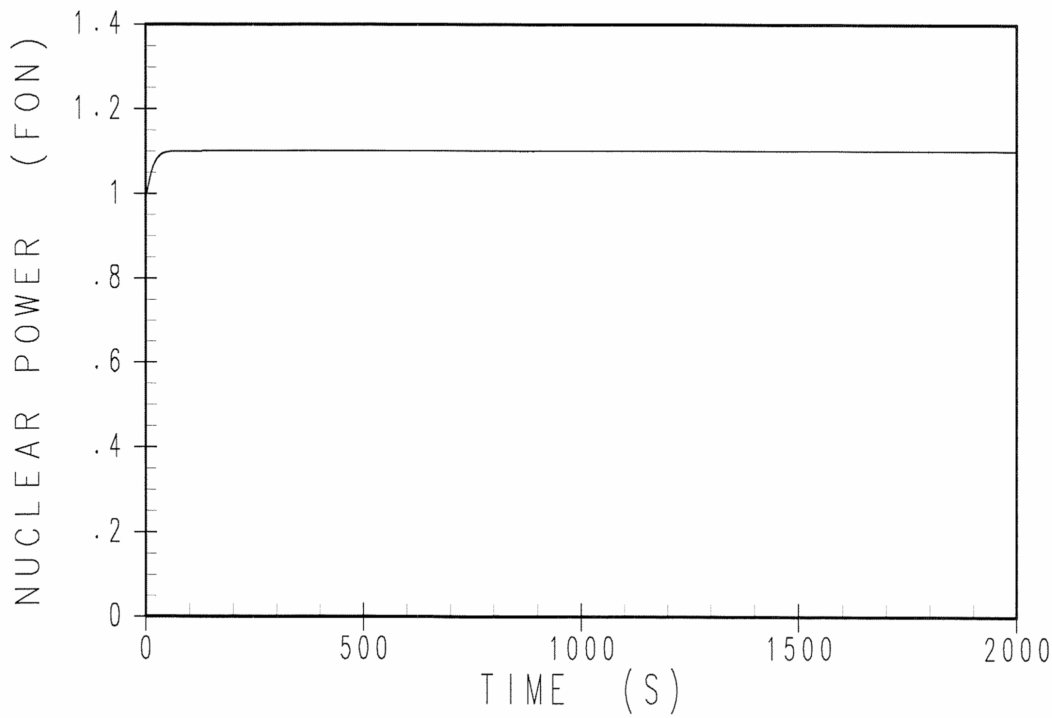

Figure 15.1.3-6

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

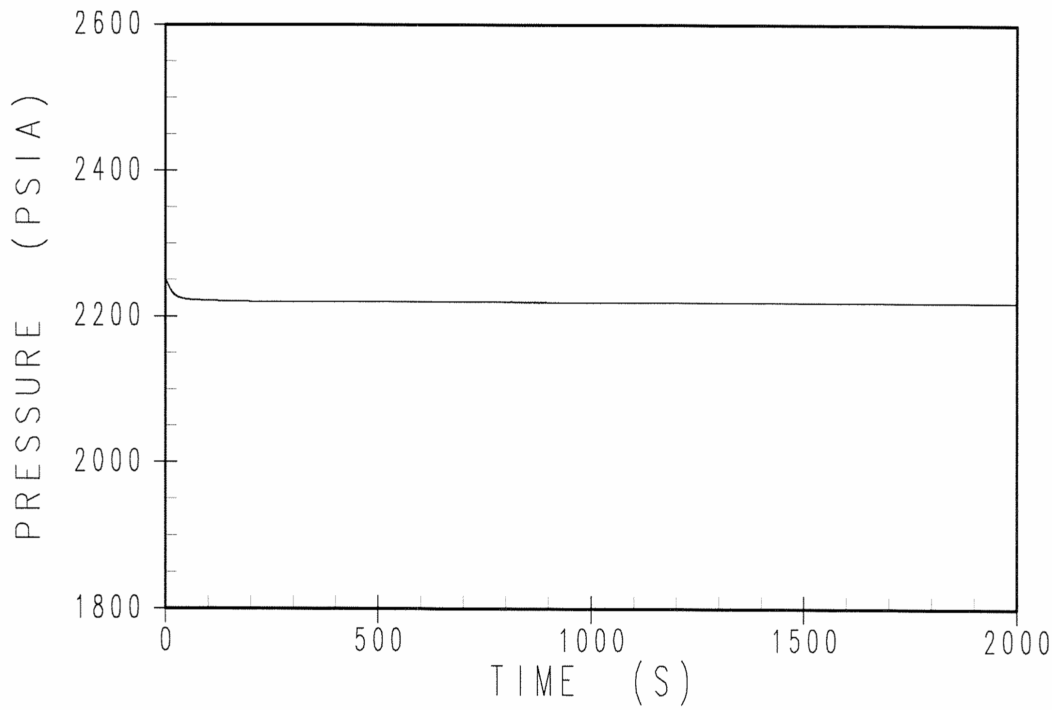

Figure 15.1.3-7

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

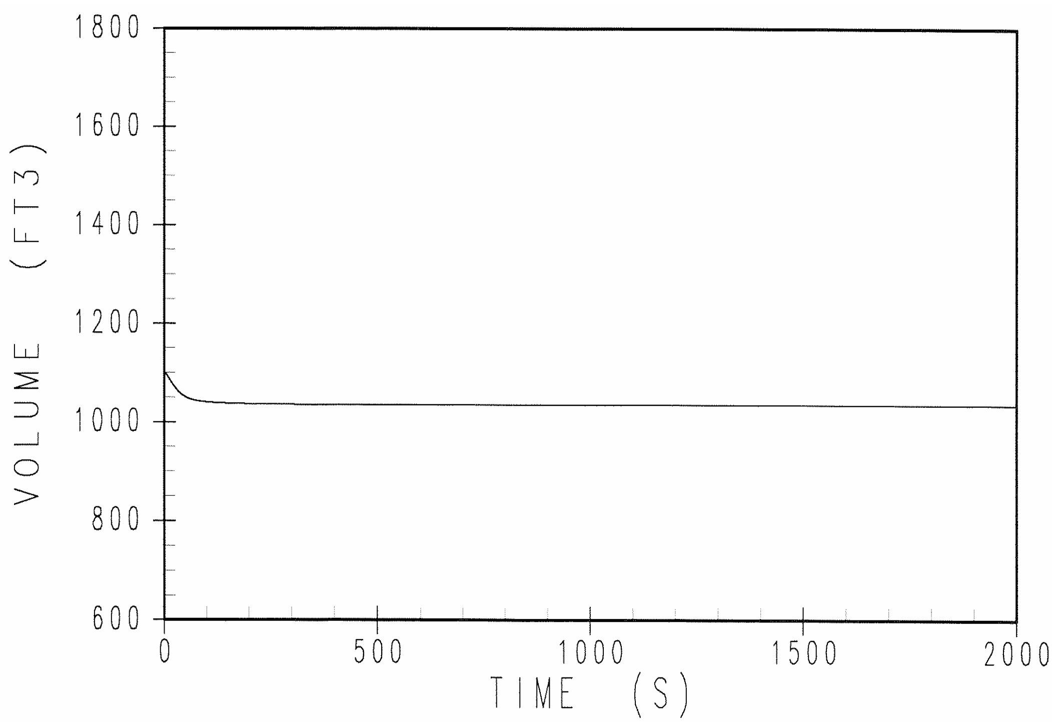

Figure 15.1.3-8

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

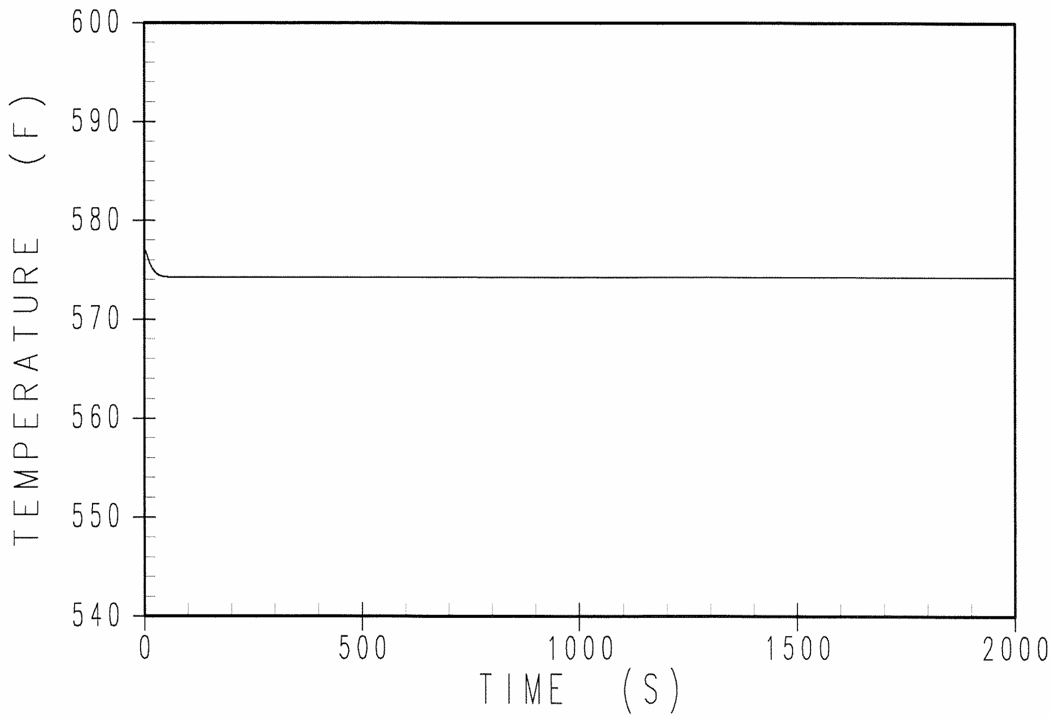

Figure 15.1.3-9

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

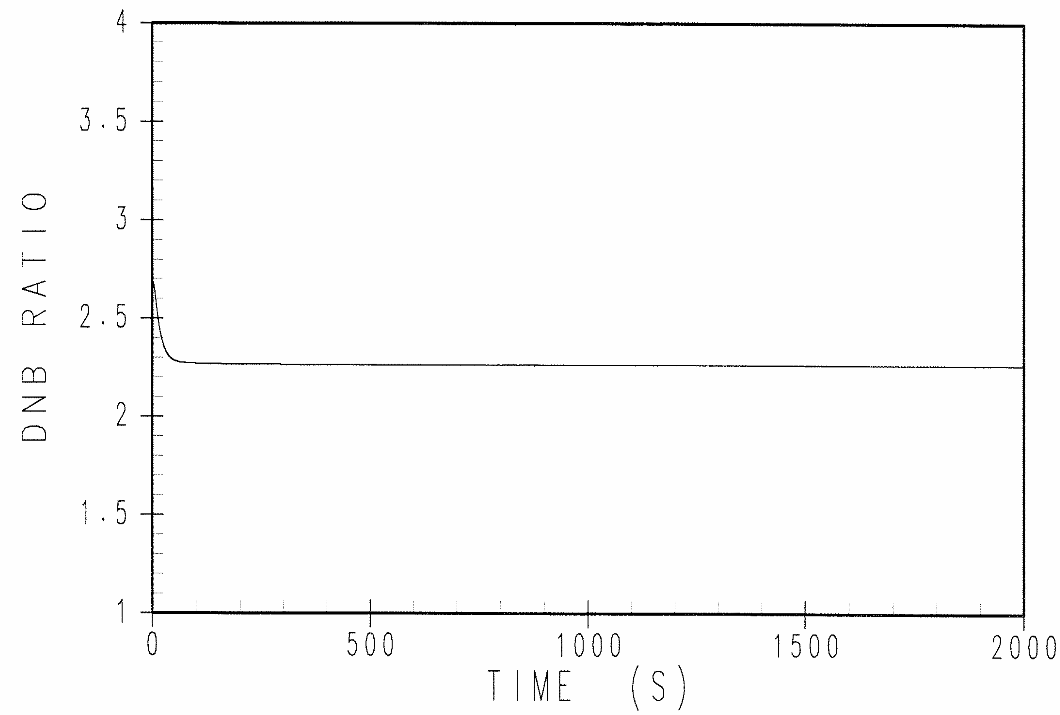

Figure 15.1.3-10

DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

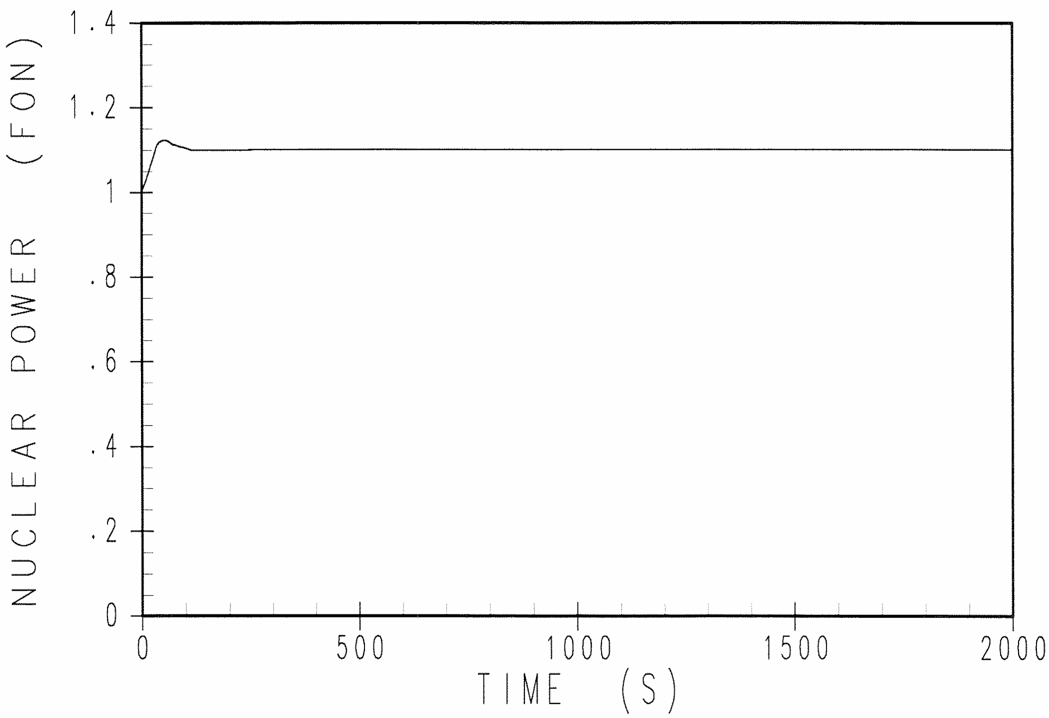

Figure 15.1.3-11

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

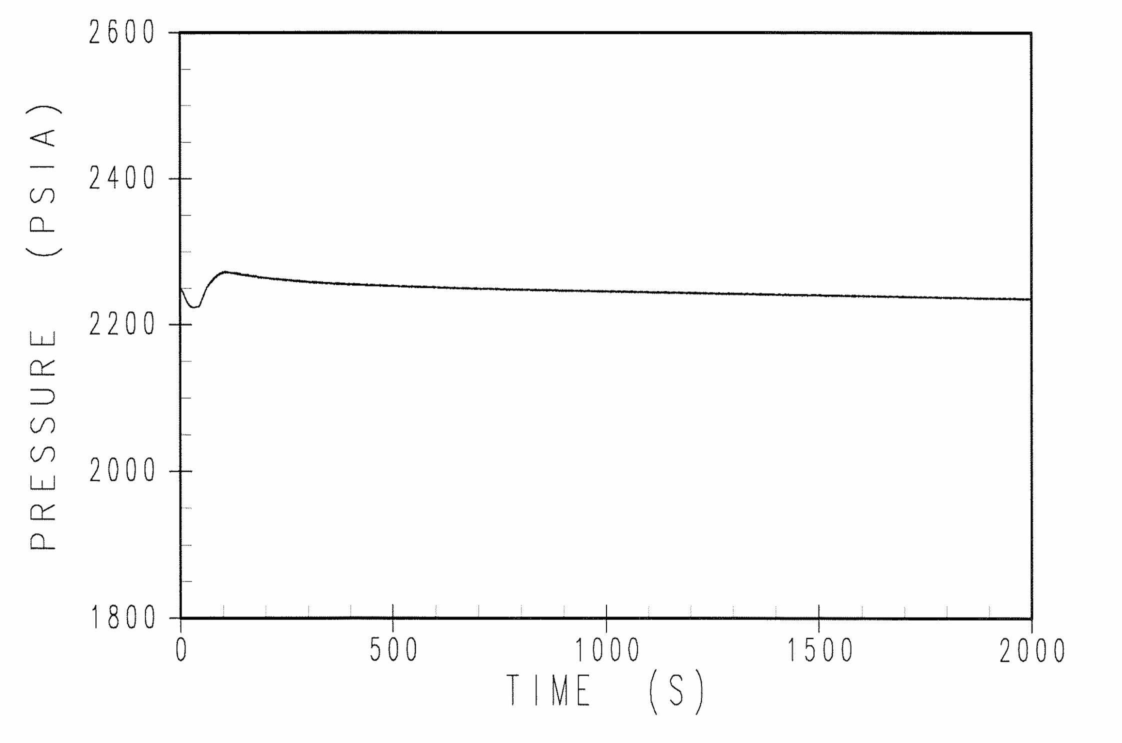

Figure 15.1.3-12

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

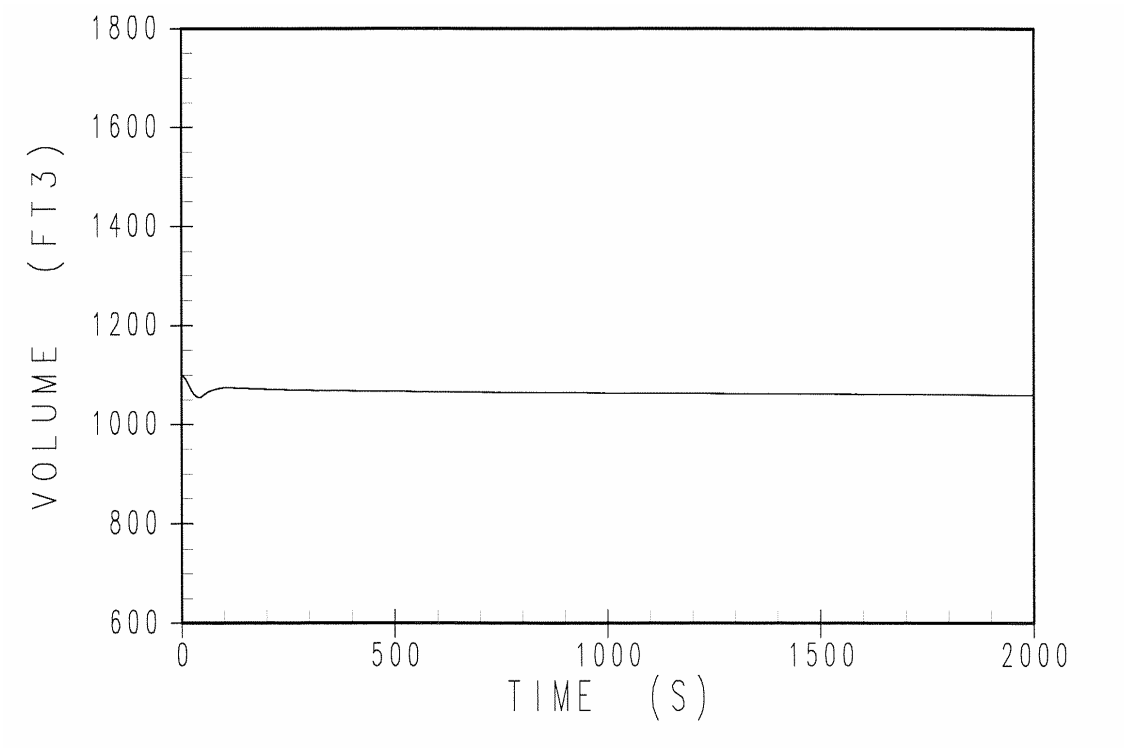

Figure 15.1.3-13

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

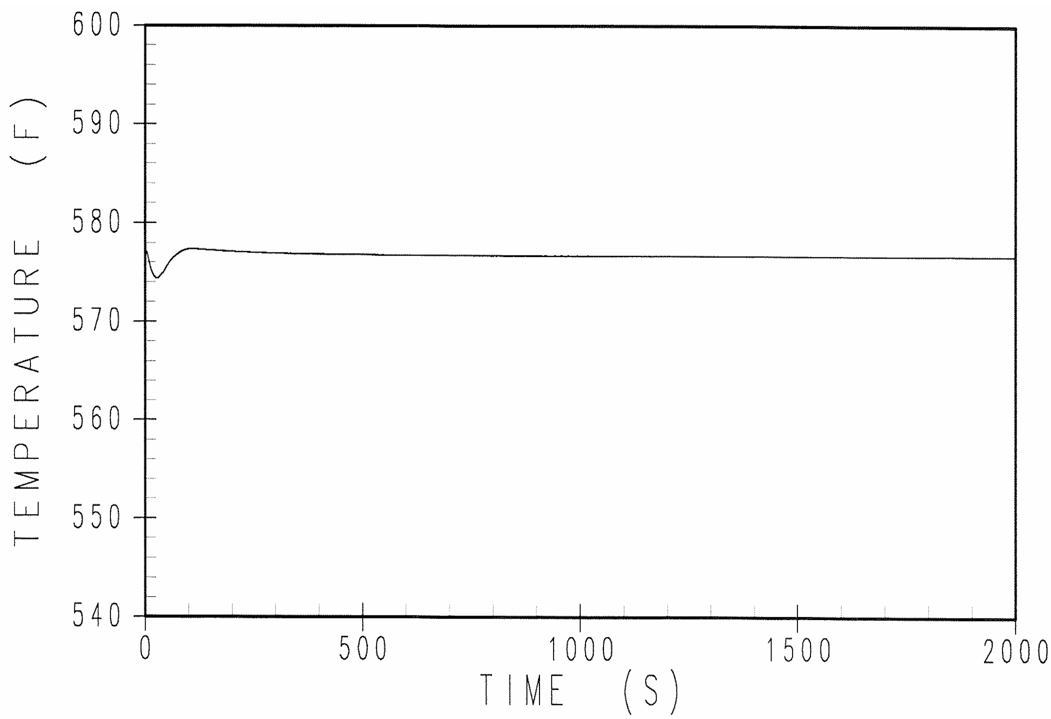

Figure 15.1.3-14

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

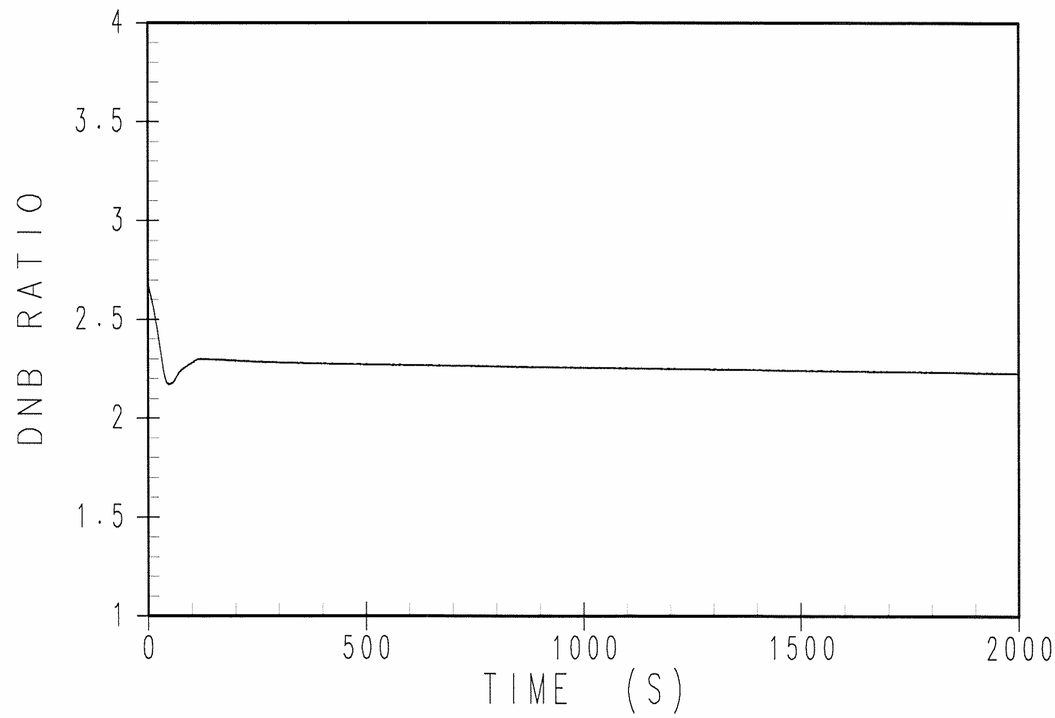

Figure 15.1.3-15

DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

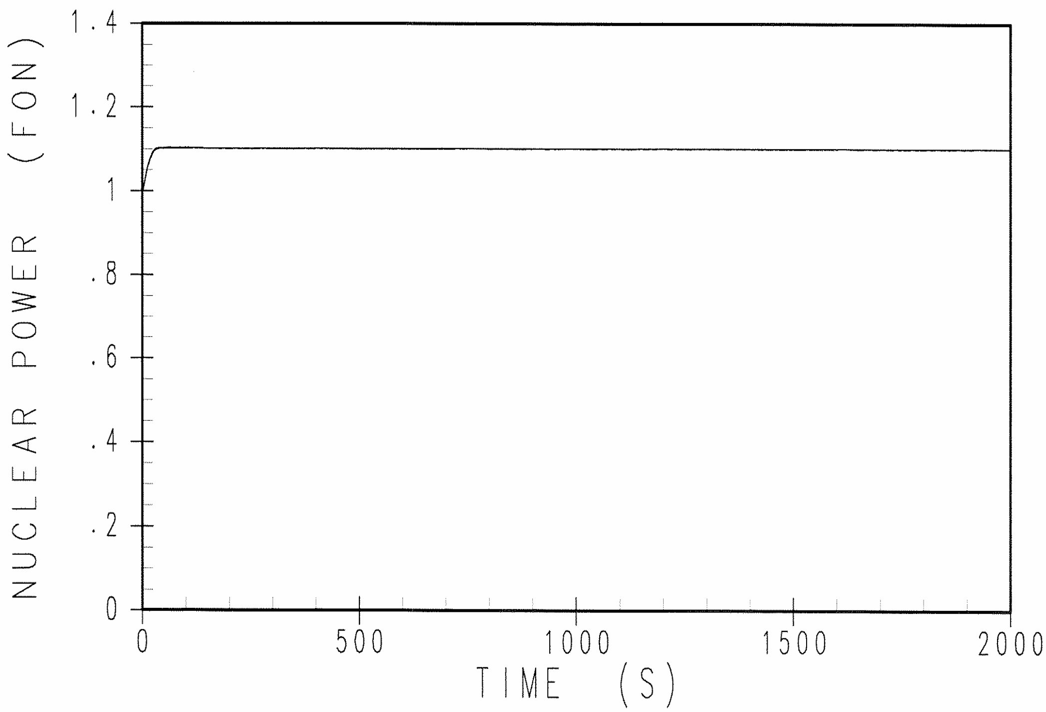

Figure 15.1.3-16

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

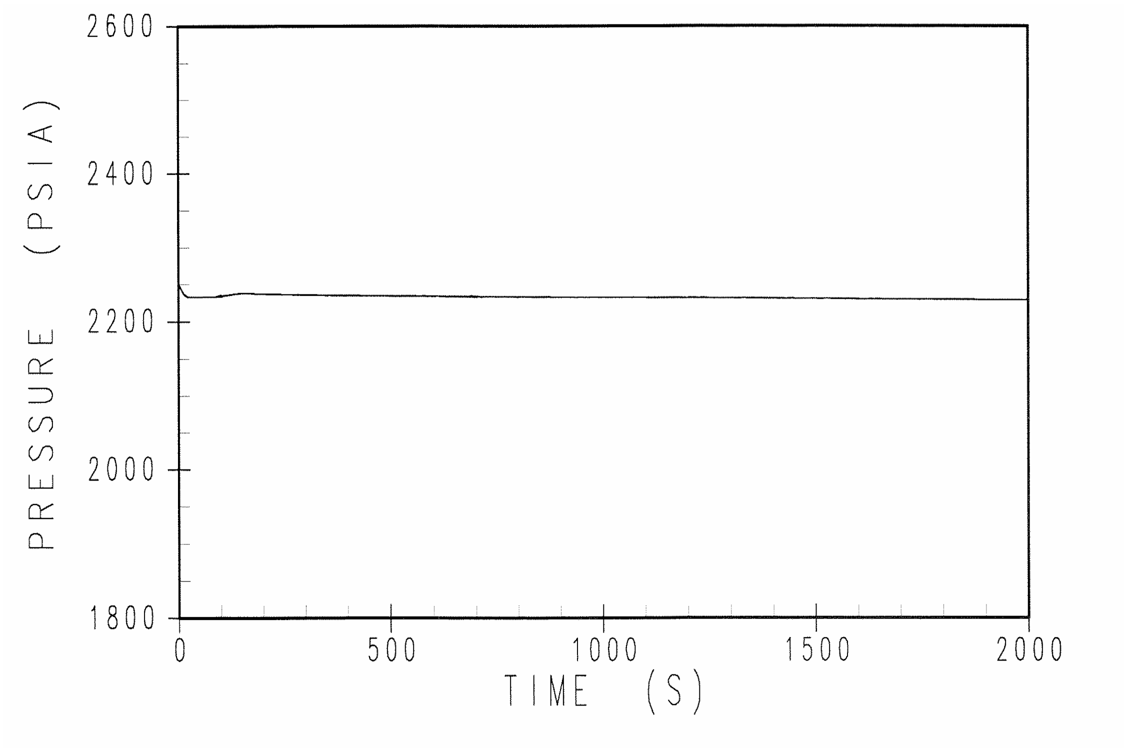

Figure 15.1.3-17

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

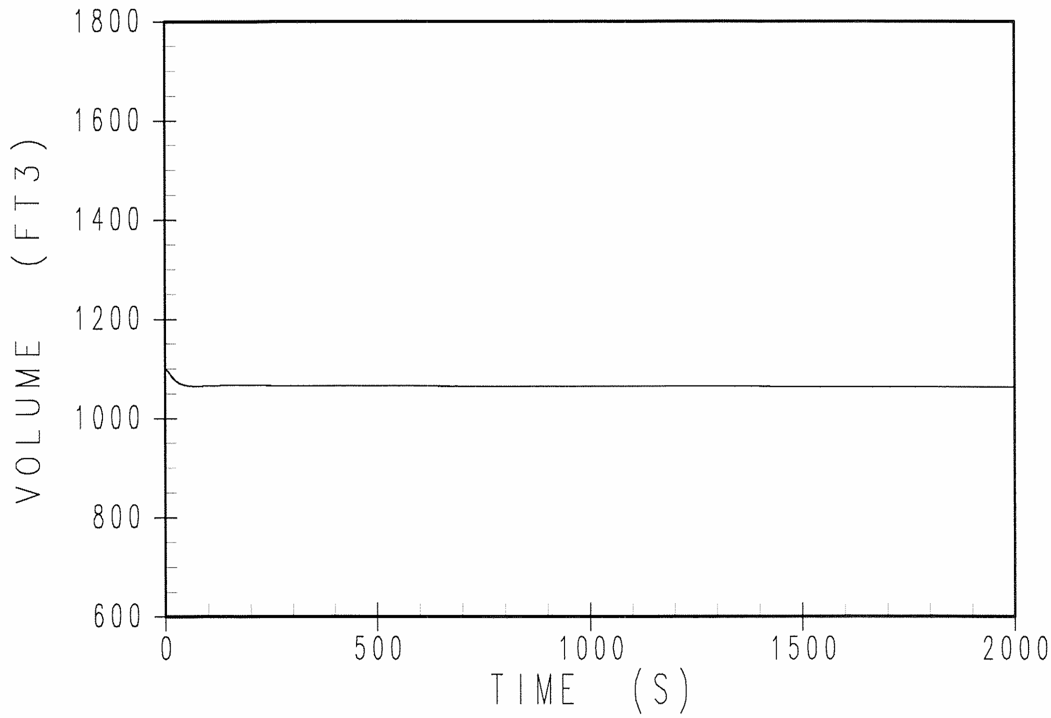

Figure 15.1.3-18

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

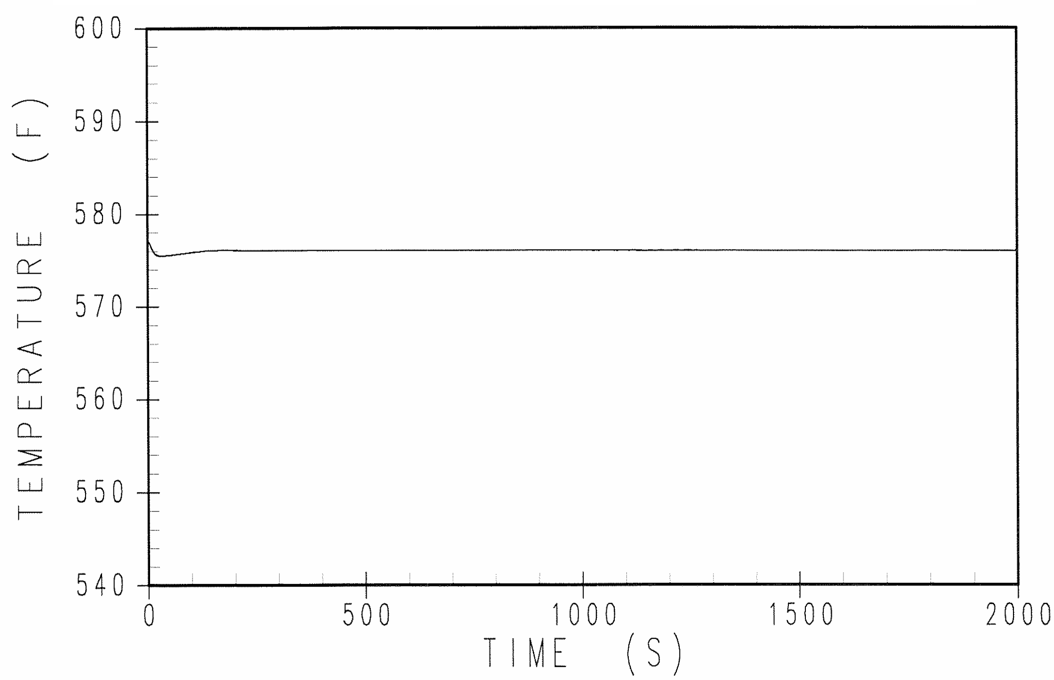

Figure 15.1.3-19

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

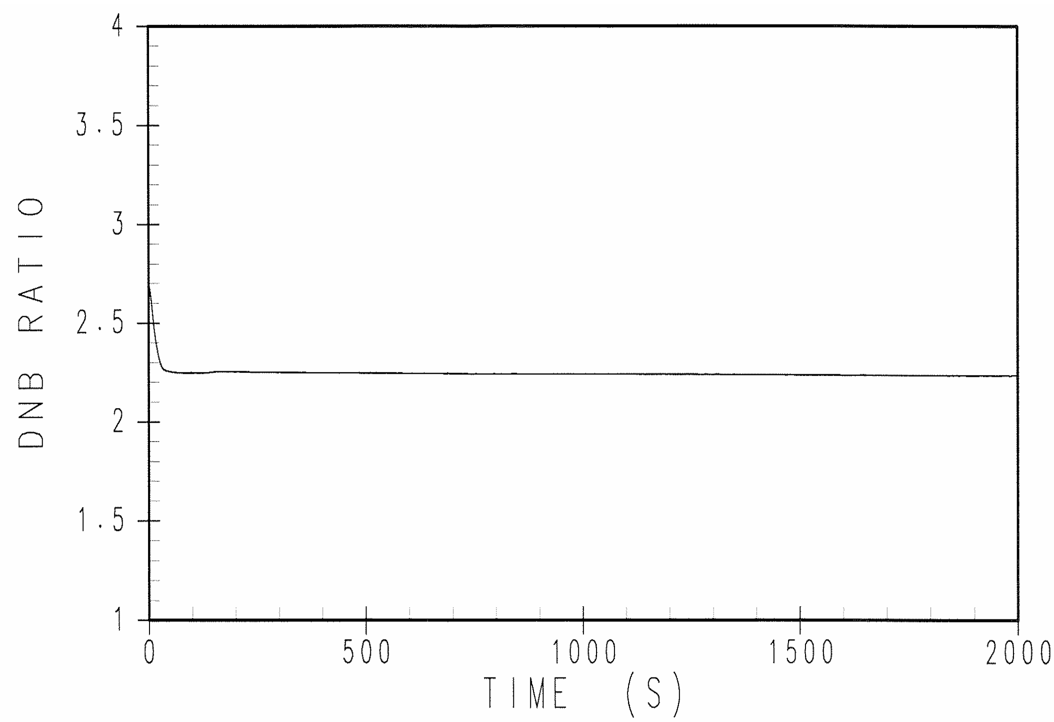

Figure 15.1.3-20

DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

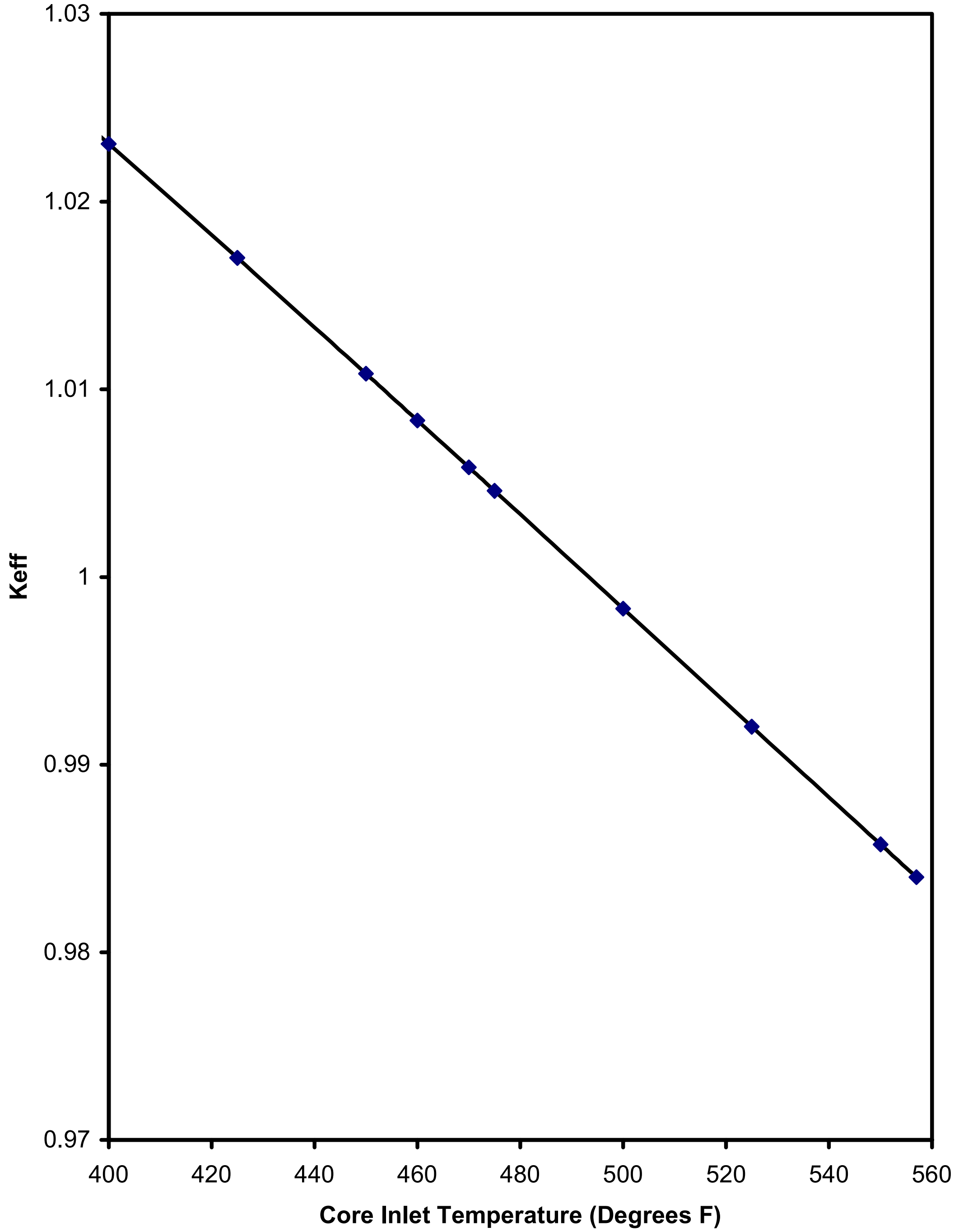

Figure 15.1.4-1

K_{eff} Versus Core Inlet Temperature Steam Line Break Events

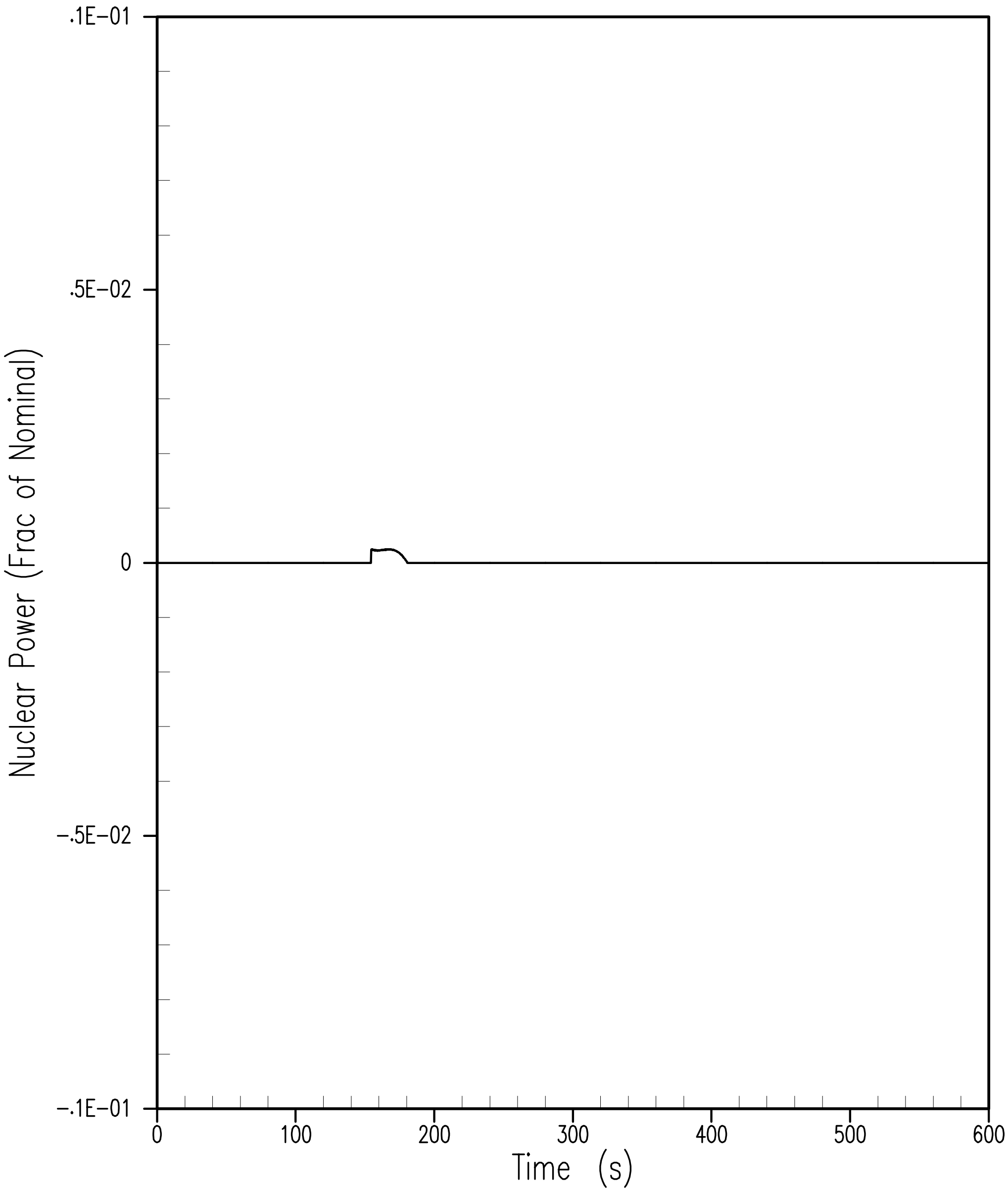

Figure 15.1.4-2

Nuclear Power Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

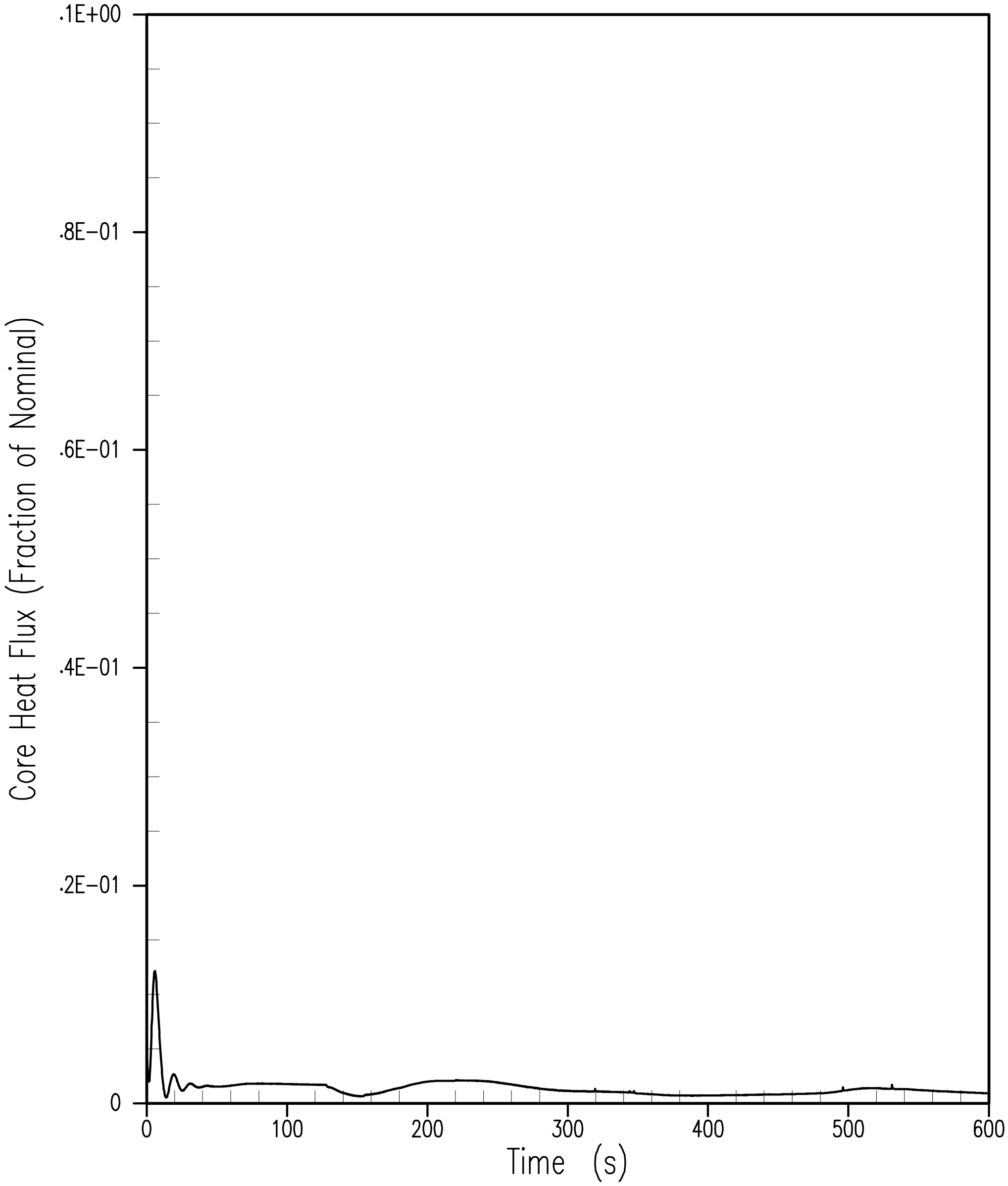

Figure 15.1.4-3

Core Heat Flux Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

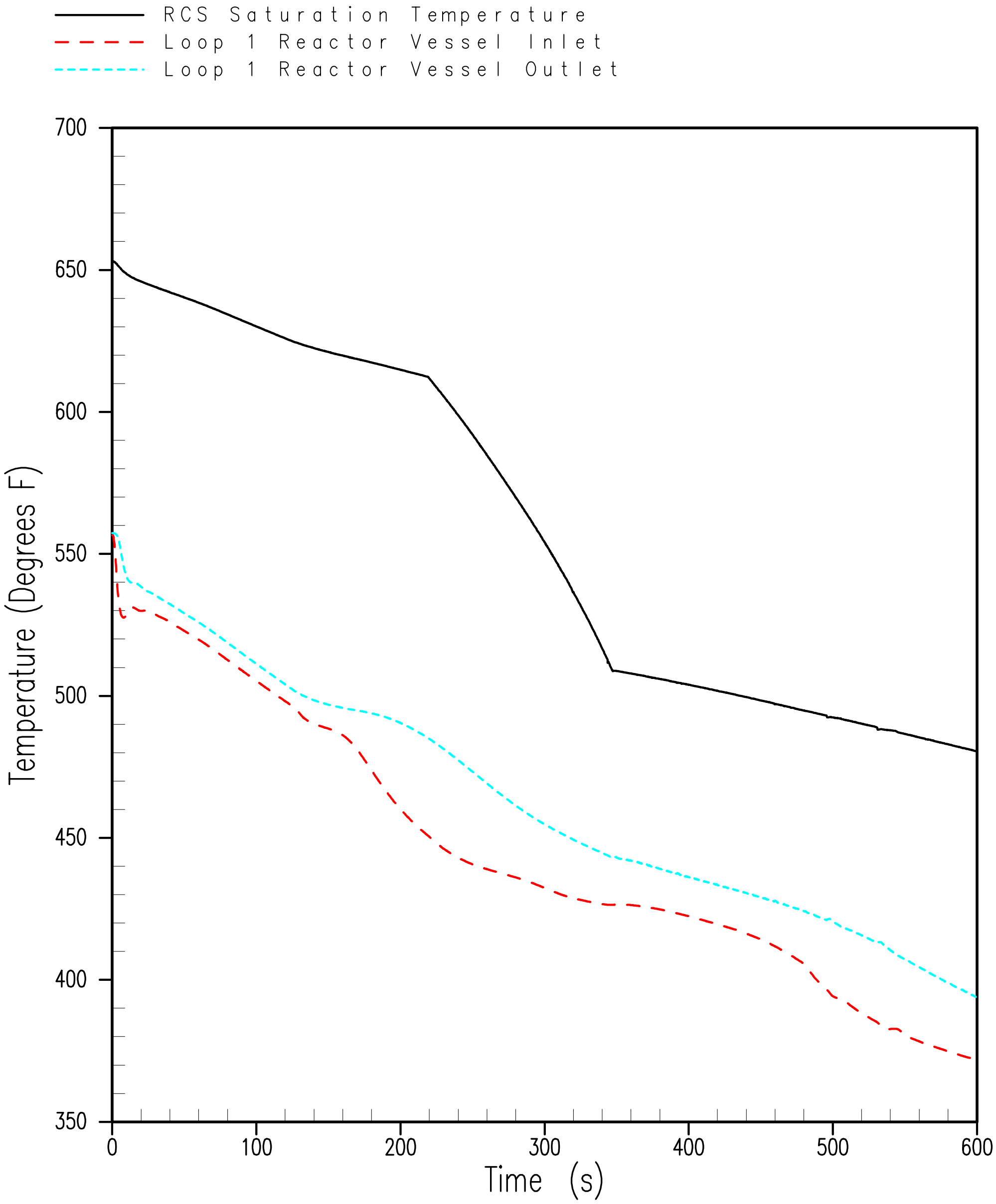

Figure 15.1.4-4

Loop 1 Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

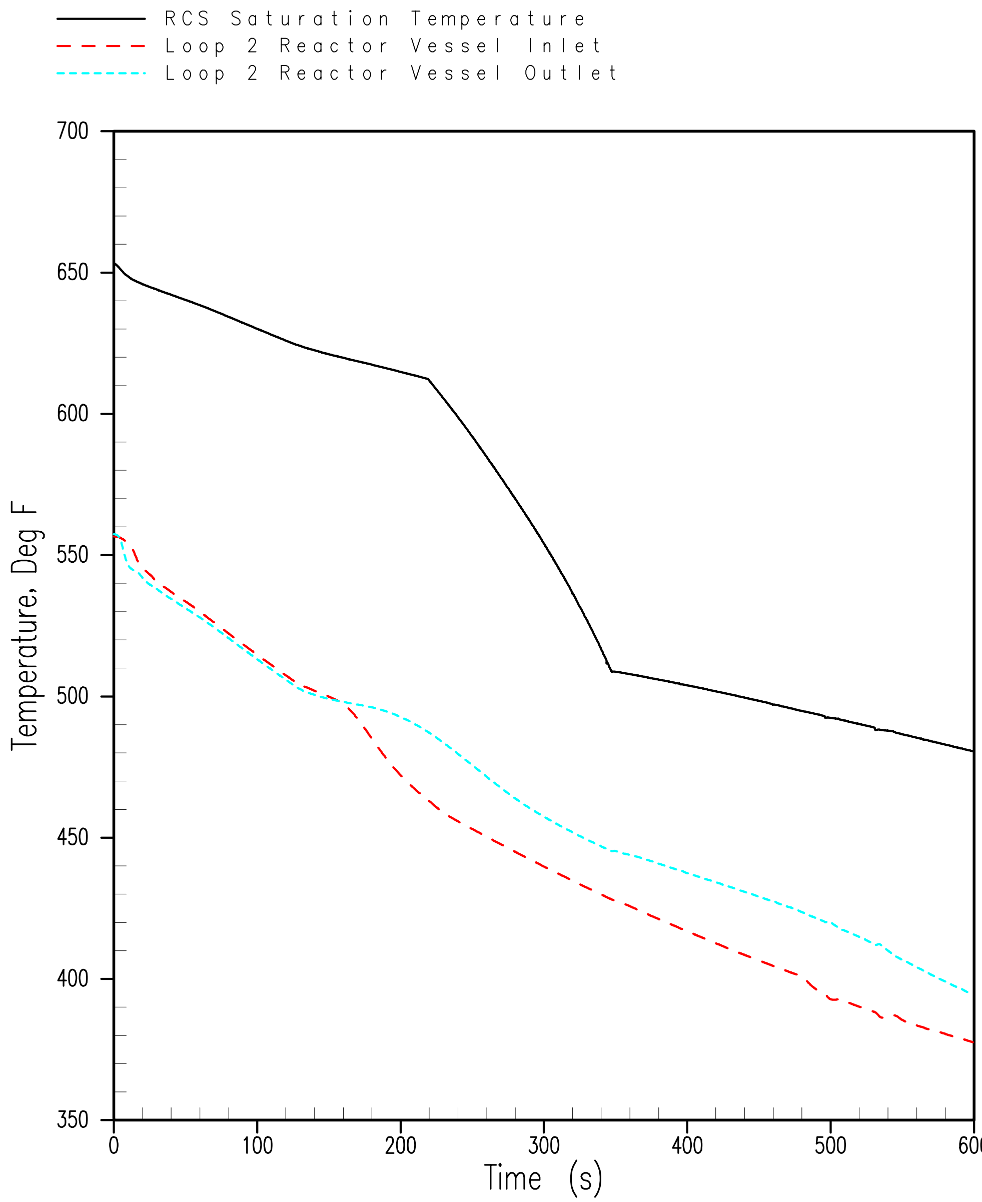

Figure 15.1.4-5

Loop 2 (Faulted Loop) Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

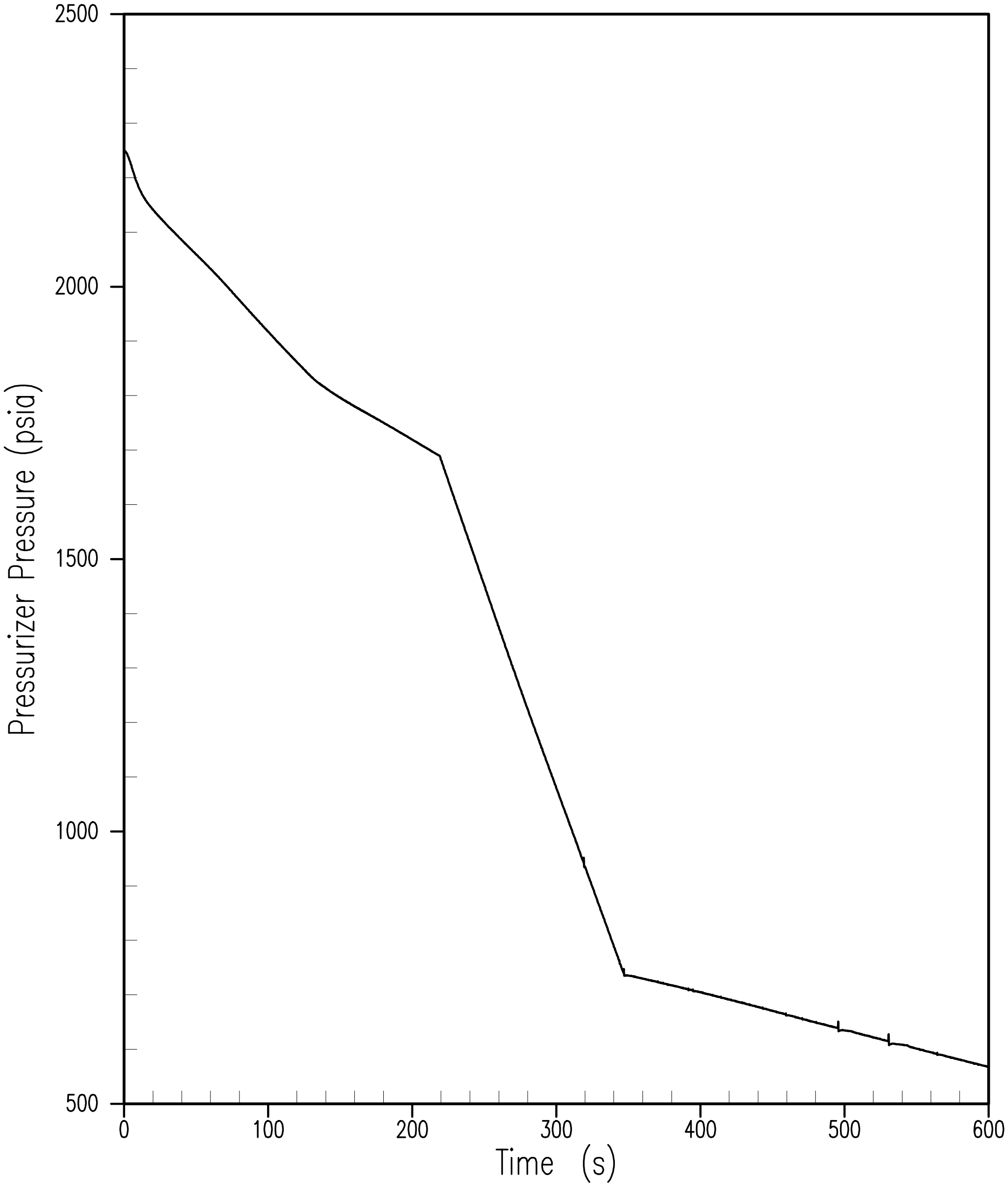

Figure 15.1.4-6

Reactor Coolant System Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

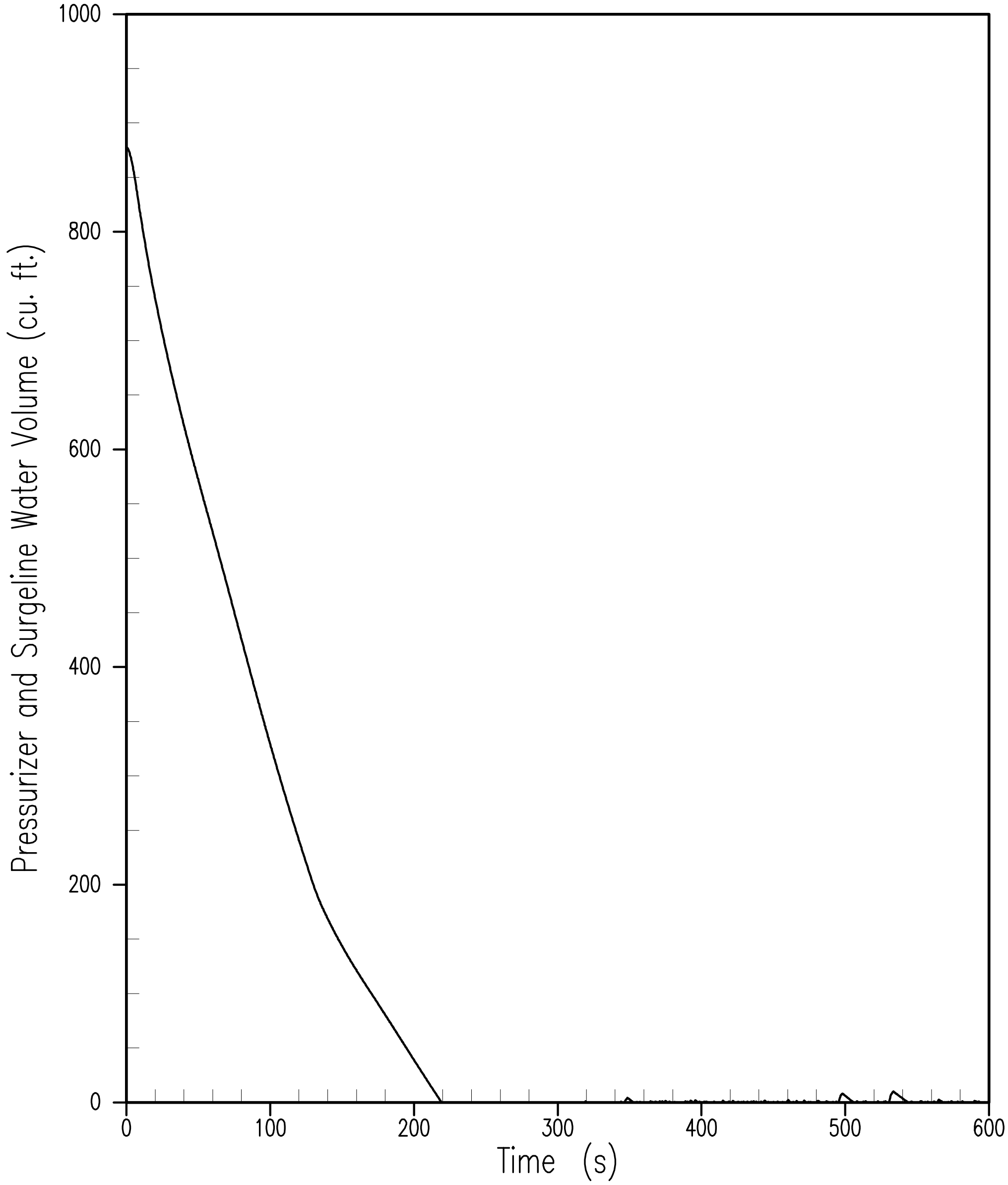

Figure 15.1.4-7

Pressurizer Water Volume Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

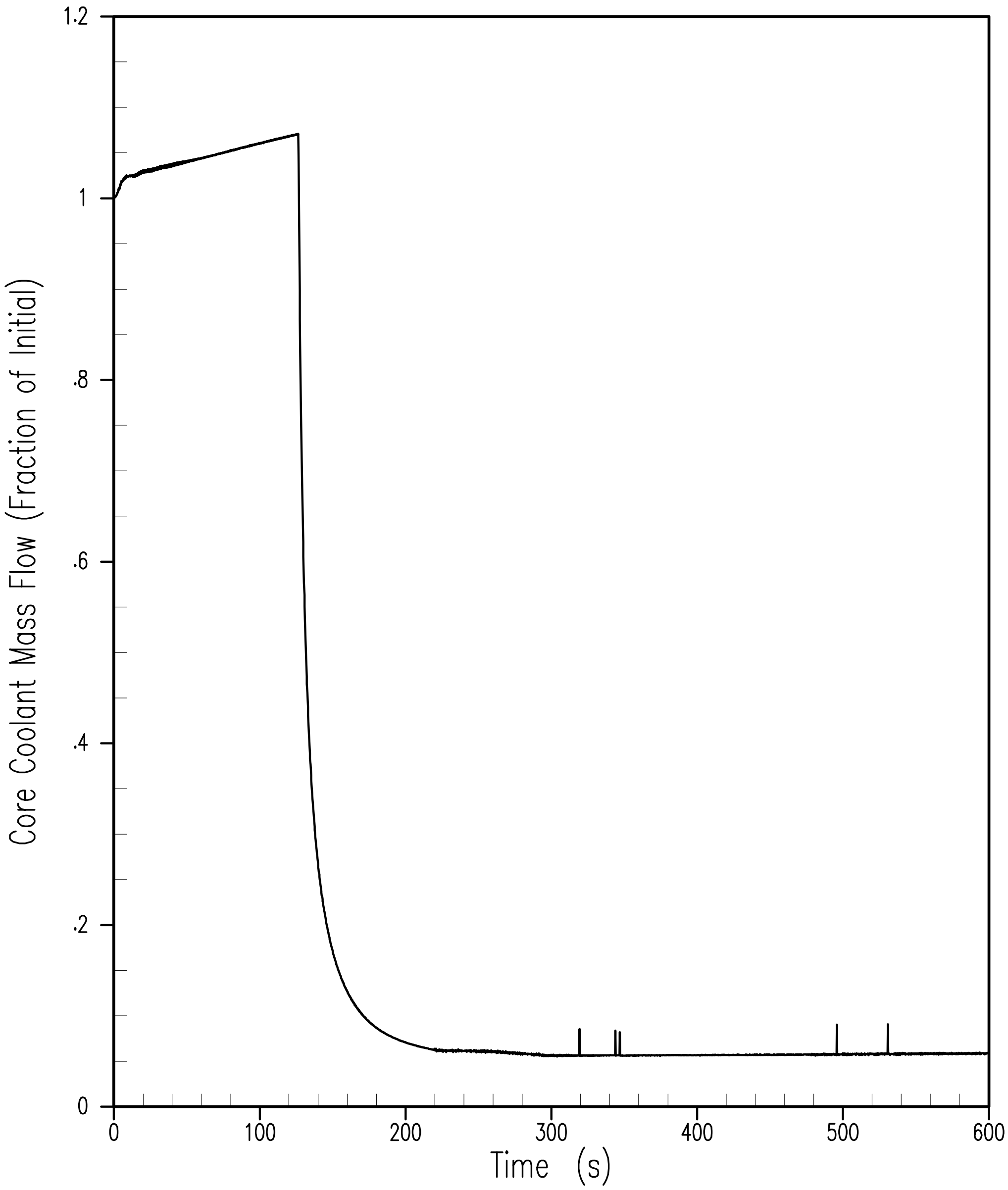

Figure 15.1.4-8

Core Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

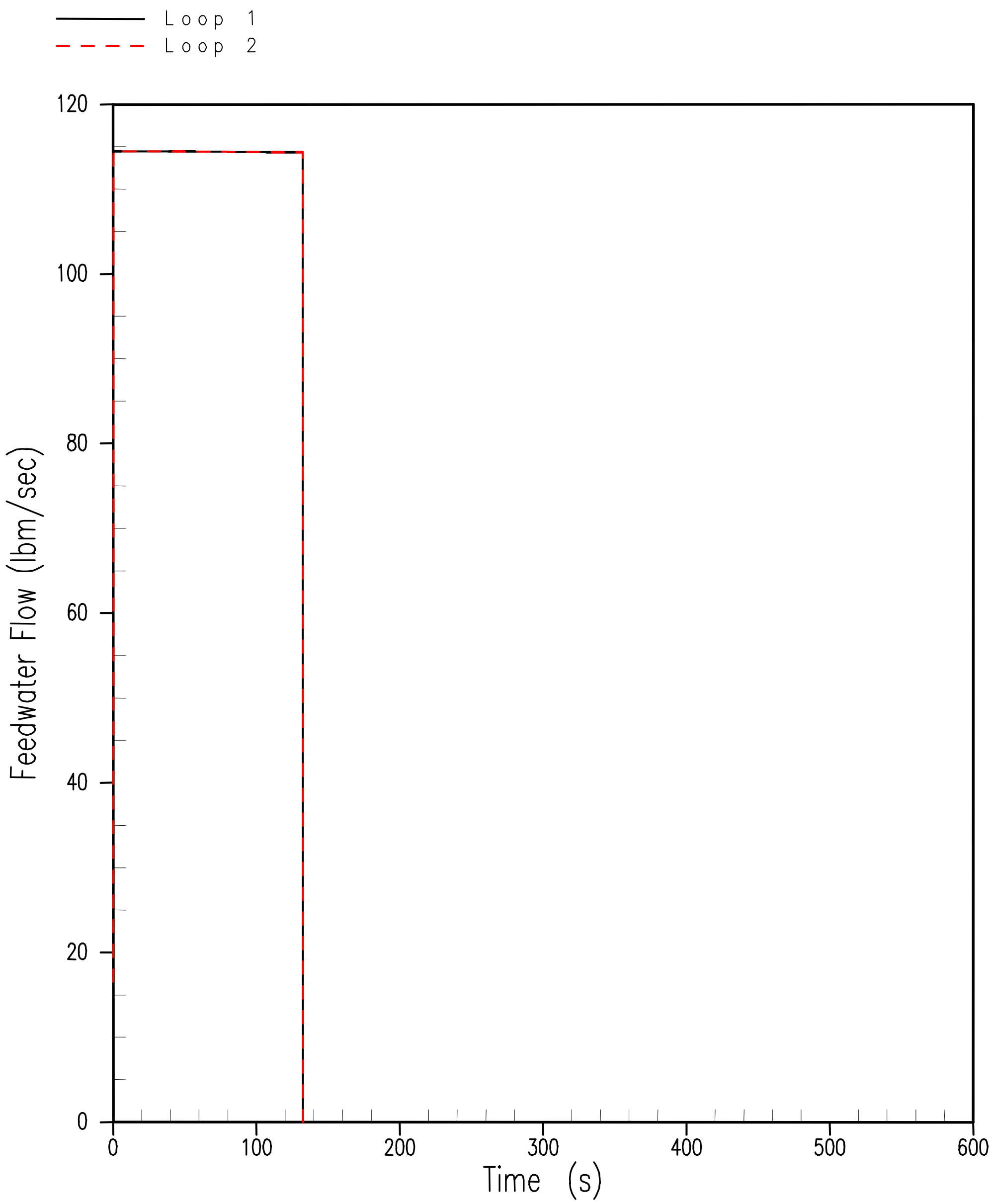

Figure 15.1.4-9

Feedwater Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

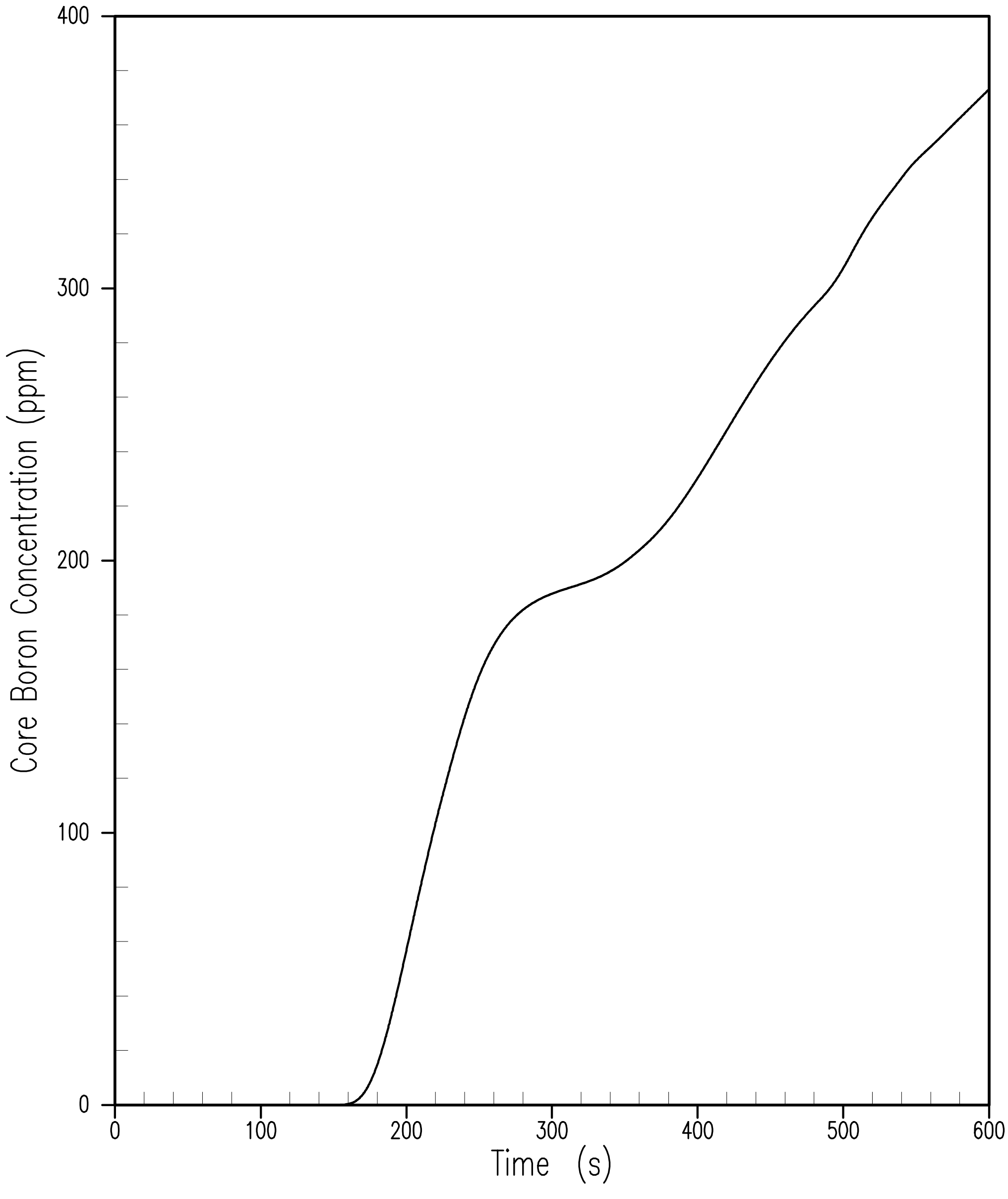

Figure 15.1.4-10

Core Boron Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

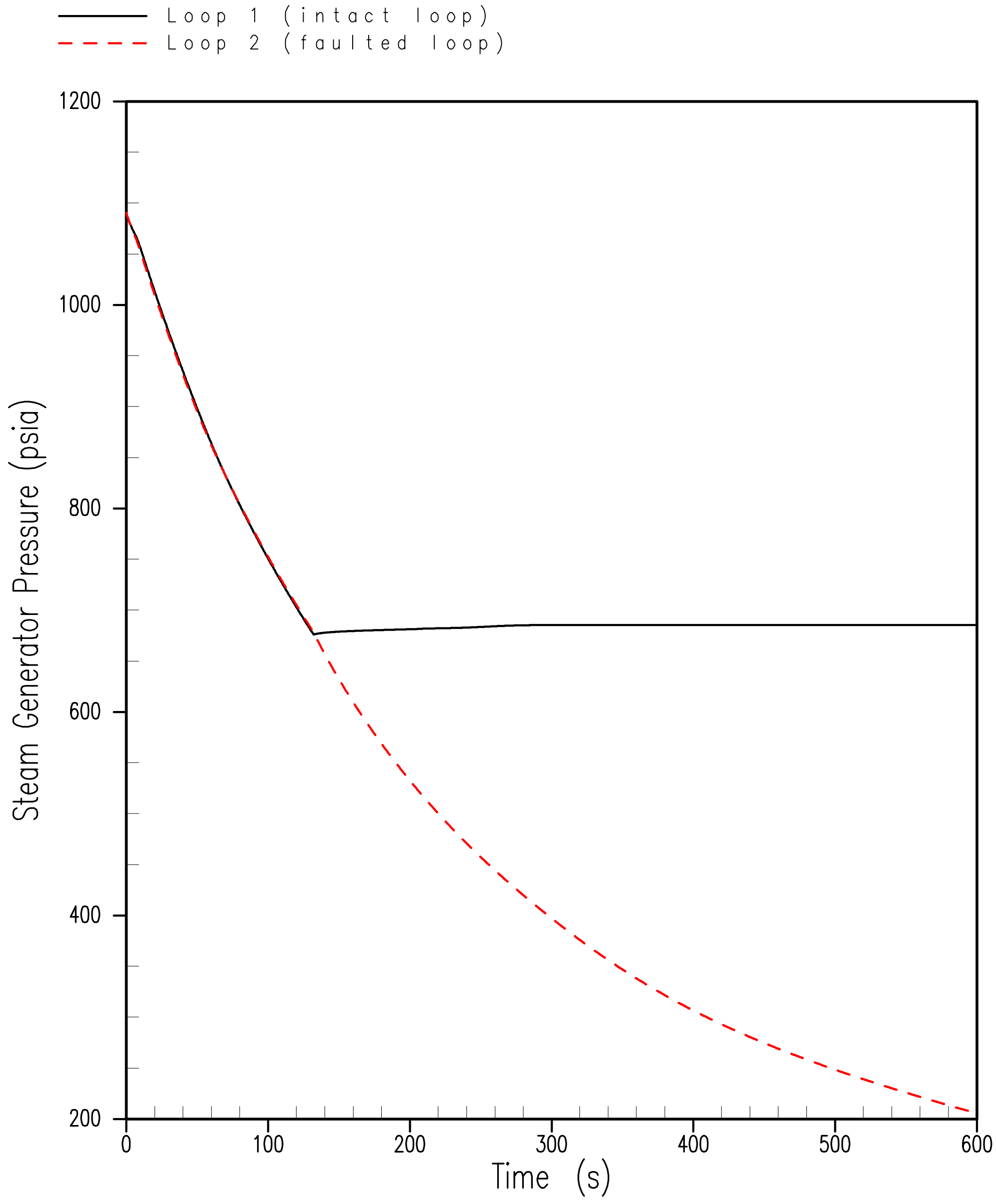

Figure 15.1.4-11

Steam Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

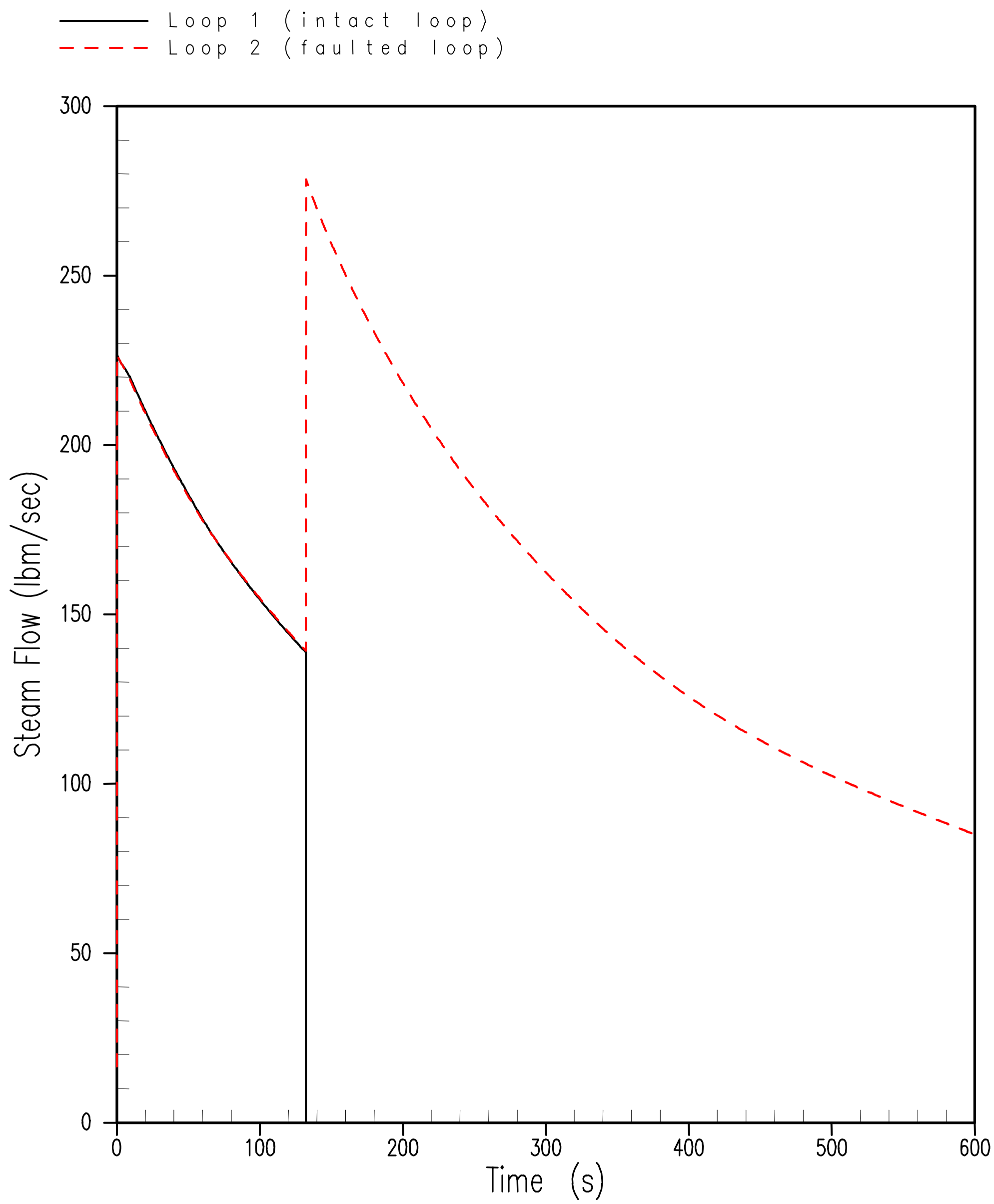

Figure 15.1.4-12

Steam Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

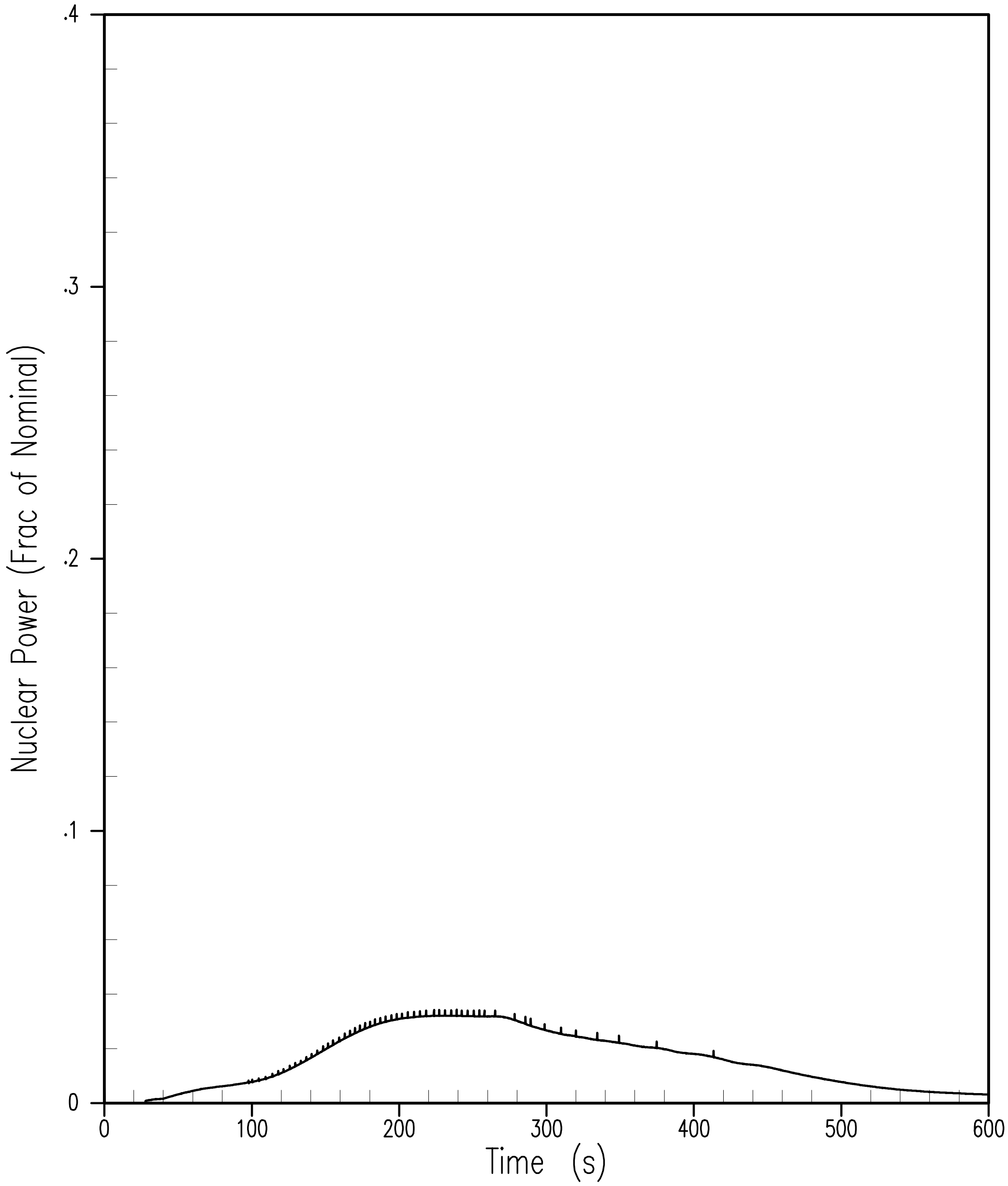

Figure 15.1.5-1

Nuclear Power Transient Steam System Piping Feature

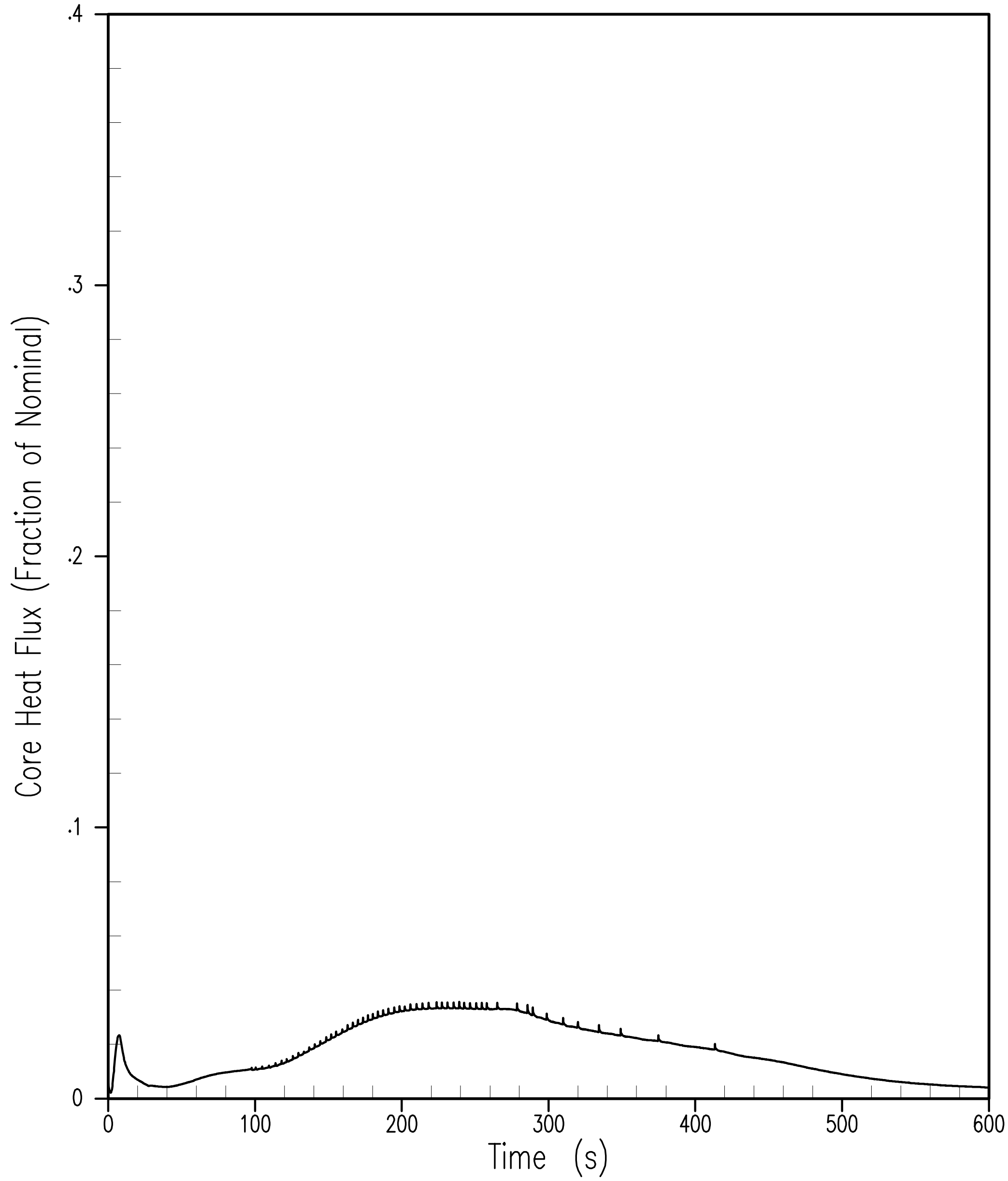

Figure 15.1.5-2

Core Heat Flux Transient Steam System Piping Failure

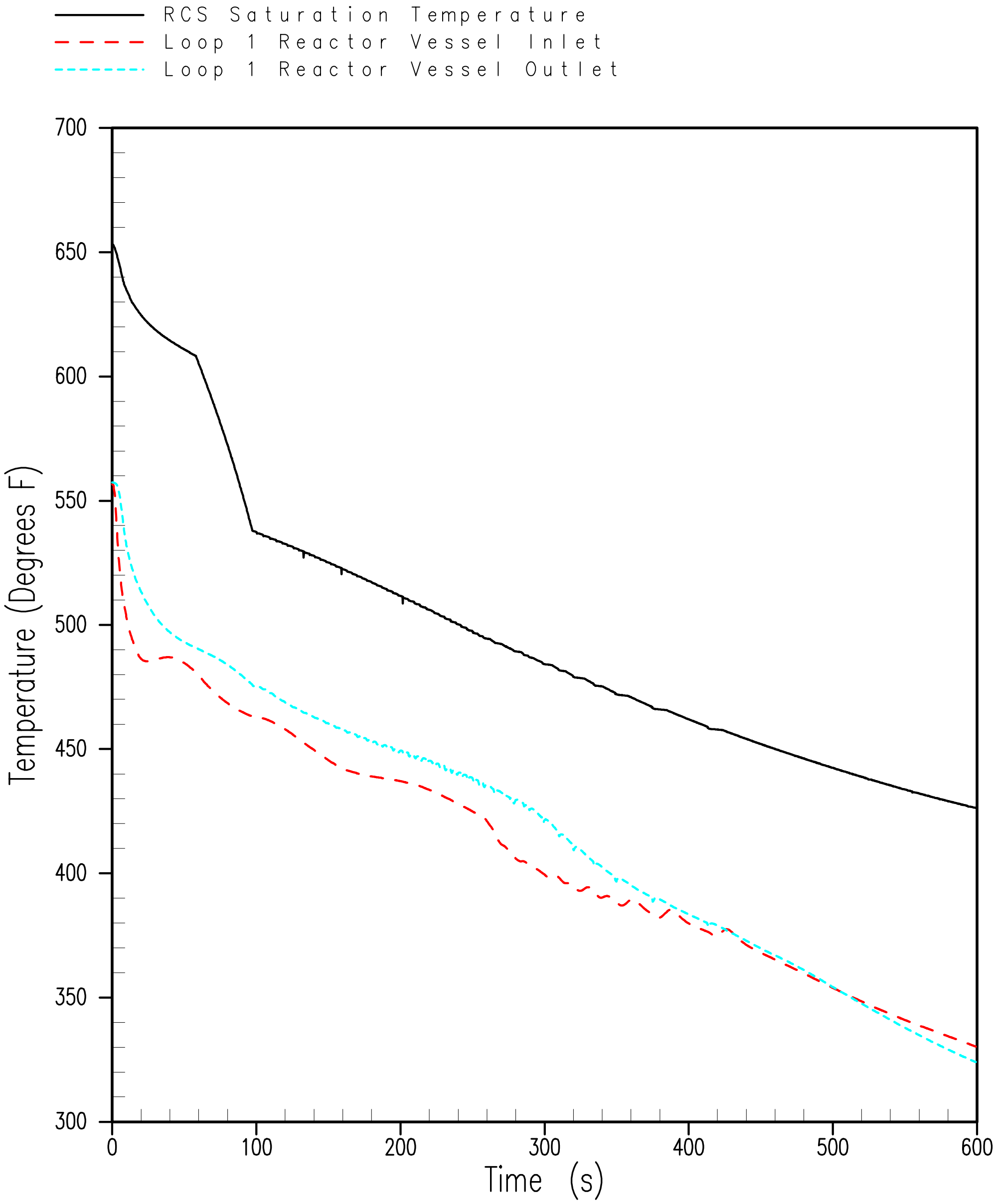

Figure 15.1.5-3

**Loop 1 Reactor Coolant Temperatures
Steam System Piping Failure**

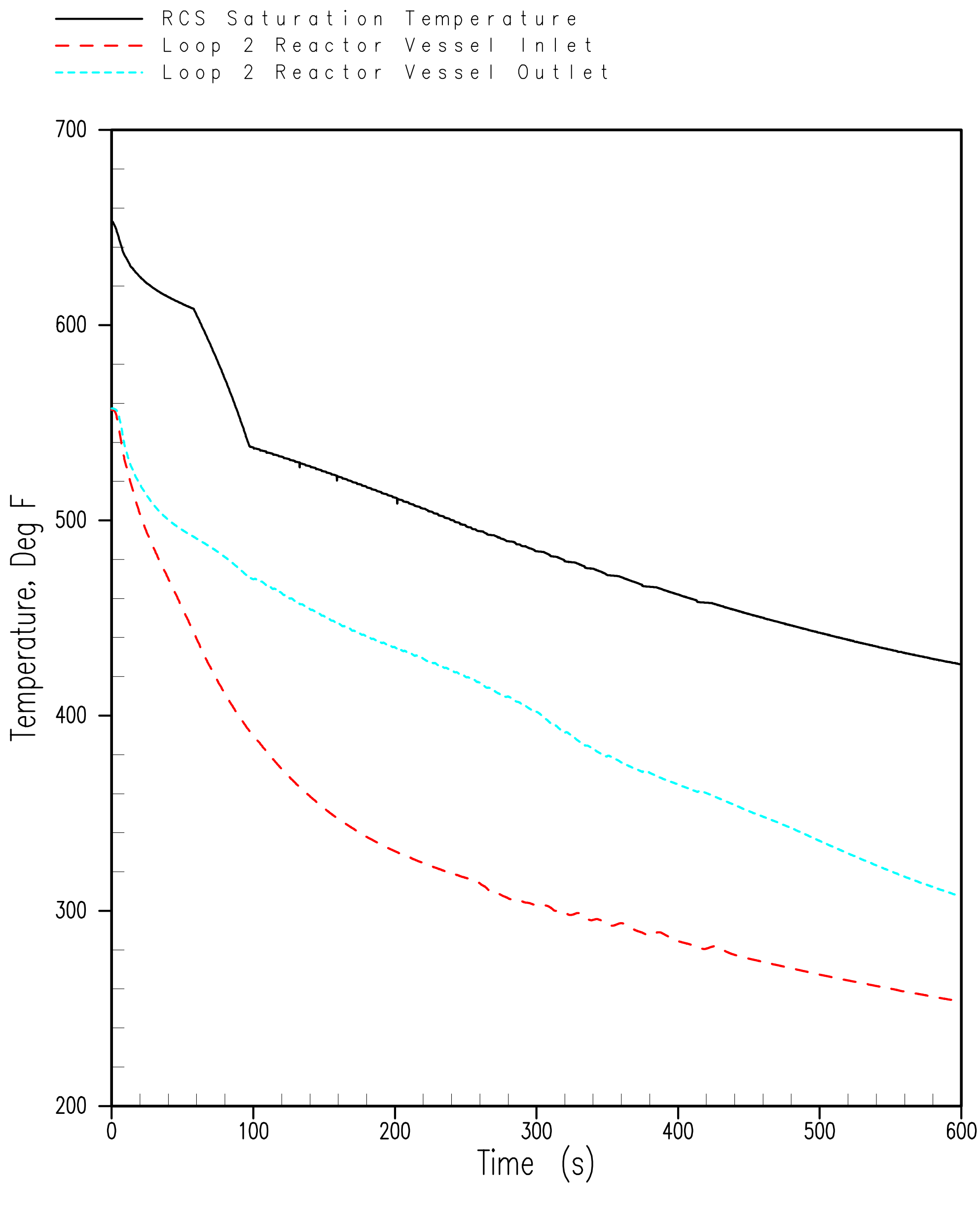

Figure 15.1.5-4

Loop 2 Reactor Coolant Temperatures
Steam System Piping Failure

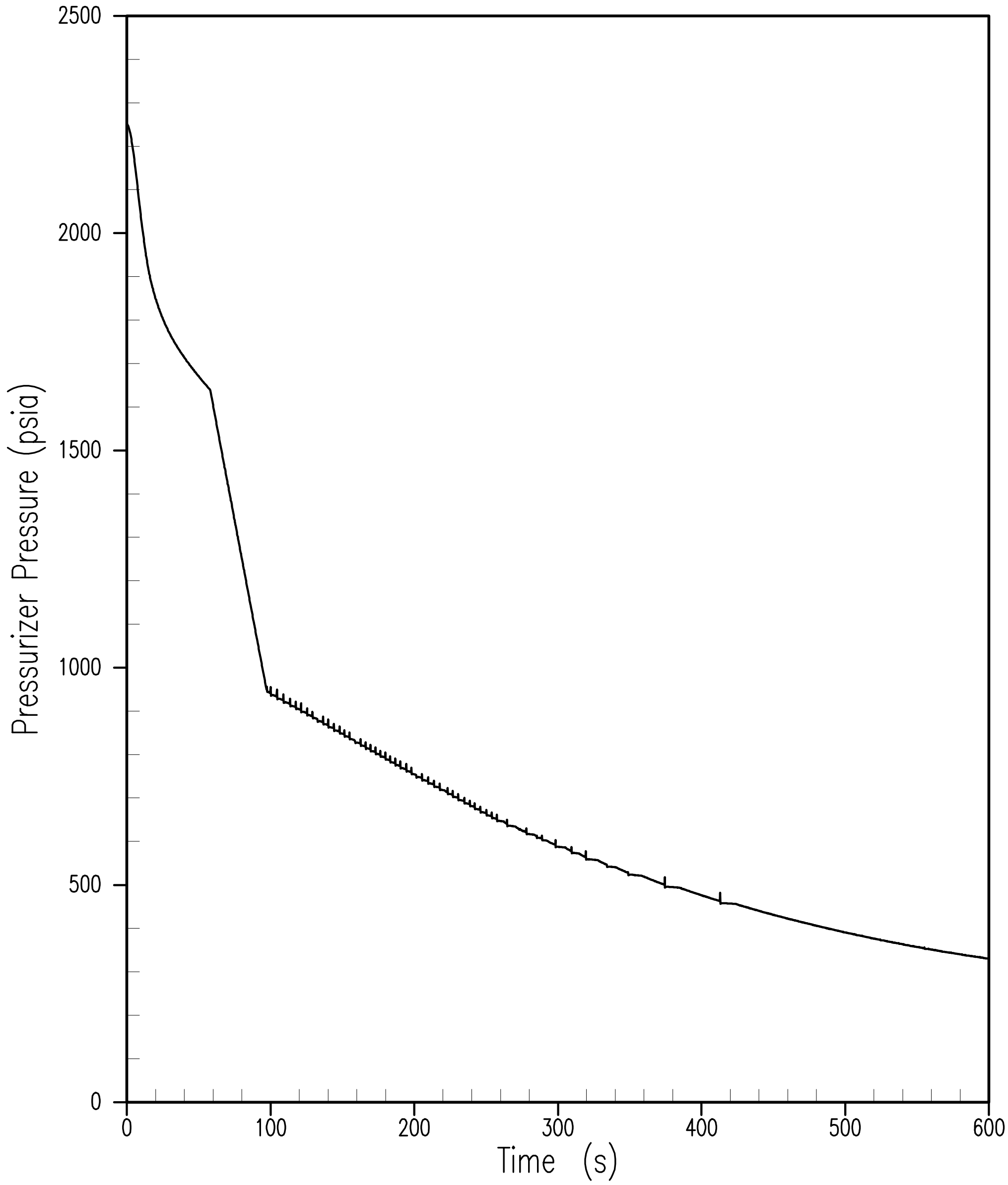

Figure 15.1.5-5

Reactor Coolant System Pressure Transient
Steam System Piping Failure

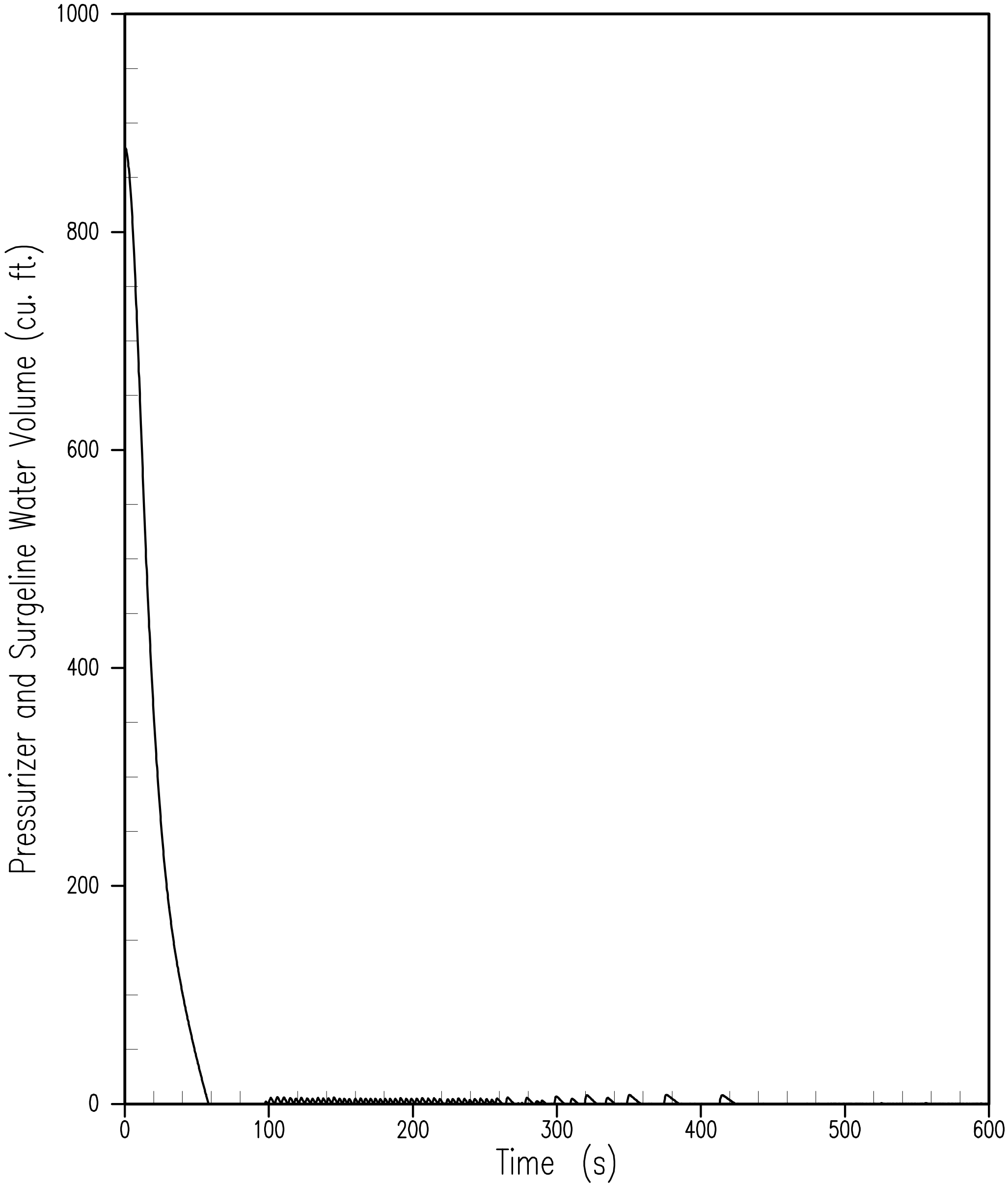

Figure 15.1.5-6

Pressurizer Water Volume Transient
Steam System Piping Failure

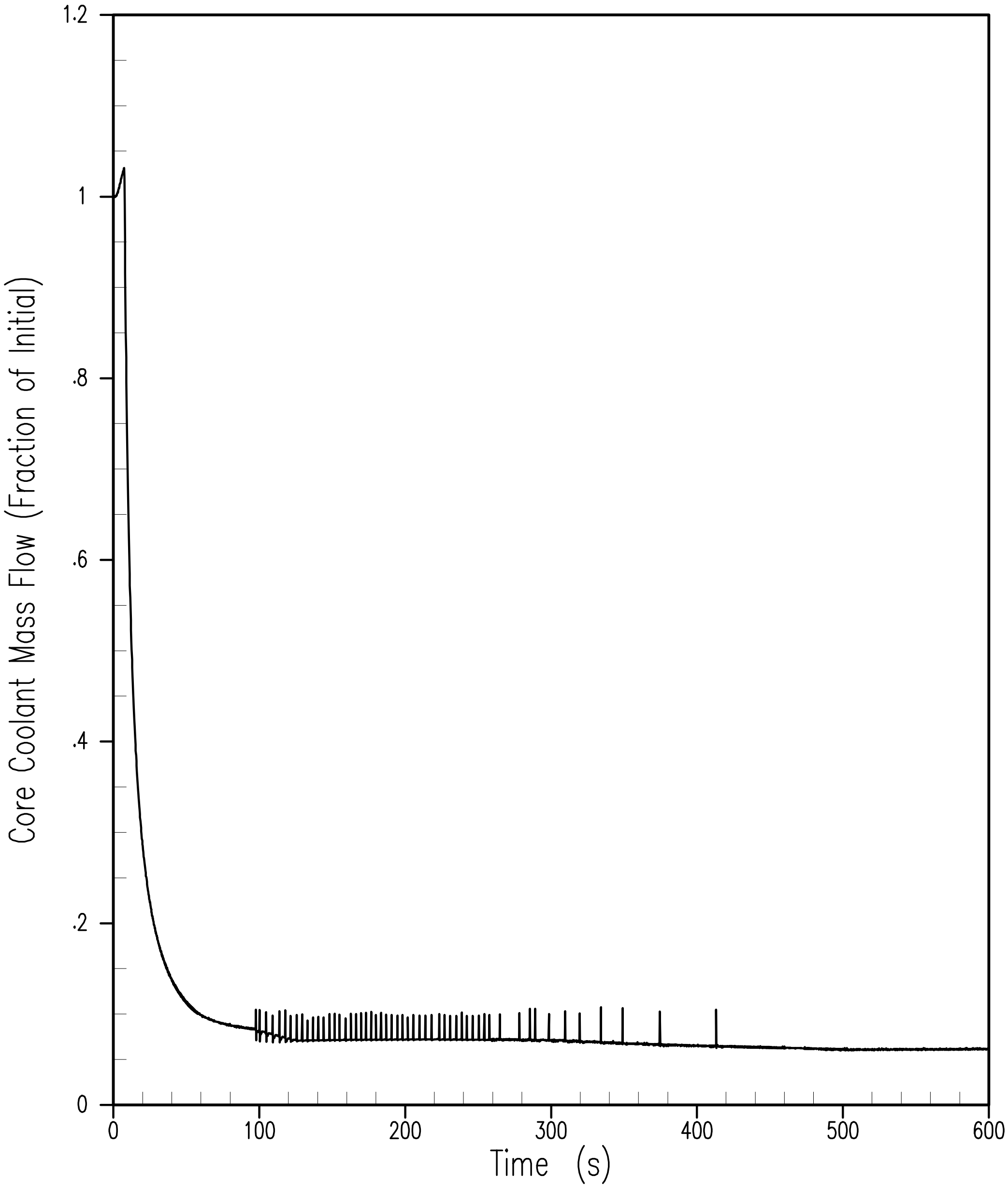

Figure 15.1.5-7

Core Flow Transient Steam System Piping Failure

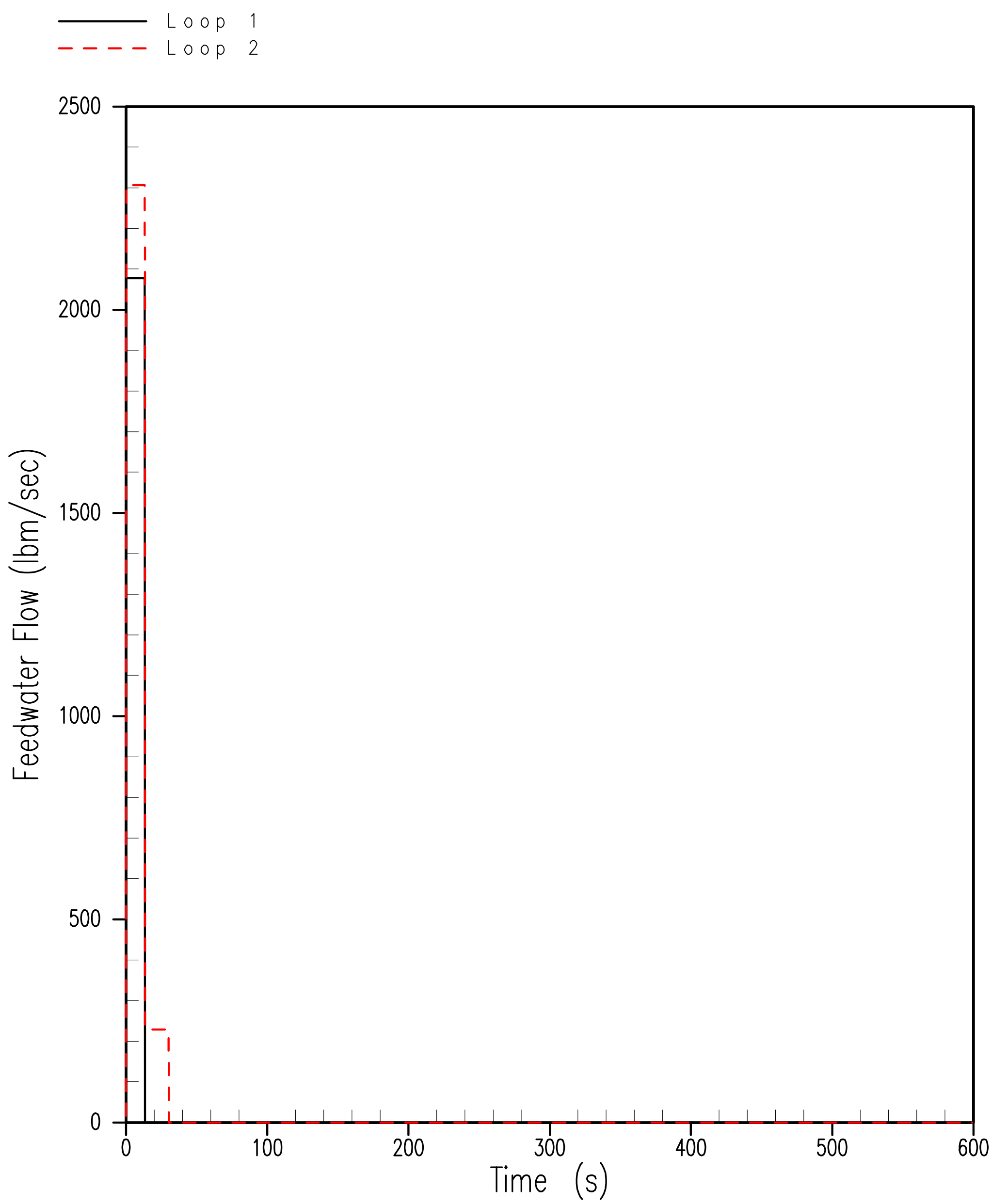

Figure 15.1.5-8

Feedwater Flow Transient Steam System Piping Failure

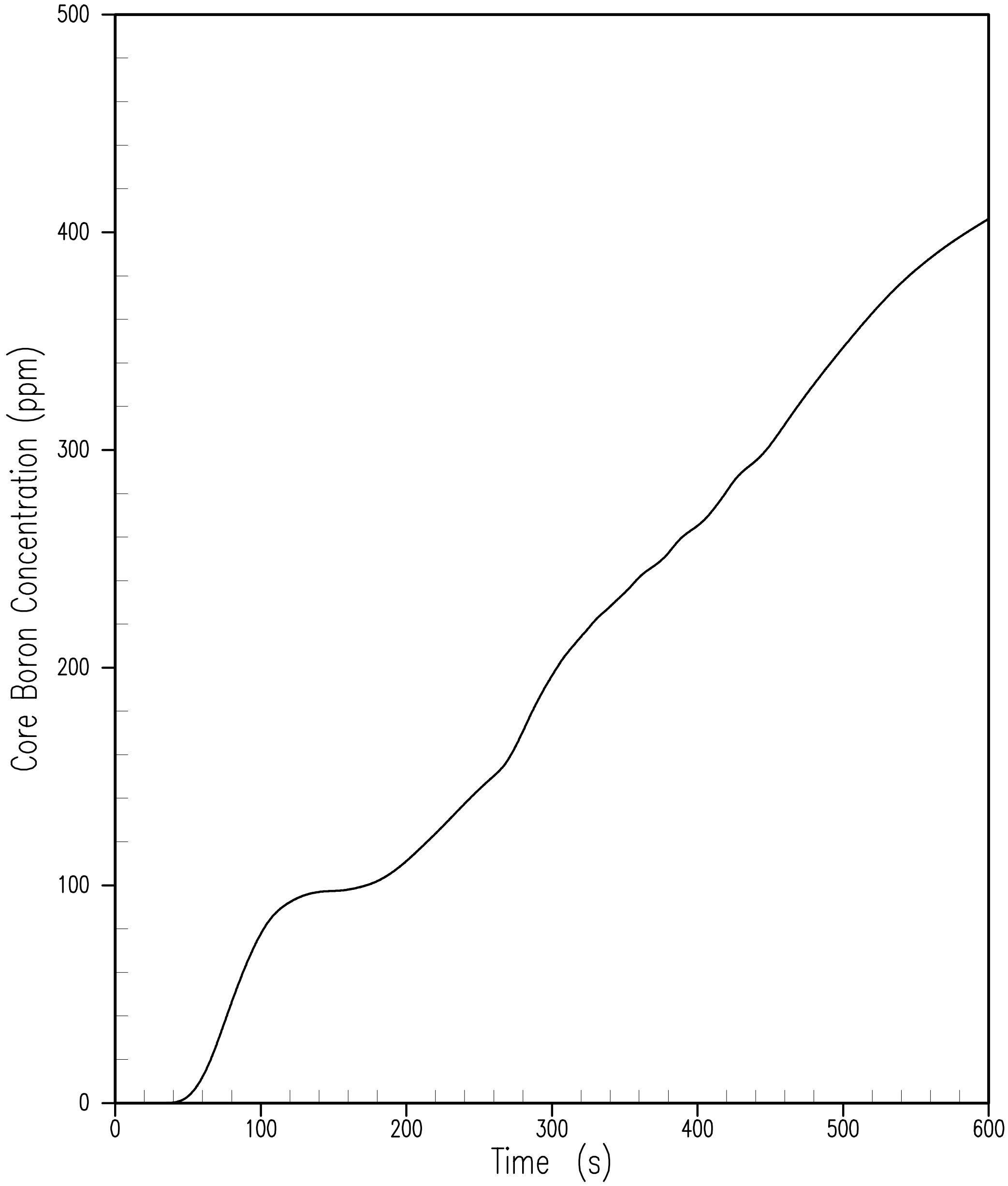

Figure 15.1.5-9

Core Boron Transient Steam System Piping Failure

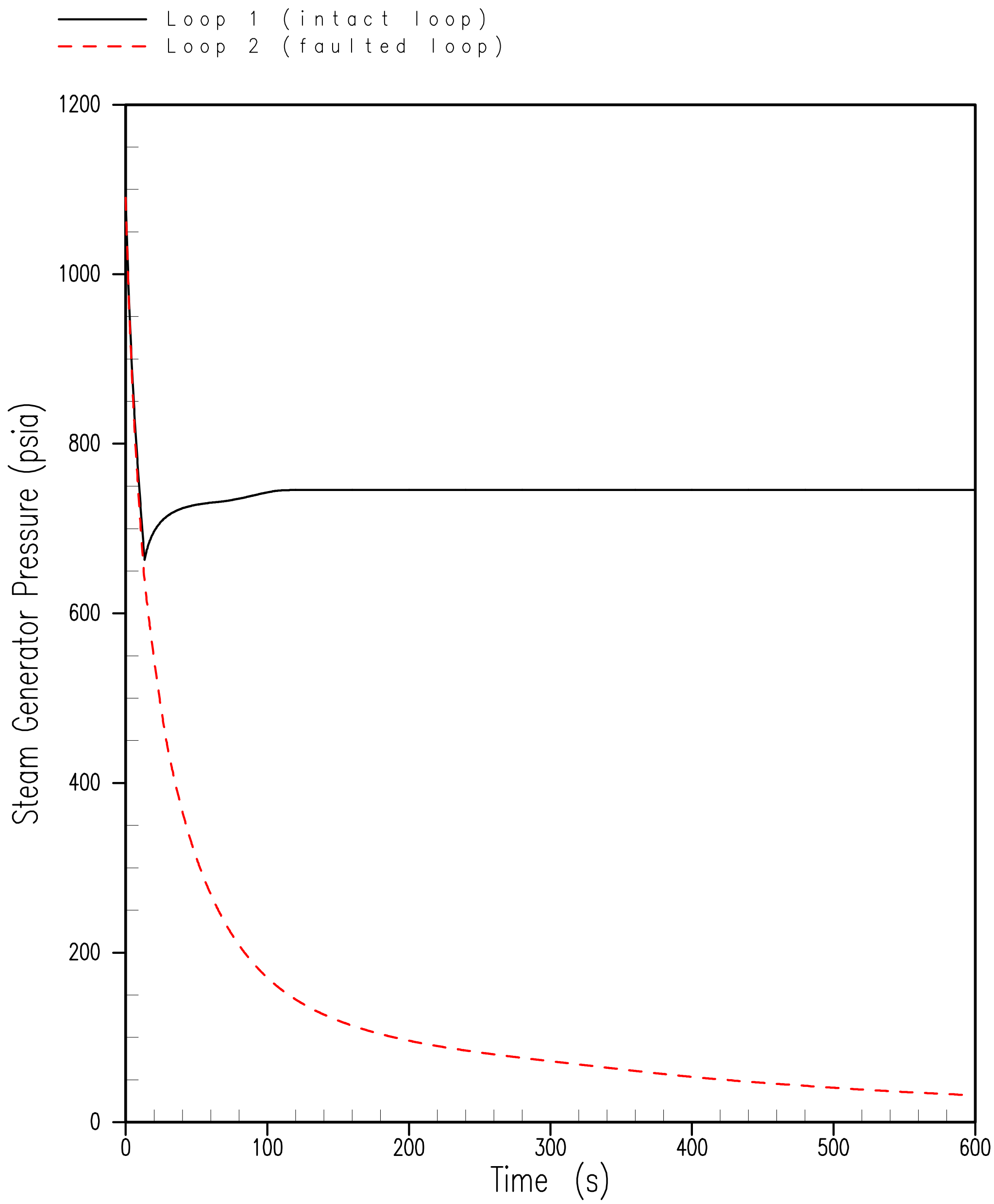

Figure 15.1.5-10

Steam Pressure Transient Steam System Piping Failure

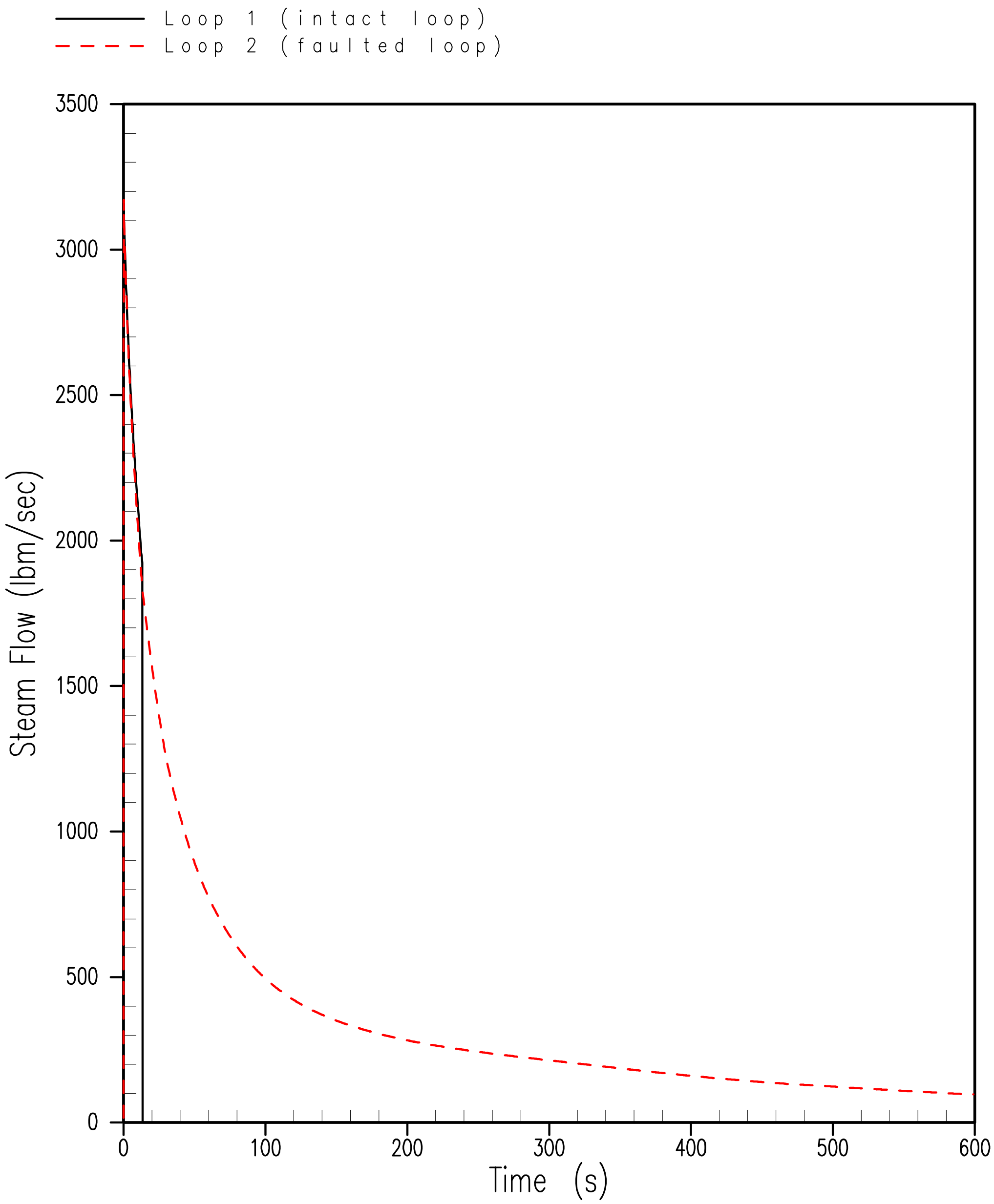

Figure 15.1.5-11

Steam Flow Transient Steam System Piping Failure

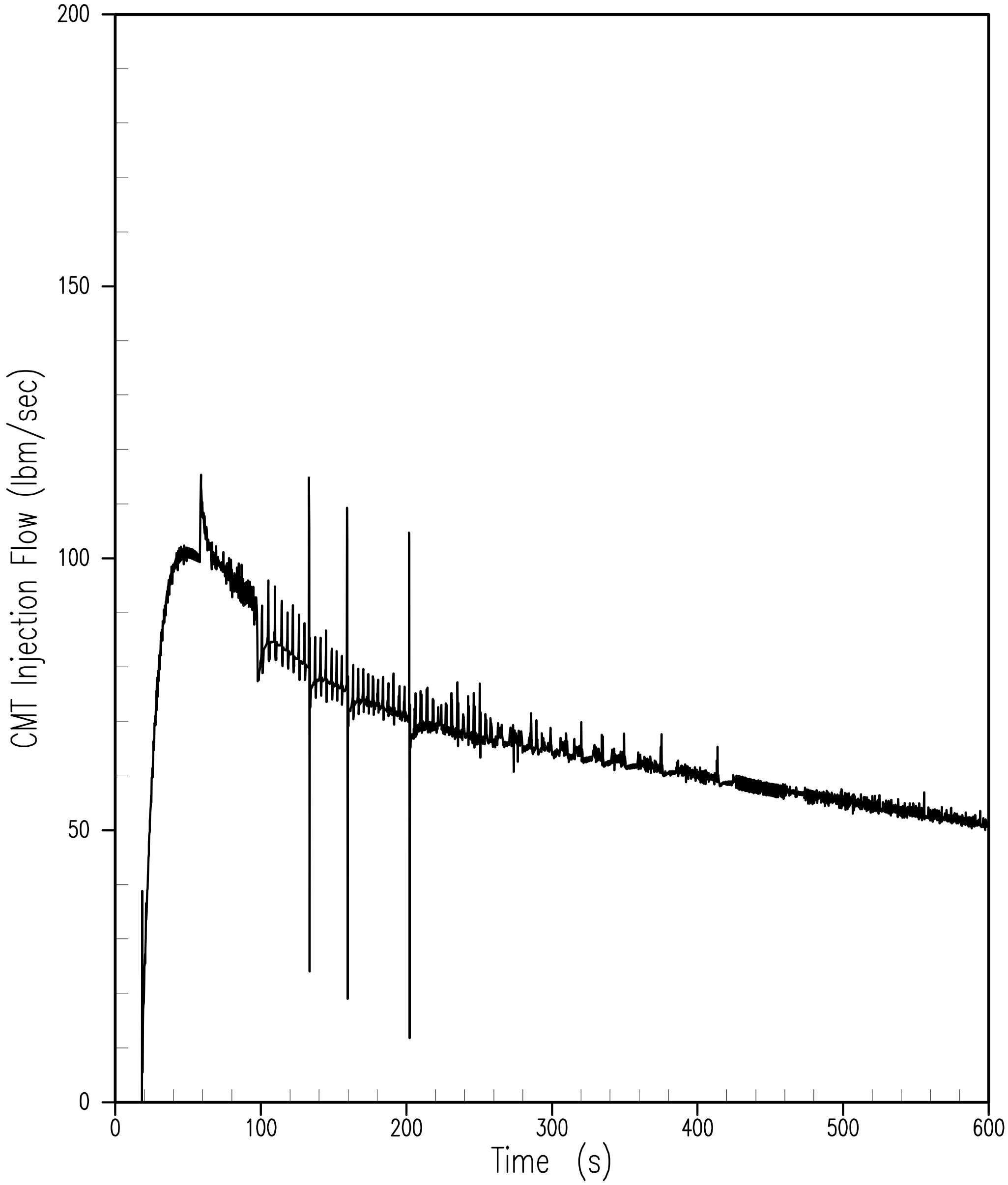

Figure 15.1.5-12

Core Makeup Tank Injection Flow
Steam System Piping Failure

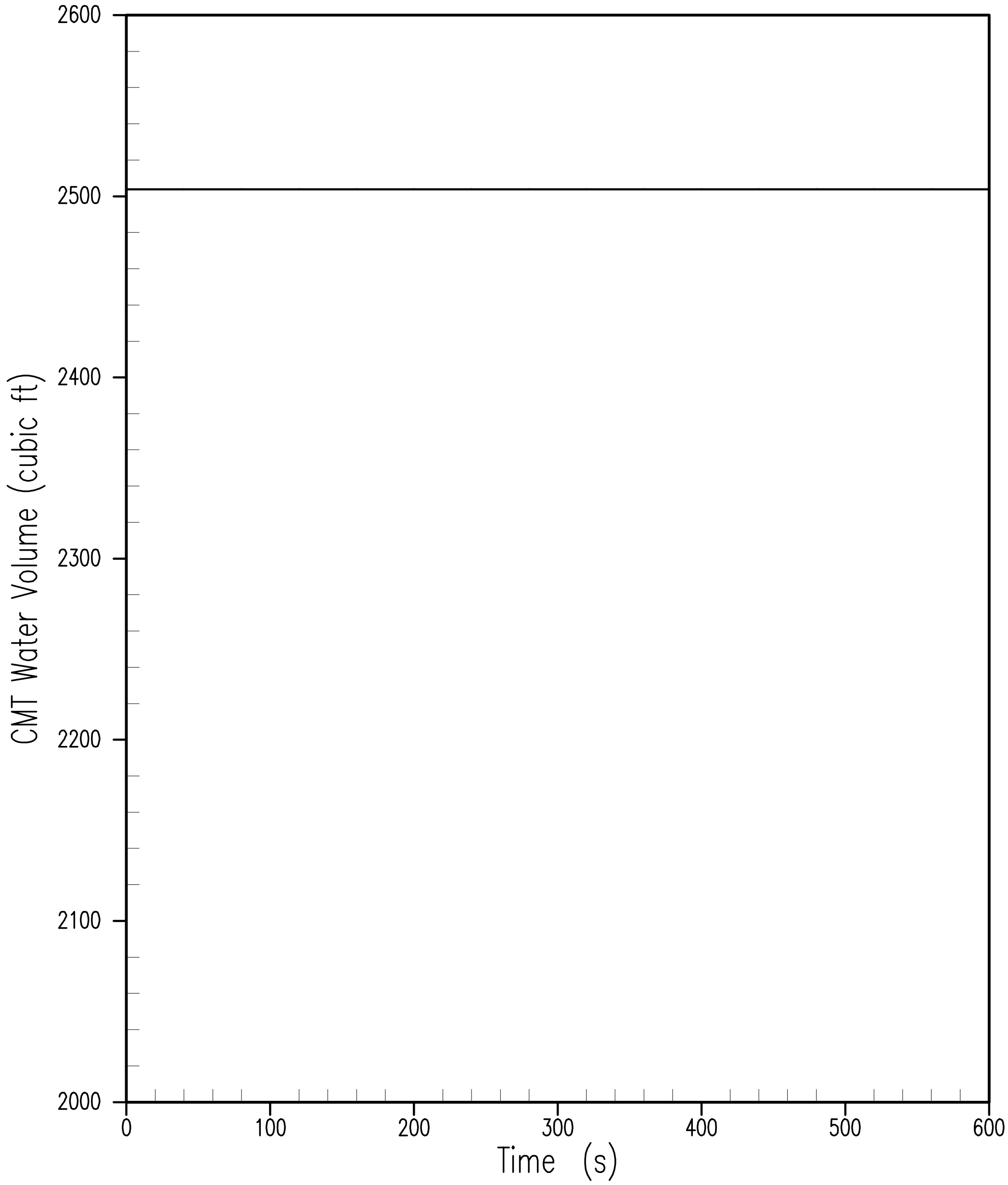

Figure 15.1.5-13

Core Makeup Tank Water Volume Steam System Piping Failure

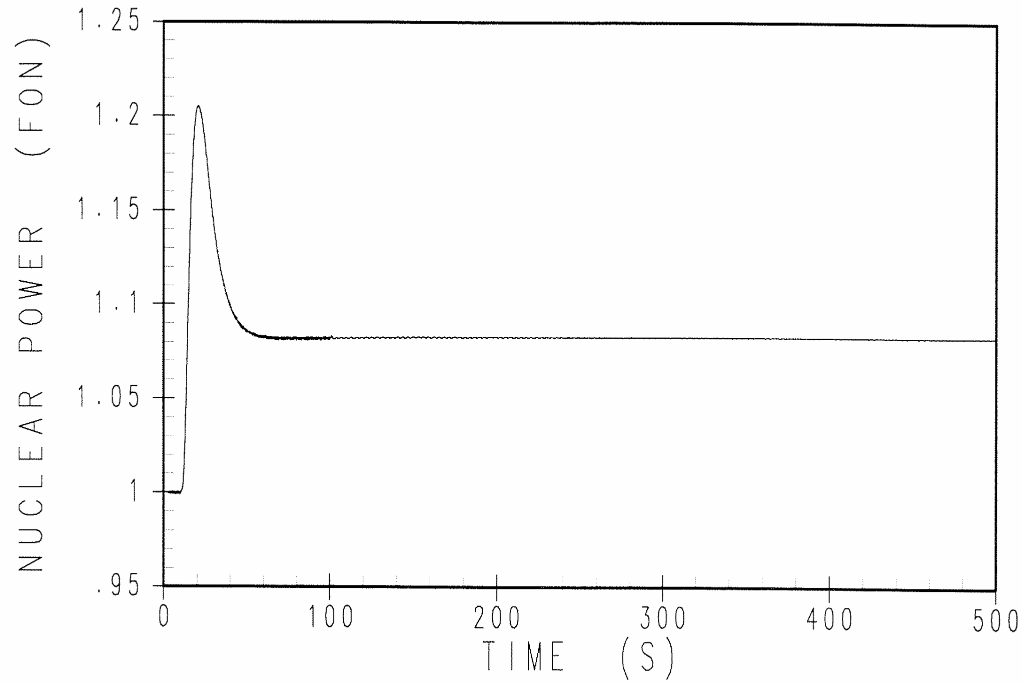

Figure 15.1.6-1

Nuclear Power Transient
Inadvertent Operation of the PRHR

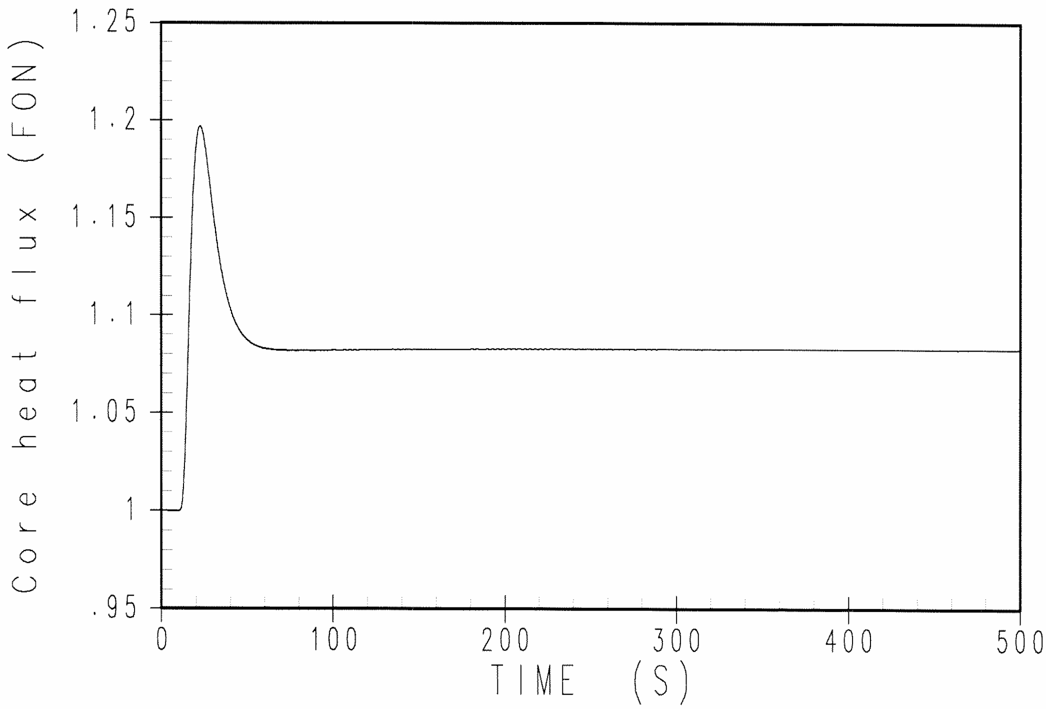

Figure 15.1.6-2

Core Heat Flux Transient
Inadvertent Operation of the PRHR

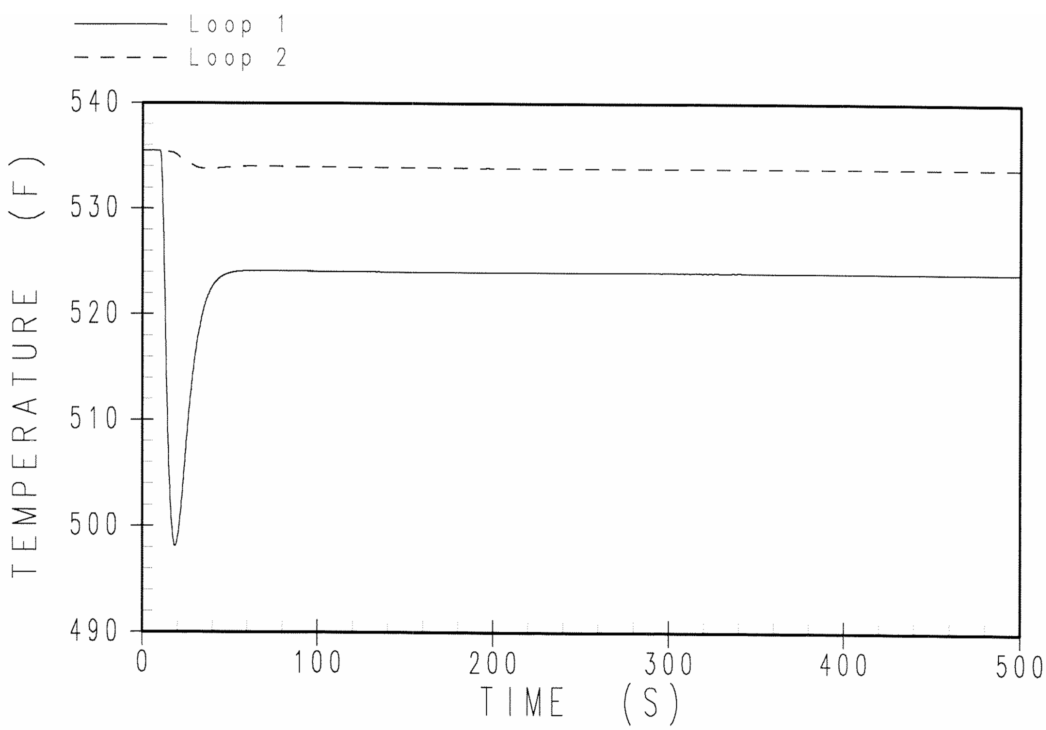

Figure 15.1.6-3

Reactor Vessel Inlet Temperature Transient
Inadvertent Operation of the PRHR

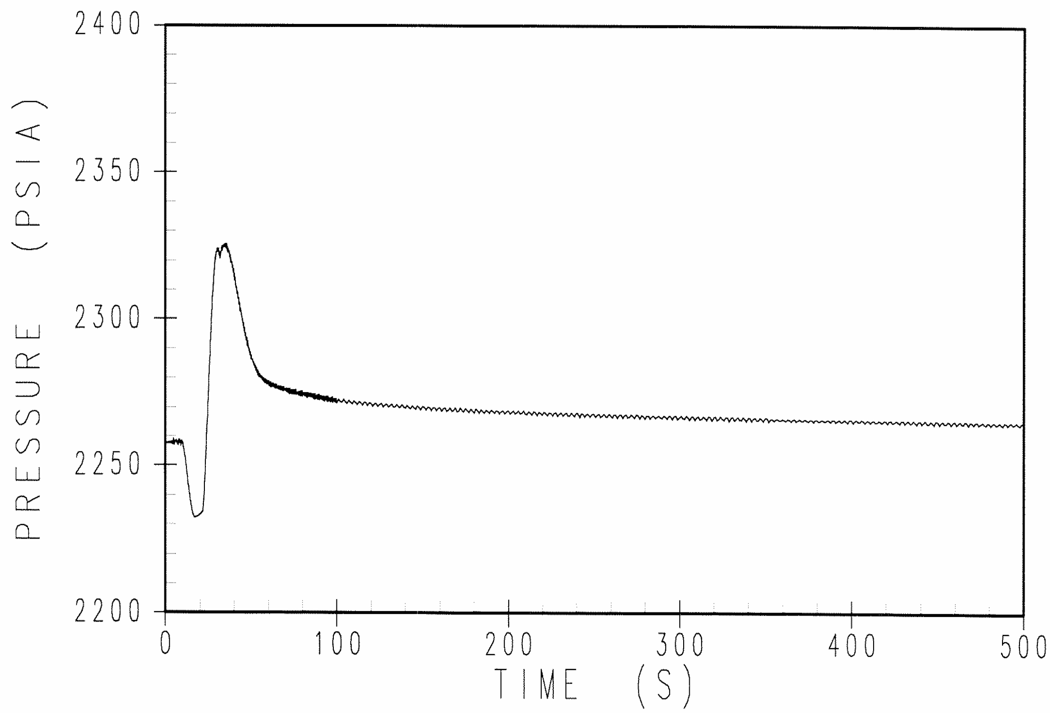

Figure 15.1.6-4

Reactor Coolant System Pressure Transient Inadvertent Operation of the PRHR

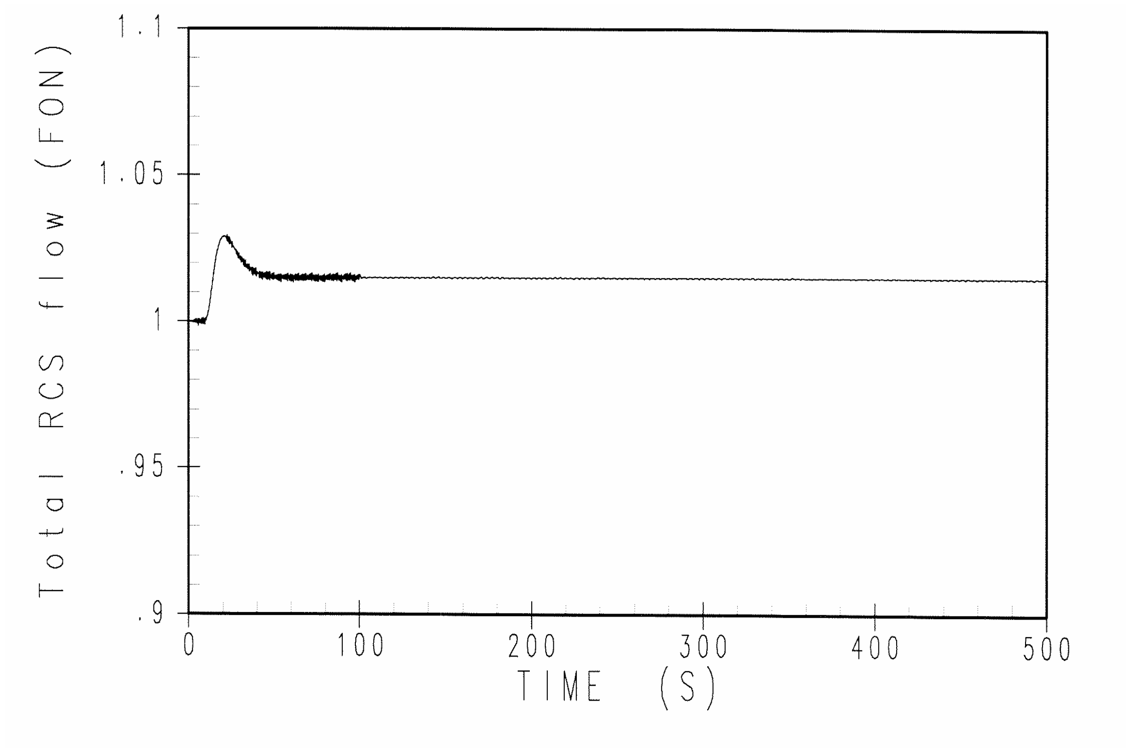

Figure 15.1.6-5

Reactor Coolant System Flow Transient
Inadvertent Operation of the PRHR

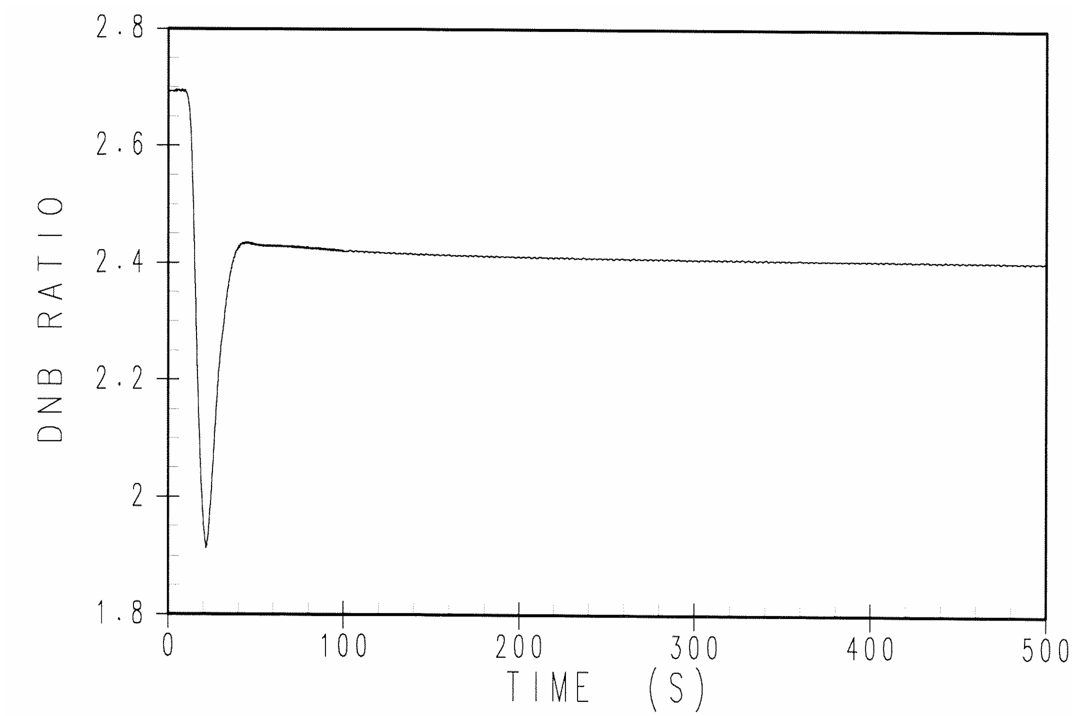

Figure 15.1.6-6

DNBR Transient
Inadvertent Operation of the PRHR

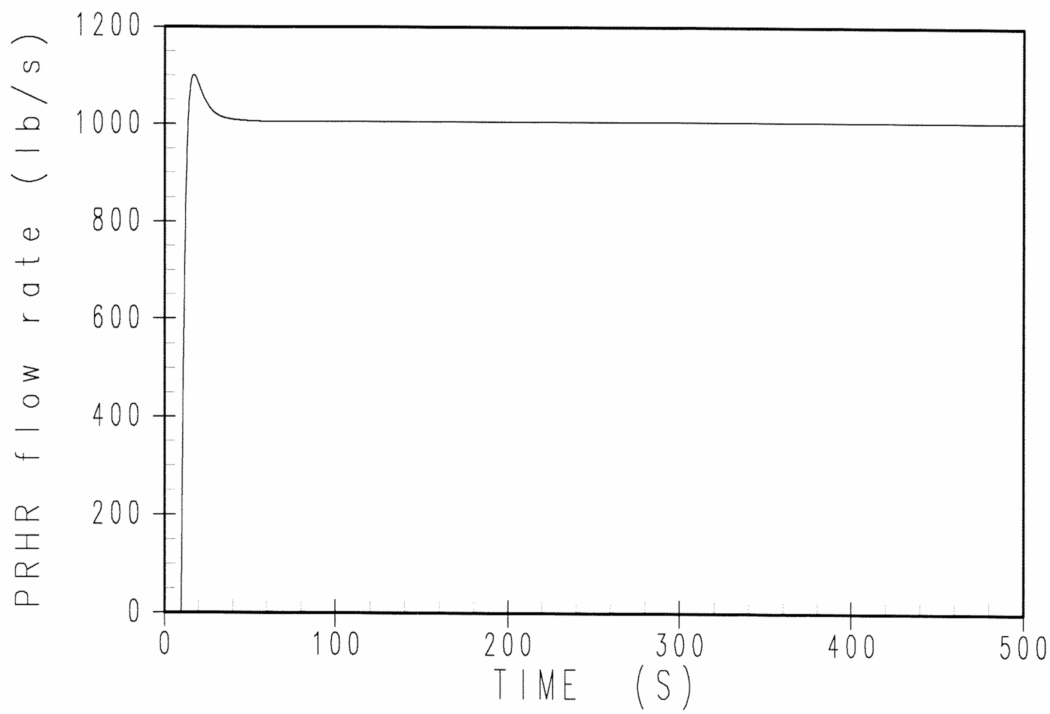

Figure 15.1.6-7

PRHR Flow Transient
Inadvertent Operation of the PRHR

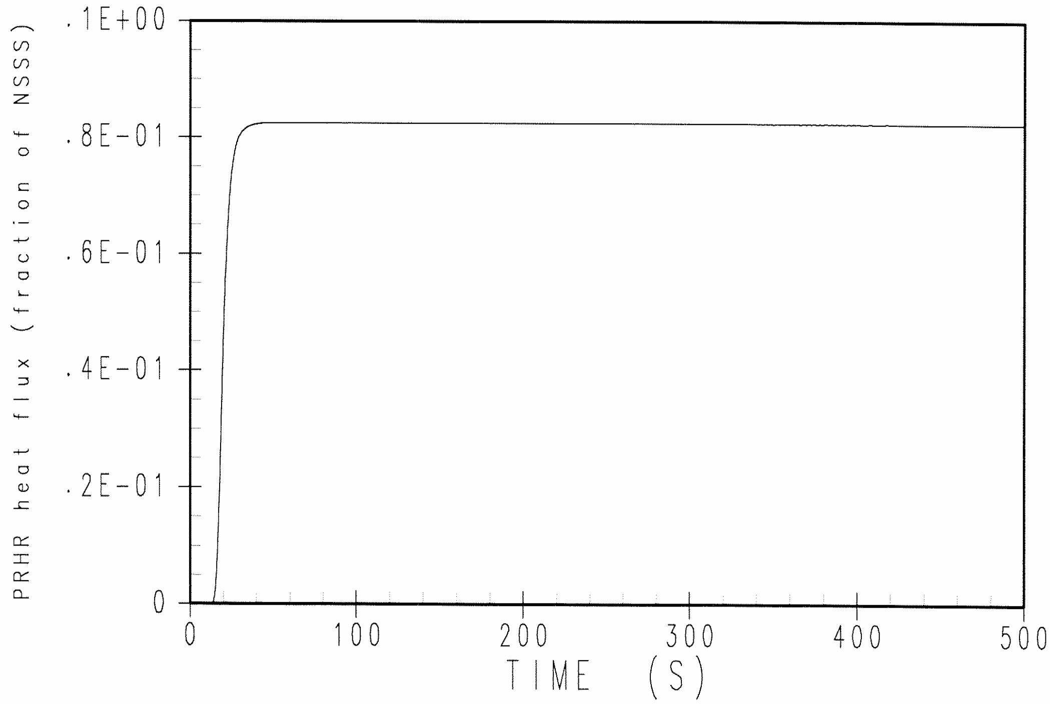

Figure 15.1.6-8

PRHR Heat Transfer Transient
Inadvertent Operation of the PRHR

15.2 Decrease in Heat Removal by the Secondary System

A number of transients and accidents that could result in a reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system are postulated. Analyses are presented in this section for the following events that are identified as more limiting than the others:

- Steam pressure regulator malfunction or failure that results in decreasing steam flow
- Loss of external electrical load
- Turbine trip
- Inadvertent closure of main steam isolation valves
- Loss of condenser vacuum and other events resulting in turbine trip
- Loss of ac power to the station auxiliaries
- Loss of normal feedwater flow
- Feedwater system pipe break

The above items are considered to be Condition II events, with the exception of a feedwater system pipe break, which is considered to be a Condition IV event.

The radiological consequences of the accidents in this section are bounded by the radiological consequences of a main steam line break (see subsection 15.1.5).

15.2.1 Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow

There are no steam pressure regulators in the AP1000 whose failure or malfunction causes a steam flow transient.

15.2.2 Loss of External Electrical Load

15.2.2.1 Identification of Causes and Accident Description

A major load loss on the plant can result from loss of electrical load due to an electrical system disturbance. The ac power remains available to operate plant components such as the reactor coolant pumps; as a result, the standby onsite diesel generators do not function for this event. Following the loss of generator load, an immediate fast closure of the turbine control valves occurs. The automatic turbine bypass system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the turbine bypass system and pressurizer pressure control system function properly. If the condenser is not available, the excess steam generation is relieved to the atmosphere. Additionally, main feedwater flow is lost if the condenser is not available. For this transient, feedwater flow is maintained by the startup feedwater system.

For a loss of electrical load without subsequent turbine trip, no direct reactor trip signal is generated. The plant trips from the protection and safety monitoring system if a safety limit is approached. A continued steam load of approximately 5 percent exists after total loss of external electrical load because of the steam demand of plant auxiliaries.

If a safety limit is approached, protection is provided by high pressurizer pressure, high pressurizer water level, and overtemperature ΔT trips. Voltage and frequency relays associated with the reactor coolant pump provide no additional safety function for this event. Following a complete loss of external electrical load, the maximum turbine overspeed is not expected to affect the voltage and frequency sensors. Any increased frequency to the reactor coolant pump motors results in a slightly increased flow rate and subsequent additional margin to safety limits. For postulated loss of load and subsequent turbine-generator overspeed, an overfrequency condition is not seen by the protection and safety monitoring system equipment or other safety-related loads. Safety-related loads and the protection and safety monitoring system equipment are supplied from the 120-Vac instrument power supply system, which in turn is supplied from the inverters. The inverters are supplied from a dc bus energized from batteries or by a regulated ac voltage.

If the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. This would cause steam generator shell side pressure and reactor coolant temperature to increase rapidly. However, the pressurizer safety valves and steam generator safety valves are sized to protect the reactor coolant system and steam generator against overpressure for load losses, without assuming the operation of the turbine bypass system, pressurizer spray, or automatic rod cluster control assembly control.

The steam generator safety valve capacity is sized to remove the steam flow at the nuclear steam supply system thermal rating from the steam generator, without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized to accommodate a complete loss of heat sink, with the plant initially operating at the maximum turbine load, along with operation of the steam generator safety valves. The pressurizer safety valves can then relieve sufficient steam to maintain the reactor coolant system pressure within 110 percent of the reactor coolant system design pressure.

A discussion of overpressure protection can be found in WCAP-7769, Revision 1 (Reference 1).

A loss-of-external-load event is classified as a Condition II event, fault of moderate frequency.

A loss-of-external-load event results in a plant transient that is bounded by the turbine trip event analyzed in subsection 15.2.3. Therefore, a detailed transient analysis is not presented for the loss-of-external-load event.

The primary side transient is caused by a decrease in heat transfer capability, from primary to secondary, due to a rapid termination of steam flow to the turbine, accompanied by an automatic reduction of feedwater flow (should feedwater flow not be reduced, a larger heat sink is available and the transient is less severe). Reduction of steam flow to the turbine following a loss-of-external load event occurs due to automatic fast closure of the turbine control valves. Following a turbine trip event, termination of steam flow occurs via turbine stop valve closure, which occurs in approximately 0.15 seconds. The transient in primary pressure, temperature, and water volume is less severe for the loss-of-external-load event than for the turbine trip due to a slightly slower loss of heat transfer capability.

The protection available to mitigate the consequences of a loss-of-external-load event is the same as that for a turbine trip, as listed in Table 15.0-6.

15.2.2.2 Analysis of Effects and Consequences

Refer to subsection 15.2.3.2 for the method used to analyze the limiting transient (turbine trip) in this grouping of events. The results of the turbine trip event analysis bound those expected for the loss-of-external-load event, as discussed in subsection 15.2.2.1.

Plant systems and equipment that may be required to function in order to mitigate the effects of a complete loss of load are discussed in subsection 15.0.8 and listed in Table 15.0-6.

The protection and safety monitoring system may be required to terminate core heat input and to prevent departure from nucleate boiling (DNB). Depending on the magnitude of the load loss, pressurizer safety valves and/or steam generator safety valves may open to maintain system pressures below allowable limits. No single active failure prevents operation of any system required to function. Normal plant control systems and engineered safety systems are not required to function. The passive residual heat removal (PRHR) system may be automatically actuated following a loss of main feedwater, further mitigating the effects of the transient.

15.2.2.3 Conclusions

Based on results obtained for the turbine trip event and considerations described in subsection 15.2.2.1, the applicable Standard Review Plan, subsection 15.2.1, evaluation criteria for a loss-of-external-load event, are met (see subsection 15.2.3).

15.2.3 Turbine Trip

15.2.3.1 Identification of Causes and Accident Description

The turbine stop valves close rapidly (about 0.15 seconds) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. Turbine trip initiation signals include:

- Generator trip
- Low condenser vacuum
- Loss of lubricating oil
- Turbine thrust bearing failure
- Turbine overspeed
- Manual trip
- Reactor trip

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. Sensors on the stop valves detect the turbine trip and initiate turbine bypass. The loss of steam flow results in a rapid increase in secondary system temperature and pressure, with a resultant primary system transient, described in subsection 15.2.2.1, for the loss-of-external-load event. A slightly more severe transient occurs for the turbine trip event due to the rapid loss of steam flow caused by the abrupt valve closure.

The automatic turbine bypass system accommodates up to 40 percent of rated steam flow. Reactor coolant temperatures and pressure do not increase significantly if the turbine bypass system and pressurizer pressure control system are functioning properly. If the condenser is not available, the excess steam generation is relieved to the atmosphere and main feedwater flow is lost. For this situation, feedwater flow is maintained by the startup feedwater system to provide adequate residual and decay heat removal capability. Should the turbine bypass system fail to operate, the steam generator safety valves may lift to provide pressure control. See subsection 15.2.2.1 for a further discussion of the transient.

A turbine trip is classified as a Condition II event, fault of moderate frequency.

A turbine trip is a more limiting than a loss-of-external-load event, loss of condenser vacuum, and other events which result in a turbine trip. As such, this event is analyzed and presented in subsection 15.2.3.2.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 100 percent of full power, without rapid power reduction, primarily to show the adequacy of the pressure-relieving devices, and to demonstrate core protection margins. The turbine is assumed to trip without actuating the rapid power reduction system. This assumption delays reactor trip until conditions in the reactor coolant system result in a trip due to other signals. Thus, the analysis assumes a bounding transient. In addition, no credit is taken for the turbine bypass system. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for startup feedwater or the PRHR heat exchanger (except for long-term recovery) to mitigate the consequences of the transient.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, analyses are performed to evaluate the effects produced by a possible consequential loss of offsite power during a complete loss of steam load. As discussed in subsection 15.0.14, the loss of offsite power is considered as a direct consequence of a turbine trip occurring while the plant is operating at power. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

The turbine trip transients are analyzed by using the computer program LOFTRAN (Reference 2). The program simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables, including temperatures, pressures, and power level.

In the turbine trip analyses, that include a primary coolant flow coastdown caused by a consequential loss of offsite power, a combination of three computer codes is used to perform the departure from nucleate boiling ratio (DNBR) analyses. First, the LOFTRAN code (References 2 and 6) is used to calculate the plant system transient. The FACTRAN code (Reference 7) is then used to calculate the core heat flux based on nuclear power and reactor coolant flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR using heat flux from FACTRAN and flow from LOFTRAN.

The major assumptions used in the analysis are summarized below.

Initial Operating Conditions

Two sets of initial operating conditions are used. Cases performed to evaluate the minimum DNBR obtained are analyzed using the revised thermal design procedure. Initial core power, reactor coolant temperature, and pressure are assumed to be at their nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions are included in the DNBR limit as described in WCAP-11397-P-A (Reference 5).

Cases performed to evaluate the maximum calculated RCS pressure include uncertainties on the initial conditions. Initial core power, reactor coolant temperature, and pressure are assumed to be at the nominal full-power values plus or minus uncertainties. The direction of the uncertainties is chosen to maximize the RCS pressure.

Reactivity Coefficients

Two cases are analyzed:

- Minimum reactivity feedback – A least-negative moderator temperature coefficient and a least-negative Doppler-only power coefficient are assumed (see Figure 15.0.4-1).

- Maximum reactivity feedback – A conservatively large negative moderator temperature coefficient and a most-negative Doppler-only power coefficient are assumed (see Figure 15.0.4-1).

Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor is in automatic control, the control rod banks move prior to trip and reduce the severity of the transient.

Steam Release

No credit is taken for the operation of the turbine bypass system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

Pressurizer Spray

Two cases for both the minimum and maximum reactivity feedback cases are analyzed:

- Full credit is taken for the effect of pressurizer spray in reducing or limiting the coolant pressure. Safety valves are also available.

- No credit is taken for the effect of pressurizer spray in reducing or limiting the coolant pressure. Safety valves are operable.

Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for startup feedwater flow or the PRHR heat exchanger, because a stabilized plant condition is reached before initiation of the startup feedwater or the PRHR heat exchanger is normally assumed to occur. The startup feedwater flow or PRHR heat exchanger remove core decay heat following plant stabilization.

Reactor Trip

Reactor trip is actuated by the first reactor trip setpoint reached, with no credit taken for the rapid power reduction on the turbine trip. Trip signals are expected due to high pressurizer pressure, overtemperature ΔT, low RCP speed, high pressurizer water level, and low steam generator water level.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3. Plant systems and equipment that may be required to function in order to mitigate the effects of a turbine trip event are discussed in subsection 15.0.8 and listed in Table 15.0-6.

The protection and safety monitoring system may be required to function following a turbine trip. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure prevents operation of systems required to function. Cases are analyzed, both with and without the operation of pressurizer spray, to determine the worst case for presentation.

Availability of Offsite Power

Each case is analyzed with and without offsite power available. As discussed in subsection 15.0.14, the loss of offsite power is considered to be a consequence of an event due to disruption of the electrical grid following a turbine trip during the event. The grid is assumed to remain stable for 3 seconds following the turbine trip. In the analysis for the complete loss of steam load, the event is initiated by a turbine trip. Therefore, offsite power is assumed to be lost 3 seconds after the start of the event. For the loss of steam load analysis, the primary impact of the loss of offsite power is a coastdown of the reactor coolant pumps.

15.2.3.2.2 Results

The transient responses for a turbine trip from 100 percent of full-power operation are shown for eight cases. The eight analysis cases are performed assuming minimum and maximum reactivity feedback, with and without credit for pressurizer spray, and with and without offsite power available. The results of the analyses are shown in Figures 15.2.3-1 through 15.2.3-26. The calculated sequence of events for the accident is shown in Table 15.2-1.

Minimum Reactivity Feedback, Without Pressurizer Spray, With and Without Offsite Power Available

The results for these cases are shown in Figures 15.2.3-15 through 15.2.3-20. In the case with offsite power available, the reactor is tripped by the high pressurizer pressure trip function. The

pressure safety valves are actuated in this case and maintain the reactor coolant system pressure below 110 percent of the design value. The DNB design basis defined in Section 4.4 is met for this case.

If offsite power is lost, the reactor is tripped by the low reactor coolant pump speed reactor trip function. Offsite power is assumed to be lost 3 seconds after turbine trip. This causes a reduction in reactor coolant system flow, which is illustrated in Figure 15.2.3-20. The DNB design basis defined in Section 4.4 is met for this case. This case is the most limiting with respect to DNB margin of the loss of steam load cases. The pressurizer safety valves actuate in this case and maintain the reactor coolant system pressure below 110 percent of the design value. Pressurizer pressure for this case is shown in Figure 15.2.3-16. With respect to maximum reactor coolant system pressure, this case is also the most limiting for complete loss of steam load cases.

Minimum Reactivity Feedback, With Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-1 through 15.2.3-7 show the transient responses with and without offsite power available. In the case with offsite power available, the reactor is tripped by the high pressurizer pressure trip function. Pressurizer pressure is shown in Figure 15.2.3-2, and the pressure within the reactor coolant system is maintained below 110 percent of the design value. The DNBR for the case with offsite power is shown in Figure 15.2.3-6, and the DNB design basis defined in Section 4.4 is met.

The case without offsite power is tripped by the low reactor coolant pump speed trip function. The DNB transient is similar to, and bounded by, the minimum reactivity feedback case without pressurizer spray and without offsite power. The DNB design basis defined in Section 4.4 is met. The pressurizer pressure is shown in Figure 15.2.3-2, and the pressure within the reactor coolant system is maintained below 110 percent of the design value.

Maximum Reactivity Feedback, With Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-8 through 15.2.3-14 show the transient responses with and without offsite power available. In the case with offsite power available, the reactor is tripped by the high pressurizer pressure trip function. The pressure safety valves are actuated in this case and maintain the reactor coolant system pressure below 110 percent of the design value. Pressurizer pressure is shown in Figure 15.2.3-9. The transient DNBR for the case with offsite power available is shown in Figure 15.2.3-13. The DNB design basis defined in Section 4.4 is met for this case.

The case without offsite power is tripped by the low reactor coolant pump speed trip function. The DNB transient is similar to, and bounded by, the minimum feedback case without pressurizer spray and without offsite power. The DNB design basis defined in Section 4.4 is met. The pressurizer pressure is shown in Figure 15.2.3-9, and the pressure within the reactor coolant system is maintained below 110 percent of the design value.

Maximum Reactivity Feedback, Without Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-21 through 15.2.3-26 show the transient responses with and without offsite power available. In the case with offsite power available, the reactor is tripped by the high pressurizer pressure function.

Pressurizer pressure is shown in Figure 15.2.3-22, and the pressure within the reactor coolant system is maintained below 110 percent of the design value. The DNB design basis defined in Section 4.4 is met for this case.

The case without offsite power is tripped by the low reactor coolant pump speed trip function. The DNB transient is similar to, and bounded by, the minimum feedback case without pressurizer spray and without offsite power. The DNB design basis defined in Section 4.4 is met. The pressurizer pressure is shown in Figure 15.2.3-22, and the pressure within the reactor coolant system is maintained below 110 percent of the design value.

15.2.3.3 Conclusions

Results of the analyses show that a turbine trip presents no challenge to the integrity of the reactor coolant system or the main steam system. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The analyses show that the predicted DNBR is greater than the design limit at any time during the transient. Thus, the departure from nucleate boiling design basis, as described in Section 4.4, is met.

15.2.4 Inadvertent Closure of Main Steam Isolation Valves

Inadvertent closure of the main steam isolation valves results in a turbine trip with no credit taken for the turbine bypass system. Turbine trips are discussed in subsection 15.2.3.

15.2.5 Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip

Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip initiating events are described in subsection 15.2.3. A loss of condenser vacuum prevents the use of steam dump to the condenser. Because steam dump is assumed to be unavailable in the turbine trip analysis, no additional adverse effects result if the turbine trip is caused by loss of condenser vacuum. Therefore, the analysis results and conclusions contained in subsection 15.2.3 apply to the loss of the condenser vacuum. In addition, analyses for the other possible causes of a turbine trip, listed in subsection 15.2.3.1, are covered by subsection 15.2.3. Possible overfrequency effects, due to a turbine overspeed condition, are discussed in subsection 15.2.2.1 and are not a concern for this type of event.

15.2.6 Loss of ac Power to the Plant Auxiliaries

15.2.6.1 Identification of Causes and Accident Description

The loss of power to the plant auxiliaries is caused by a complete loss of the offsite grid accompanied by a turbine-generator trip. The onsite standby ac power system remains available but is not credited to mitigate the accident.

From the decay heat removal point of view, in the long term this transient is more severe than the turbine trip event analyzed in subsection 15.2.3 because, for this case, the decrease in heat removal by the secondary system is accompanied by a reactor coolant flow coastdown, which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip:

- Upon reaching one of the trip setpoints in the primary or secondary systems as a result of the flow coastdown and decrease in secondary heat removal.

- Due to the loss of power to the control rod drive mechanisms as a result of the loss of power to the plant.

Following a loss of ac power with turbine and reactor trips, the sequence described below occurs:

- Plant vital instruments are supplied from the Class 1E and uninterruptable power supply.

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for turbine bypass. If the steam flow rate through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- The onsite standby power system, if available, supplies ac power to the selected plant nonsafety loads.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition if the startup feedwater is available to supply water to the steam generators.

- If startup feedwater is not available, the PRHR heat exchanger is actuated.

During a plant transient, core decay heat removal is normally accomplished by the startup feedwater system if available, which is started automatically when low levels occur in either steam generator. If that system is not available, emergency core decay heat removal is provided by the PRHR heat exchanger. The PRHR heat exchanger is a C-tube heat exchanger connected, through inlet and outlet headers, to the reactor coolant system. The inlet to the heat exchanger is from the reactor coolant system hot leg, and the return is to the steam generator outlet plenum. The heat exchanger is located above the core to provide natural circulation flow when the reactor coolant

pumps are not operating. The IRWST provides the heat sink for the heat exchanger. The PRHR heat exchanger, in conjunction with the passive containment cooling system, keeps the reactor coolant subcooled indefinitely. After the IRWST water reaches saturation (in about two and half hours), steam starts to vent to the containment atmosphere. The condensation that collects on the containment steel shell (cooled by the passive containment cooling system) returns to the IRWST, maintaining fluid level for the PRHR heat exchanger heat sink. The analysis shows that the natural circulation flow in the reactor coolant system following a loss of ac power event is sufficient to remove residual heat from the core.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant and PRHR loops.

A loss of ac power to the plant auxiliaries is a Condition II event, a fault of moderate frequency. This event is more limiting with respect to long-term heat removal than the turbine trip initiated decrease in secondary heat removal without loss of ac power, which is discussed in subsection 15.2.3. A loss of offsite power to the plant auxiliaries will also result in a loss of normal feedwater.

The plant systems and equipment available to mitigate the consequences of a loss of ac power event are discussed in subsection 15.0.8 and listed in Table 15.0-6.

15.2.6.2 Analysis of Effects and Consequences

15.2.6.2.1 Method of Analysis

The analysis is performed to demonstrate the adequacy of the protection and safety monitoring system, the PRHR heat exchanger, and the reactor coolant system natural circulation capability in removing long-term (approximately 36,000 seconds) decay heat. This analysis also demonstrates the adequacy of these systems in preventing excessive heatup of the reactor coolant system with possible reactor coolant system overpressurization or loss of reactor coolant system water.

A modified version of the LOFTRAN code (Reference 2), described in WCAP-14234 (Reference 6), is used to simulate the system transient following a plant loss of offsite power. The simulation describes the plant neutron kinetics and reactor coolant system, including the natural circulation, pressurizer, and steam generator system responses. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in this analysis minimize the energy removal capability of the PRHR heat exchanger and maximize the coolant system expansion.

The transient response of the plant following a loss of ac power to plant auxiliaries is similar to the loss of normal feedwater flow accident (see subsection 15.2.7), except that power is assumed to be lost to the reactor coolant pumps at the time of the reactor trip.

The assumptions used in the analysis are as follows:

- The plant is initially operating at 102 percent of the design power rating with initial reactor coolant temperature 7°F below the nominal value and the pressurizer pressure 50 psi above the nominal value.

- Core residual heat generation is based on ANSI 5.1 (Reference 3). ANSI 5.1 is a conservative representation of the decay energy release rates.

- Reactor trip occurs on steam generator low level (narrow range). Offsite power is assumed to be lost at the time of reactor trip. This is more conservative than the case in which offsite power is lost at time zero because of the lower steam generator water mass at the time of the reactor trip.

- A heat transfer coefficient is assumed in the steam generator associated with reactor coolant system natural circulation flow conditions following the reactor coolant pump coastdown.

- The PRHR heat exchanger is actuated by the low steam generator water level (narrow range coincident with low start up feed water flow).

- Conservative PRHR heat exchanger heat transfer coefficients (low) associated with the low flow rate caused by the reactor coolant pump trip are assumed.

- For the loss of ac power to the station auxiliaries, the only safety function required is core decay heat removal. That is accomplished by the PRHR heat exchanger. One of two parallel valves in the PRHR outlet line is assumed to fail to open. This is the worst single failure.

- Secondary system steam relief is achieved through the steam generator safety valves.

- The pressurizer safety valves are assumed to function.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

Plant systems and equipment necessary to mitigate the effects of a loss of ac power to the station auxiliaries are discussed in subsection 15.0.8 and listed in Table 15.0-6. Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of ac power. The PRHR heat exchanger is required to function with a minimum heat transfer capability. No single active failure prevents operation of any system required to function.

The DNB analysis is not specifically addressed for this event since, from the point of view of DNBR transient, the loss of ac power to auxiliaries is similar and bounded by the Turbine Trip event analyzed in subsection 15.2.3. In fact, the Turbine Trip is analyzed assuming that, following the turbine trip, a loss of ac power occurs with three seconds delay. This results in the coastdown of reactor coolant pumps, but, in the analysis, reactor trip on the loss of power is not assumed. The reactor trip is assumed to occur on an RCP Underspeed set point and rods begin to drop with more than one second delay from the pumps coastdown.

If a loss of ac power occurs as an initiating event, the first result would be the immediate reactor trip and the concomitant coastdown of the reactor coolant pumps. The calculated DNBR for such an event would be the same or higher than predicted for the Complete Loss of Reactor Coolant System flow as presented in 15.3.2.

15.2.6.2.2 Results

The transient response of the reactor coolant system following a loss of ac power to the plant auxiliaries is shown in Figures 15.2.6-1 through 15.2.6-11. The calculated sequence of events for this event is listed in Table 15.2-1.

The LOFTRAN code results show that the natural circulation flow and the PRHR system are sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

Immediately following the reactor trip, the heat transfer capability of the PRHR heat exchanger and the steam generator heat extraction rate are sufficient to slowly cool down the plant. The cooldown continues until a low T_{cold} “S” signal is reached. The “S” signal actuates the core makeup tanks. During this transient, the core makeup tanks operate in water recirculation mode. The cold borated water injected by the core makeup tanks accelerates the cooldown of the plant. The core makeup tank flow slowly decreases as the core makeup tank fluid temperature increases due to water recirculation.

As the plant cools down, the heat removal capacity of the PRHR heat exchanger is lowered. When the heat removal rate from the reactor coolant system, due to the core makeup tank injection and the PRHR heat exchanger, decreases below the core decay heat produced, the reactor coolant system begins heating up again. As the reactor coolant system temperature is elevated, the heat removal capacity of the PRHR heat exchanger increases. The reactor coolant system temperature slowly increases until the heat removal rate of the PRHR heat exchanger matches the core decay heat produced.

Pressurizer safety valves open to discharge steam to containment and reclose later in the transient when the heat removal rate of the PRHR heat exchanger exceeds the decay heat production rate.

The capacity of the PRHR heat exchanger is sufficient to avoid water relief through the pressurizer safety valves.

The calculated sequence of events for this accident is listed in Table 15.2-1. As shown in Figures 15.2.6-5 and 15.2.6-6, in the long-term the plant starts a slow cooldown driven by the PRHR heat exchanger. Plant procedures may be followed to further cool down the plant.

15.2.6.3 Conclusions

Results of the analysis show that for the loss of ac power to plant auxiliaries event, all safety criteria are met. PRHR heat exchanger capacity is sufficient to prevent water relief through the pressurizer safety valves.

The analysis demonstrates that sufficient long-term reactor coolant system heat removal capability exists, via natural circulation and the PRHR heat exchanger, following reactor coolant pump coastdown to prevent fuel or cladding damage and reactor coolant system overpressure.

15.2.7 Loss of Normal Feedwater Flow

15.2.7.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of ac power sources) results in a reduction in the capability of the secondary system to remove the heat generated in the reactor core. If startup feedwater is not available, the safety-related PRHR heat exchanger is automatically aligned by the protection and safety monitoring system to remove decay heat.

A small secondary system break can affect normal feedwater flow control, causing low steam generator levels prior to protective actions for the break. This scenario is addressed by the assumptions made for the feedwater system pipe break (see subsection 15.2.8).

The following occurs upon loss of normal feedwater (assuming main feedwater pump fails or valve malfunctions):

- The steam generator water inventory decreases as a consequence of the continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater flow leads to the reactor trip on a low steam generator water level signal. The same signal also actuates the startup feedwater system (see subsection 15.2.6.1).

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. The condenser is assumed to be unavailable for turbine bypass. If the steam flow path through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the decay heat and to maintain the plant at the hot shutdown condition, if the startup feedwater is used to supply water to the steam generator.

- If startup feedwater is not available, the PRHR heat exchanger is actuated on either a low steam generator water level (narrow range), coincident with a low startup feedwater flow rate signal or a low steam generator water level (wide range) signal. The PRHR heat exchanger transfers the core decay heat and sensible heat to the IRWST so that core heat removal is uninterrupted following a loss of normal and startup feedwater (see subsection 15.2.6).

A loss-of-normal-feedwater event is classified as a Condition II event, a fault of moderate frequency.

15.2.7.2 Analysis of Effects and Consequences

An analysis of the system transient is presented below to show that, following a loss of normal feedwater, the PRHR heat exchanger is capable of removing the stored and decay heat to prevent either overpressurization of the reactor coolant system or loss of water from the reactor coolant system.

15.2.7.2.1 Method of Analysis

An analysis using a modified version of the LOFTRAN code (Reference 2), described in WCAP-14234 (Reference 6), is performed to obtain the plant transient following a loss of normal feedwater. The simulation describes the neutron kinetics, reactor coolant system (including the natural circulation), pressurizer, and steam generators. The program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in the analysis are as follows:

- The plant is initially operating at 102 percent of the design power rating.
- Reactor trip occurs on steam generator low (narrow range) level.
- The only safety function required is the core decay heat removal that is carried by the PRHR heat exchanger; therefore, the worst single failure is assumed to occur in the PRHR heat exchanger. The actuation of the PRHR heat exchanger requires the opening of one of the two fail-open valves arranged in parallel at the PRHR heat exchanger discharge. Because no single failure can be assumed that impairs the opening of both valves, the failure of a single valve is assumed.

  The PRHR heat exchanger is actuated by the low steam generator water level narrow range signal, coincident with low start up feedwater flow.
- Secondary system steam relief is achieved through the steam generator safety valves.
- The initial reactor coolant average temperature is 7°F lower than the nominal value, and initial pressurizer pressure is 50 psi lower than nominal.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the protection and safety monitoring system and the PRHR heat exchanger in removing long-term decay heat and preventing excessive heatup of the reactor coolant system with possible resultant reactor coolant system overpressurization or loss of reactor coolant system water. The assumptions used in this analysis minimize the energy removal capability of the system, and maximize the coolant system expansion.

For the loss of normal feedwater transient, the reactor coolant volumetric flow remains at its normal value and the reactor trips via the low steam generator narrow range level trip. The reactor coolant pumps continue to run until automatically tripped when the core makeup tanks are actuated.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

Plant systems and equipment necessary to mitigate the effects of a loss of normal feedwater accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of normal feedwater. The PRHR heat exchanger is required to function with a minimum heat transfer capability. No single active failure prevents operation of any system to perform its required function. A discussion of anticipated transients without scram considerations is presented in Section 15.8.

15.2.7.2.2 Results

Figures 15.2.7-1 through 15.2.7-10 show the significant plant parameters following a loss of normal feedwater.

Prior to reactor trip and the insertion of the rods into the core, the loss of normal feedwater transient is the same as the transient response presented in subsection 15.2.6 for the loss of ac power to plant auxiliaries. The DNB results, presented in Figure 15.2.6-12 for the loss of ac power to plant auxiliaries, are also applicable for a loss of normal feedwater and demonstrate that the DNB design basis is met.

Following the reactor and turbine trip from full load, the water level in the steam generators falls due to the reduction of steam generator void fraction. Steam flow through the safety valves continues to dissipate the stored and core decay heat.

The capacity of the PRHR heat exchanger, when the reactor coolant pumps are operating, is much larger than the decay heat, and in the first part of the transient, the reactor coolant system is cooled down and the pressure decreases.

The cooldown continues until a low T_{cold} "S" signal is eventually reached. The "S" signal actuates the core makeup tanks. During this transient, the core makeup tanks operate in water recirculation mode. The cold borated water injected by the core makeup tanks accelerates the cooldown of the plant. The core makeup tank flow slowly decreases as the core makeup tank fluid temperature increases due to water recirculation.

As the plant cools down, the heat removal capacity of the passive residual heat exchanger is lowered. The heat removal rate from the reactor coolant system, due to the core makeup tank injection and the PRHR heat exchanger, then decreases below the core decay heat produced. The reactor coolant system then begins heating up again. As the reactor coolant system temperature is elevated, the heat removal capacity of the PRHR heat exchanger increases again. The reactor coolant system temperature slowly increases until the heat removal rate of the PRHR heat exchanger matches the core decay heat produced.

The capacity of the PRHR heat exchanger is sufficient to avoid water relief through the pressurizer safety valves.

The calculated sequence of events for this accident is listed in Table 15.2-1. As shown in Figures 15.2.7-3 and 15.2.7-4, the plant starts a slow cooldown driven by the PRHR heat exchanger. Plant procedures may be followed to further cool down the plant.

15.2.7.3 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the reactor coolant system, or the steam system. The heat removal capacity of the PRHR heat exchanger is such that reactor coolant water is not relieved from the pressurizer safety valves. DNBR always remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values.

15.2.8 Feedwater System Pipe Break

15.2.8.1 Identification of Causes and Accident Description

A major feedwater line rupture is a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators in order to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. (A break upstream of the feedwater line check valve would affect the plant only as a loss of feedwater. This case is covered by the evaluation in subsections 15.2.6 and 15.2.7.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break) or a reactor coolant system heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated in subsection 15.1.5. Therefore, only the reactor coolant system heatup effects are evaluated for a feedwater line rupture in this subsection.

The feedwater line rupture reduces the ability to remove heat generated by the core from the reactor coolant system for the following reasons:

- Feedwater flow to the steam generators is reduced. Because feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.

- Fluid in the steam generator may be discharged through the break and would not be available for decay heat removal after trip.

- The break may be large enough to prevent the addition of main feedwater after trip.

A major feedwater line rupture is classified as a Condition IV event.

The severity of the feedwater line rupture transient depends on a number of system parameters, including the break size, initial reactor power, and the functioning of various control and safety-related systems. Sensitivity studies presented in WCAP-9230 (Reference 4) illustrate that the most limiting feedwater line rupture is a double-ended rupture of the largest feedwater line. At the beginning of the transient, the main feedwater control system is assumed to malfunction due to an adverse environment. Interactions between the break and the main feedwater control system

result in no feedwater flow being injected or lost through the steam generator feedwater nozzles. This assumption causes the water levels in both steam generators to decrease equally until the low steam generator level (narrow range) reactor trip setpoint is reached. After reactor trip, a full double-ended rupture of the feedwater line is assumed such that the faulted steam generator blows down through the break and no main feedwater is delivered to the intact steam generator. These assumptions conservatively bound the most limiting feedwater line rupture that can occur. Analysis is performed at full power assuming the loss of offsite power at the time of the reactor trip. This is more conservative than the case where power is lost at the initiation of the event. The case with offsite power available is not presented because, due to the fast core makeup tanks actuation (on an "S" signal generated by the low steam line pressure), the reactor coolant pumps are tripped by the protection and safety monitoring system a few seconds after the reactor trip. The only difference between the cases with and without offsite power available is the operating status of the reactor coolant pumps.

The following provides the protection for a main feedwater line rupture:

- A reactor trip on any of the following four conditions:

  – High pressurizer pressure
  – Overtemperature ΔT
  – Low steam generator water level in either steam generator
  – "S" signals from either of the following:

    - Two out of four low steam line pressure in either steam generator
    - Two out of four high containment pressure (high-2)

Refer to Sections 7.1 and 7.2 for a description of the actuation system.

- The PRHR heat exchanger provides a passive method for decay heat removal. The heat exchanger is a C-tube type, located inside the IRWST. The heat exchanger is above the reactor coolant system to provide natural circulation of the reactor coolant. Operation of the PRHR heat exchanger is initiated by the opening of one of the two parallel power-operated valves at the PRHR heat exchanger cold leg.

- Prevent substantial overpressurization of the reactor coolant system (less than 110 percent of design pressures).

- Maintain sufficient liquid in the reactor coolant system so that the core remains in place, and geometrically intact, with no loss of core cooling capability.

  Refer to subsection 6.3.2.2.5 for a description of the PRHR heat exchanger.

15.2.8.2 Analysis of Effects and Consequences

15.2.8.2.1 Method of Analysis

An analysis using a modified version, described in WCAP-14234 (Reference 6), of the LOFTRAN code (Reference 2) is performed to determine the plant transient following a feedwater line rupture. The code describes the reactor thermal kinetics, reactor coolant system (including natural circulation), pressurizer, steam generators, and feedwater system responses and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

The case analyzed assumes a double-ended rupture of the largest feedwater pipe at full power. Major assumptions used in the analysis are as follows:

- The plant is initially operating at 102 percent of the design plant rating.
- Initial reactor coolant average temperature is 6.5°F above the nominal value, and the initial pressurizer pressure is 50 psi below its nominal value.
- The pressurizer spray is turned on.
- Initial pressurizer level is at a conservative maximum value and a conservative initial steam generator water level is assumed in both steam generators.
- No credit is taken for the high pressurizer pressure reactor trip.
- At the start of the transient, interaction between the break in the feedline and the main feedwater control system is assumed to result in a complete loss of feedwater flow to both steam generators. No feedwater flow is delivered to or lost through the steam generator nozzles.
- Reactor trip is assumed to be initiated when the low steam generator narrow range level setpoint is reached on the ruptured steam generator.
- After reactor trip, the faulted steam generator blows down through a double-ended break area of 1.755 ft^2. A saturated liquid discharge is assumed until all the water inventory is discharged from the faulted steam generator. This minimizes the heat removal capability of the faulted steam generator and maximizes the resultant heatup of the reactor coolant. No feedwater flow is assumed to be delivered to the intact steam generator.
- The PRHR heat exchanger is actuated by the low steam generator water level (wide range) signal. A 15-second delay is assumed following the low level signal to allow time for the alignment of PRHR heat exchanger valves.
- Credit is taken for heat energy deposited in reactor coolant system metal during the reactor coolant system heatup.

- No credit is taken for charging or letdown.
- Pressurizer safety valve setpoint is assumed to be at its minimum value.
- Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases. The heat transfer remains approximately 100 percent in the faulted steam generator until the liquid mass reaches about 11 percent. The heat transfer is then reduced to 0 percent with the liquid inventory.
- Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip (Reference 3).
- No credit is taken for the following four protection and safety monitoring system reactor trip signals to mitigate the consequences of the accident:
  - High pressurizer pressure
  - Overtemperature ΔT
  - High pressurizer level
  - High containment pressure

The PRHR heat exchanger is initiated if the steam generator water level drops to the low steam generator level (wide range). Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal that closes all main steam line and feed line isolation valves. This signal also gives an "S" signal that initiates flow of cold borated water from the core makeup tanks to the reactor coolant system.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

The plant control system is not assumed to function in order to mitigate the consequences of the event. The protection and safety monitoring system is required to function following a feedwater line rupture as analyzed here. No single active failure prevents operation of this system.

The engineered safety features assumed to function are the PRHR heat exchanger, core makeup tank, and steam line isolation valves. The single failure assumed is the failure of one of the two parallel discharge valves in the PRHR outlet line (see Table 15.0-7).

For the case without offsite power, there is a flow coastdown until flow in the loops reaches the natural circulation value. The natural circulation capability of the reactor coolant system is shown (see subsection 15.2.6) to be sufficient to remove core decay heat following reactor trip for the loss of ac power transient. Pump coastdown characteristics are demonstrated in subsections 15.3.1 and 15.3.2 for single and multiple reactor coolant pump trips, respectively.

A description and analysis of the core makeup tank is provided in subsection 6.3.2.2.1. The PRHR heat exchanger is described in subsection 6.3.2.2.5.

15.2.8.2.2 Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 15.2.8-1 through 15.2.8-10. The calculated sequence of events for the case analyzed is listed in Table 15.2-1.

The results presented in Figures 15.2.8-5 and 15.2.8-7 show that pressures in the reactor coolant system and main steam system remain below 110 percent of the respective design pressure. Pressurizer pressure decreases after reactor trip on the low steam generator water level (70.3 seconds) due to the loss of heat input.

In the first part of the transient, due to the conservative analysis assumptions, the system response following the feedwater line rupture is similar to the loss of ac power to the station auxiliaries (subsection 15.2.6). The DNB results, presented in Figure 15.2.6-12 for the loss of ac power to plant auxiliaries, are also applicable to a feedwater system pipe break and demonstrate that the DNB design basis is met.

After the trip, the core makeup tanks are actuated (95 seconds) on low steam line pressure in the ruptured loop while the PRHR heat exchanger is actuated on a low steam generator water level wide range (90.1 seconds).

The addition of the PRHR heat exchanger and the core makeup tanks flow rates helps to cool down the primary system and to provide sufficient fluid to keep the core covered with water.

Pressurizer safety valves open due to the mismatch between decay heat and the heat transfer capability of the PRHR heat exchanger. In the first part of the transient, there is a cooling effect due to the core makeup tanks that inject cold water into the reactor coolant system and receive hot water from the cold leg. This effect decreases due to the heatup of the core makeup tanks from recirculation flow. Also, the injection driving head is lowered as the core makeup tanks heat up.

Reactor coolant system temperatures are low (approximately 510°F at about 2,500 seconds) and, in this condition, the PRHR heat exchanger cannot remove the entire decay heat load. Reactor coolant system temperatures increase until an equilibrium between decay heat power and heat absorbed by the PRHR heat exchanger is reached. After about 11,300 seconds, the heat transfer capability of the PRHR heat exchanger exceeds the decay heat power and the reactor coolant system temperatures, pressure, and pressurizer water volumes start to steadily decrease. Core cooling capability is maintained throughout the transient because reactor coolant system inventory is increasing due to core makeup tank injection.

15.2.8.3 Conclusions

Results of the analyses show that for the postulated feedwater line rupture, the capacity of the PRHR heat exchanger is adequate to remove decay heat, to prevent overpressurizing the reactor coolant system, and to maintain the core cooling capability. Radioactivity doses from ruptures of the postulated feedwater lines are less than those presented for the postulated main steam line break. The Standard Review Plan, subsection 15.2.8, evaluation criteria are therefore met.

15.2.9 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.2.10 References

1. Cooper, L., Miselis, V., and Starek, R. M., "Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Revision 1, June 1972. (Also letter NS-CE-622, C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1, April 16, 1975).

2. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

3. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ANS-5.1-1979, August 1979.

4. Lang, G. E., and Cunningham, J. P., "Report on the Consequences of a Postulated Main Feedline Rupture," WCAP-9230 (Proprietary) and WCAP-9231 (Nonproprietary), January 1978.

5. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

6. "AP1000 Code Applicability Report," WCAP-15644-P (Proprietary) and WCAP-15644-NP (Nonproprietary), Revision 2, March 2004.

7. Hargrove, H. G., "FACTRAN – A FORTRAN-TV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

Table 15.2-1 (Sheet 1 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
I. Turbine trip		
A.1. With pressurizer control, minimum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater	0.0
	Minimum DNBR occurs	0.0
	High pressurizer pressure reactor trip point reached	6.2
	Rods begin to drop	8.2
	Peak RCS pressure occurs	10.0
	Initiation of steam release from steam generator safety valves	12.4
A.2. With pressurizer control, minimum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low reactor coolant pump speed reactor trip setpoint reached	3.47
	Rods begin to drop	4.24
	Minimum DNBR (1.57) occurs	6.1
	Peak RCS pressure occurs	6.5
	Initiation of steam release from steam generator safety valves	18.7

Table 15.2-1 (Sheet 2 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
B.1. With pressurizer control, maximum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	Minimum DNBR occurs	0.0
	High pressurizer pressure reactor trip setpoint reached	6.6
	Rods begin to drop	8.6
	Peak RCS pressure occurs	9.6
	Initiation of steam release from steam generator safety valves	13.0
B.2. With pressurizer control, maximum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low reactor coolant pump speed reactor trip setpoint reached	3.47
	Rods begin to drop	4.24
	Minimum DNBR (2.44) occurs	4.4
	Peak RCS pressure occurs	7.7
	Initiation of steam release from steam generator safety valves	24.9

Table 15.2-1 (Sheet 3 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
C.1. Without pressurizer control, minimum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip point reached	5.9
	Rods begin to drop	7.9
	Peak RCS pressure occurs	9.5
	Initiation of steam release from steam generator safety valves	10.5
C.2. Without pressurizer control, minimum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low reactor coolant pump speed reactor trip setpoint reached	3.47
	Rods begin to drop	4.24
	Peak RCS pressure occurs	6.3
	Initiation of steam release from steam generator safety valves	14.0

Table 15.2-1 (Sheet 4 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
D.1. Without pressurizer control, maximum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip	6.0
	Rods begin to drop	8.0
	Peak RCS pressure occurs	8.4
	Initiation of steam release from steam generator safety valves	10.7
D.2. Without pressurizer control, maximum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low reactor coolant pump speed reactor trip setpoint reached	3.47
	Rods begin to drop	4.24
	Peak RCS pressure occurs	5.9
	Initiation of steam release from steam generator safety valves	15.6

Table 15.2-1 (Sheet 5 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
II.A. Loss of ac power to the plant auxiliaries	Feedwater is lost	10.0
	Low steam generator water level reactor trip set point is reached	70.4
	Rods begin to drop, ac power is lost, reactor coolant pumps start to coastdown	72.4
	Pressurizer safety valves open	76.5
	Maximum pressurizer pressure reached	77.0
	Steam generator safety valves open	87.0
	PRHR heat exchanger actuation on low steam generator water level (narrow range coincident with low start up flow rate)	132.4
	Maximum pressurizer water volume reached	139.0
	Pressurizer safety valves reclose	142.0
	Steam generator 1 safety valves close	2,326
	Core makeup tank actuation on low T_{cold} "S" signal	4,753
	Steam line isolation on low T_{cold} "S" signal	4,765
	Steam generator 2 safety valves close	7,006
	Pressurizer safety valves open	8,056
	Pressurizer safety valves reclose	16,944
	Second pressurizer water volume peak is reached	22,152
	PRHR heat exchanger extracted heat matches decay heat	~ 19,100
	Second pressurizer water volume peak is reached	22,152

Table 15.2-1 (Sheet 6 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
III. Loss of normal feedwater flow	Feedwater is lost	10.0
	Low steam generator water level (narrow range) reactor trip reached	70.4
	Rods begin to drop	72.4
	Steam generator safety valves open	80.0
	Pressurizer safety valves open	-
	Maximum pressurizer pressure reached	-
	Pressurizer safety valves reclose	-
	PRHR heat exchanger actuation on low steam generator water level (narrow range coincident with low start up feeedwater flow rate)	132.4
	Steam generator safety valves reclose	144
	Cold leg temperature reaches low T_{cold} setpoint	1,154.6
	Reactor coolant pump trip on low T_{cold} “S” signal	1,160.6
	Steam line isolation on low T_{cold} “S” signal	1,166.6
	Core makeup tank actuation on low T_{cold} “S” signal	1,171.6
	Pressurizer safety valves open	3,500
	Pressurizer safety valves reclose	17,702
	Passive residual heat removal heat exchanger extracted heat matches decay heat	~ 17,620
	Maximum pressurizer water volume reached	19,548

Table 15.2-1 (Sheet 7 of 7)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (seconds)
IV. Feedwater system pipe break	Main feedwater flow to both steam generators stops due to interaction between the break and the main feedwater control system	10.0
	Low steam generator water level (narrow range) setpoint reached	70.3
	Reverse flow from the faulted steam generator through a full double-ended rupture starts	70.3
	Rods begin to drop	72.3
	Loss of offsite power occurs	72.3
	Low steam generator water level (wide range) set point reached	73.1
	Pressurizer safety valves open	74.5
	Low steam line pressure set point reached	78.0
	Pressurizer safety valves close	80.0
	All steam and feedline isolation valves close	90.0
	PRHR heat exchanger actuation on low steam generator water level (wide range)	90.1
	Core makeup tank valves fully opened	95.0
	Faulted steam generator empties	100.0
	Intact steam generator safety valves open	180
	Intact steam generator safety valves close	425
	Pressurizer safety valves open	1,848
	PRHR heat exchanger extracted heat matches decay heat	~ 11,300
	Pressurizer safety valves close	~ 11,300

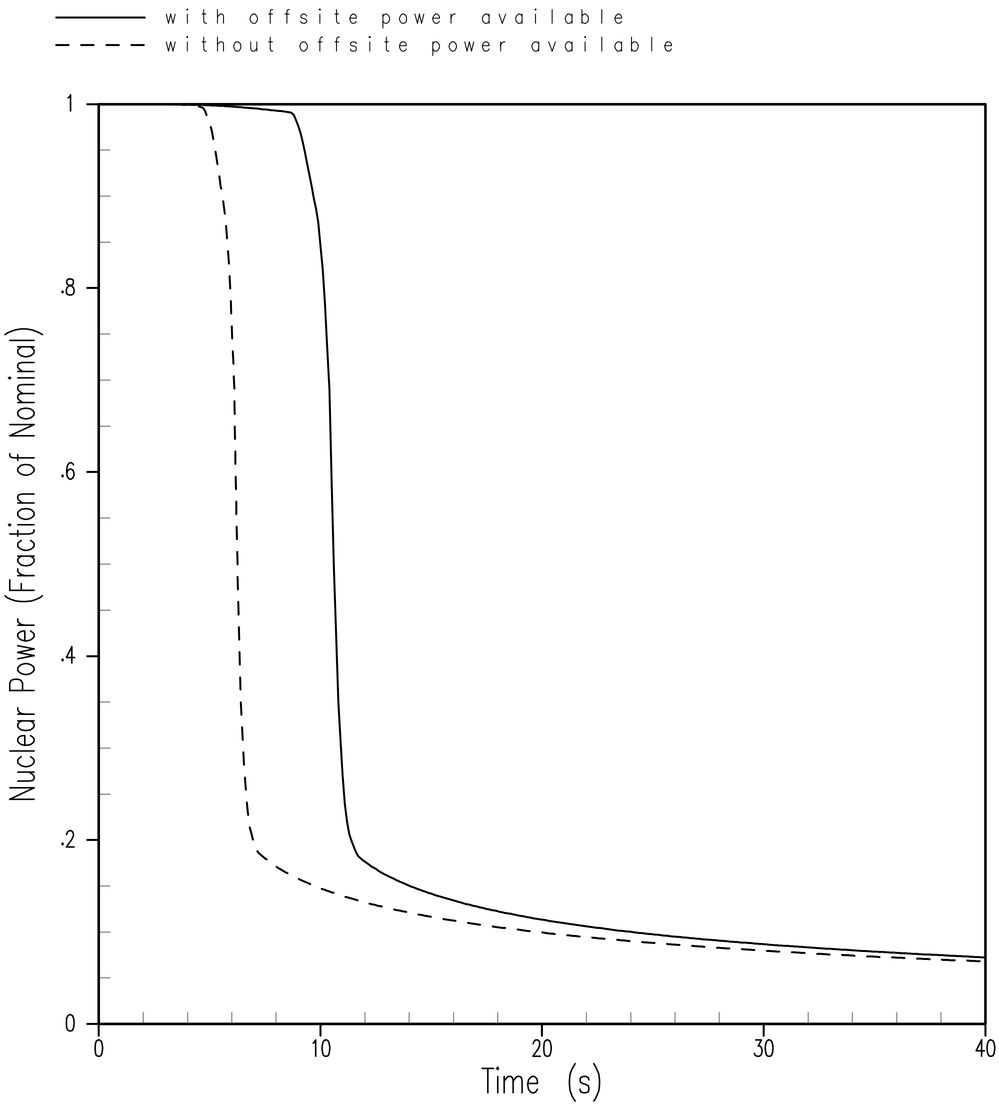

Figure 15.2.3-1

Nuclear Power (Fraction of Nominal) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

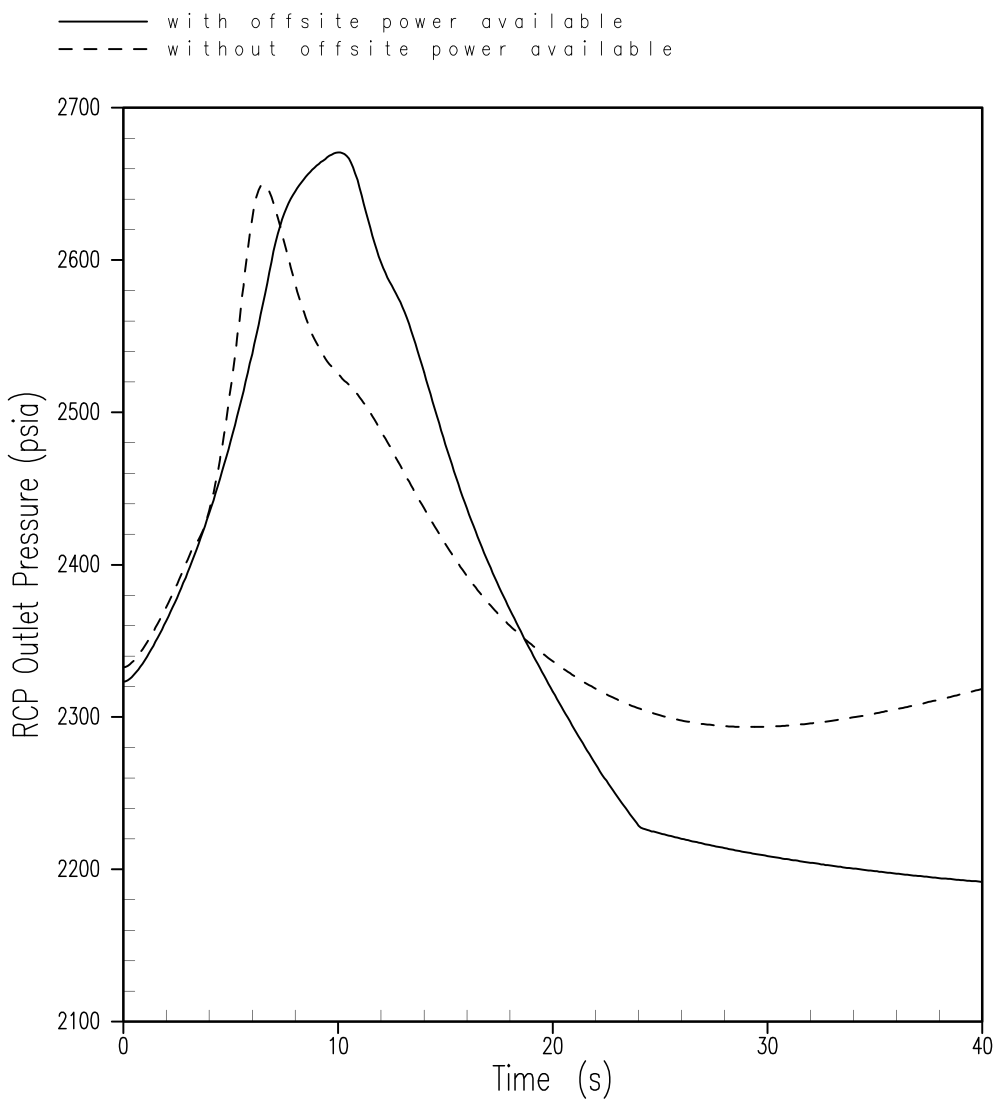

Figure 15.2.3-2

Pressurizer Pressure (psia) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

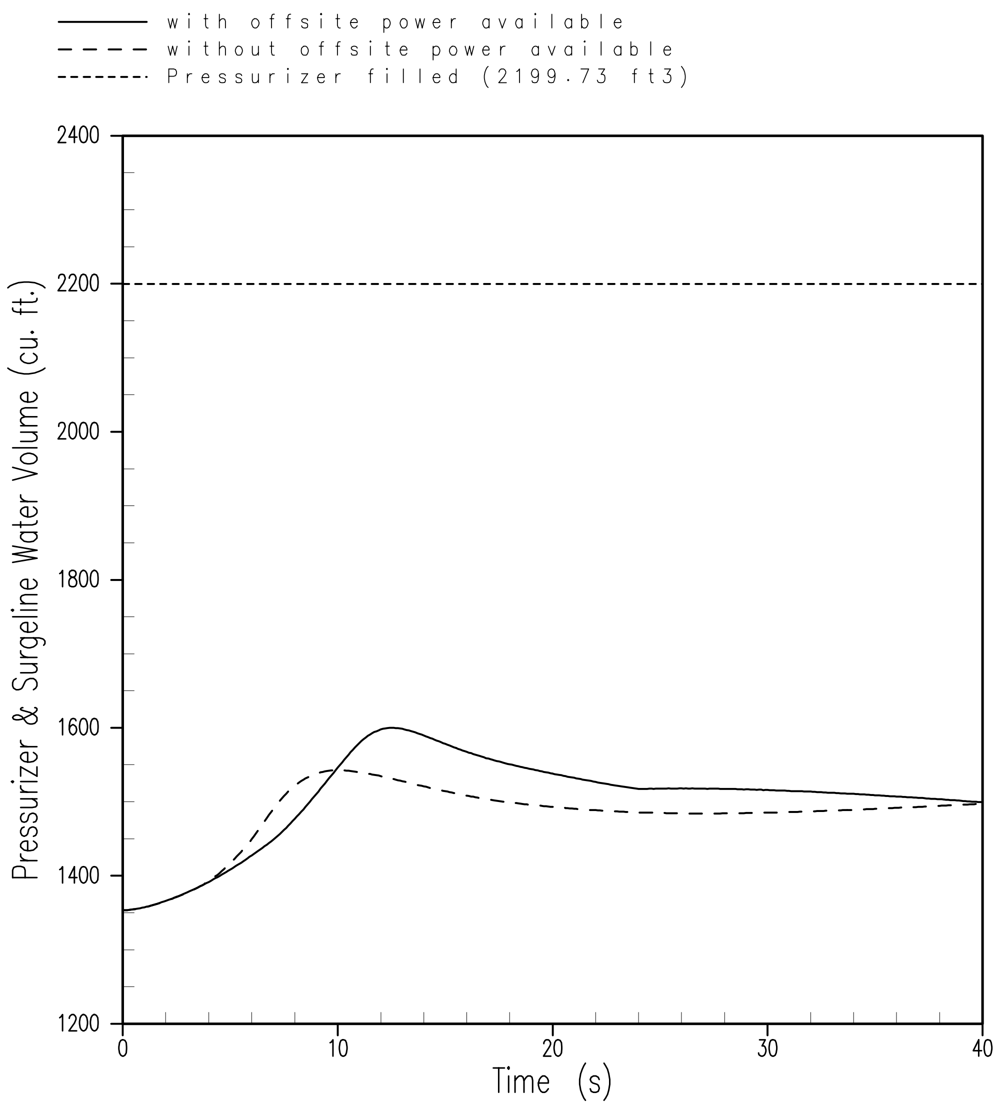

Figure 15.2.3-3

Pressurizer Water Volume (ft^3) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

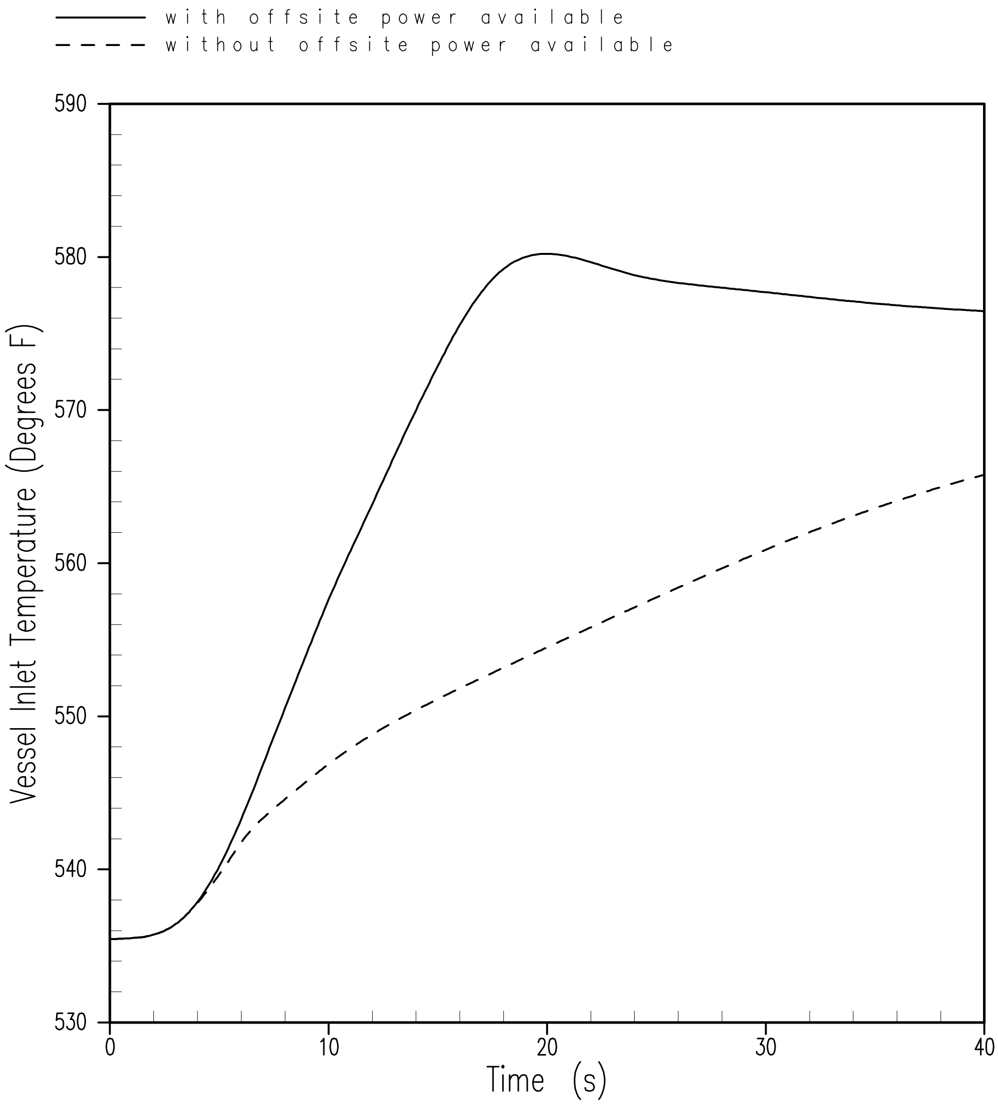

Figure 15.2.3-4

Vessel Inlet Temperature (°F) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

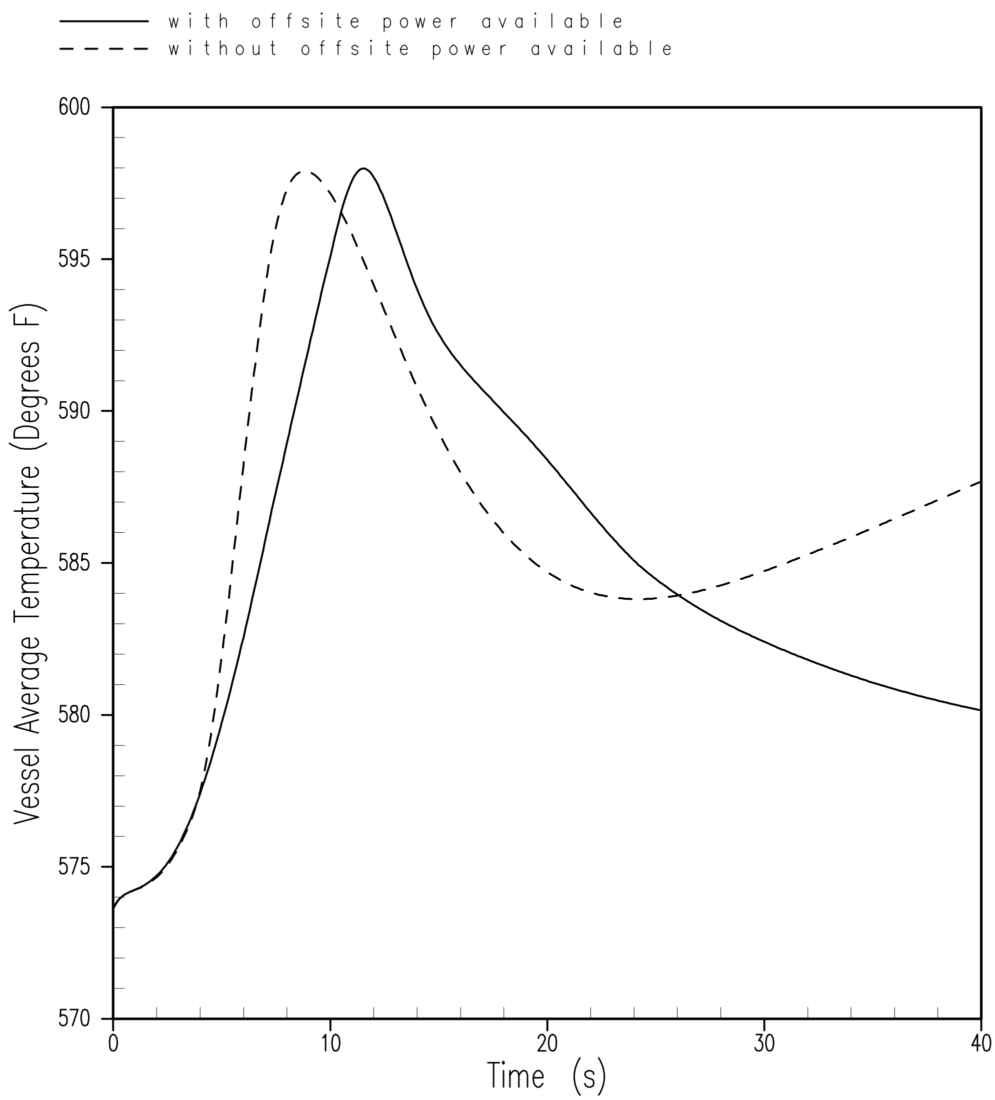

Figure 15.2.3-5

Vessel Average Temperature (°F) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

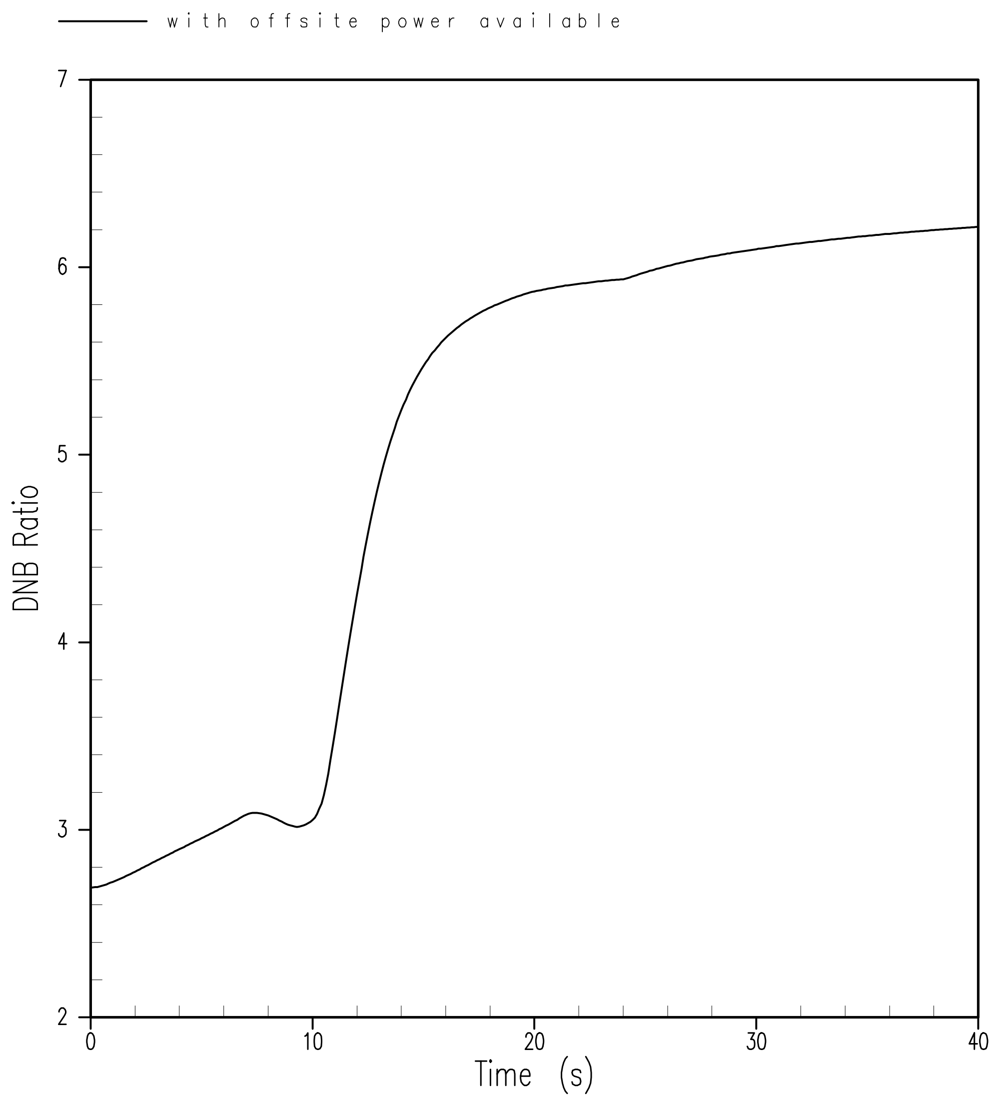

Figure 15.2.3-6

DNBR versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

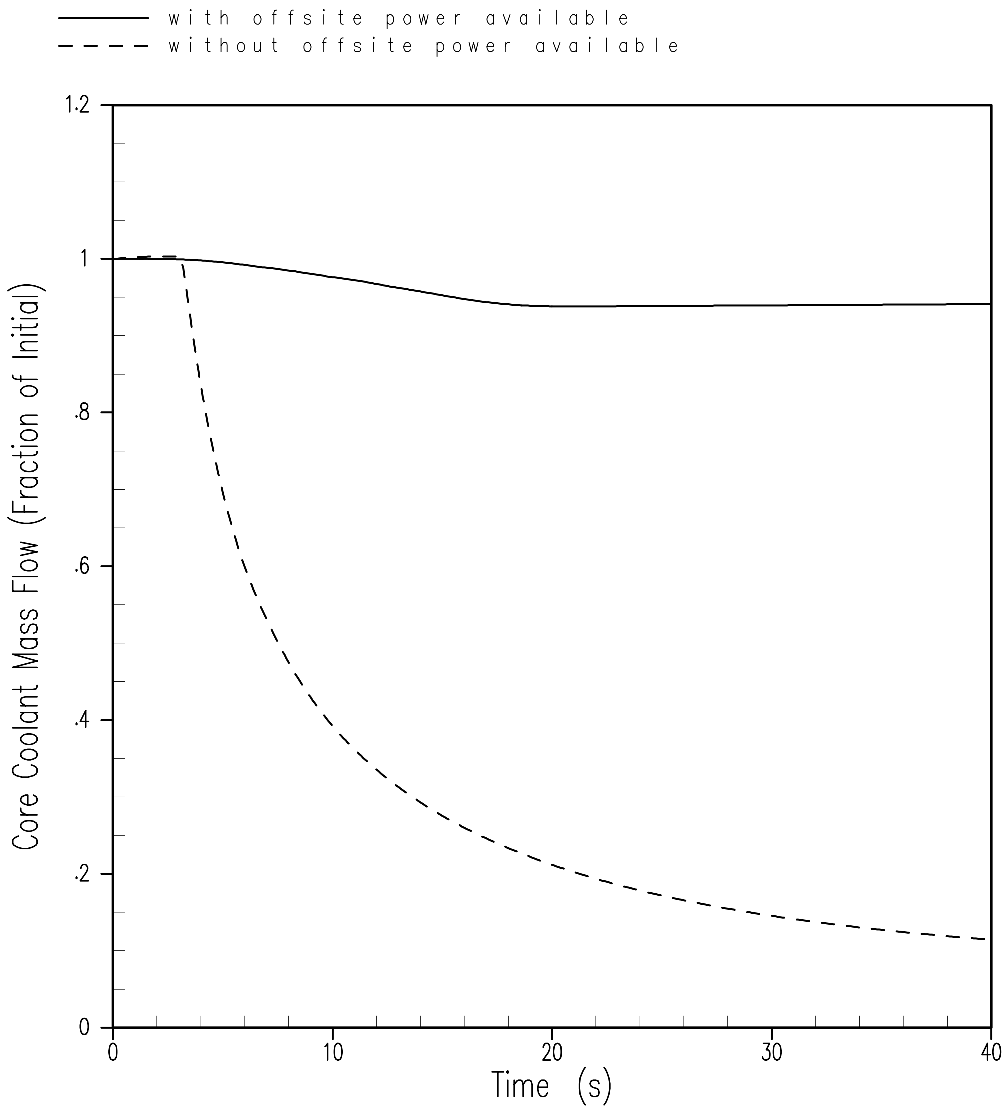

Figure 15.2.3-7

Core Mass Flow Rate (Fraction of Initial) versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

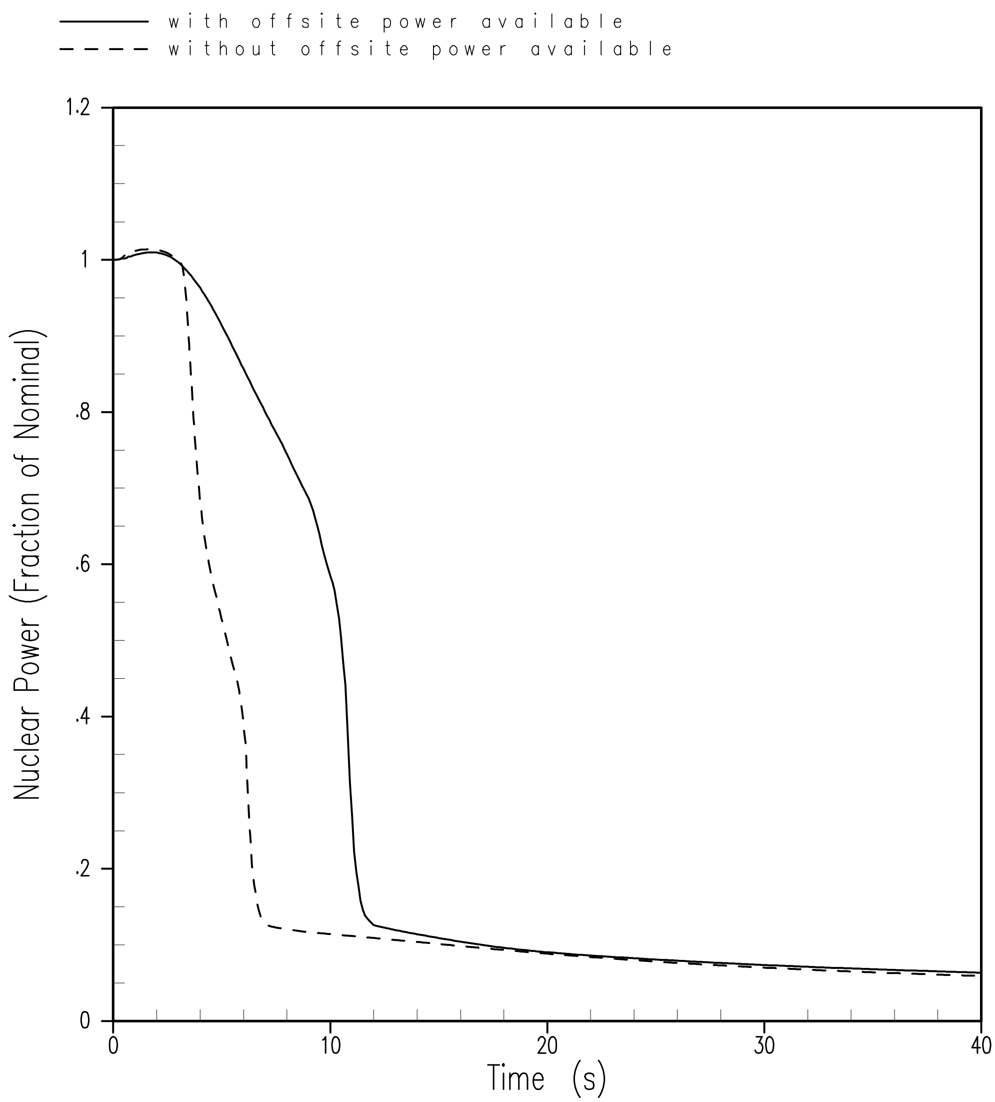

Figure 15.2.3-8

Nuclear Power (Fraction of Nominal) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

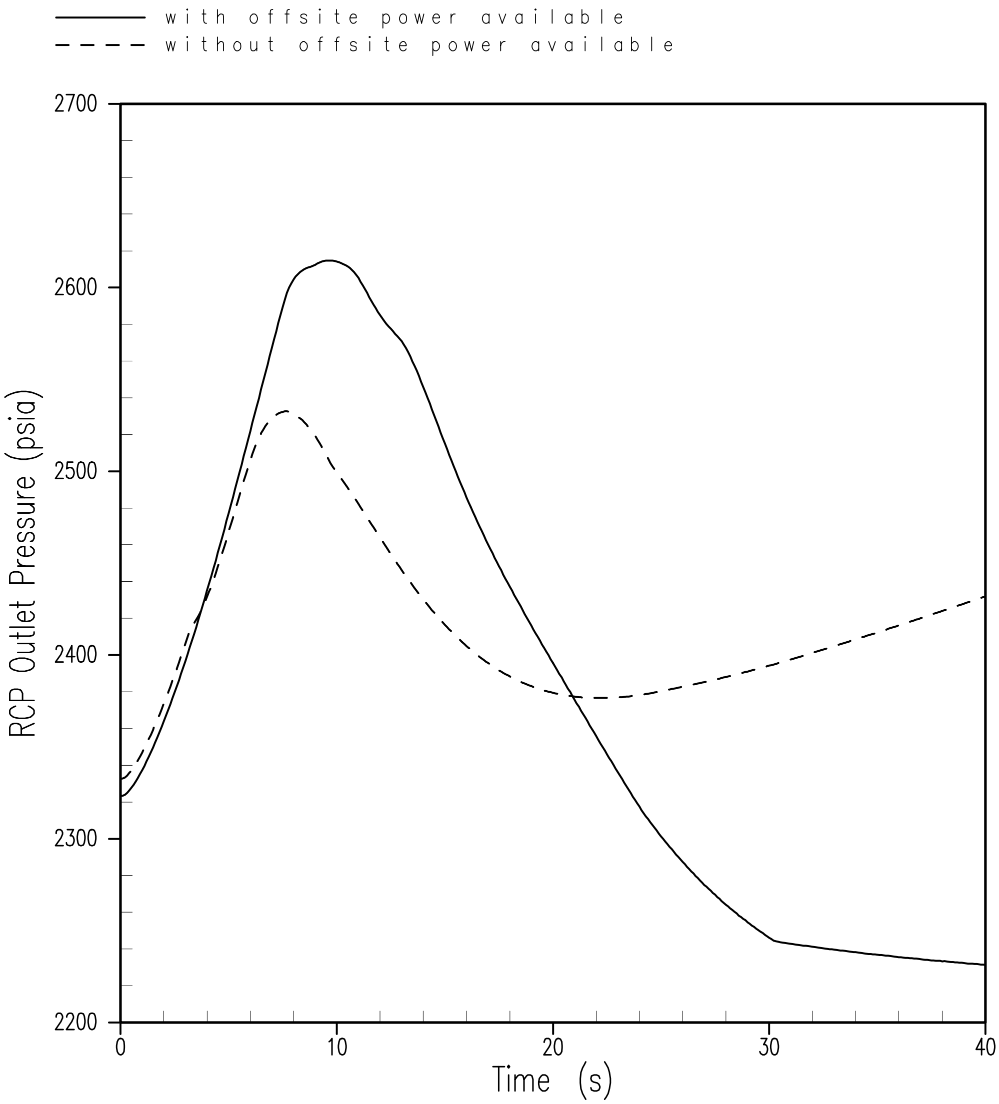

Figure 15.2.3-9

Pressurizer Pressure (psia) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

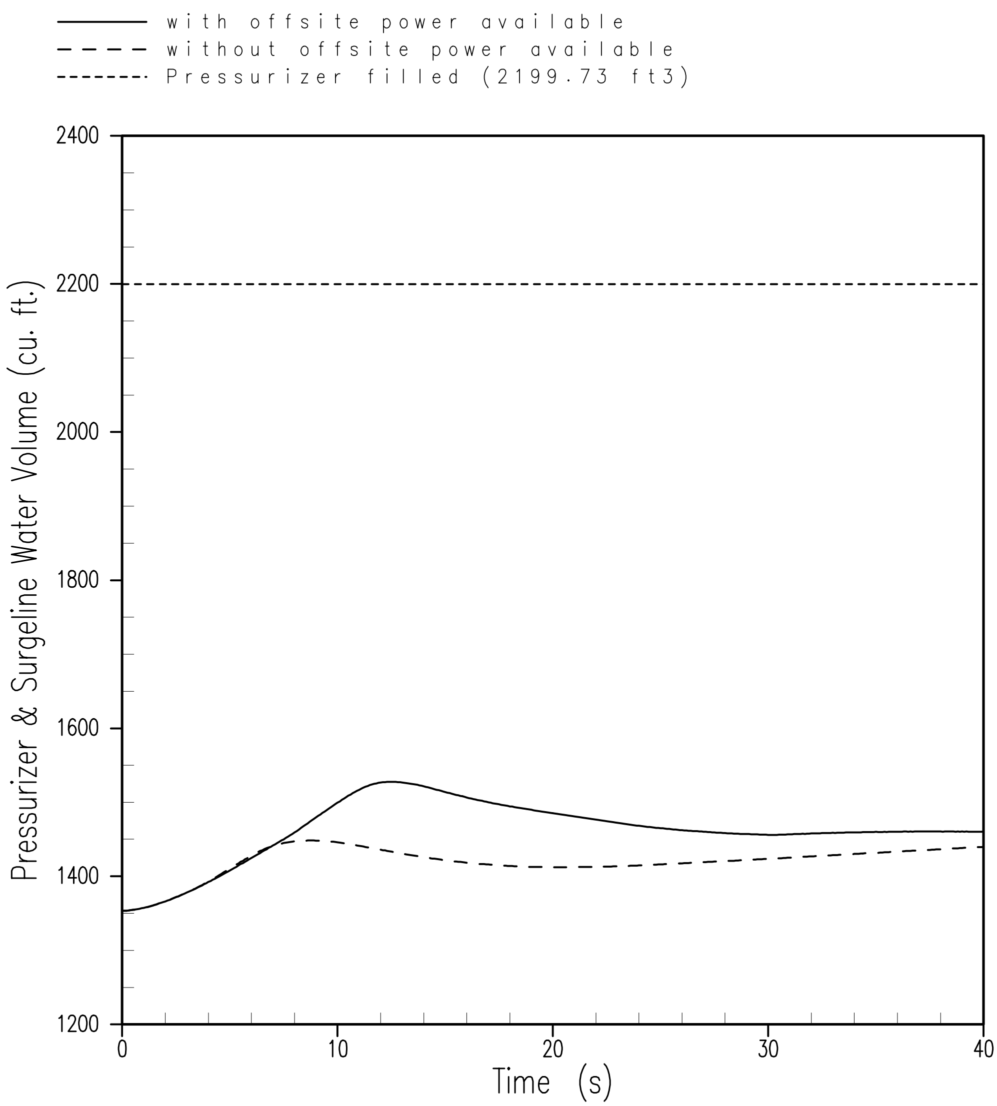

Figure 15.2.3-10

Pressurizer Water Volume (ft^3) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

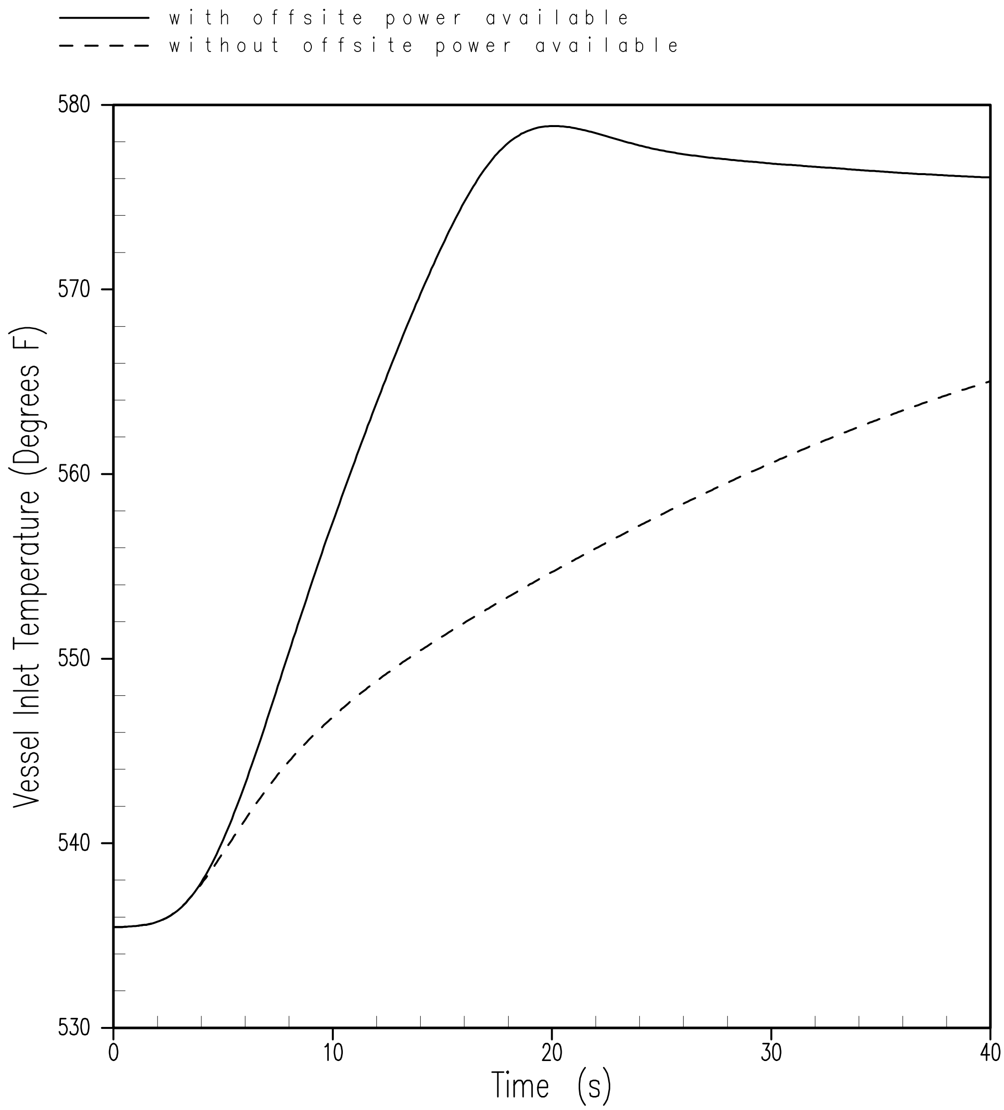

Figure 15.2.3-11

Vessel Inlet Temperature (°F) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

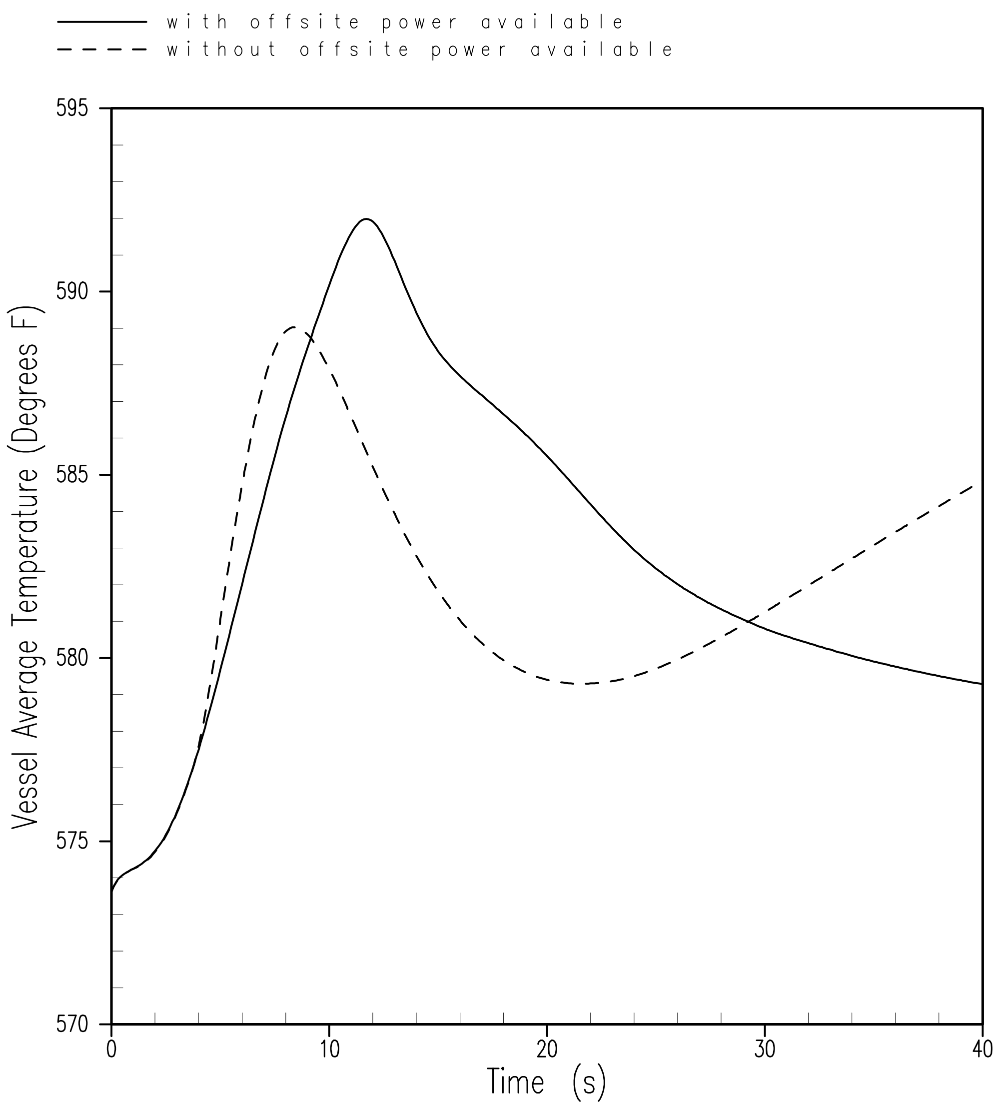

Figure 15.2.3-12

Vessel Average Temperature (°F) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

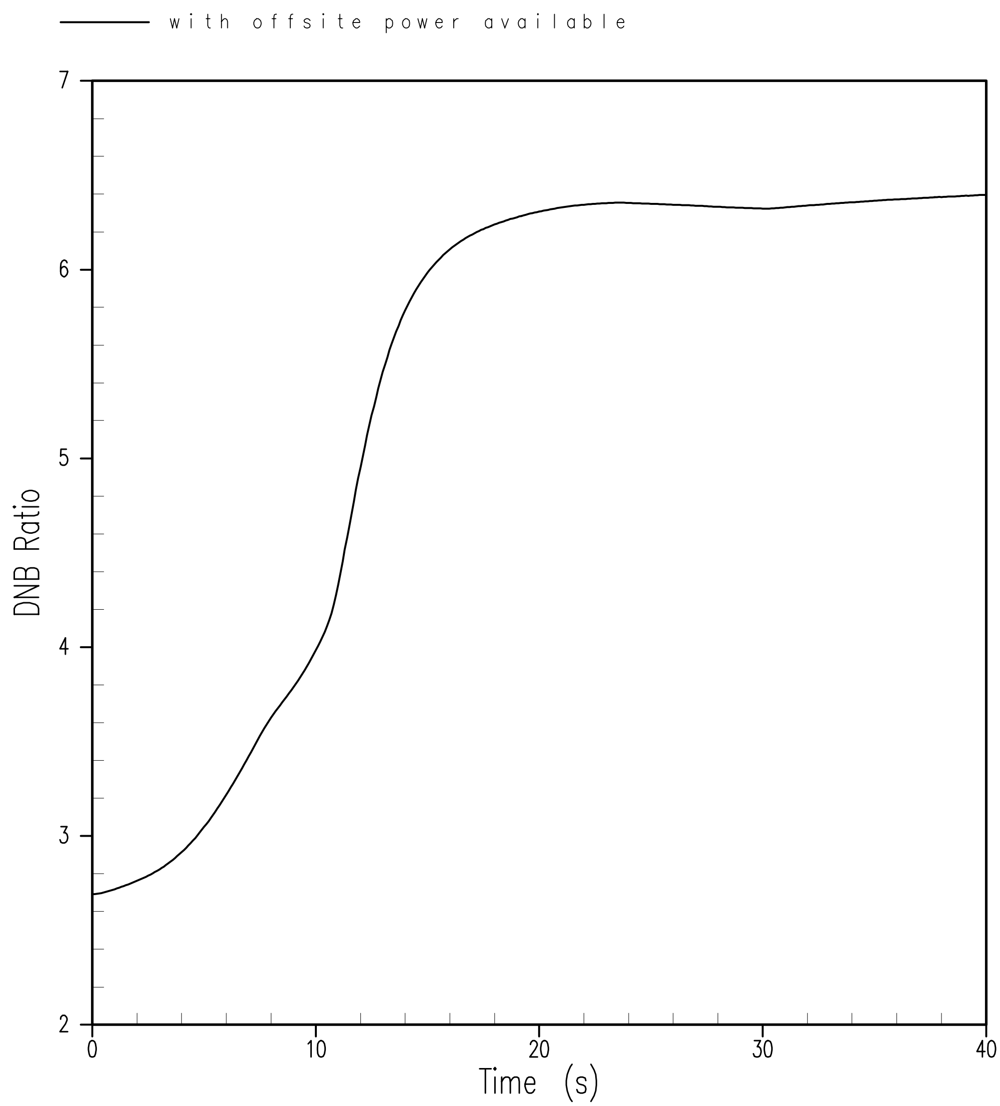

Figure 15.2.3-13

DNBR versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

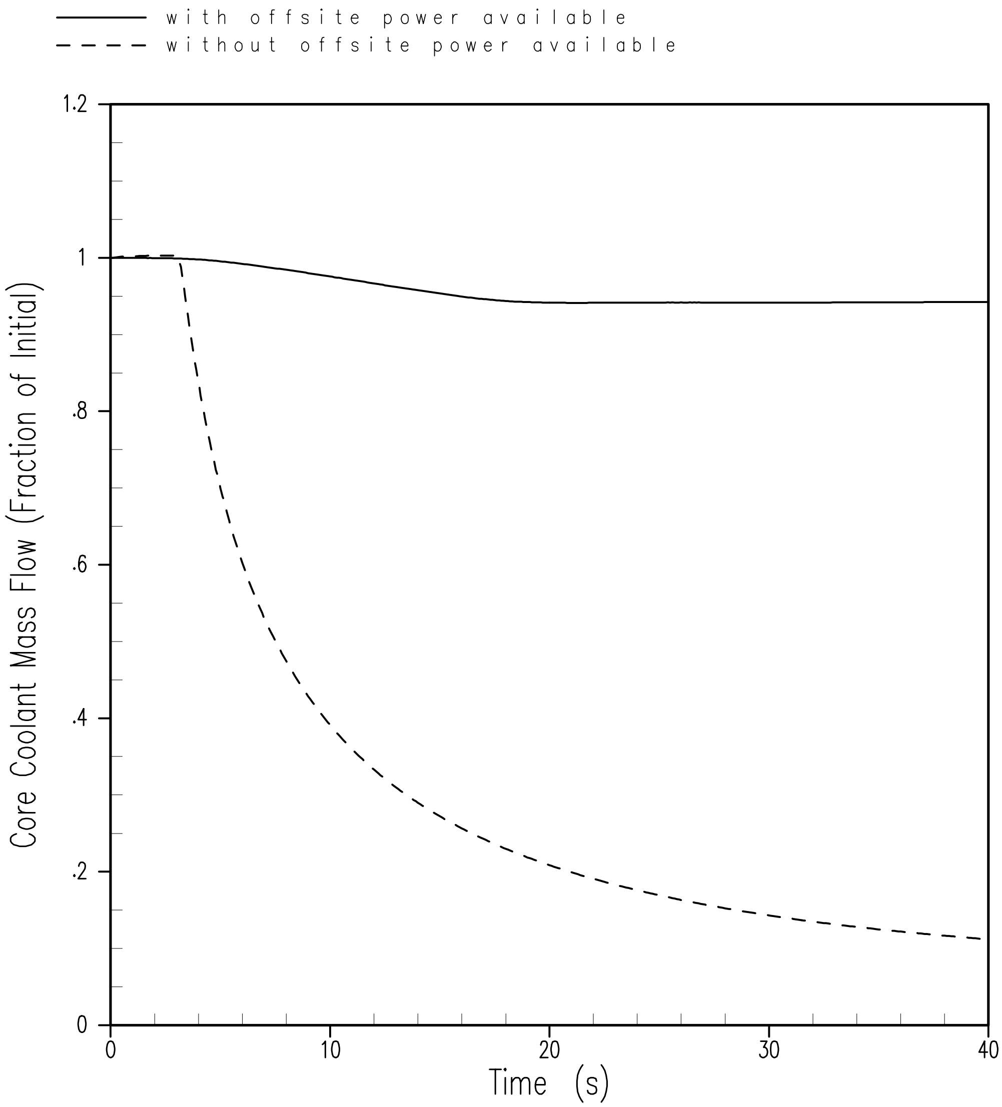

Figure 15.2.3-14

Core Mass Flow Rate (Fraction of Initial) versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

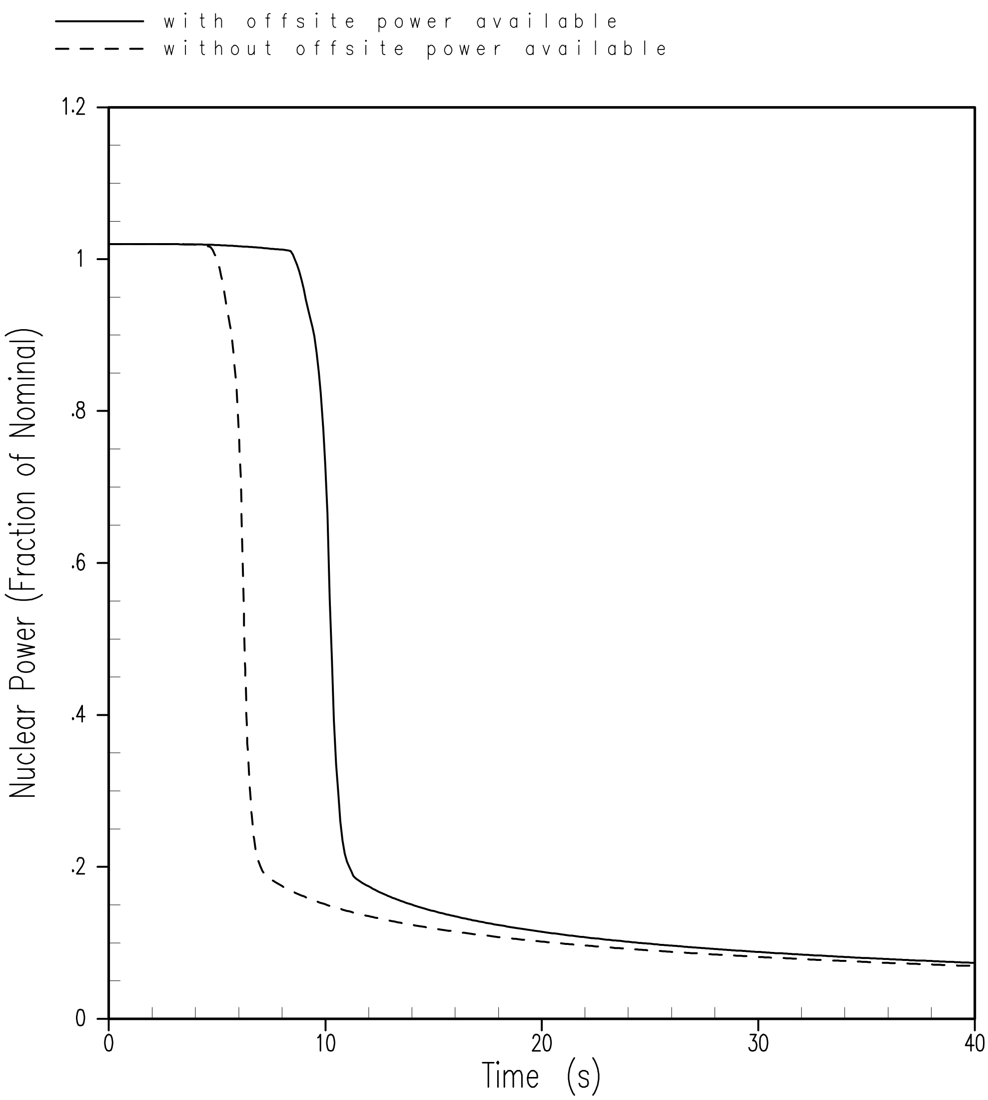

Figure 15.2.3-15

Nuclear Power (Fraction of Nominal) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

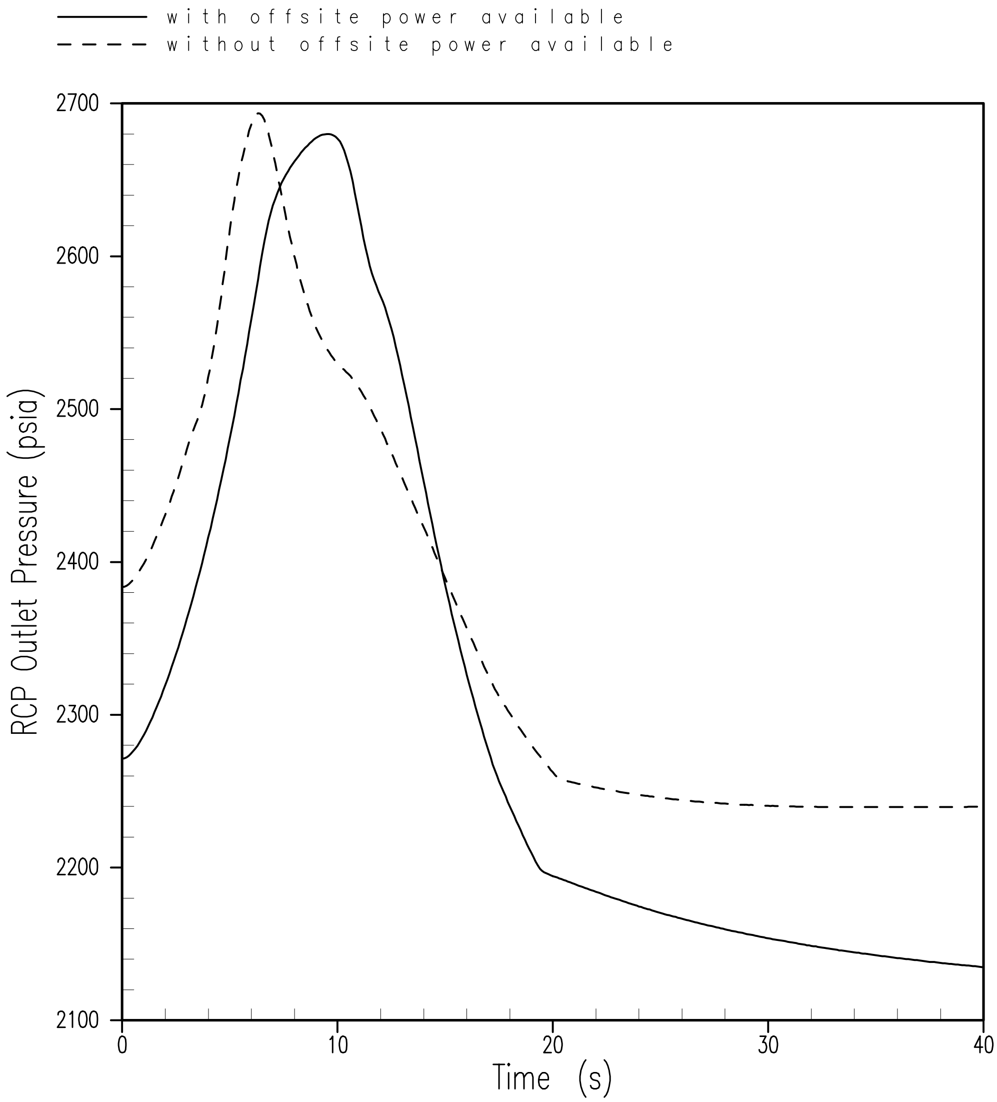

Figure 15.2.3-16

Pressurizer Pressure (psia) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

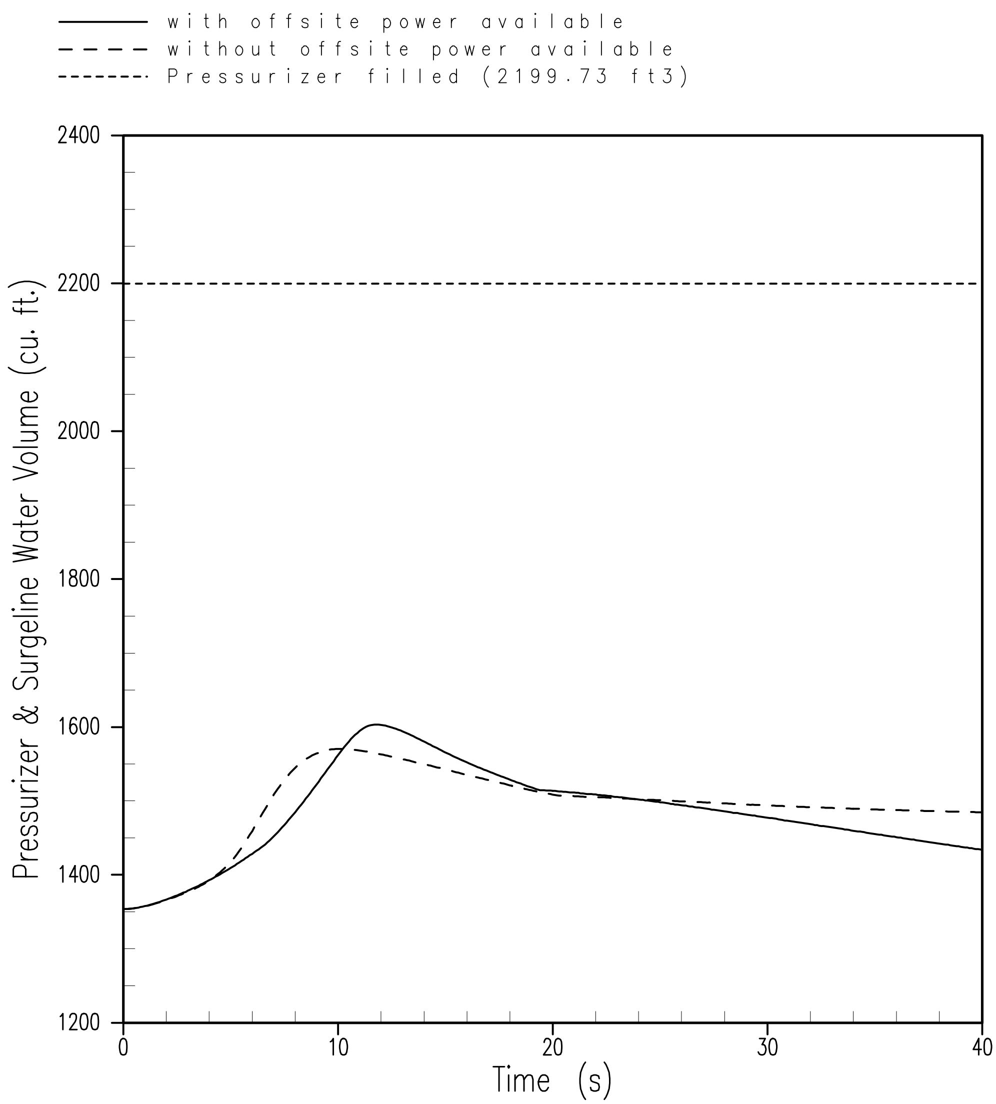

Figure 15.2.3-17

Pressurizer Water Volume (ft^3) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

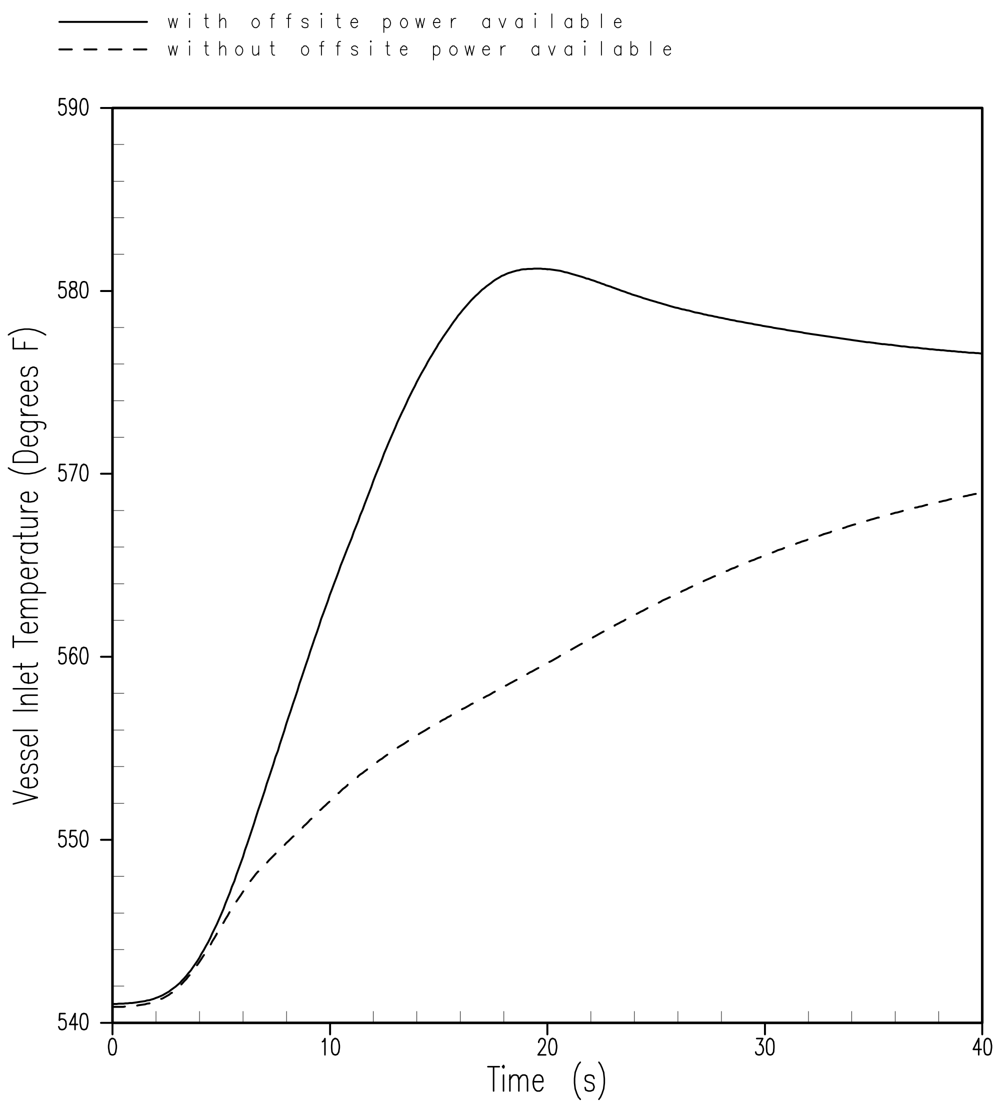

Figure 15.2.3-18

Vessel Inlet Temperature (°F) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

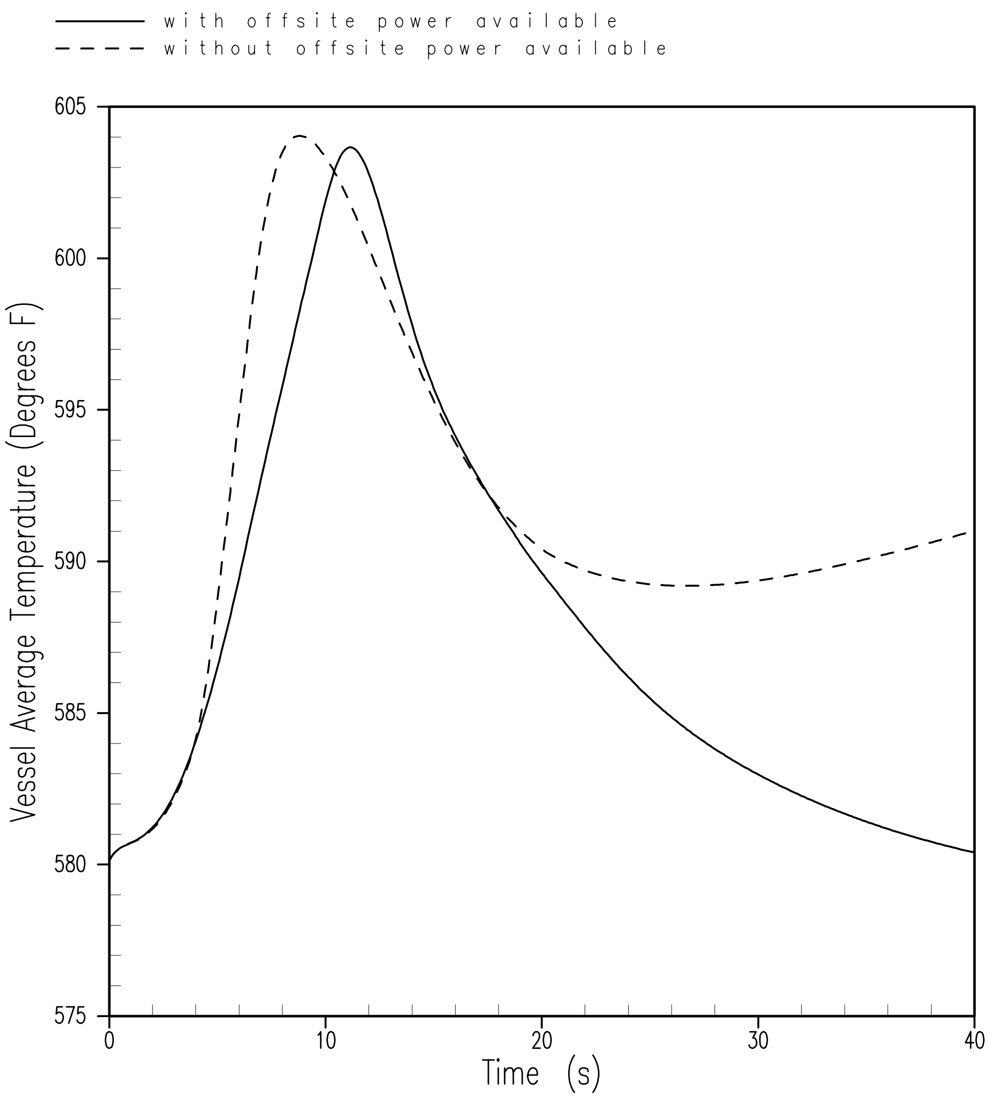

Figure 15.2.3-19

Vessel Average Temperature (°F) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

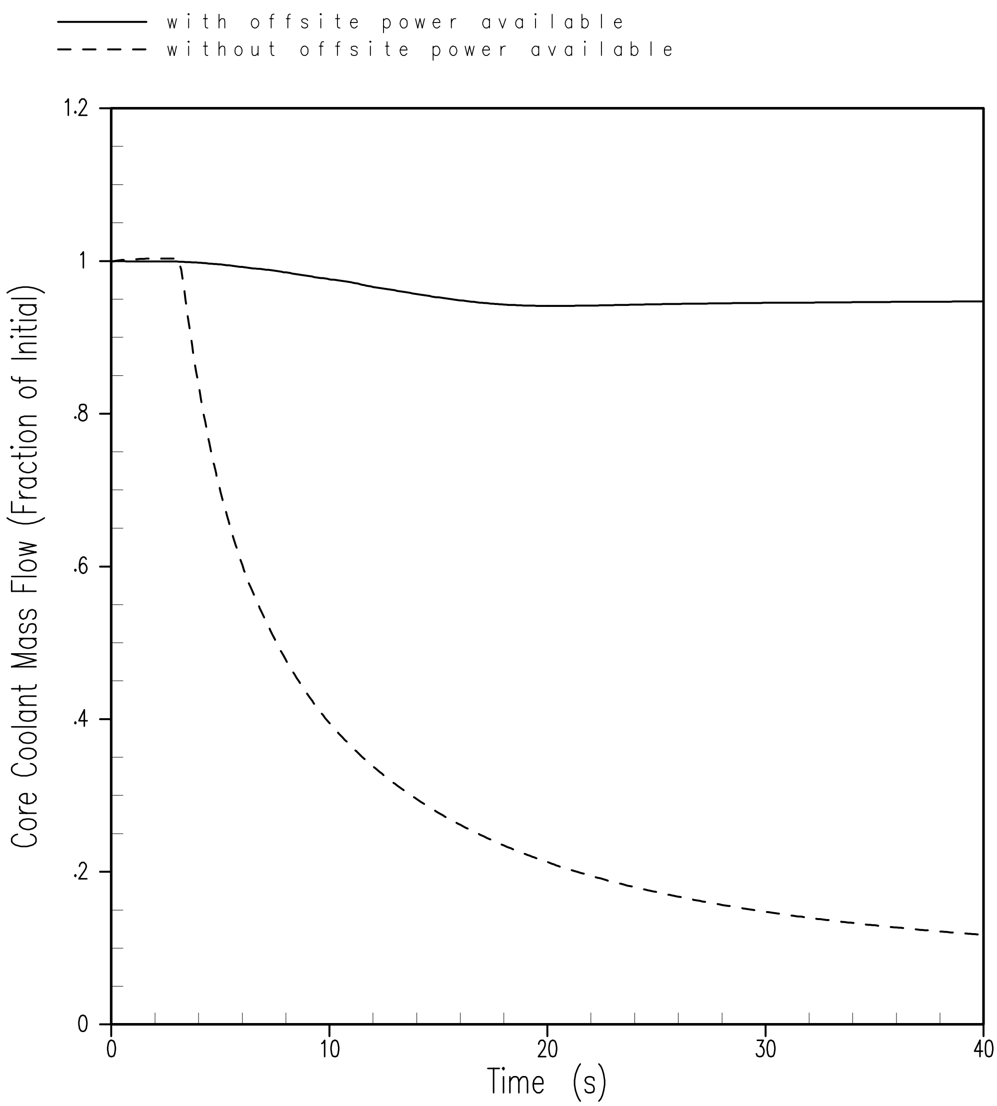

Figure 15.2.3-20

Core Mass Flow Rate (Fraction of Initial) versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

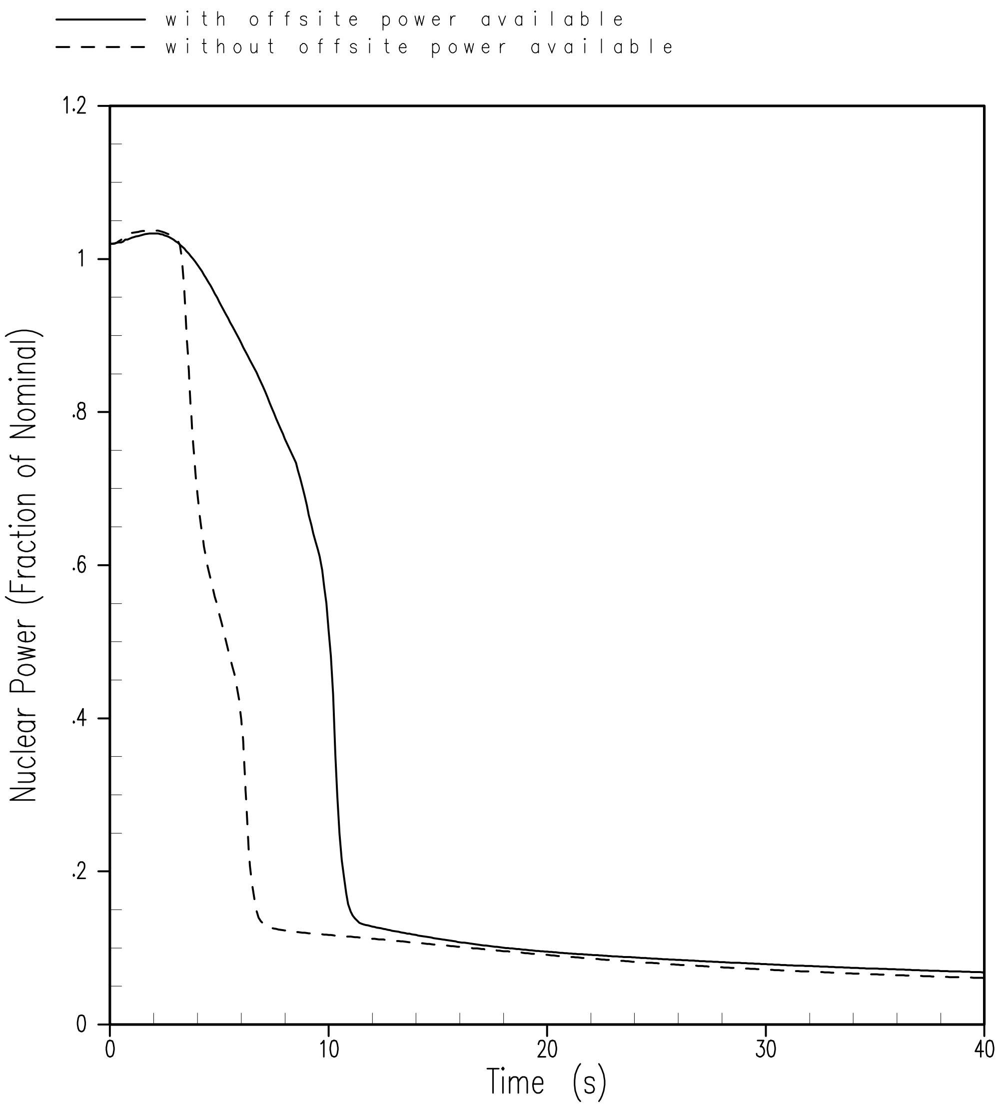

Figure 15.2.3-21

Nuclear Power (Fraction of Nominal) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

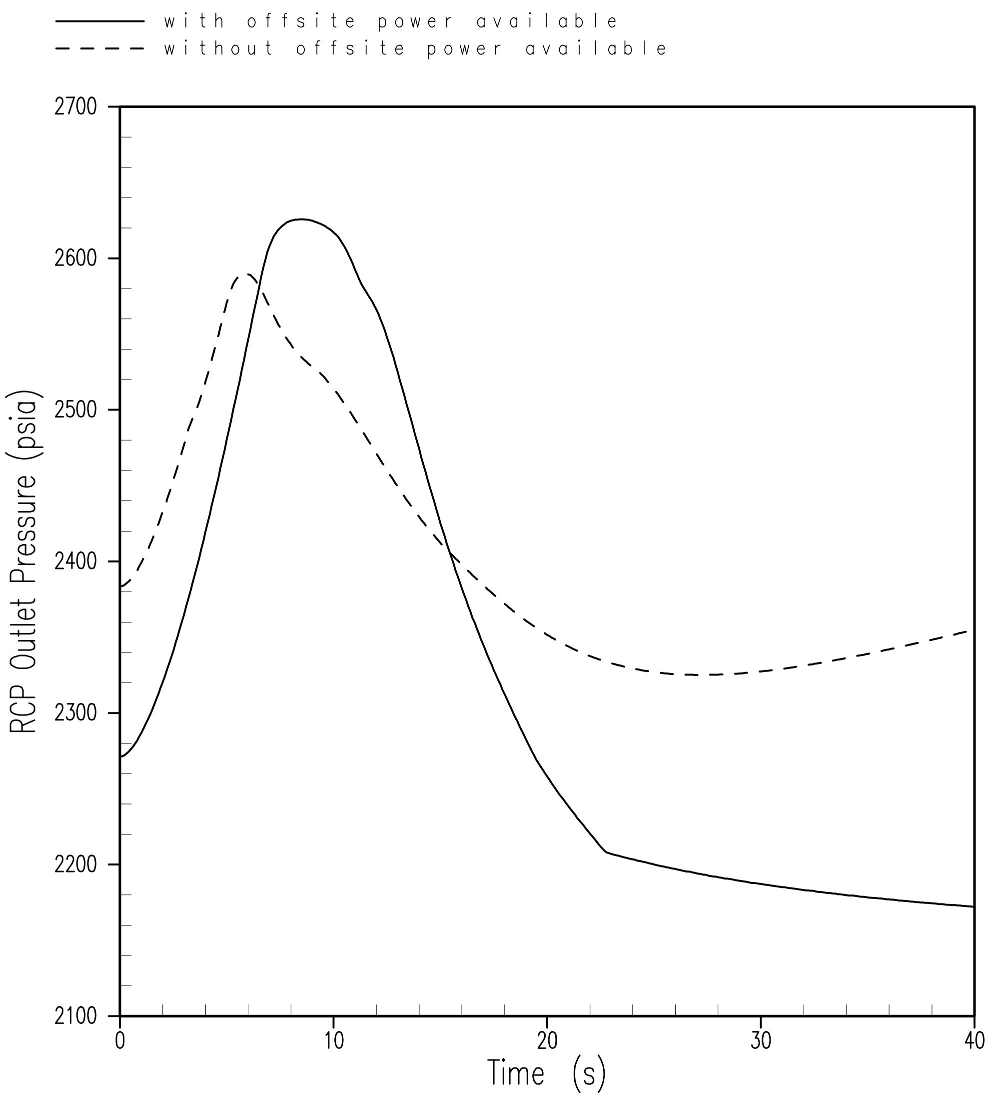

Figure 15.2.3-22

Pressurizer Pressure (psia) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

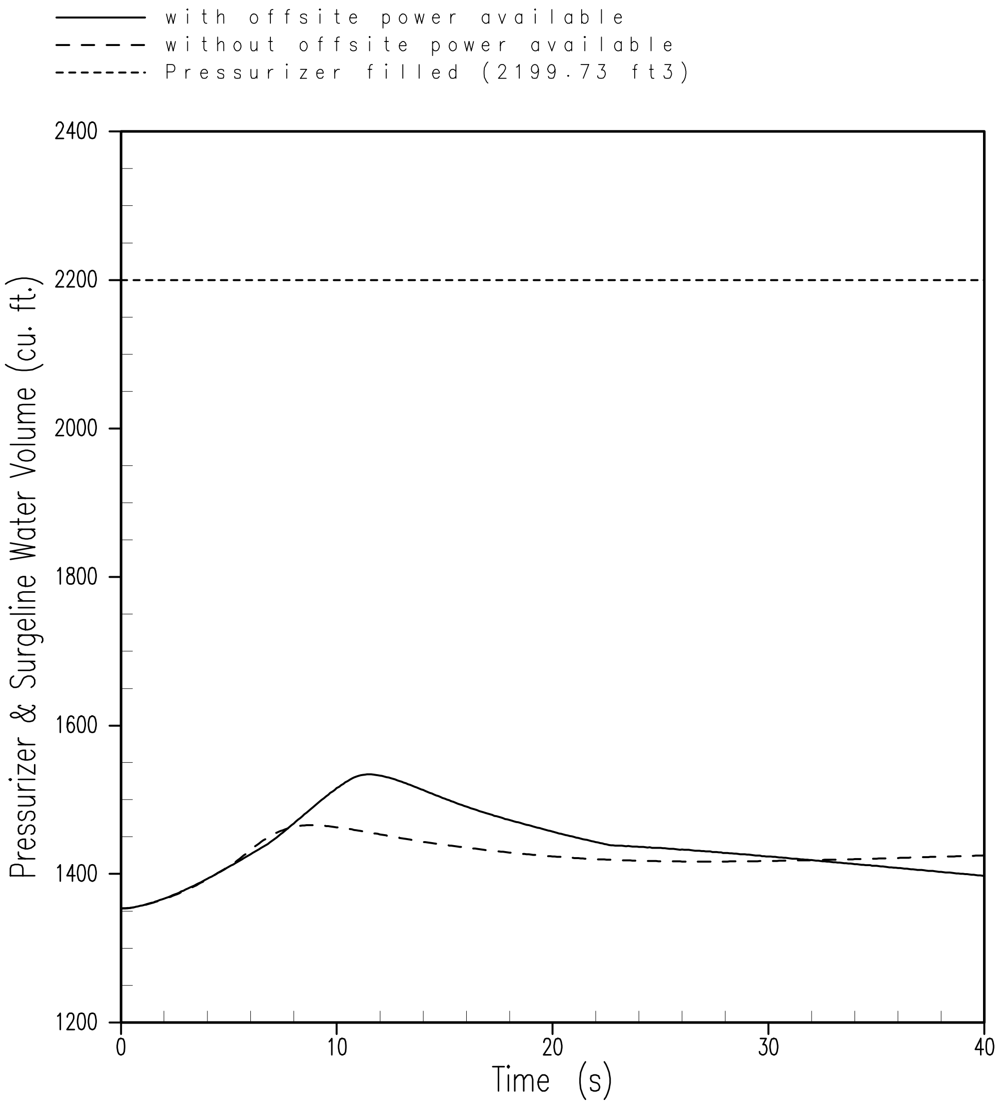

Figure 15.2.3-23

Pressurizer Water Volume (ft^3) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

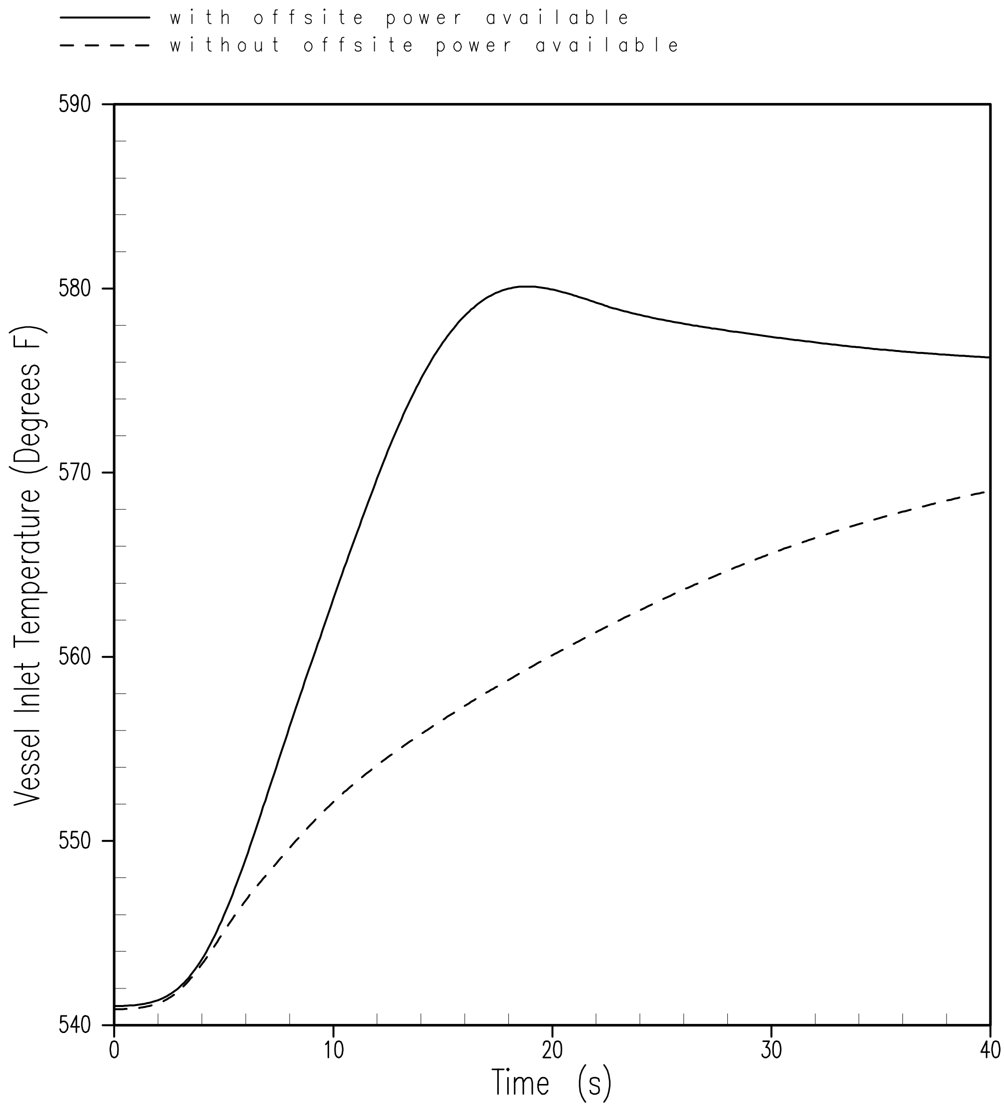

Figure 15.2.3-24

Vessel Inlet Temperature (°F) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

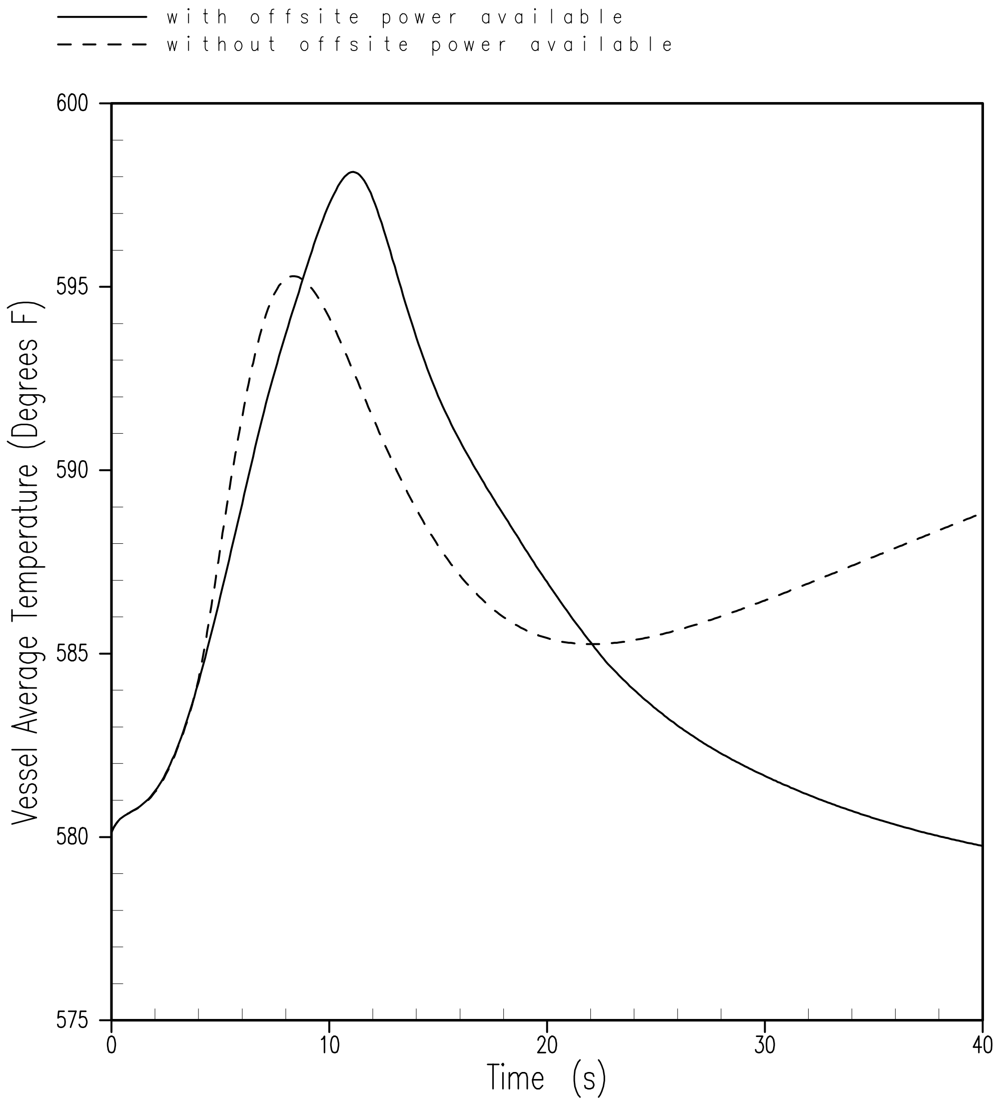

Figure 15.2.3-25

Vessel Average Temperature (°F) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

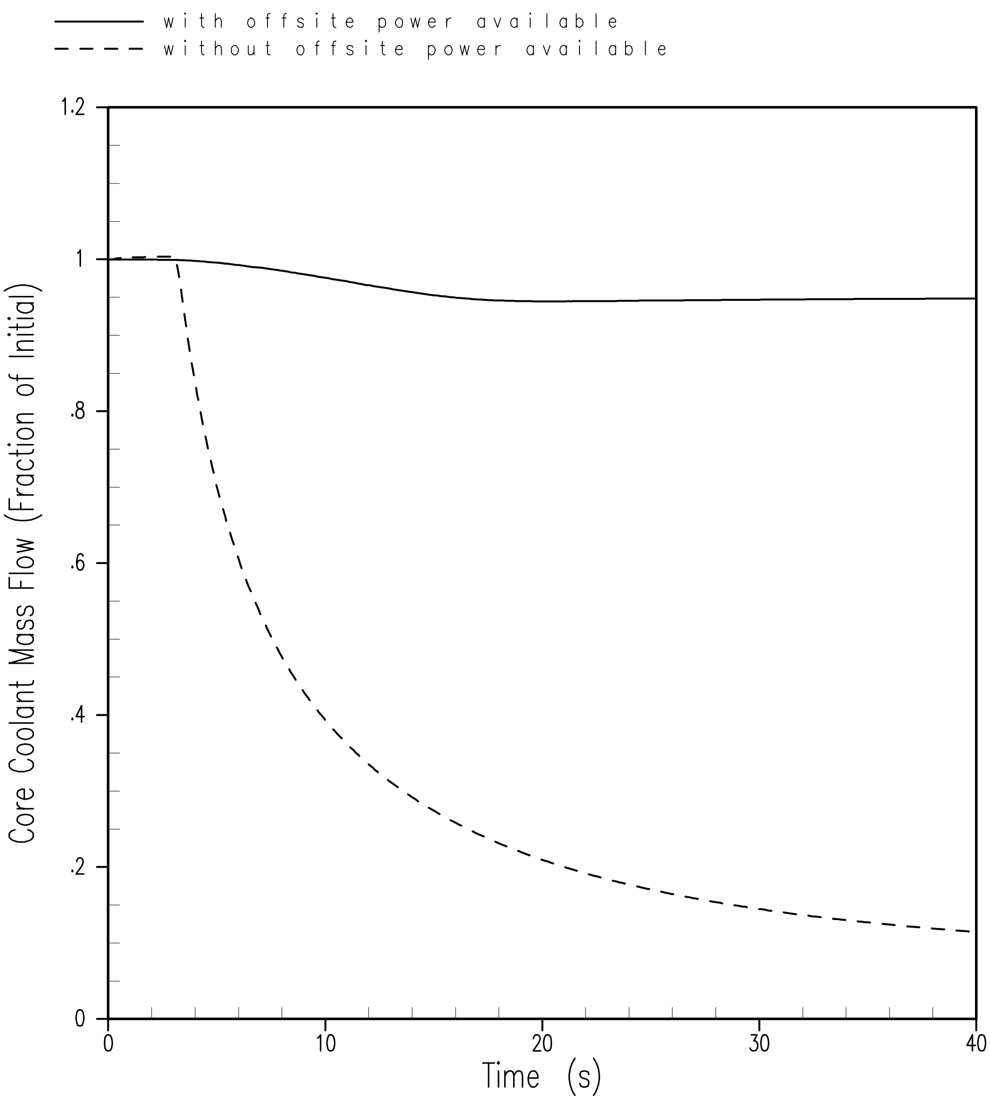

Figure 15.2.3-26

Core Mass Flow Rate (Fraction of Initial) versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

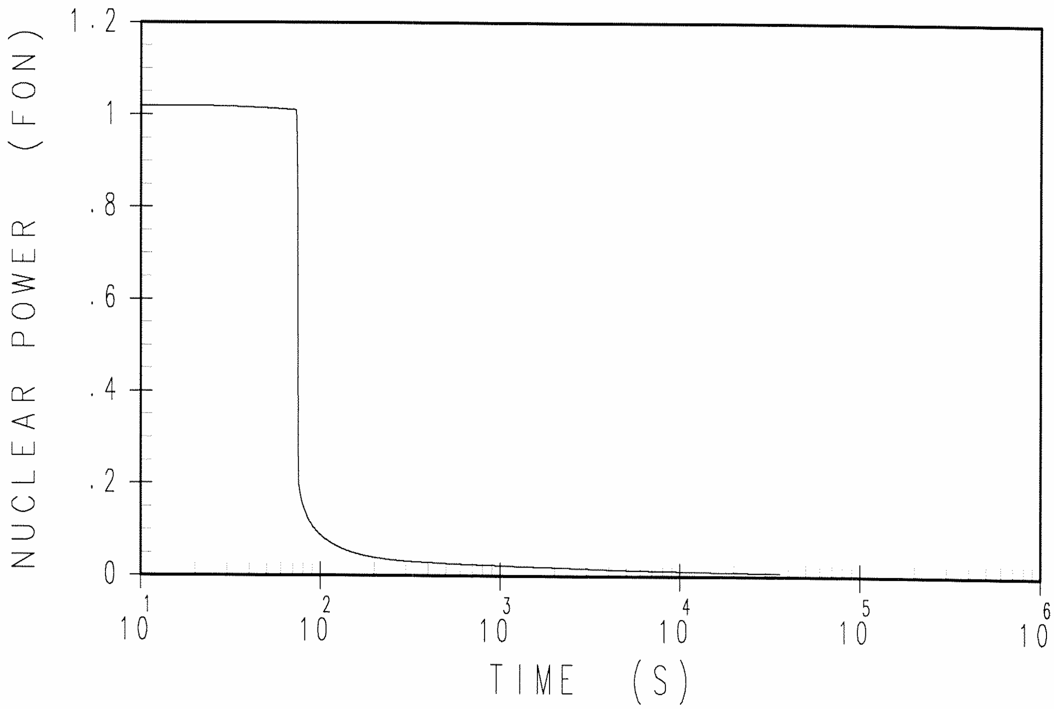

Figure 15.2.6-1

Nuclear Power Transient for Loss of ac Power to the Plant Auxiliaries

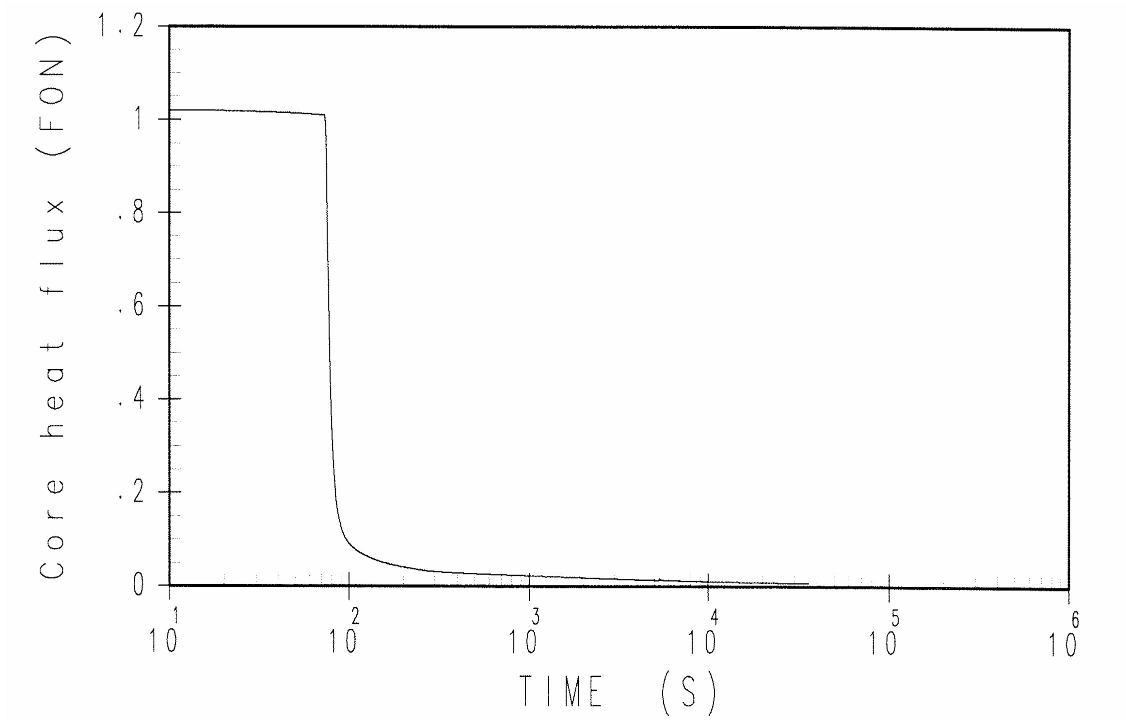

Figure 15.2.6-2

Core Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries

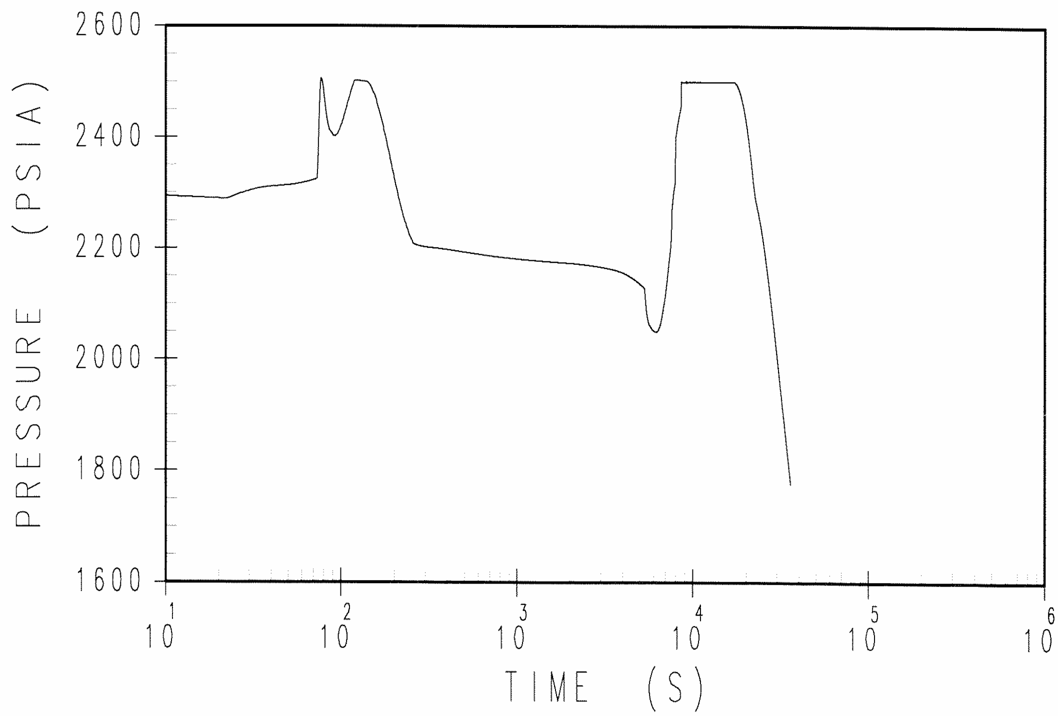

Figure 15.2.6-3

Pressurizer Pressure Transient for Loss of ac Power to the Plant Auxiliaries

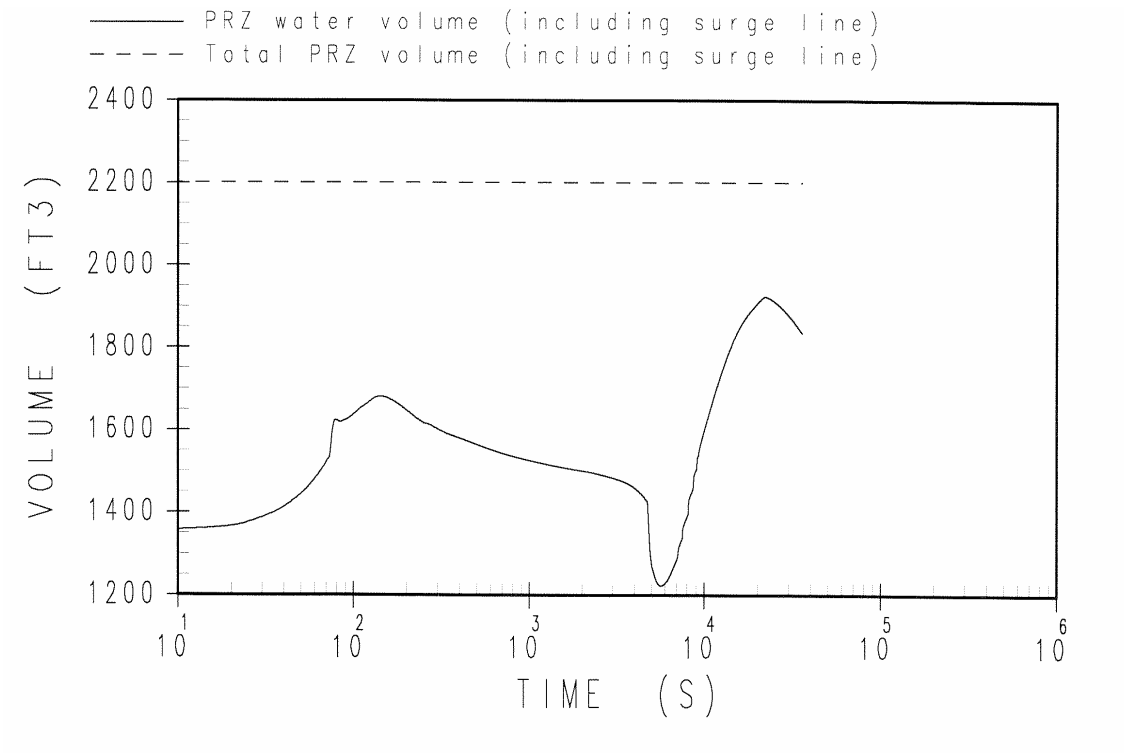

Figure 15.2.6-4

Pressurizer Water Volume Transient for Loss of ac Power to the Plant Auxiliaries

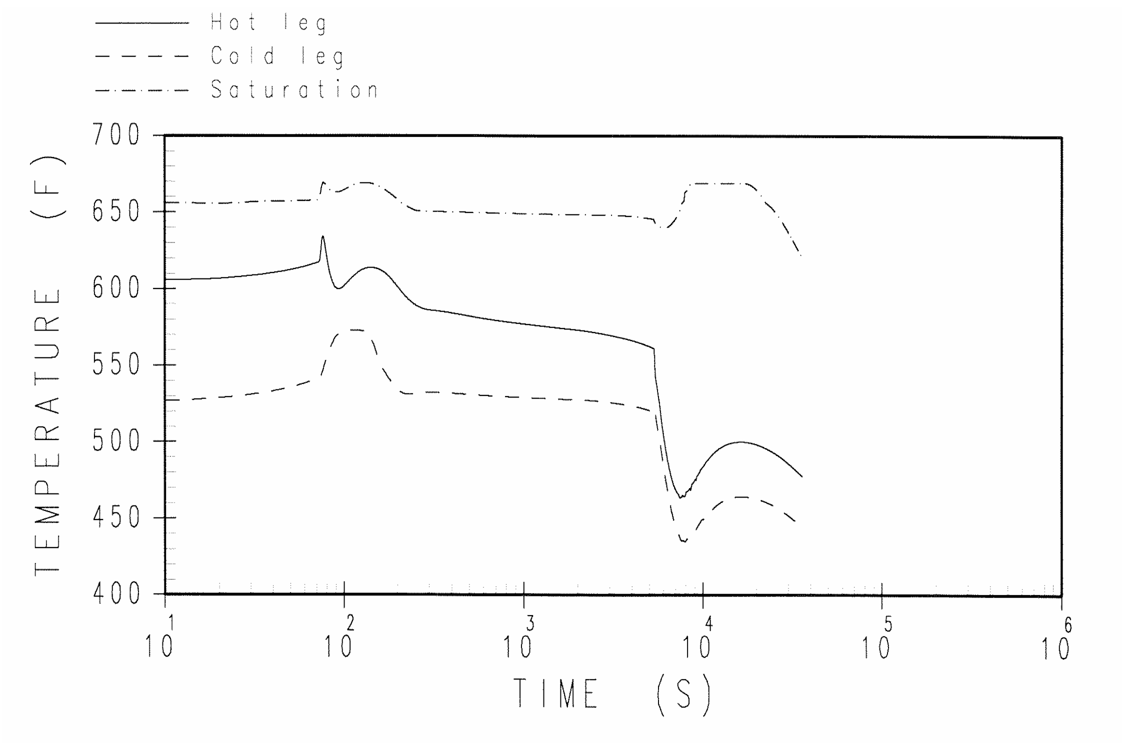

Figure 15.2.6-5

Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

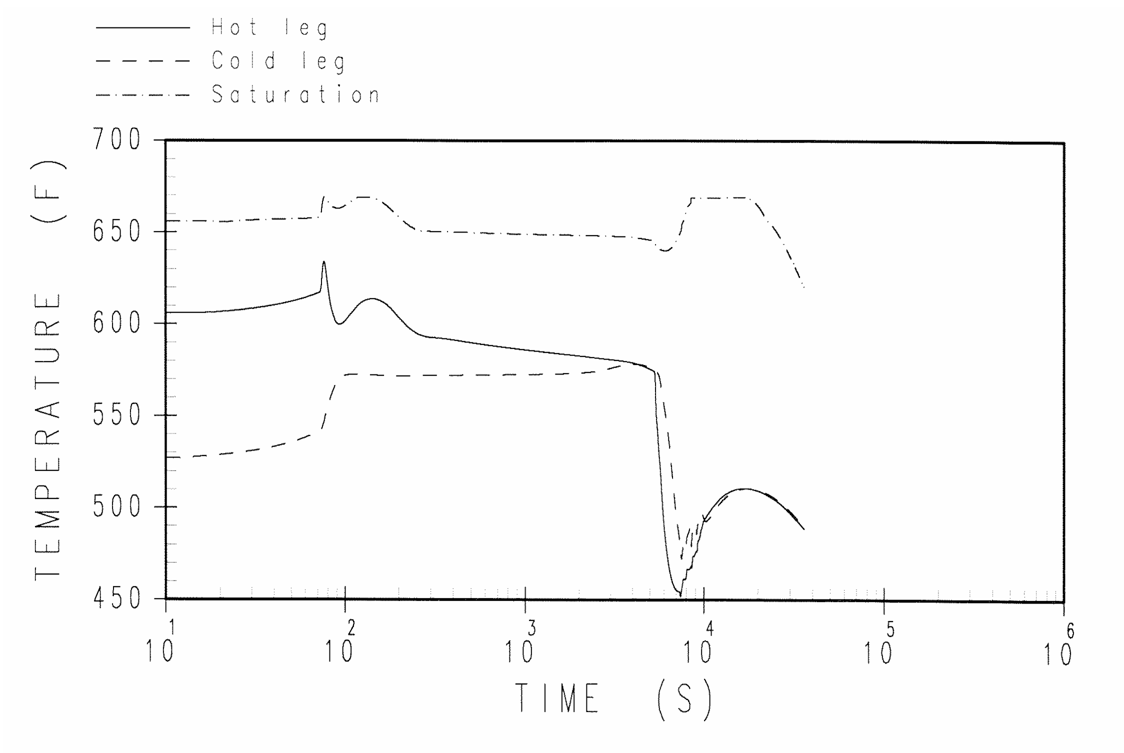

Figure 15.2.6-6

Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

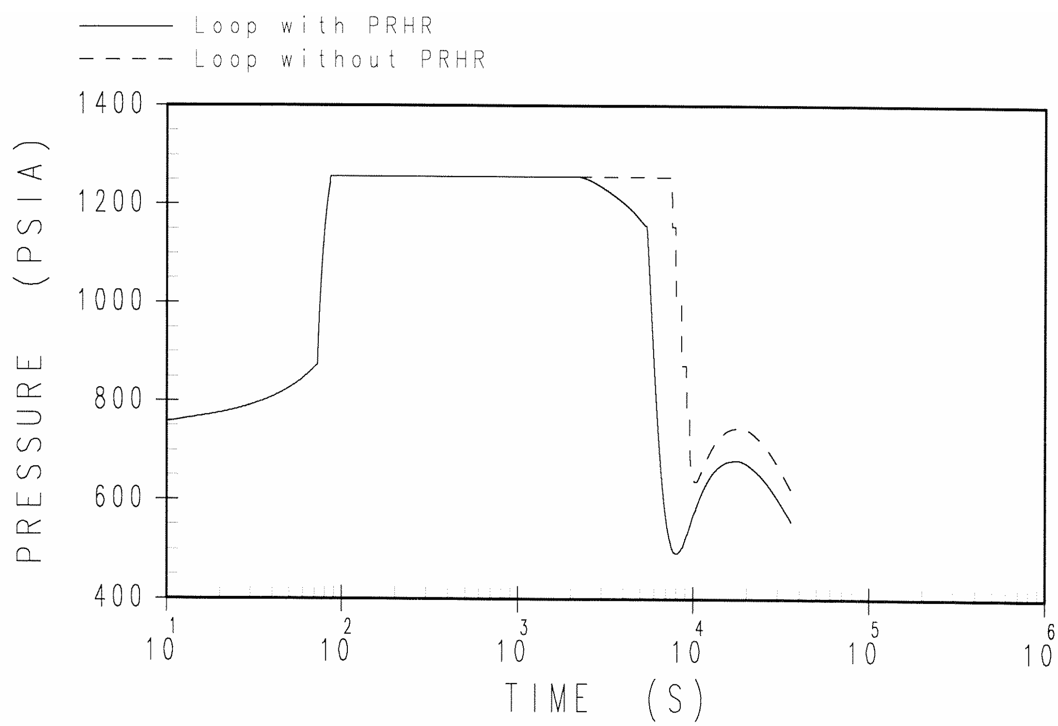

Figure 15.2.6-7

Steam Generator Pressure Transient for Loss of ac Power to the Plant Auxiliaries

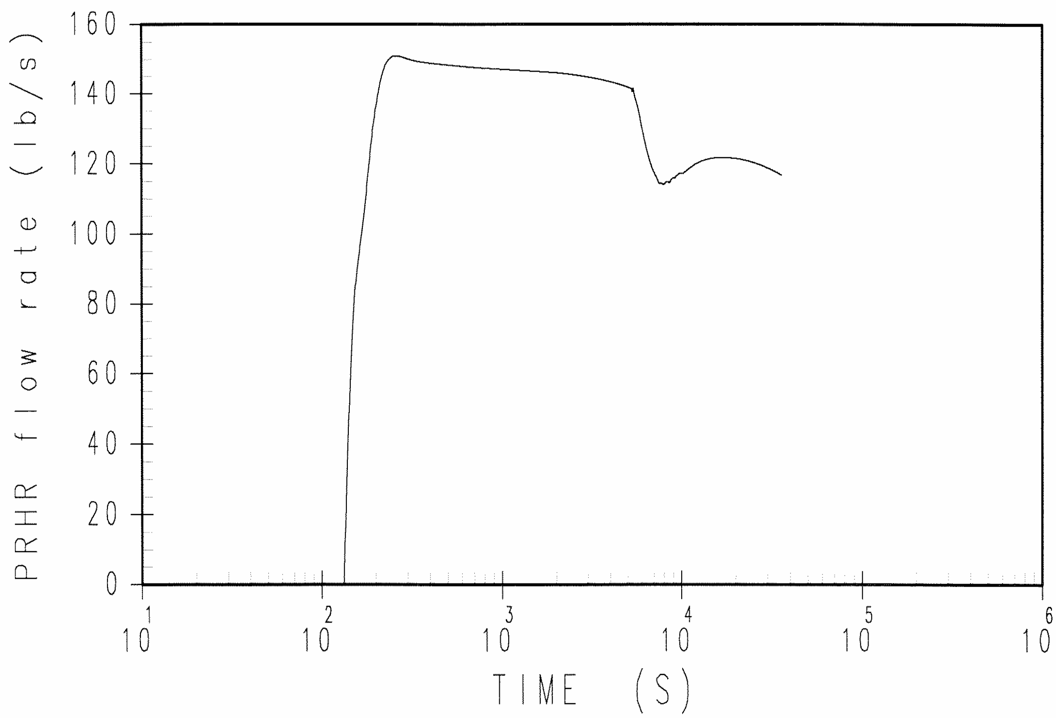

Figure 15.2.6-8

PRHR Flow Rate Transient
for Loss of ac Power to the Plant Auxiliaries

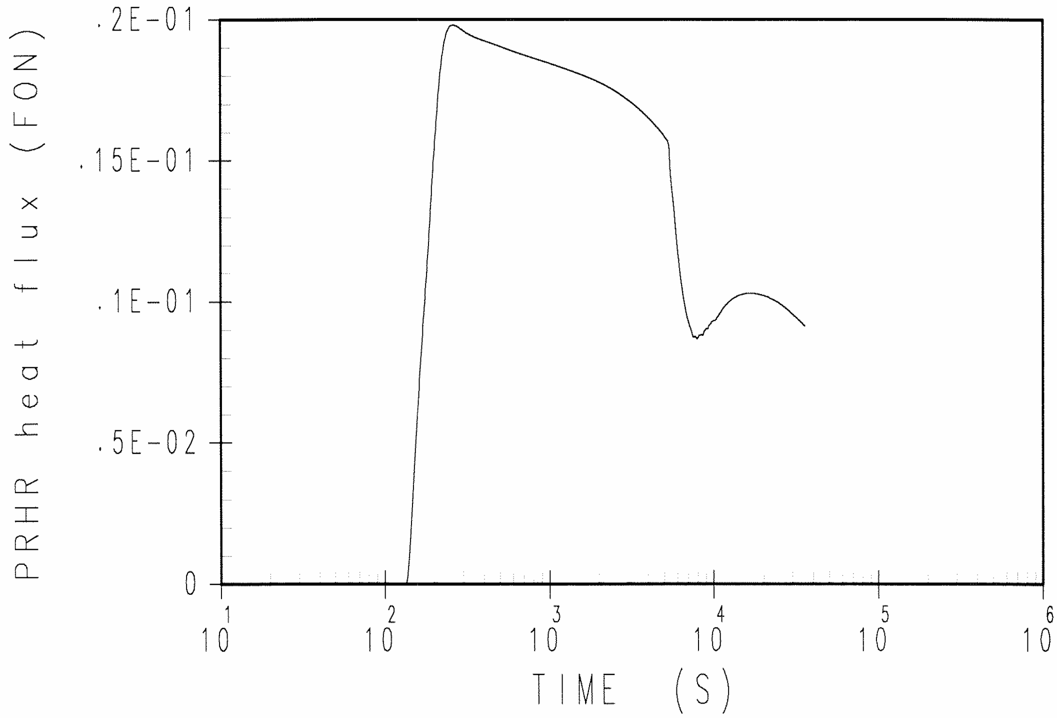

Figure 15.2.6-9

PRHR Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries

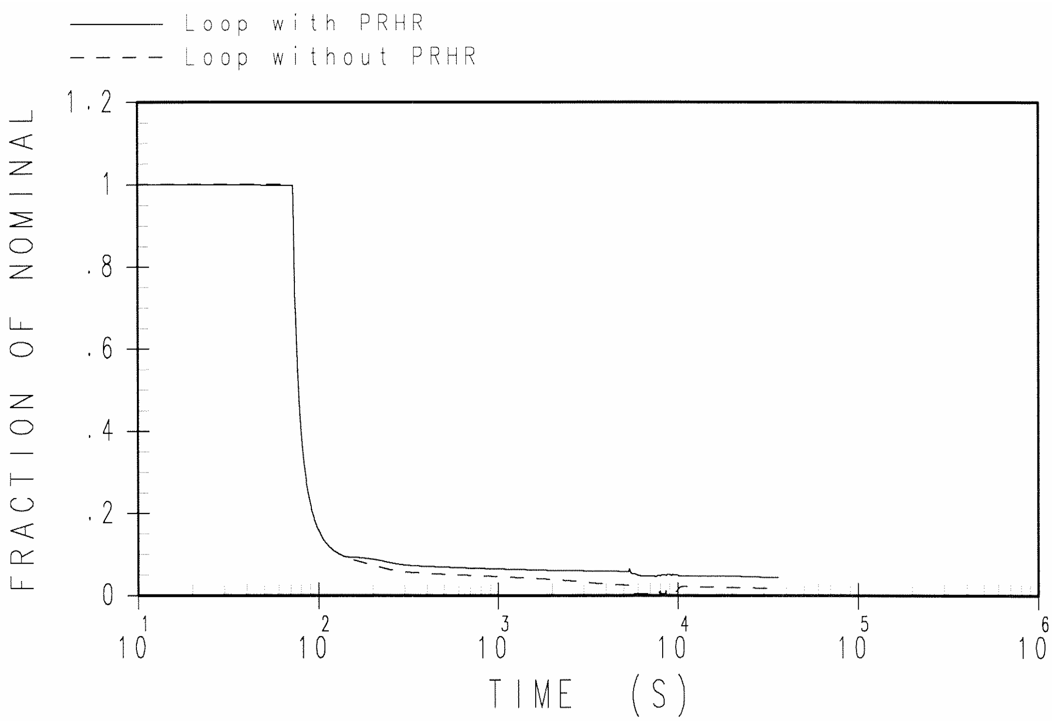

Figure 15.2.6-10

Reactor Coolant Volumetric Flow Rate
Transient for Loss of ac Power to the Plant Auxiliaries

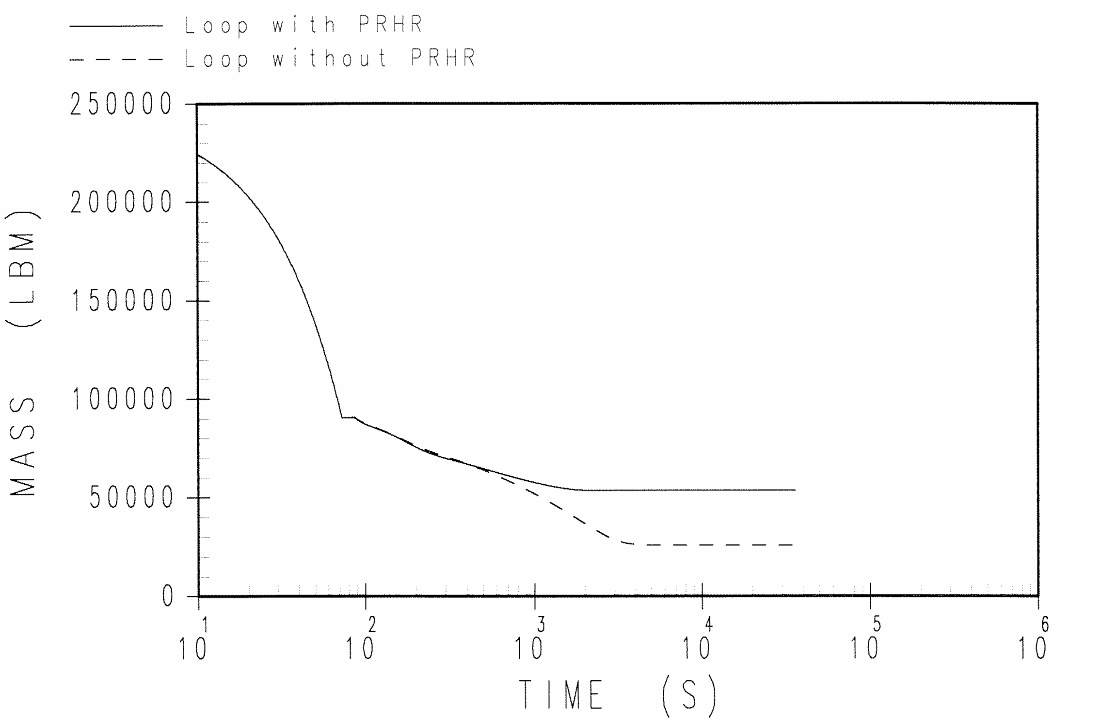

Figure 15.2.6-11

Steam Generator Inventory Transient for Loss of ac Power to the Plant Auxiliaries

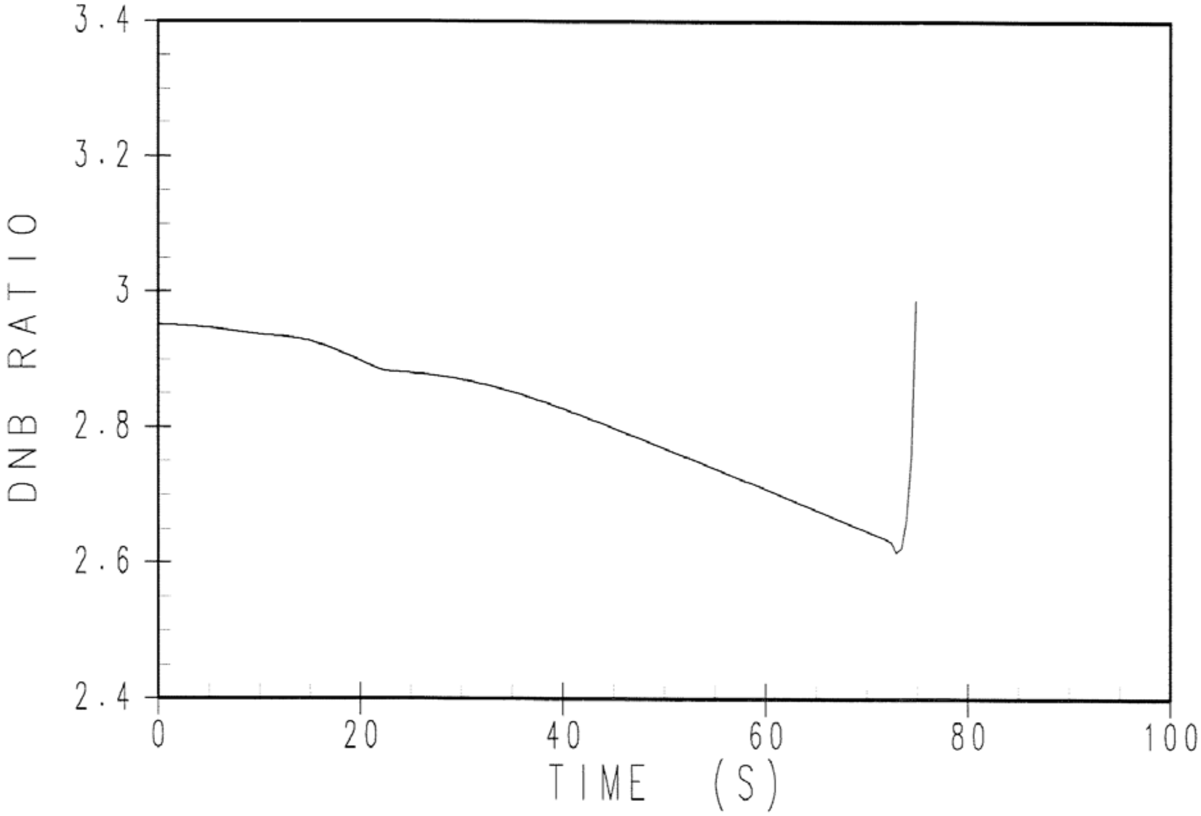

Figure 15.2.6-12

DNB Ratio Transient for Loss of ac Power to the Plant Auxiliaries

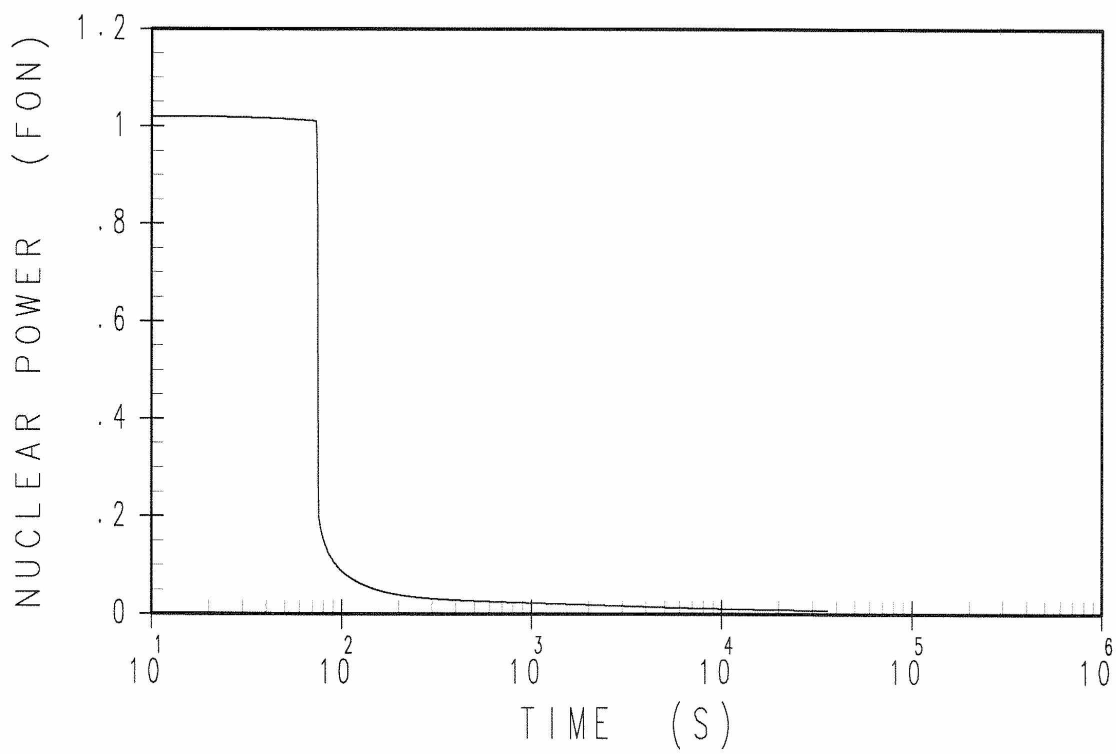

Figure 15.2.7-1

Nuclear Power Transient for Loss of Normal Feedwater Flow

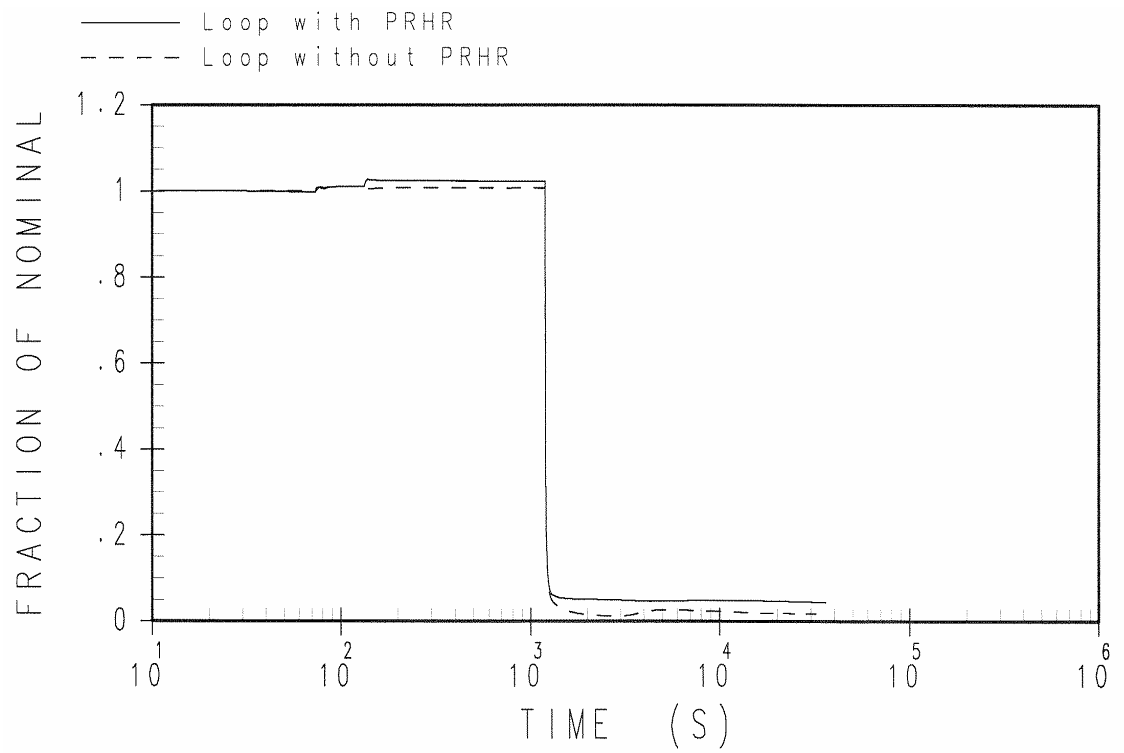

Figure 15.2.7-2

Reactor Coolant System Volumetric Flow Transient for Loss of Normal Feedwater Flow

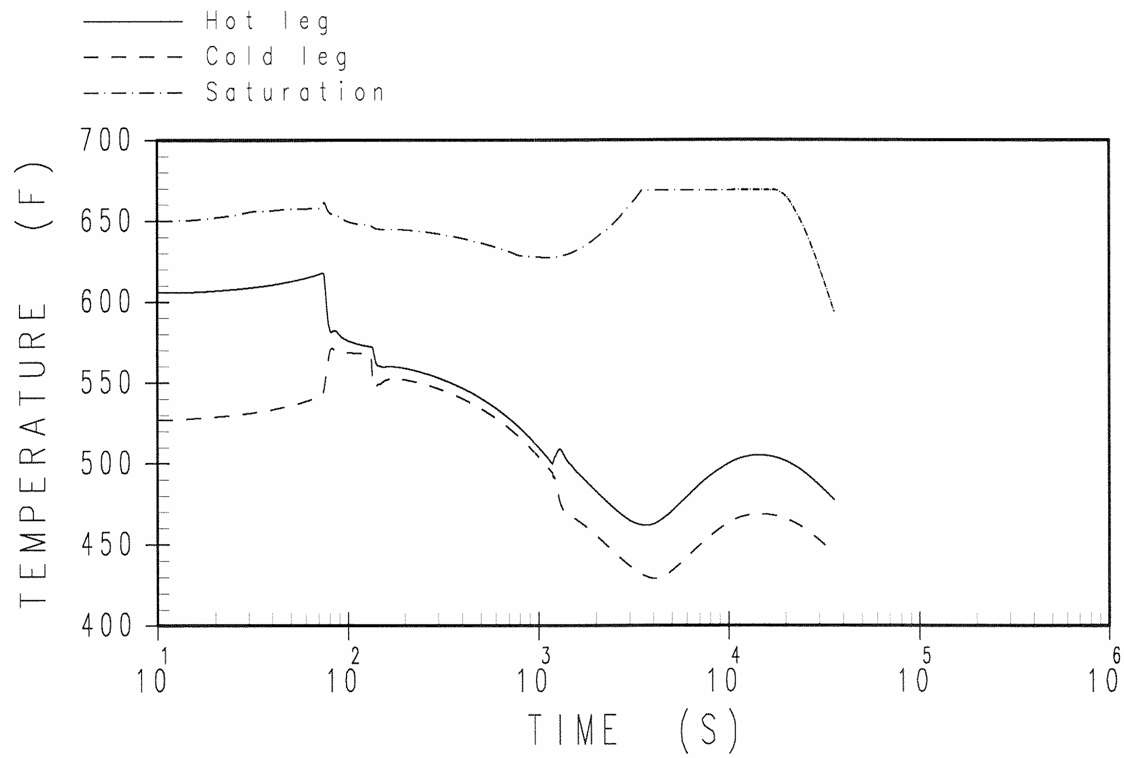

Figure 15.2.7-3

Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss Normal Feedwater Flow

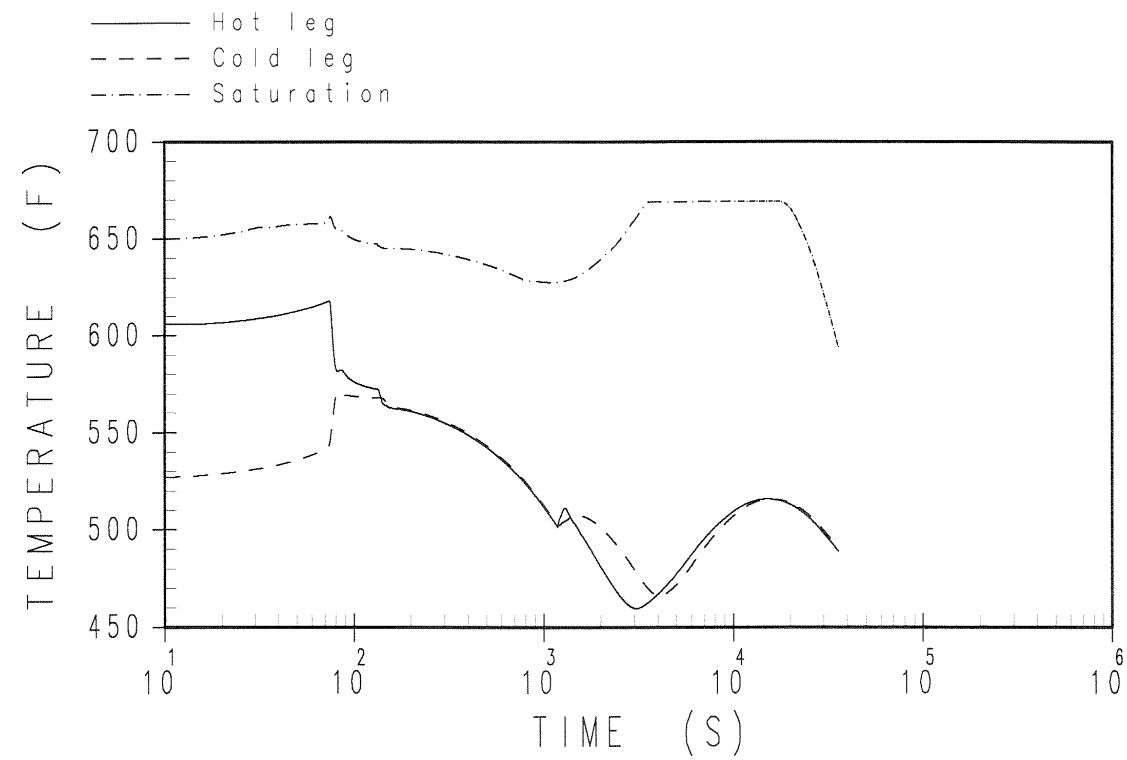

Figure 15.2.7-4

Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of Normal Feedwater Flow

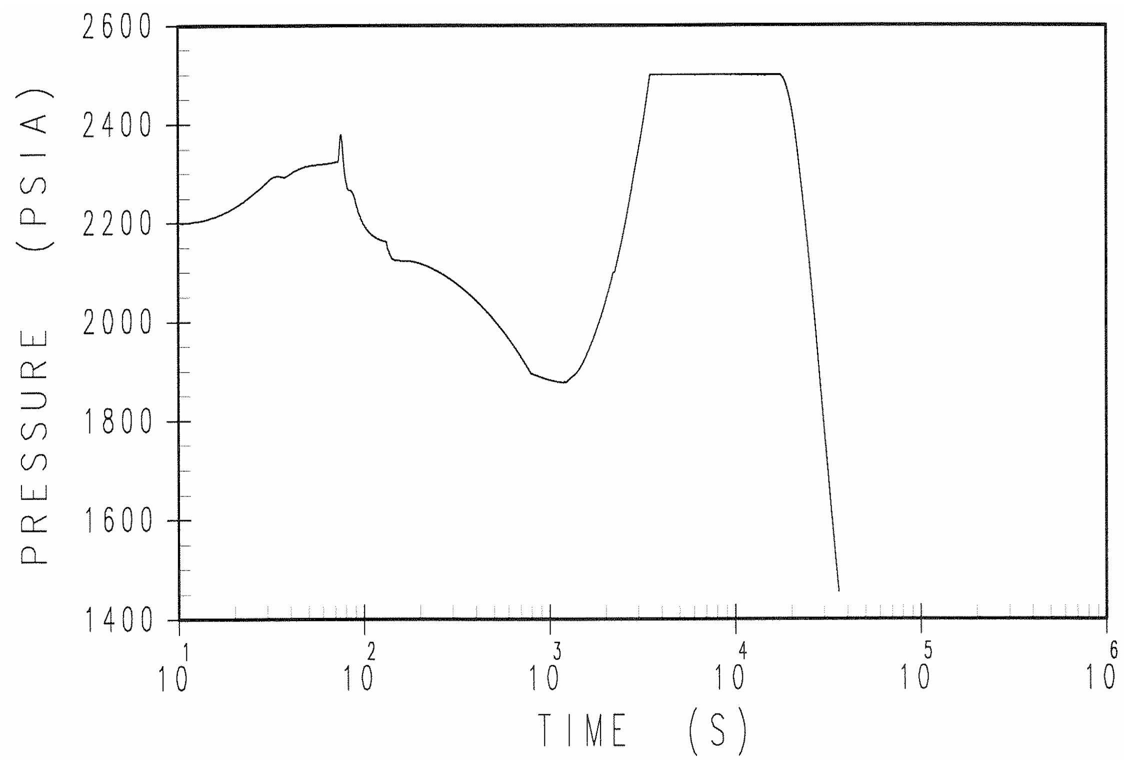

Figure 15.2.7-5

Pressurizer Pressure Transient for Loss of Normal Feedwater Flow

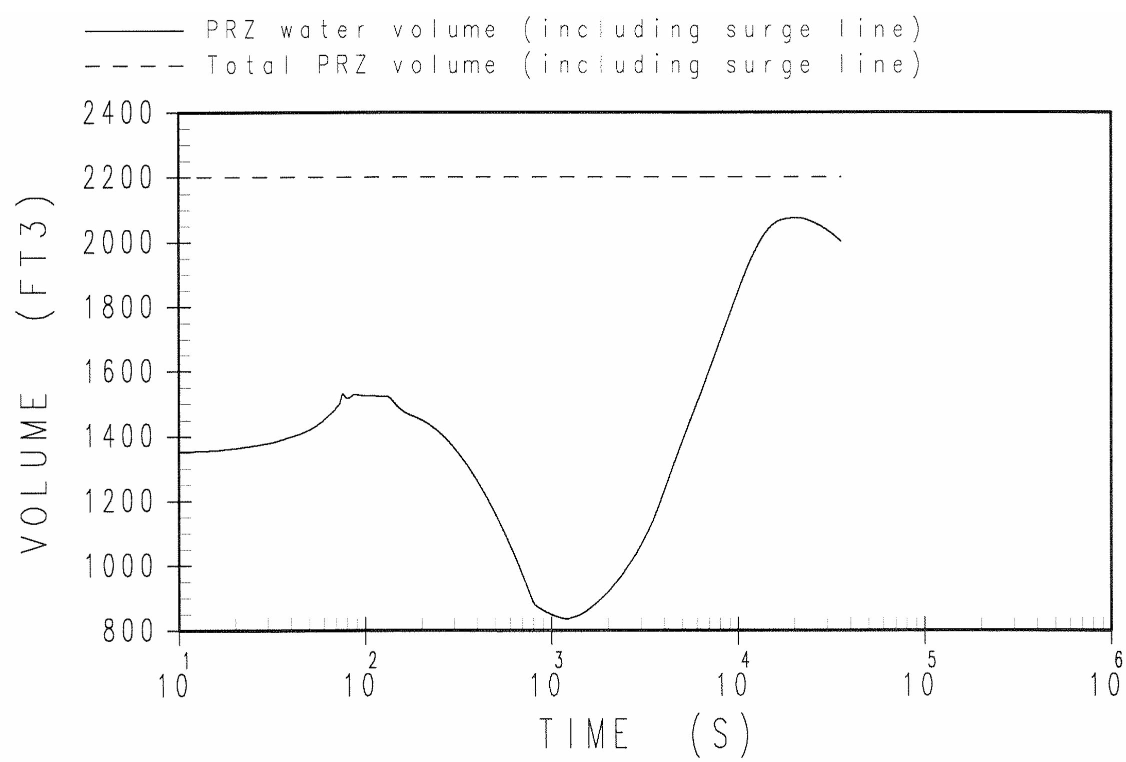

Figure 15.2.7-6

Pressurizer Water Volume Transient for Loss of Normal Feedwater Flow

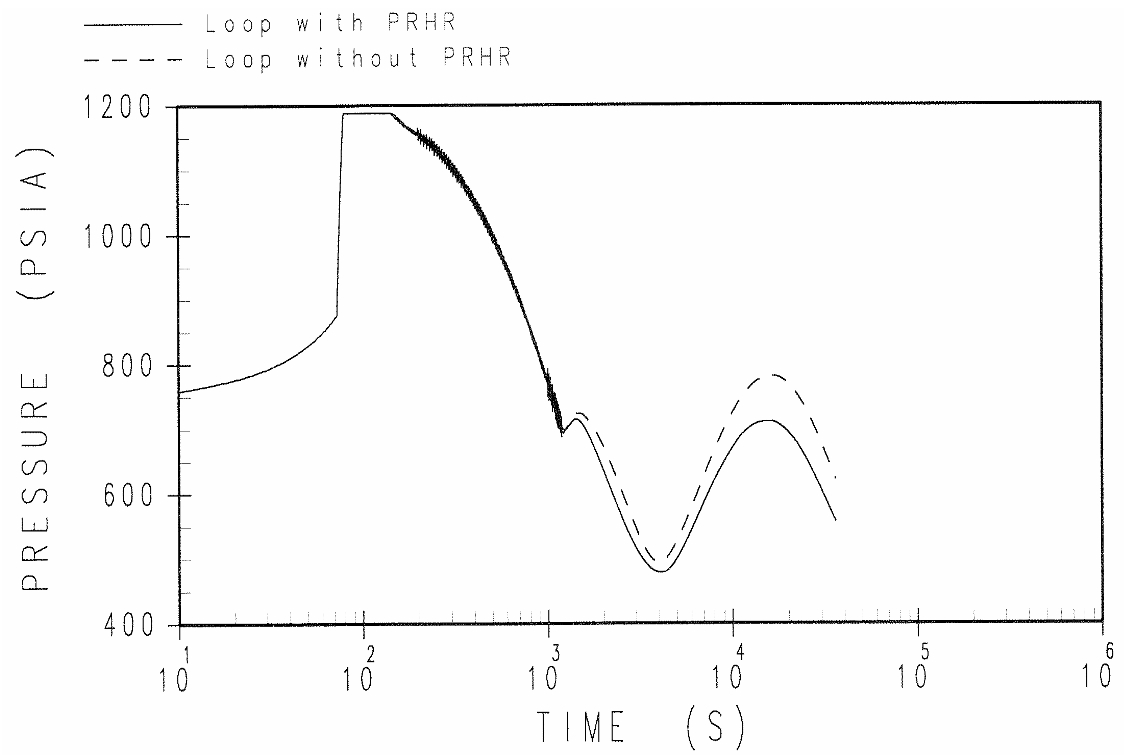

Figure 15.2.7-7

Steam Generator Pressure Transient for Loss of Normal Feedwater Flow

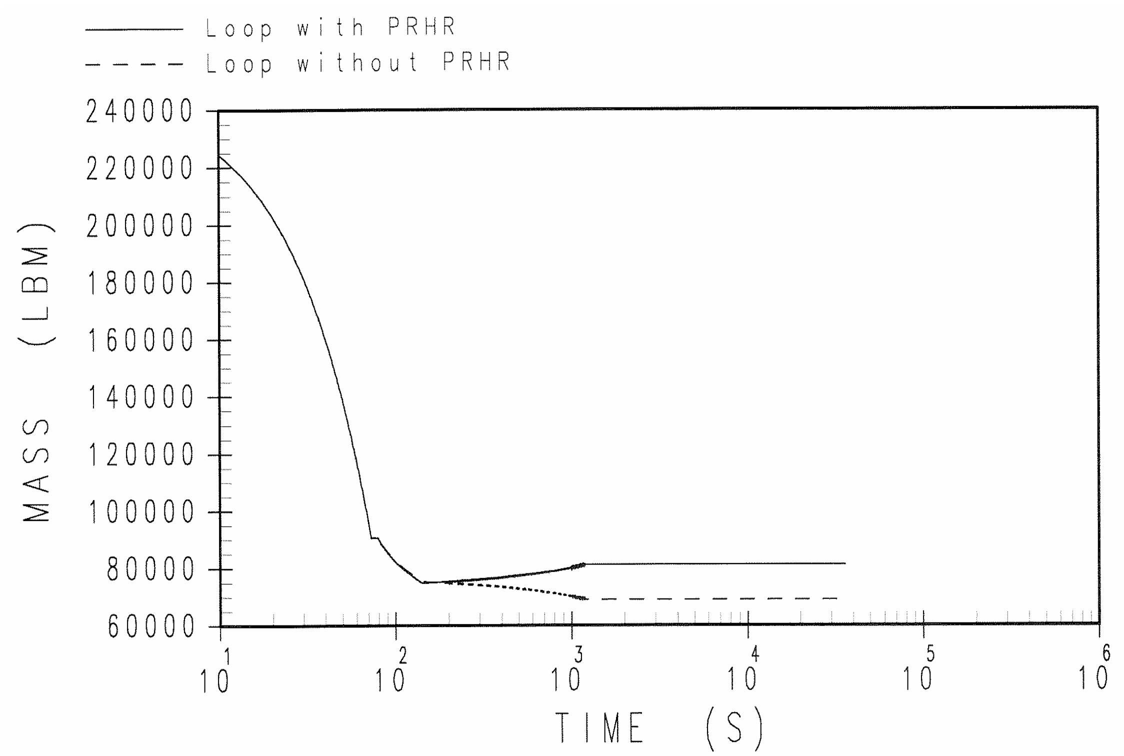

Figure 15.2.7-8

Steam Generator Inventory Transient for Loss of Normal Feedwater Flow

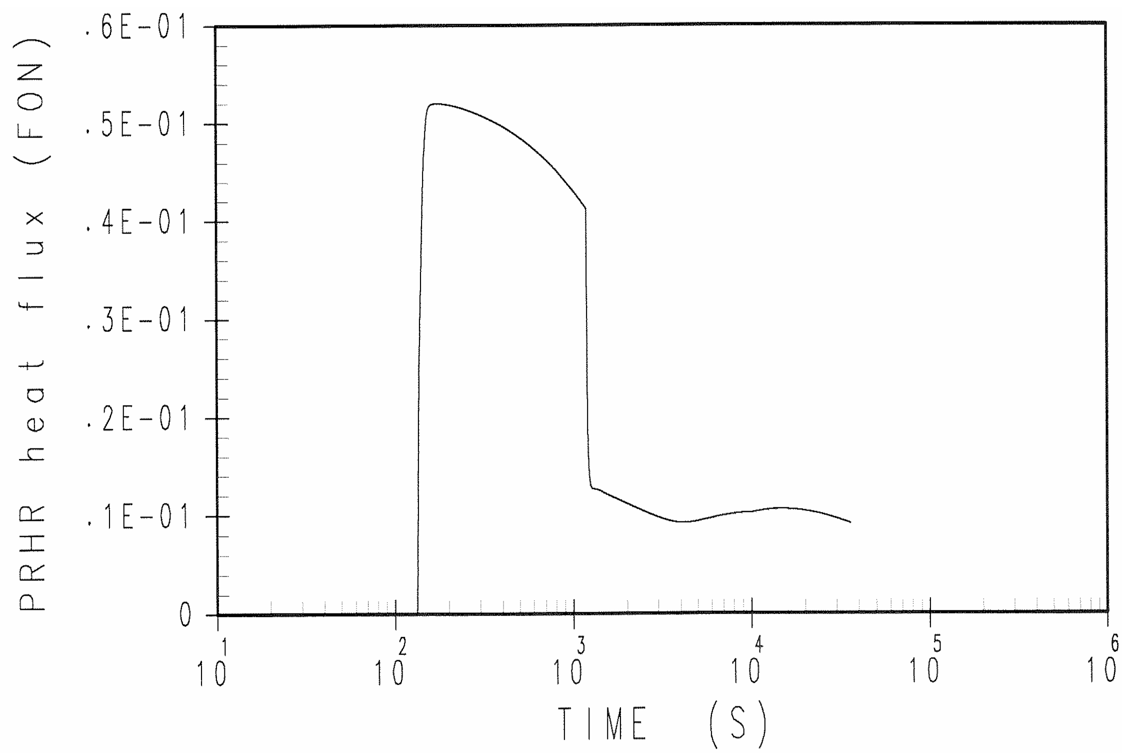

Figure 15.2.7-9

PRHR Heat Flux Transient for Loss of Normal Feedwater Flow

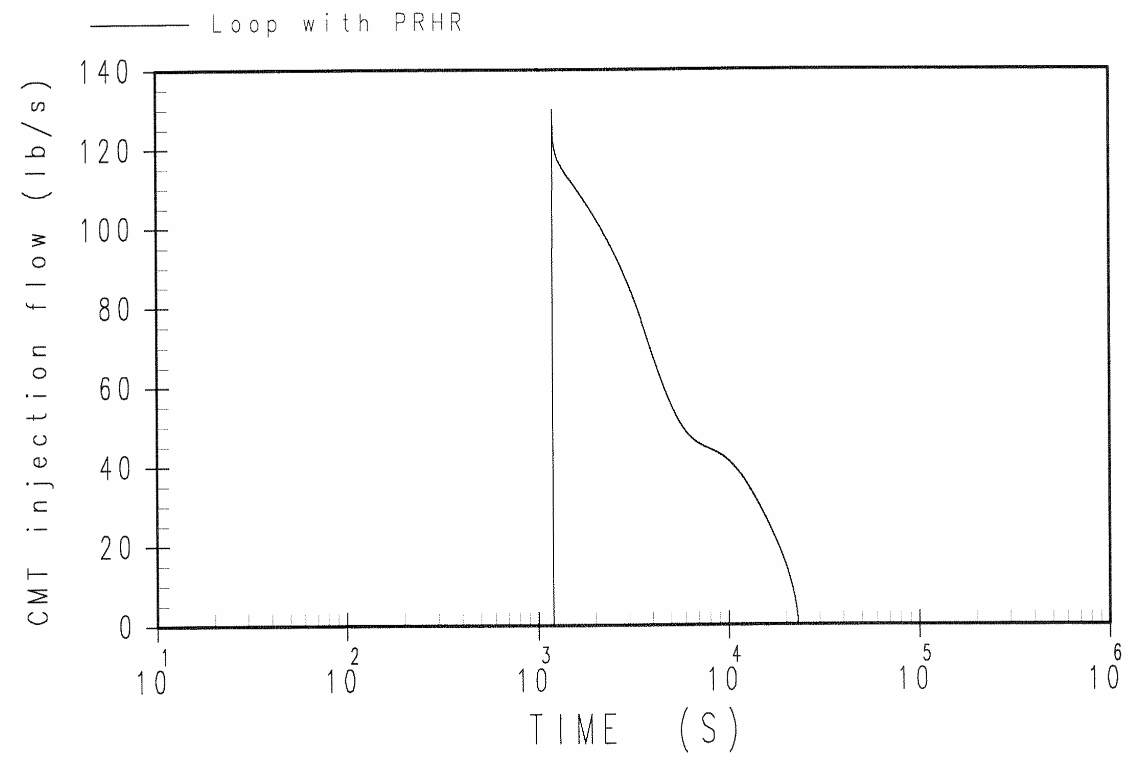

Figure 15.2.7-10

CMT Injection Flow Rate Transient for Loss of Normal Feedwater Flow

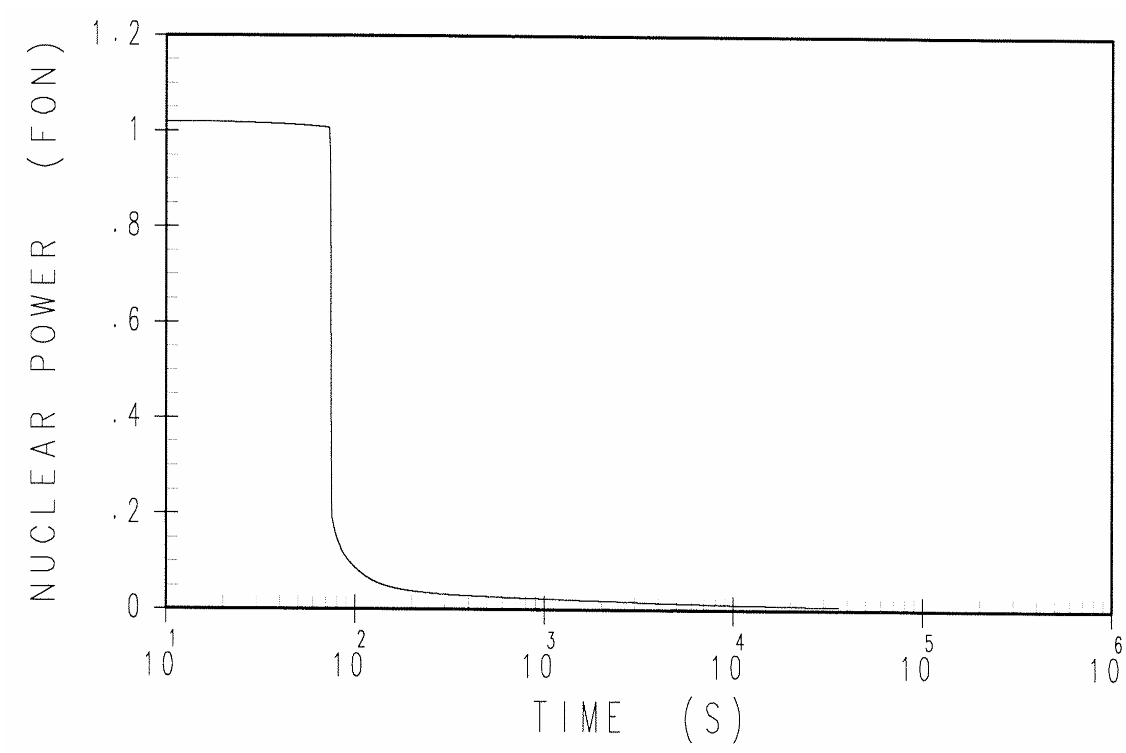

Figure 15.2.8-1

Nuclear Power Transient for Main Feedwater Line Rupture

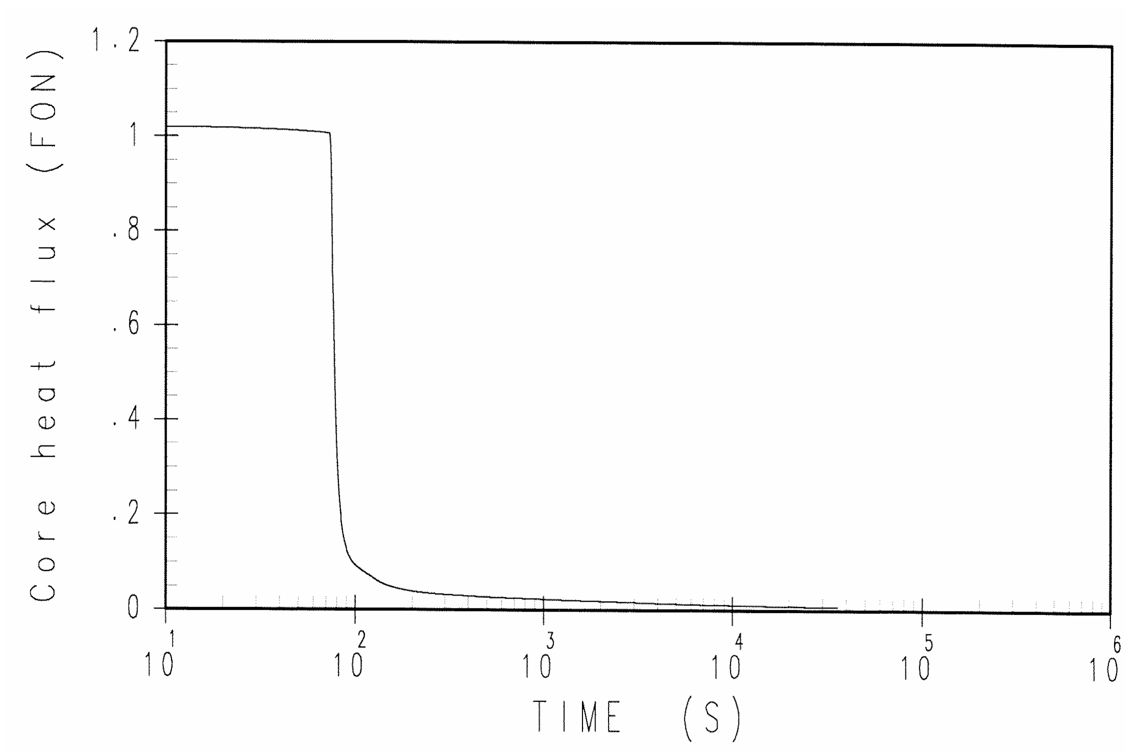

Figure 15.2.8-2

Core Heat Flux Transient for Main Feedwater Line Rupture

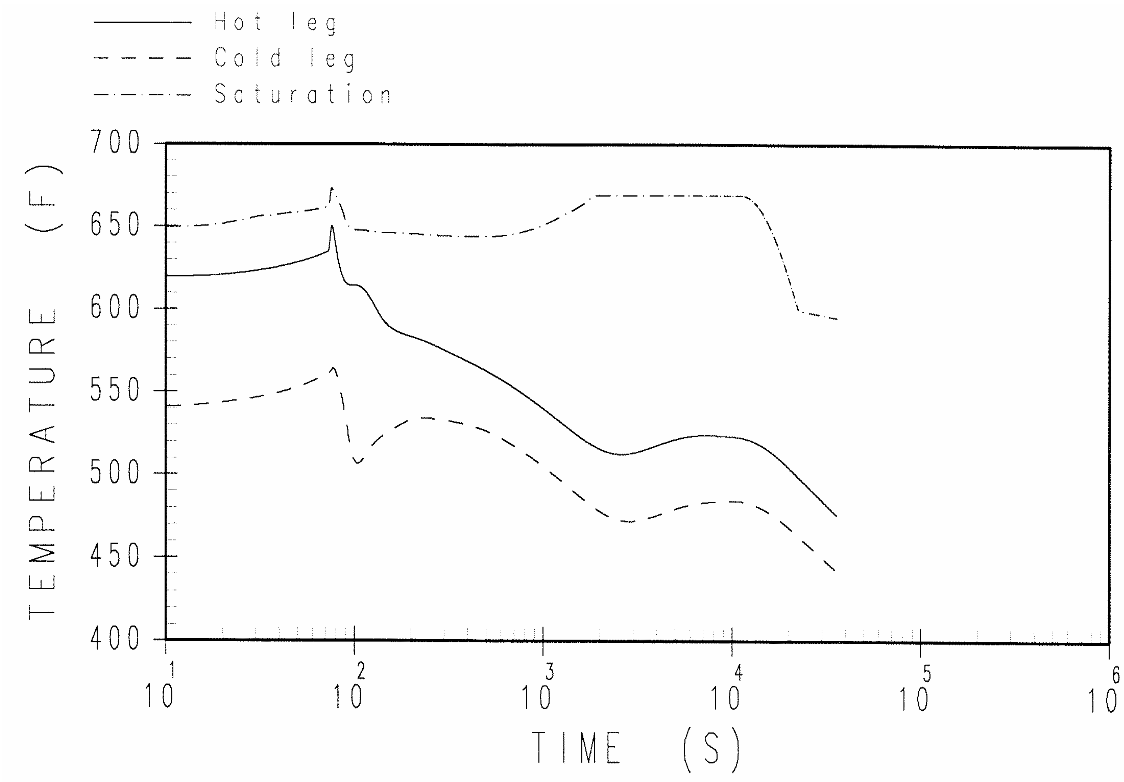

Figure 15.2.8-3

Faulted Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture

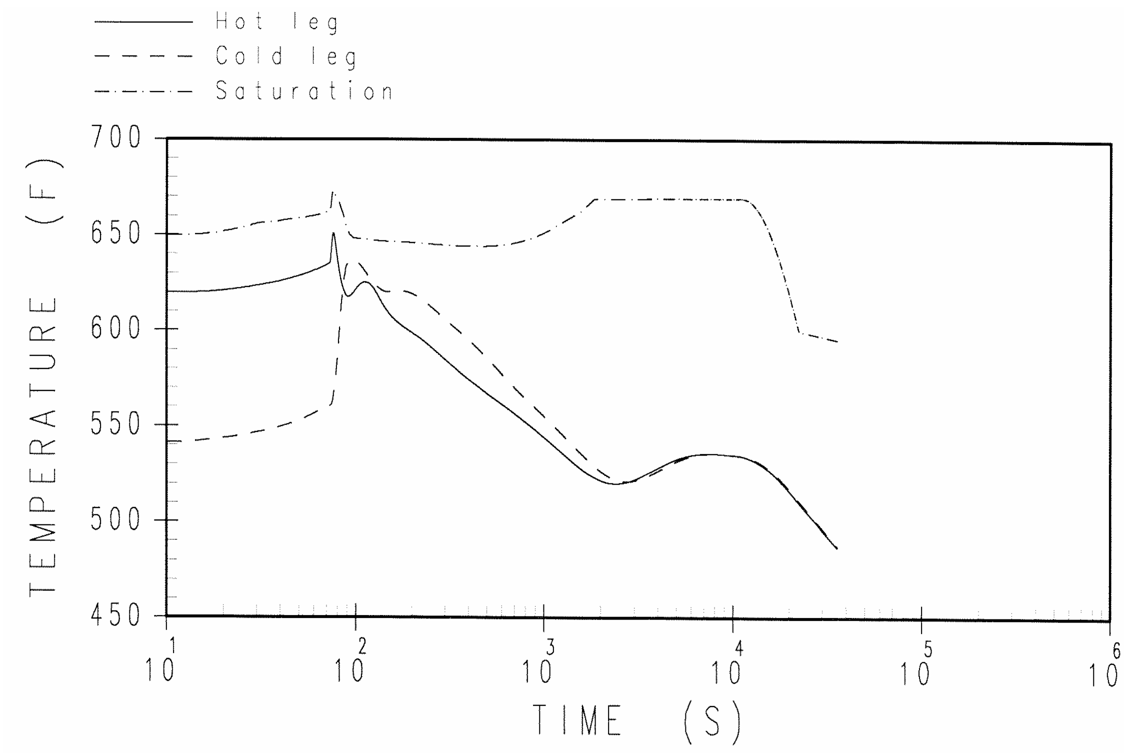

Figure 15.2.8-4

Intact Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture

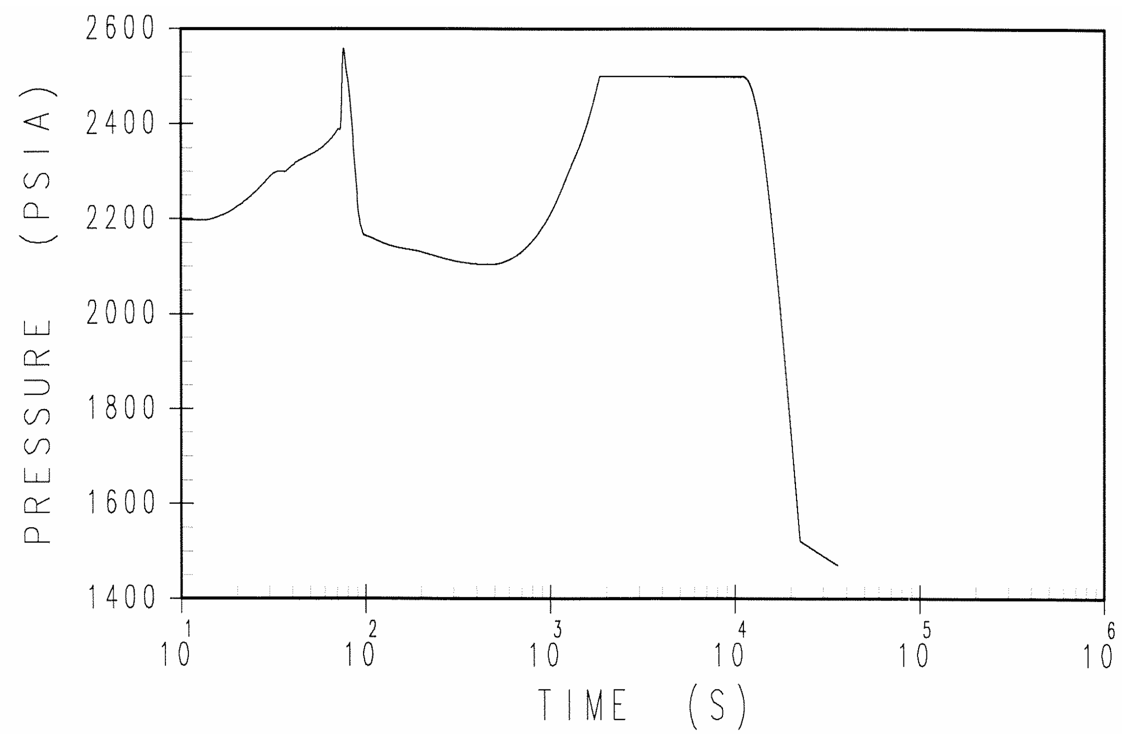

Figure 15.2.8-5

Pressurizer Pressure Transient for Main Feedwater Line Rupture

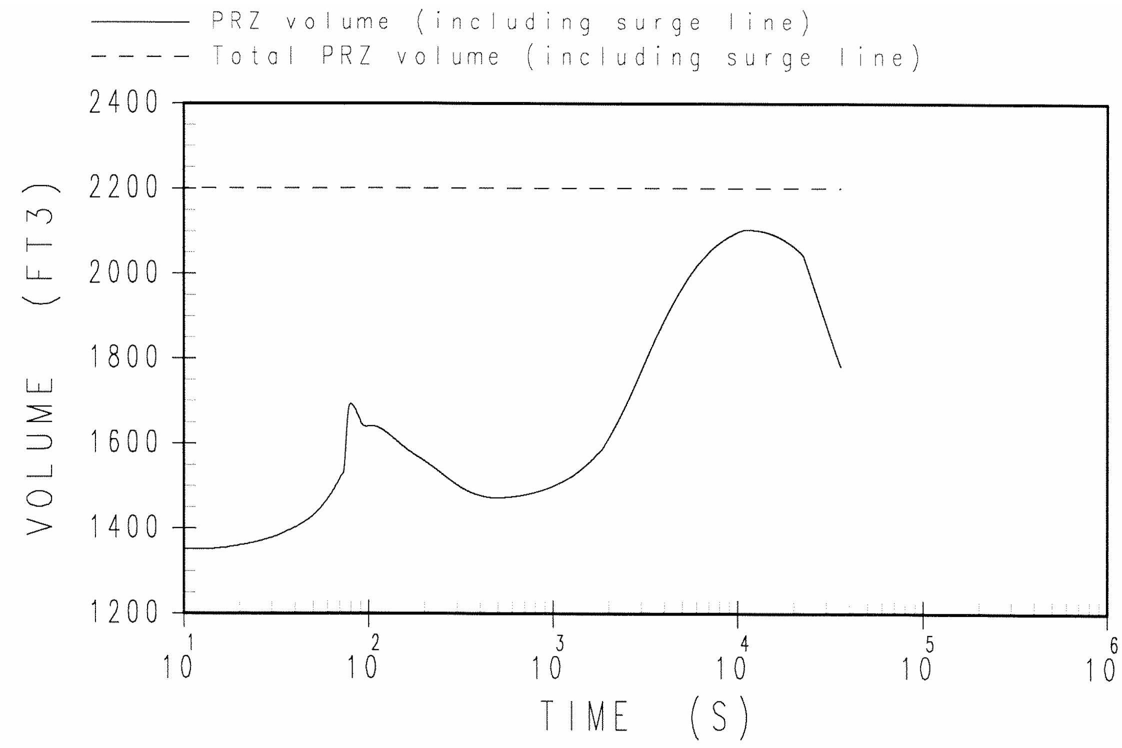

Figure 15.2.8-6

Pressurizer Water Volume Transient for Main Feedwater Line Rupture

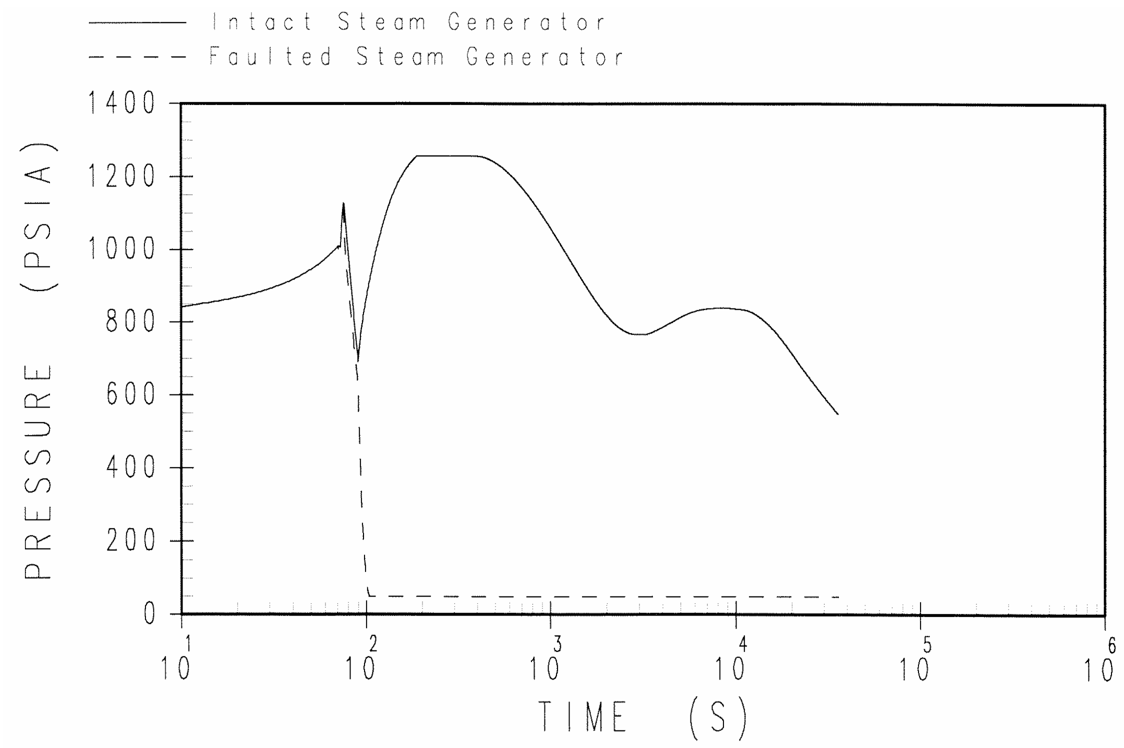

Figure 15.2.8-7

Steam Generator Pressure Transient for Main Feedwater Line Rupture

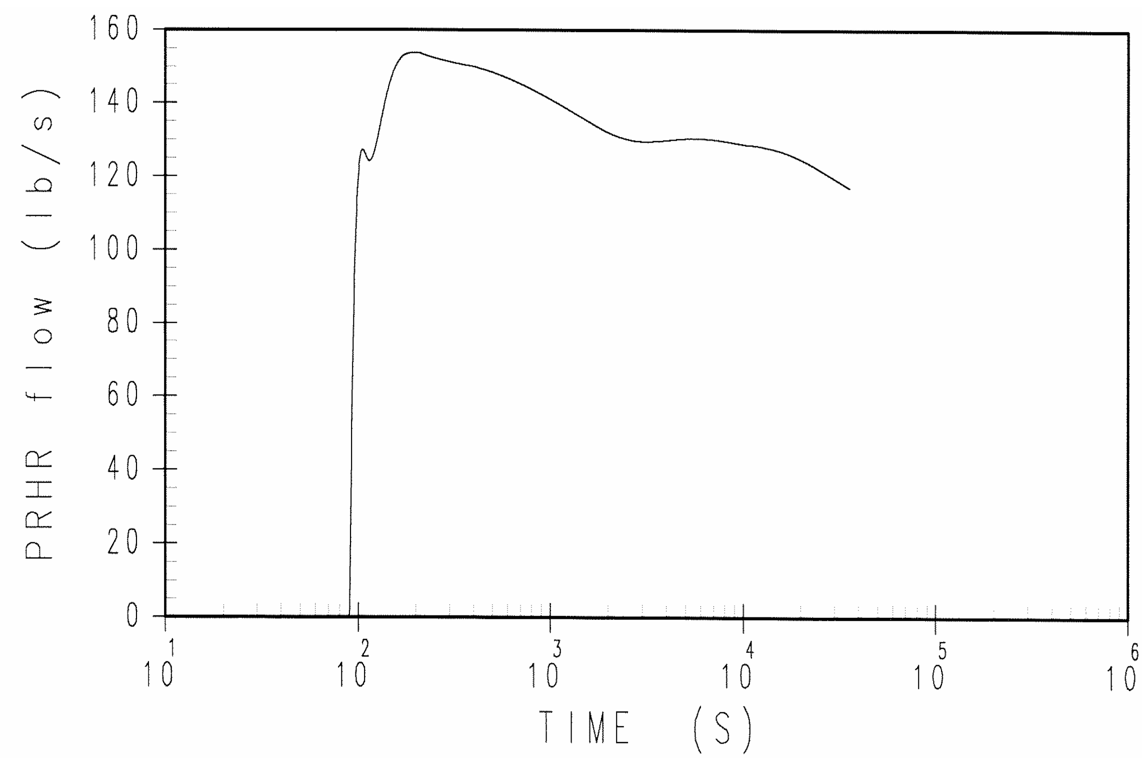

Figure 15.2.8-8

PRHR Flow Rate Transient for Main Feedwater Line Rupture

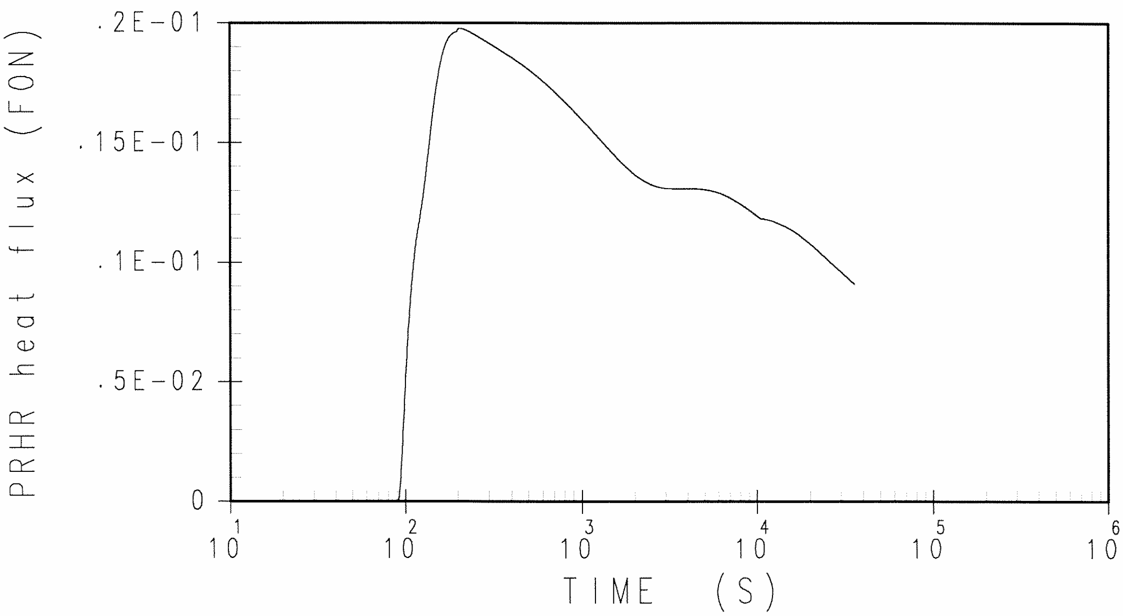

Figure 15.2.8-9

PRHR Heat Flux Transient for Main Feedwater Line Rupture

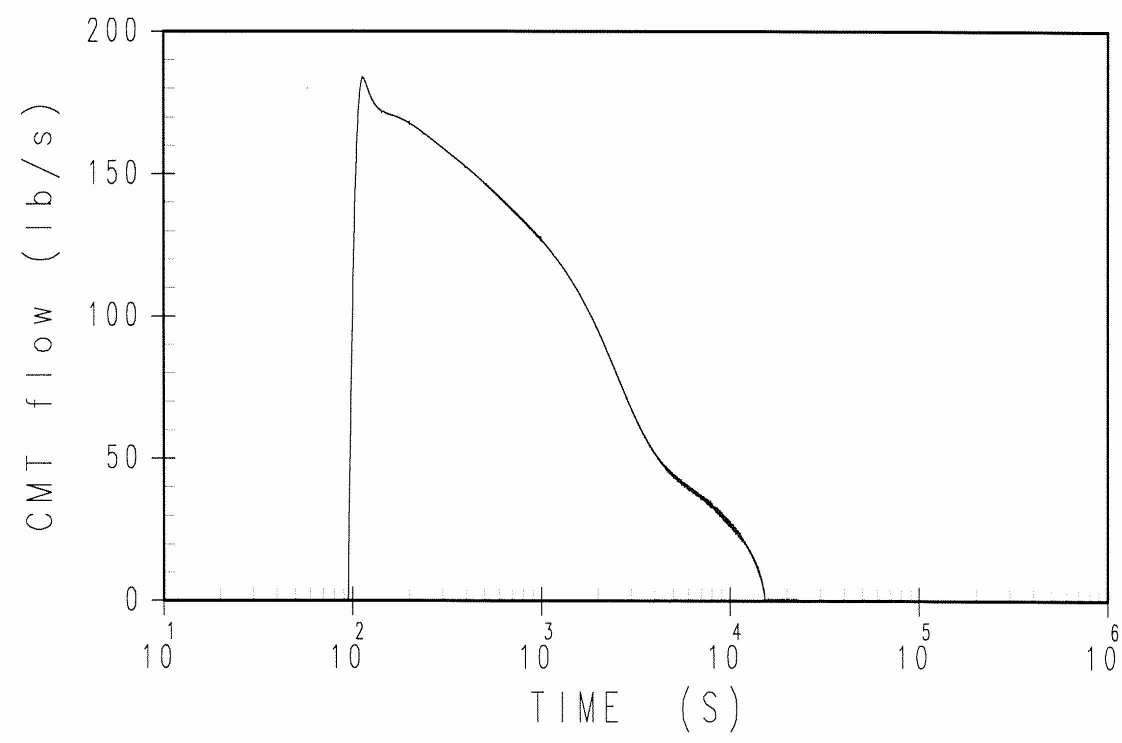

Figure 15.2.8-10

CMT Injection Flow Rate Transient for Main Feedwater Line Rupture

15.3 Decrease in Reactor Coolant System Flow Rate

A number of faults that could result in a decrease in the reactor coolant system flow rate are postulated. These events are discussed in this section. Detailed analyses are presented for the most limiting of the following reactor coolant system flow decrease events:

- Partial loss of forced reactor coolant flow
- Complete loss of forced reactor coolant flow
- Reactor coolant pump shaft seizure (locked rotor)
- Reactor coolant pump shaft break

The first event is a Condition II event, the second is a Condition III event, and the last two are Condition IV events.

The four limiting flow rate decrease events described above are analyzed in this section. The most severe radiological consequences result from the reactor coolant pump shaft seizure accident discussed in subsection 15.3.3. Doses are reported only for that case.

15.3.1 Partial Loss of Forced Reactor Coolant Flow

15.3.1.1 Identification of Causes and Accident Description

A partial loss of coolant flow accident can result from a mechanical or an electrical failure of a reactor coolant pump or from a fault in the power supply to the pump or pumps. If the reactor is at power at the time of the event, the immediate effect of the loss of coolant flow is a rapid increase in the coolant temperature.

Normal power for the pumps is supplied through four buses connected to the generator. When a generator trip occurs, the buses are supplied from offsite power. The pumps continue to operate.

A partial loss of coolant flow is classified as a Condition II incident (a fault of moderate frequency), as defined in subsection 15.0.1.

Protection against this event is provided by the low primary coolant flow reactor trip signal, which is actuated by two-out-of-four low-flow signals. Above permissive P8, low flow in either hot leg actuates a reactor trip (see Section 7.2). Between approximately 10-percent power (permissive P10) and the power level corresponding to permissive P8, low flow in both hot legs actuates a reactor trip.

As specified in GDC 17 of 10 CFR Part 50, Appendix A, the effects of a loss of offsite power are considered in evaluating partial loss of forced reactor coolant flow transients. As discussed in subsection 15.0.14, the loss of offsite power is considered to be a potential consequence of the event due to disruption of the electrical grid following a turbine trip during the event. A delay of 3 seconds is assumed between the turbine trip and the loss of offsite power. In addition, turbine trip occurs 5.0 seconds following a reactor trip condition being reached. This delay on turbine trip is a feature of the AP1000 reactor trip system. The primary effect of the loss of offsite power is to cause the remaining operating reactor coolant pumps to coast down.

15.3.1.2 Analysis of Effects and Consequences

15.3.1.2.1 Method of Analysis

This transient is analyzed using three computer codes. First, the LOFTRAN code (Reference 1) is used to calculate the core flow during the transient based on the input loop flows, the nuclear power transient, and the primary system pressure and temperature transients as predicted from the loss of two reactor coolant pumps. The FACTRAN code (Reference 2) is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the departure from nucleate boiling ratio (DNBR) during the transient, based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR transients presented represent the minimum of the typical cell or the thimble cell.

15.3.1.2.2 Initial Conditions

Initial reactor power, pressure, and reactor coolant system temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit, as described in WCAP-11397-P-A (Reference 5).

Plant characteristics and initial conditions assumed in this analysis are further discussed in subsection 15.0.3.

15.3.1.2.3 Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used (see Figure 15.0.4-1). This is equivalent to a total integrated Doppler reactivity from 0- to 100-percent power of 0.0160 Δk.

The least-negative moderator temperature coefficient is assumed because this results in the maximum core power during the initial part of the transient, when the minimum DNBR is reached.

For these analyses, a curve of trip reactivity versus time based on a 2.5-second rod cluster control assembly insertion time to the dashpot is used (see subsection 15.0.5).

15.3.1.2.4 Flow Coastdowns

Conservative flow coastdowns are used to simulate the transient. The flow coastdowns are calculated externally to the LOFTRAN code using the COAST computer code which is described in Section 15.0.11.

Plant systems and equipment necessary to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.3.1.2.5 Results

Figures 15.3.1-1 through 15.3.1-6 show the transient response for the loss of two reactor coolant pumps with offsite power available. Figure 15.3.1-6 shows the DNBR to be always greater than the design limit value as defined in Section 4.4.

The plant is tripped by the low-flow trip rapidly enough so that the capability of the reactor coolant to remove heat from the fuel rods is not greatly reduced. The average fuel and cladding temperatures do not increase significantly above their initial values.

The calculated sequence of events for the case analyzed is shown in Table 15.3-1. The affected reactor coolant pumps continue to coast down, and the core flow reaches a new equilibrium value.

With the reactor tripped, a stable plant condition is attained. Normal plant shutdown may then proceed.

In the event that a loss of offsite power occurs as a consequence of a turbine trip during a partial loss of reactor coolant flow, the DNB design basis continues to be met. The loss of offsite power causes the remaining two operating reactor coolant pumps to coast down.

At the time when the remaining two operating reactor coolant pumps start coasting down, reactor trip has already been initiated, core heat flux has started decreasing, and DNBR is increasing. DNBR continues to increase as the remaining two reactor coolant pumps coast down because the core heat flux has decreased and is continuing to decrease rapidly. The minimum DNB ratio occurs at the same time for cases with and without offsite power available.

15.3.1.3 Conclusions

The analysis shows that, for the partial loss of reactor coolant flow, the DNBR does not decrease below the design basis value at any time during the transient. The DNBR design basis is described in Section 4.4. The applicable Standard Review Plan, subsection 15.3.1 (Reference 4), evaluation criteria are met.

15.3.2 Complete Loss of Forced Reactor Coolant Flow

15.3.2.1 Identification of Causes and Accident Description

A complete loss of flow accident may result from a simultaneous loss of electrical supplies to the reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the coolant temperature.

Electric power for the reactor coolant pumps is supplied through buses, connected to the generator through the unit auxiliary transformers. When a generator trip occurs, the buses receive power from external power lines and the pumps continue to supply coolant flow to the core.

A complete loss of flow accident is a Condition III event (an infrequent fault), as defined in subsection 15.0.1. The following signals provide protection against this event:

- Reactor coolant pump underspeed
- Low reactor coolant loop flow

The reactor trip on reactor coolant pump underspeed protects against conditions that can cause a loss of voltage to the reactor coolant pumps. This function is blocked below approximately 10-percent power (permissive P10).

The reactor trip on reactor coolant pump underspeed is also provided to trip the reactor for an underfrequency condition resulting from frequency disturbances on the power grid. If the maximum grid frequency decay rate is less than approximately 5 hertz per second, this trip protects the core from underfrequency events. WCAP-8424, Revision 1 (Reference 3), provides analyses of grid frequency disturbances and the resulting protection requirements that are applicable to the AP1000.

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions that affect only one or two reactor coolant loop cold legs. This function is generated by two-out-of-four low-flow signals per reactor coolant loop hot leg. Above permissive P8, low flow in either hot leg actuates a reactor trip. Between approximately 10-percent power (permissive P10) and the power level corresponding to permissive P8, low flow in both reactor coolant hot legs actuates a reactor trip. If the maximum grid frequency decay rate is less than approximately 2.5 hertz per second, this trip function also protects the core from this underfrequency event. This effect is described in WCAP-8424, Revision 1 (Reference 3).

15.3.2.2 Analysis of Effects and Consequences

15.3.2.2.1 Method of Analysis

The complete loss of flow transient is analyzed for a loss of power to four reactor coolant pumps.

For the case analyzed with a complete loss of voltage, followed by the reactor coolant pumps coasting down, the method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in subsection 15.3.1, with one exception. Following the loss of power supply to all pumps at power, a reactor trip is actuated by the reactor coolant pump underspeed trip.

A loss of forced primary coolant flow can result from a reduction in the reactor coolant pump motor supply frequency. The results of the complete loss of voltage, followed by the reactor coolant pump coasting down, bound the complete loss of flow initiated by a frequency decay of up to 5 hertz per second. Therefore, only the results of the complete loss of voltage case are presented in subsection 15.3.2.2.2.

15.3.2.2.2 Results

Figures 15.3.2-1 through 15.3.2-6 show the transient response for the complete loss of voltage to all four reactor coolant pumps. The reactor is assumed to trip on the reactor coolant pump underspeed signal. Figure 15.3.2-6 shows that the DNBR is always greater than the design limit value defined in Section 4.4.

The calculated sequences of events for the cases analyzed are shown in Table 15.3-1. The reactor coolant pumps continue to coast down, and natural circulation flow is established, as demonstrated in subsection 15.2.6. With the reactor tripped, a stable plant condition is attained. Normal plant shutdown may then proceed.

15.3.2.3 Conclusions

The analysis demonstrates that, for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the design basis limit value at any time during the transient. The design basis for the DNBR is described in Section 4.4. The applicable Standard Review Plan, subsection 15.3.1 (Reference 4), evaluation criteria are met.

15.3.3 Reactor Coolant Pump Shaft Seizure (Locked Rotor)

15.3.3.1 Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of a reactor coolant pump rotor, as discussed in Section 5.4. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a low-flow signal.

Following the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant, causing the coolant temperature to increase and expand. At the same time, heat transfer to the shell side of the steam generator in the faulted loop is reduced because: 1) the reduced flow results in a decreased tube-side film coefficient, and 2) the reactor coolant in the tubes cools down while the shell-side temperature increases. (Turbine steam flow is reduced to 0 upon plant trip.) The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, and opens the pressurizer safety valves, in that sequence. For conservatism, the pressure-reducing effect of the spray is not included in the analysis.

This event is classified as a Condition IV incident (a limiting fault), as defined in subsection 15.0.1.

15.3.3.2 Analysis of Effects and Consequences

15.3.3.2.1 Method of Analysis

Two digital computer codes are used to analyze this transient. The LOFTRAN code (Reference 1) calculates the resulting core flow transient following the pump seizure and the nuclear power following reactor trip. This code is also used to determine the peak pressure. The thermal behavior

of the fuel located at the core hot spot is investigated by using the FACTRAN code (Reference 2). This code uses the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes a film-boiling heat transfer coefficient.

At the beginning of the postulated locked rotor accident (at the time the shaft in one of the reactor coolant pumps is assumed to seize), the plant is assumed to be in operation under the most adverse steady-state operating conditions, that is, maximum steady-state thermal power, maximum steady-state pressure, and maximum steady-state coolant average temperature. Plant characteristics and initial conditions are further discussed in subsection 15.0.3. The accident is evaluated for both cases with and without offsite power available. For the case without offsite power available, power is lost to the unaffected pumps at 3.0 seconds following turbine/generator trip. Turbine trip occurs 5.0 seconds following a reactor trip condition being reached. This delay on turbine trip is a feature of the AP1000 reactor trip system.

For the peak pressure evaluation, the initial pressure is conservatively estimated as 50 psi above nominal pressure (2250 psia), which allows for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure.

15.3.3.2.2 Evaluation of the Pressure Transient

After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion is assumed to begin 1.45 seconds after the flow in the affected loop reaches the reactor trip setpoint. No credit is taken for the pressure-reducing effect of the pressurizer spray, steam dump, or controlled feedwater flow after plant trip. Although these operations are expected to result in a lower peak reactor coolant system pressure, an additional conservatism is provided by ignoring their effect.

The pressurizer safety valves are fully open at 2575 psia. Their capacity for steam relief is described in Section 5.4.

15.3.3.2.3 Evaluation of Departure from Nucleate Boiling in the Core During the Accident

For this accident, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this “hot spot” condition represent the upper limit with respect to cladding temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be 2.6 times the average rod power (that is, $F_Q = 2.6$) at the initial core power level.

15.3.3.2.4 Film-Boiling Coefficient

The film-boiling coefficient is calculated in the FACTRAN code (Reference 2) using the Bishop-Sandberg-Tong film-boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step, based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient because they are the most conservative with respect to cladding temperature response. For conservatism, DNB is assumed to start at the beginning of the accident.

15.3.3.2.5 Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) have a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and the cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient is assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 Btu/h-ft^2-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel because of the small initial value of the gap coefficient is released to the cladding at the initiation of the transient.

15.3.3.2.6 Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above a cladding temperature of 1800°F. The Baker-Just parabolic rate equation is used to define the rate of the zirconium-steam reaction:

$$\frac{d\,(w^2)}{dt} = 33.3 \times 10^6 \exp\left(-\frac{45{,}500}{1.986\,T} \right)$$

where:

w = amount reacted (mg/cm^2)

t = time (s)

T = temperature (Kelvin)

The reaction heat is 1510 cal/g.

The effect of the zirconium-steam reaction is included in the calculation of the hot spot cladding temperature transient.

Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.3.3.2.7 Results

Figures 15.3.3-1 through 15.3.3-7 show the transient results for one locked rotor with four reactor coolant pumps in operation with and without offsite power available. The without-offsite-power case bounds the results for the case with offsite power. The results of these calculations are also summarized in Table 15.3-2. The peak reactor coolant system pressure reached during the transient is less than that which causes stresses to exceed the faulted condition stress limits of the

ASME Code, Section III. Also, the peak cladding surface temperature is considerably less than 2700°F. The cladding temperature is conservatively calculated, assuming that DNB occurs at the initiation of the transient. These results represent the most limiting conditions with respect to the locked rotor event or the pump shaft break.

The calculated sequence of events for the case analyzed is shown in Table 15.3-1. With the reactor tripped, a stable plant condition is eventually attained. Normal plant shutdown may then proceed.

15.3.3.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated locked reactor coolant pump rotor accident assumes that the reactor has been operating with the design basis fuel defect level (0.25 percent of power produced by fuel rods containing cladding defects) and that leaking steam generator tubes have resulted in a buildup of activity in the secondary coolant.

As a result of the accident, it is determined that no fuel rods are damaged such that the activity contained in the fuel-cladding gap is released to the reactor coolant. However, a conservative analysis has been performed assuming 10 percent of the rods are damaged. Activity carried over to the secondary side because of primary-to-secondary leakage is available for release to the environment via the steam line safety valves or the power-operated relief valves.

15.3.3.3.1 Source Term

The significant radionuclide releases due to the locked rotor accident are the iodines, alkali metals (cesiums, rubidiums) and noble gases. The reactor coolant iodine source term assumes a pre-existing iodine spike. The initial reactor coolant noble gas and alkali metal concentrations are assumed to be those associated with the design basis fuel defect level. These initial reactor coolant activities are of secondary importance compared to the release of the gap inventory of fission products from the portion of the core assumed to fail because of the accident.

Based on NUREG-1465 (Reference 6), the fission product gap fraction is 3 percent of fuel inventory. For this analysis, the gap fraction is increased to 8 percent of the inventory for I-131, 10 percent for Kr-85, 5 percent for other iodines and noble gases and 12 percent for alkali metals. Also, to address the fact that the failed fuel rods may have been operating at power levels above the core average, the source term is increased by the lead rod radial peaking factor.

The initial secondary coolant activity is assumed to be 10 percent of the maximum equilibrium primary coolant activity for iodines and alkali metals.

15.3.3.3.2 Release Pathways

There are two components to the accident releases:

- The activity initially in the secondary coolant is available for release as long as steam releases continue.

- The reactor coolant leaking into the steam generators is assumed to mix with the secondary coolant. The activity from the primary coolant mixes with the secondary coolant. As steam is

released, a portion of the iodine and alkali metal activity in the coolant is released. The fraction of activity released is defined by the assumed flashing fraction and the partition coefficient assumed for the steam generator. The noble gas activity entering the secondary side is released to the environment. These releases are terminated when the steam releases stop.

Credit is taken for the decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.3.3.3.3 Dose Calculation Models

The models used to calculate offsite doses are provided in Appendix 15A.

15.3.3.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.3-3.

Two separate accident scenarios are addressed. In the first scenario, it is assumed that the non-safety grade startup feedwater system is not available to provide feedwater to the steam generators. In this event, the water level in the steam generators drops, resulting in tube uncovery and there is flashing of a portion of the primary coolant assumed to be leaking into the secondary side of the steam generators. Also, the period of steaming is terminated at 1.5 hours when the capacity of the passive residual heat removal system exceeds the decay heat generation rate.

In the second scenario, it is assumed that the startup feedwater system is available to maintain water level in the steam generators such that the tubes remain covered. In this scenario, direct release of flashed primary coolant is not considered. Also, the passive residual heat removal system does not actuate, resulting in a longer period of steaming releases.

15.3.3.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of significant conservatisms:

- Although fuel damage is assumed to occur as a result of the accident, no fuel damage is anticipated.

- The reactor coolant activities are based on a fuel defect level of 0.25 percent; whereas, the expected fuel defect level is far less than this (see Section 11.1).

- The leakage of reactor coolant into the secondary system, at 300 gallons per day, is conservative. The leakage is normally a small fraction of this.

- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.3.3.3.6 Doses

Using the assumptions from Table 15.3-3, the calculated total effective dose equivalent (TEDE) doses are determined to be less than 0.7 rem at the exclusion area boundary for the limiting 2-hour interval (0 to 2 hours) and less than 0.4 rem at the low population zone outer boundary for the scenario in which there is no feedwater available to maintain water level in the steam generators. The doses for the scenario in which it is assumed that water level in the steam generators is maintained are 0.5 rem at the exclusion area boundary for the limiting 2-hour interval of 7 to 8 hours and 0.8 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A "small fraction" is identified as 10 percent or less consistent with the Standard Review Plan (Reference 4).

At the time the locked reactor coolant pump rotor event occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE, and when this is added to the dose calculated for the locked rotor event, the resulting total dose remains less than 0.5 rem TEDE.

15.3.4 Reactor Coolant Pump Shaft Break

15.3.4.1 Identification of Causes and Accident Description

The accident is postulated as an instantaneous failure of a reactor coolant pump shaft. Flow through the affected reactor coolant loop is rapidly reduced, though the initial rate of reduction of coolant flow is greater for the reactor coolant pump rotor seizure event. Reactor trip occurs on a low-flow signal in the affected loop.

Following the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator in the faulted loop is reduced because: 1) the reduced flow results in a decreased tube-side film coefficient, and 2) the reactor coolant in the tubes cools down while the shell-side temperature increases. (Turbine steam flow is reduced to 0 upon plant trip.) The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, and opens the pressurizer safety valves, in that sequence. For conservatism, the pressure-reducing effect of the spray is not included in the analysis.

This event is classified as a Condition IV incident (limiting fault), as defined in subsection 15.0.1.

15.3.4.2 Conclusion

With a failed shaft, the impeller could be free to spin in a reverse direction as opposed to being fixed in position as is the case when a locked rotor occurs. This results in a decrease in the end point (steady-state) core flow. For both the shaft break and locked rotor incidents, reactor trip

occurs very early in the transient. In addition, the locked rotor analysis conservatively assumes that DNB occurs at the beginning of the transient. The calculated results presented for the locked rotor analysis bound the reactor coolant pump shaft break event.

15.3.5 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.3.6 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

2. Hargrove, H. G., "FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

3. Baldwin, M. S., et al., "An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs," WCAP-8424, Revision 1, May 1975.

4. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, July 1981.

5. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

6. Soffer, L., et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

Table 15.3-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN A DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

Accident	Event	Time (seconds)
Partial loss of forced reactor coolant flow		
– Loss of two pumps with four pumps running	Coastdown begins	0.00
	Low-flow reactor trip	1.61
	Rods begin to drop	3.06
	Minimum DNBR occurs	4.90
Complete loss of forced reactor coolant		
– Loss of four pumps with four pumps running	Operating pumps lose power and begin coasting down	0.00
	Reactor coolant pump underspeed trip point reached	0.47
	Rods begin to drop	1.24
	Minimum DNBR occurs	3.0
Reactor coolant pump shaft seizure (locked rotor)		
– One locked rotor with four pumps running with offsite power available	Rotor on one pump locks	0.00
	Low-flow trip point reached	0.10
	Rods begin to drop	1.55
	Maximum reactor coolant system pressure occurs	2.30
	Maximum cladding temperature occurs	3.90
– One locked rotor with four pumps running without offsite power available	Rotor on one pump locks	0.00
	Low-flow trip point reached	0.10
	Rods begin to drop, loss of offsite power occurs	1.55
	Maximum reactor coolant system pressure occurs	2.30
	Maximum cladding temperature occurs	3.90

Table 15.3-2

SUMMARY OF RESULTS FOR LOCKED ROTOR TRANSIENTS (FOUR REACTOR COOLANT PUMPS OPERATING INITIALLY)

	Without Offsite Power Available
Maximum reactor coolant system pressure (psia)	2703
Maximum cladding temperature, core hot spot (°F)	1819
$Zr\text{-}H_2O$ reaction, core hot spot (percentage by weight)	0.30

Table 15.3-3 (Sheet 1 of 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/gm of dose equivalent I-131 (see Appendix 15A)[a]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/gm dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	10% of design basis reactor coolant concentrations at maximum equilibrium conditions
Fraction of fuel rods assumed to fail	0.10
Core activity	See Table 15A-3
Radial peaking factor (for determination of activity in failed fuel rods)	1.65
Fission product gap fractions I-131 Kr-85 Other iodines and noble gases Alkali metals	 0.08 0.10 0.05 0.12
Reactor coolant mass (lb)	3.7 E+05
Secondary coolant mass (lb)	6.06 E+05
Condenser	Not available
Atmospheric dispersion factors	See Table 15A-5
Primary to secondary leak rate (lb/hr)	104.3[b]
Partition coefficient in steam generators iodine alkali metals	 0.01 0.001
Accident scenario in which startup feedwater is not available Duration of accident (hr) Steam released (lb) 0-1.5 hours[c] Leak flashing fraction[d] 0-60 minutes > 60 minutes	 1.5 hr 6.48 E+05 0.04 0

Table 15.3-3 (Sheet 2 of 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

Accident scenario in which startup feedwater is available	
Duration of accident (hr)	8.0 hr
Steam release rate (lb/sec)	60
Leak flashing fraction	Not applicable

Notes:

a. The assumption of a pre-existing iodine spike is a conservative assumption for the initial reactor coolant activity. However, compared to the activity released to the coolant from the assumed fuel failures, it is not significant.

b. Equivalent to 300 gpd cooled liquid at 62.4 lb/ft^3.

c. Heat removal is achieved by steaming and by passive core cooling system operation in the limiting case where the startup feedwater system is not available. When heat removal by the passive core cooling system exceeds the decay heat load, steam releases are terminated.

d. No credit for iodine partitioning is taken for flashed leakage. Credit is taken for a partition coefficient of 0.10 for alkali metals. Flashing is terminated by the passive core cooling system operation reducing the RCS below the saturation temperature of the secondary.

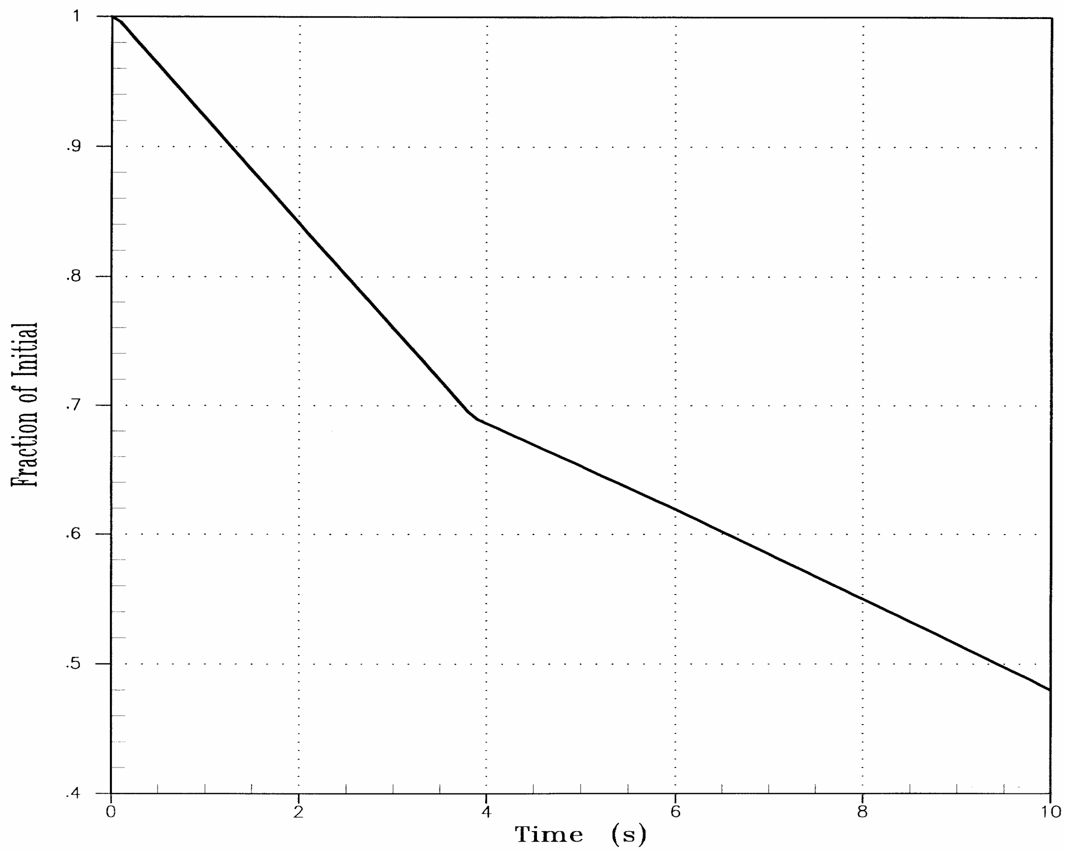

Figure 15.3.1-1

Core Mass Flow Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

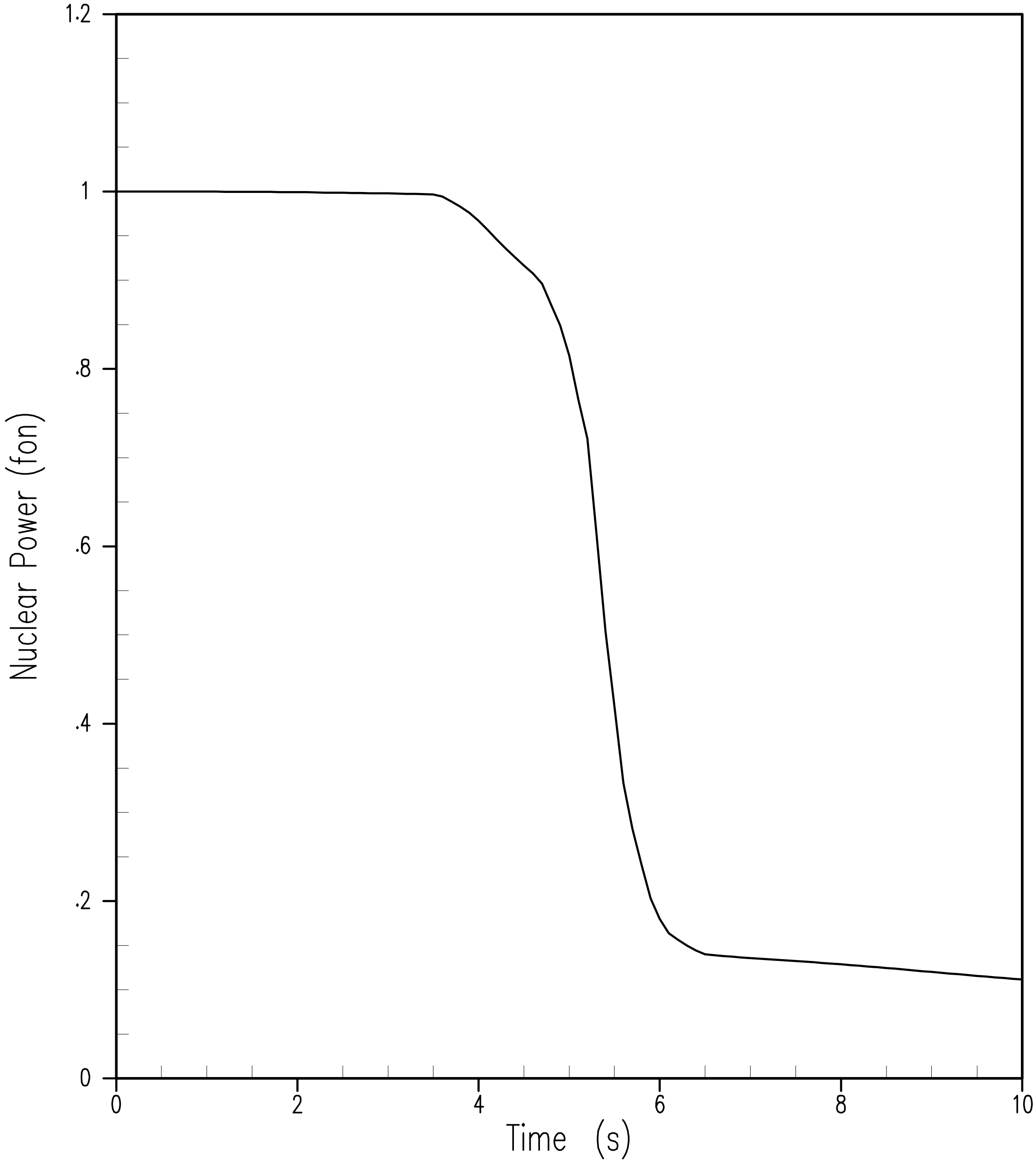

Figure 15.3.1-2

Nuclear Power Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

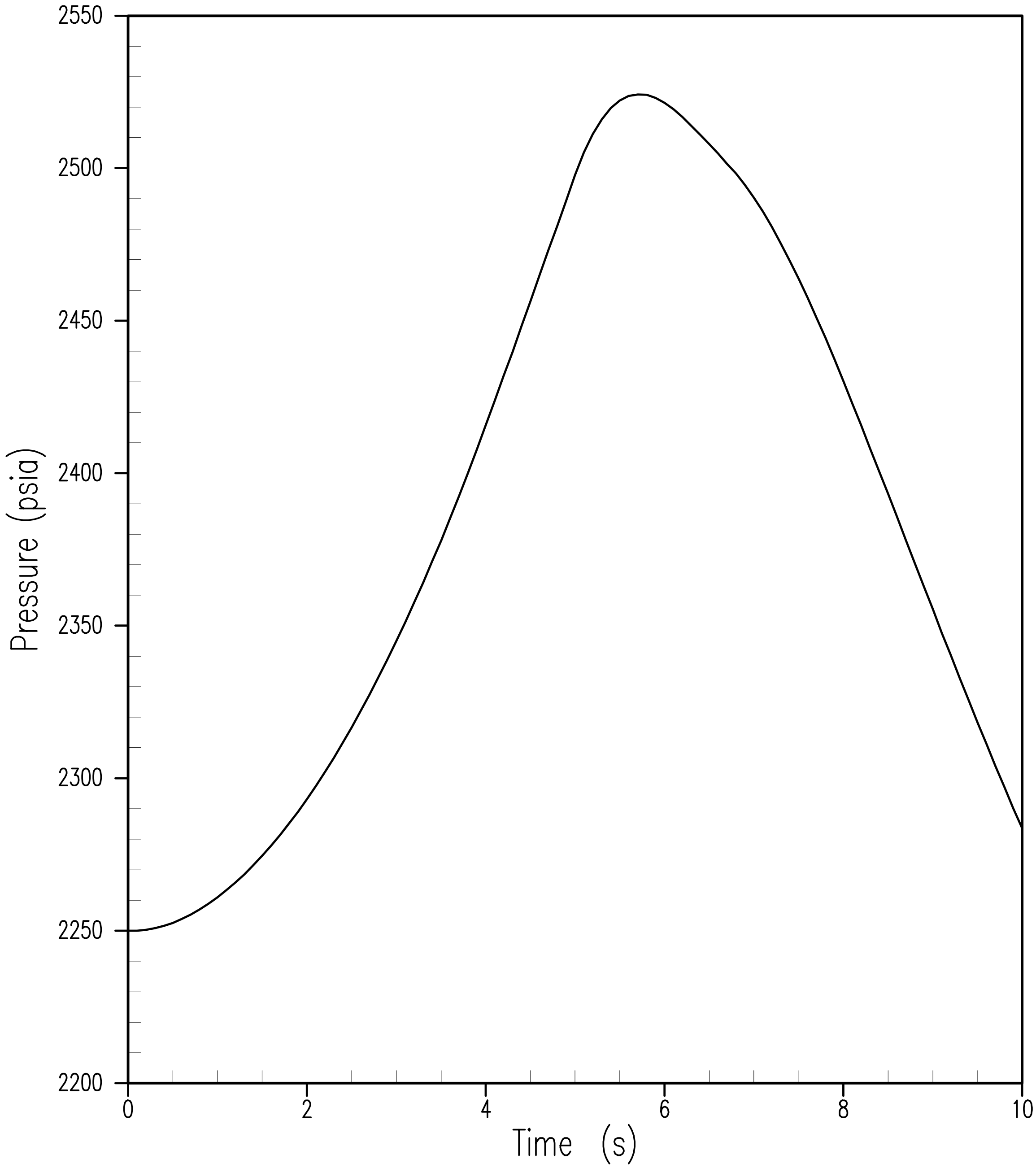

Figure 15.3.1-3

Pressurizer Pressure Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

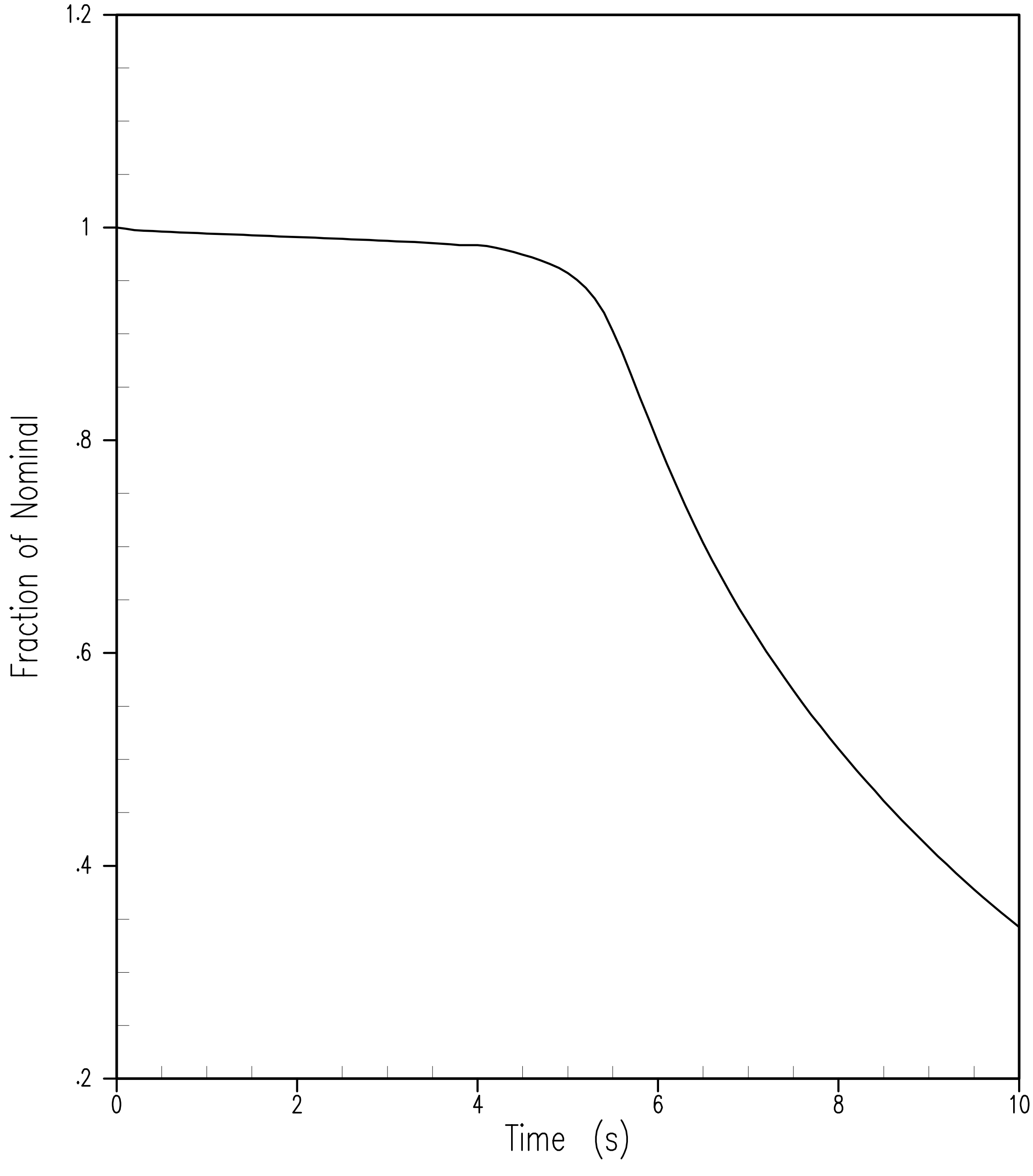

Figure 15.3.1-4

Average Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

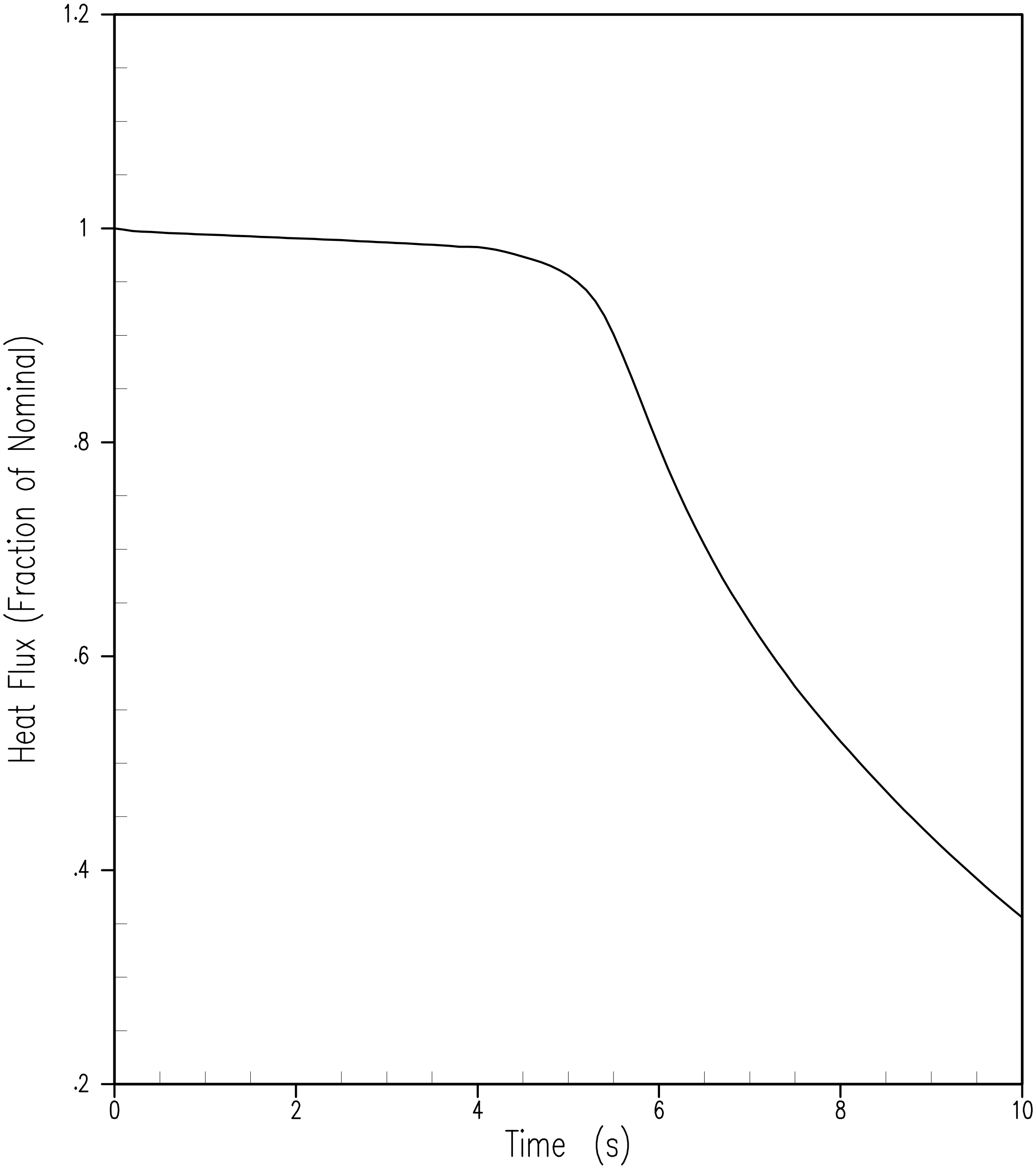

Figure 15.3.1-5

Hot Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

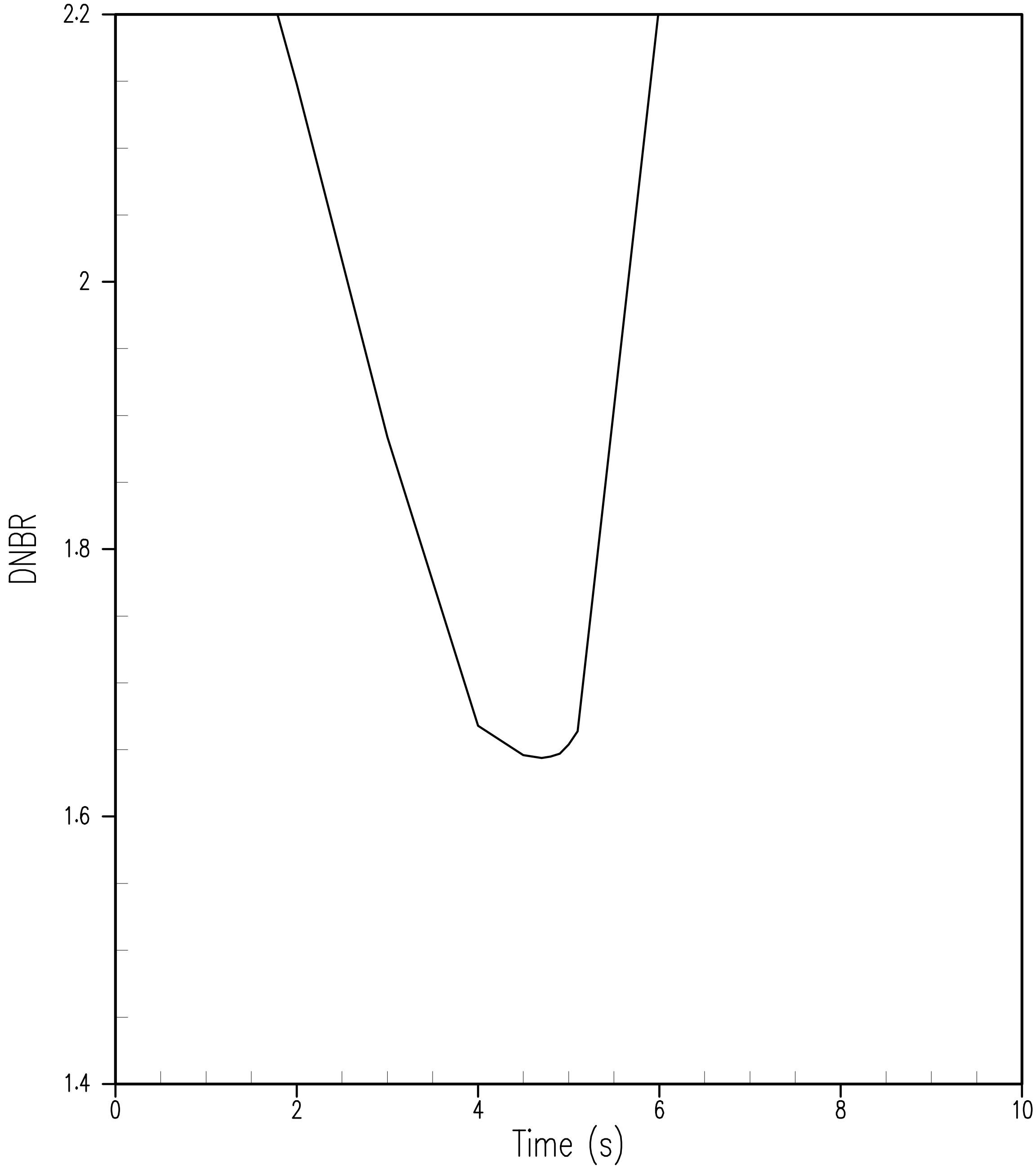

Figure 15.3.1-6

DNB Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

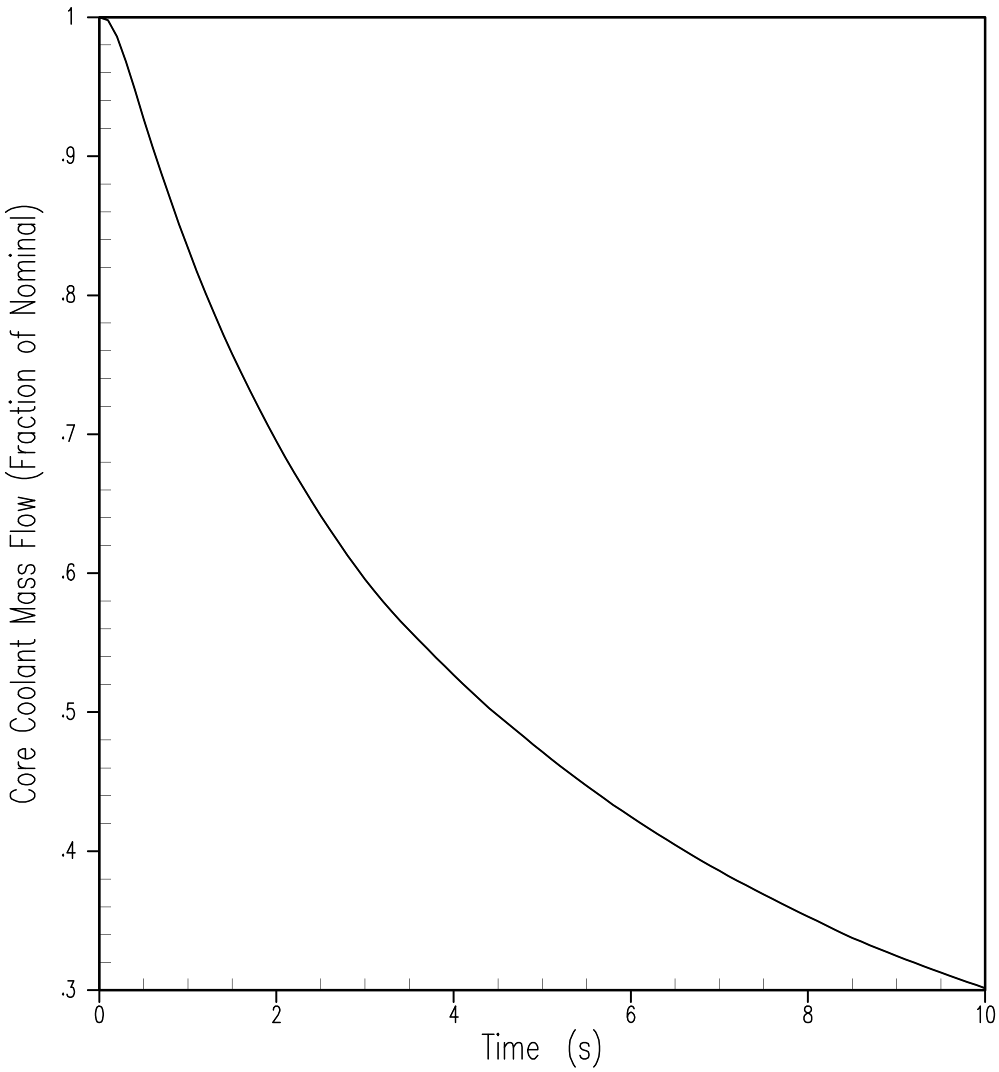

Figure 15.3.2-1

Flow Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

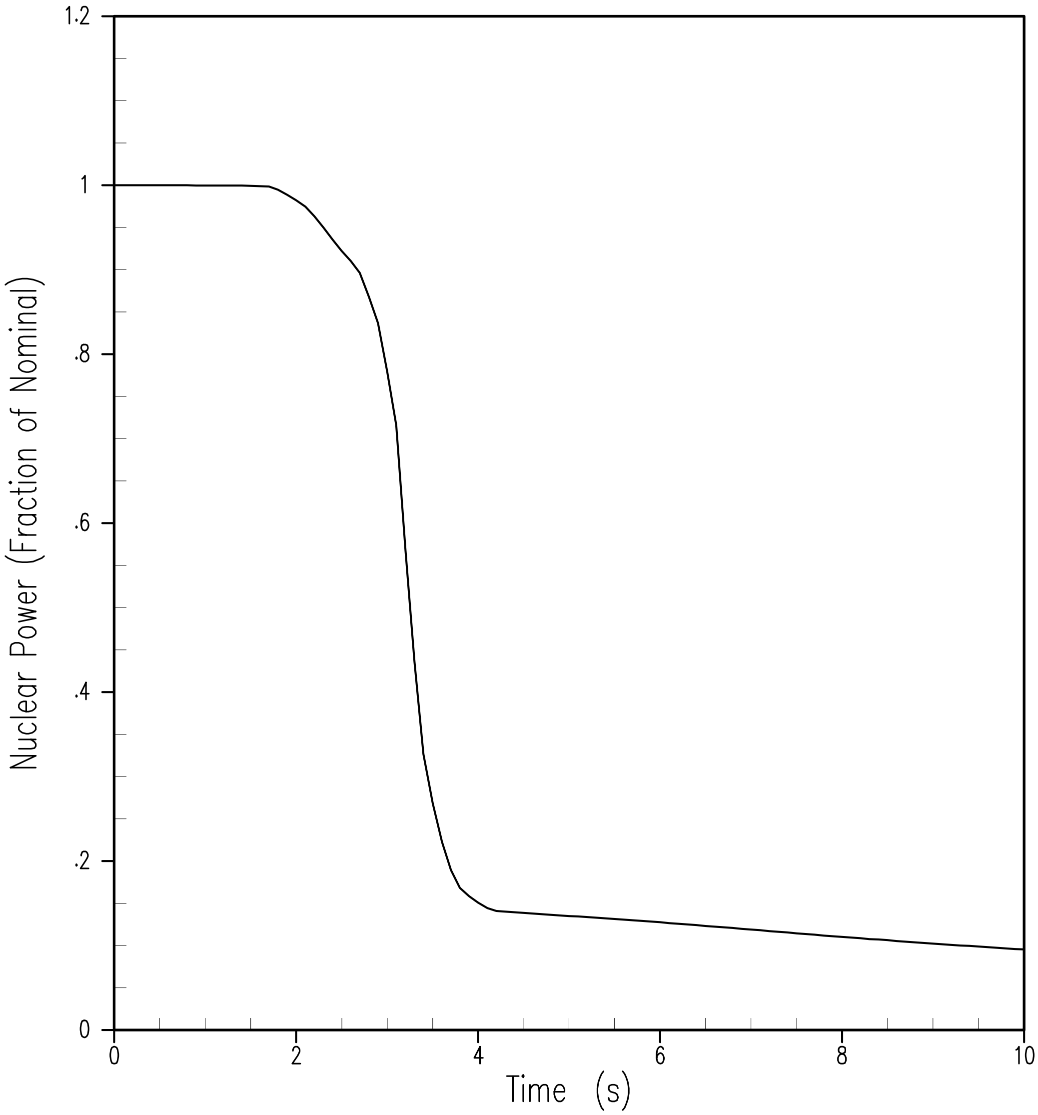

Figure 15.3.2-2

Nuclear Power Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

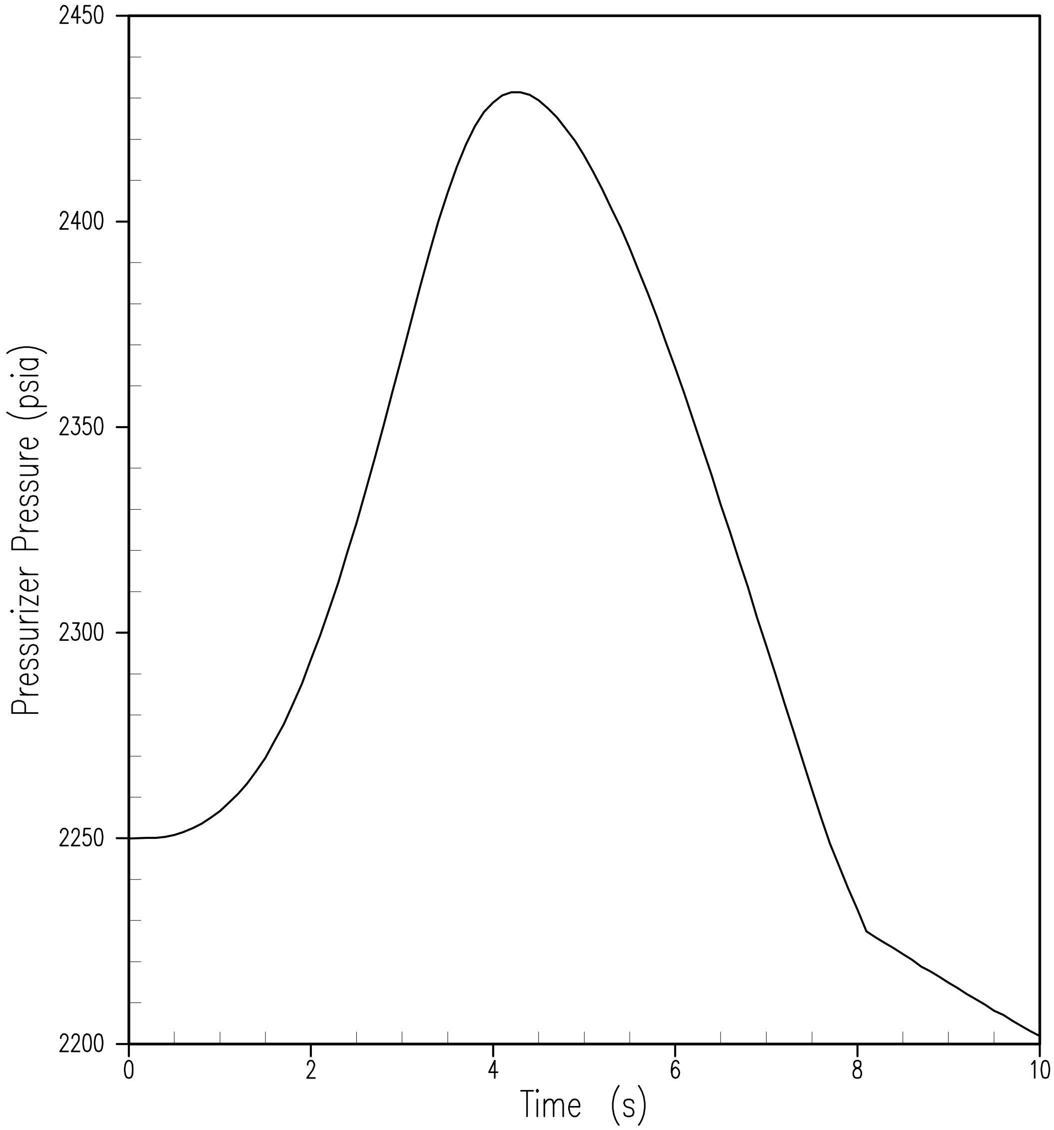

Figure 15.3.2-3

Pressurizer Pressure Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

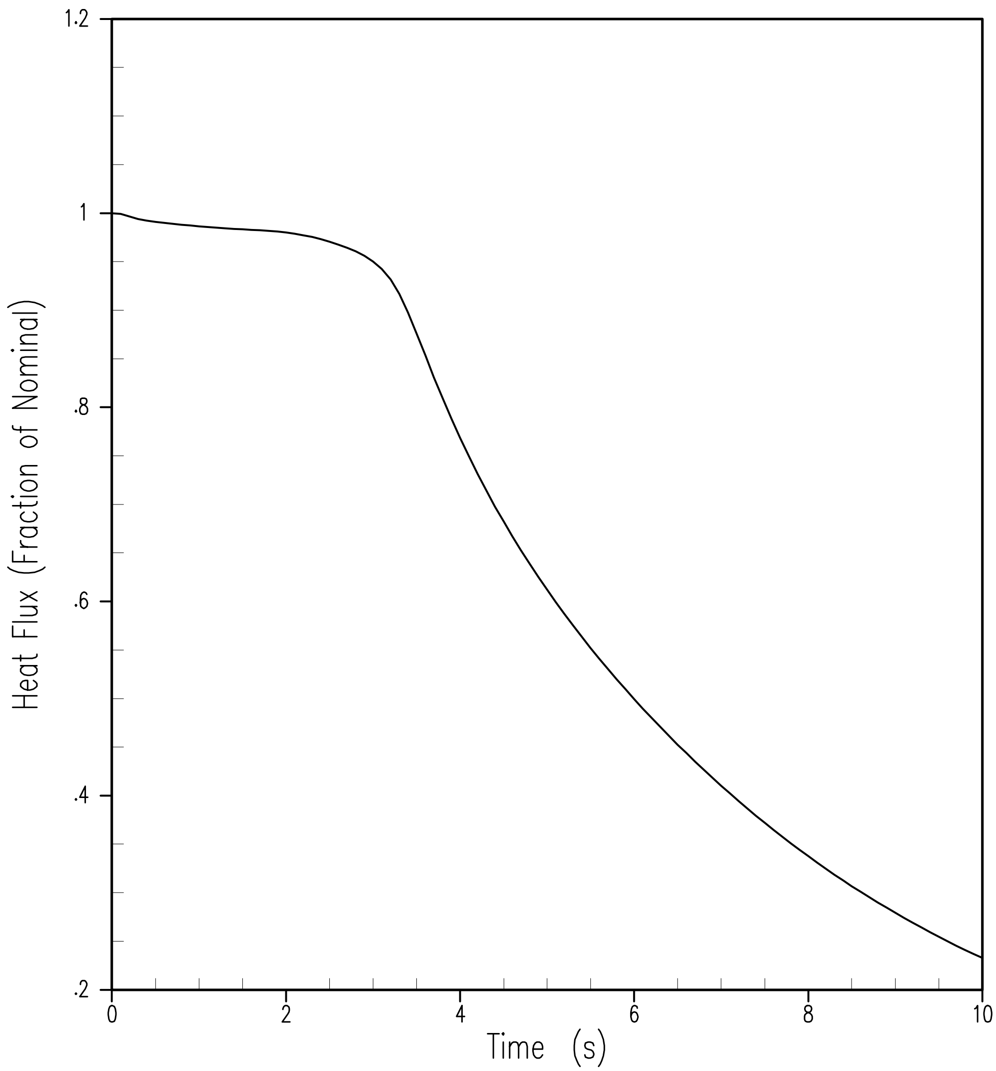

Figure 15.3.2-4

Average Channel Heat Flux Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

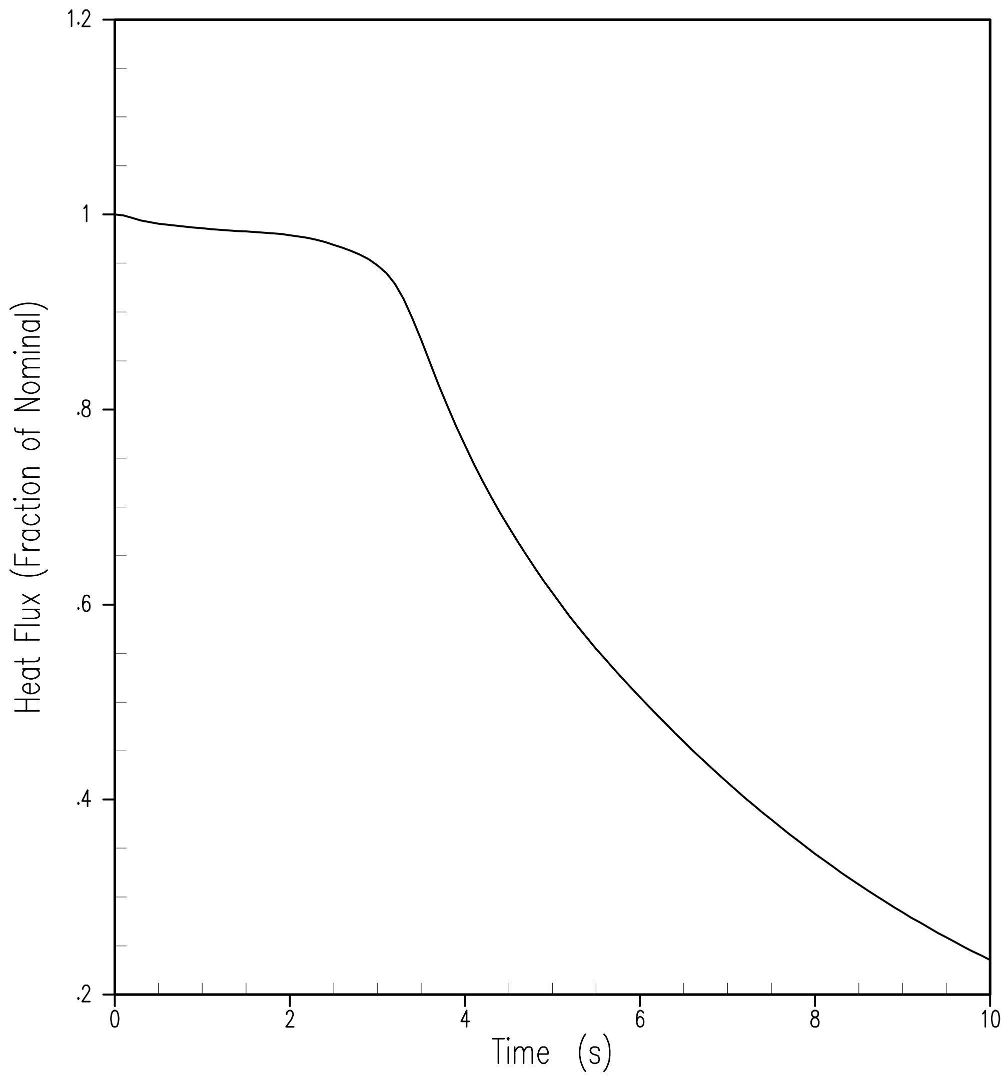

Figure 15.3.2-5

Hot Channel Heat Flux Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

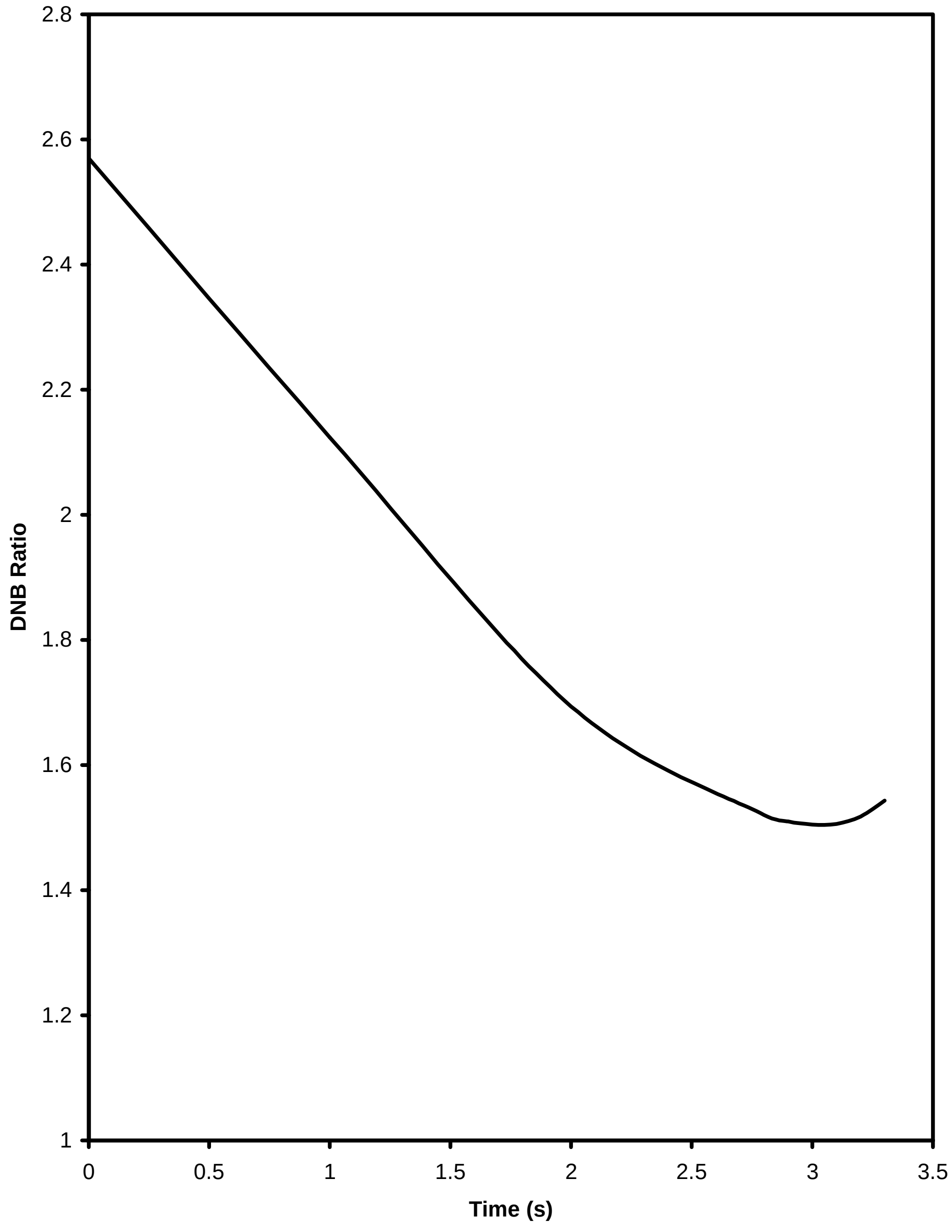

Figure 15.3.2-6

DNBR Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

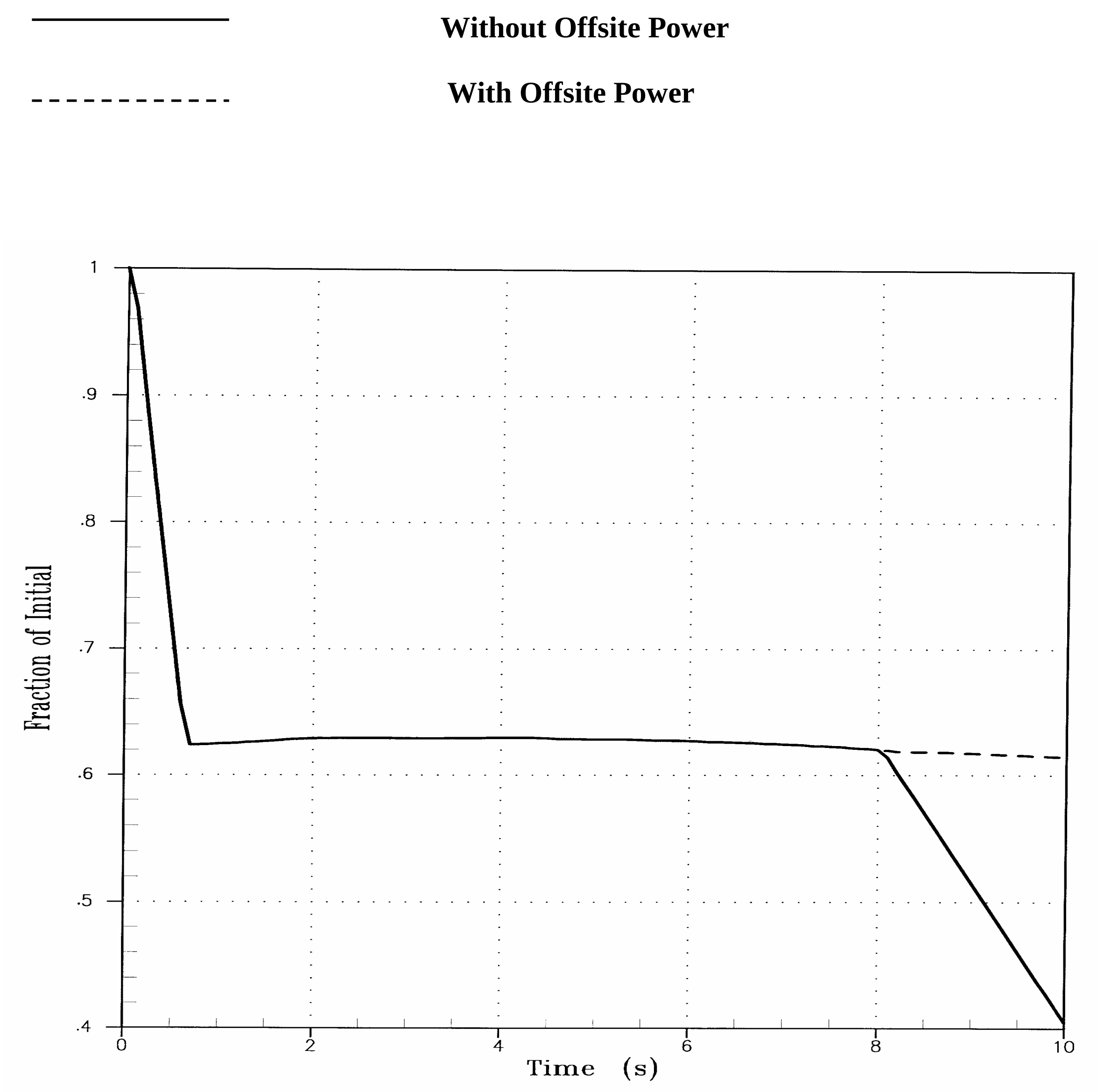

Figure 15.3.3-1

Core Mass Flow Transient for Four Cold Legs in Operation, One Locked Rotor

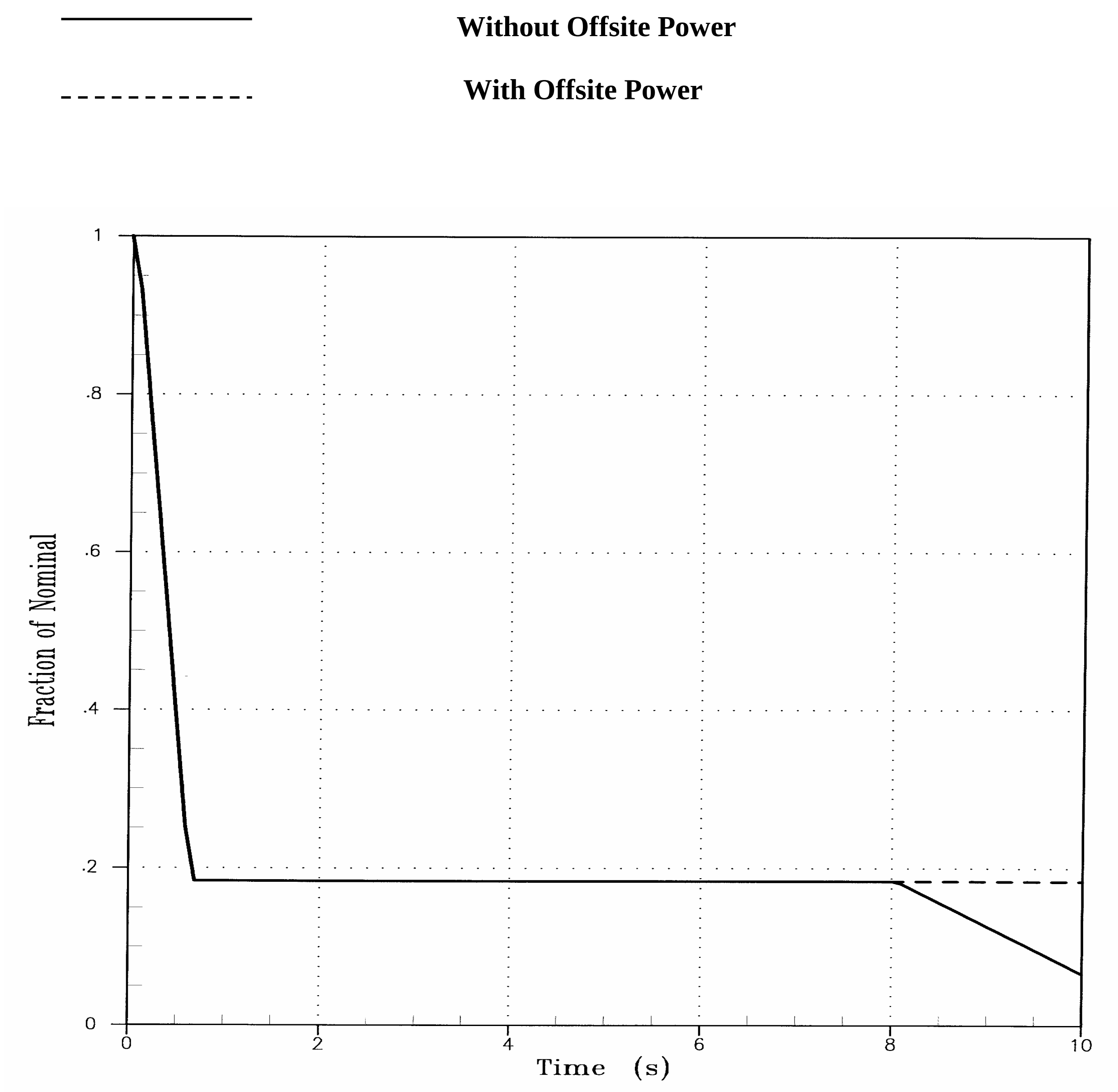

Figure 15.3.3-2

Faulted Loop Volumetric Flow Transient for Four Cold Legs in Operation, One Locked Rotor

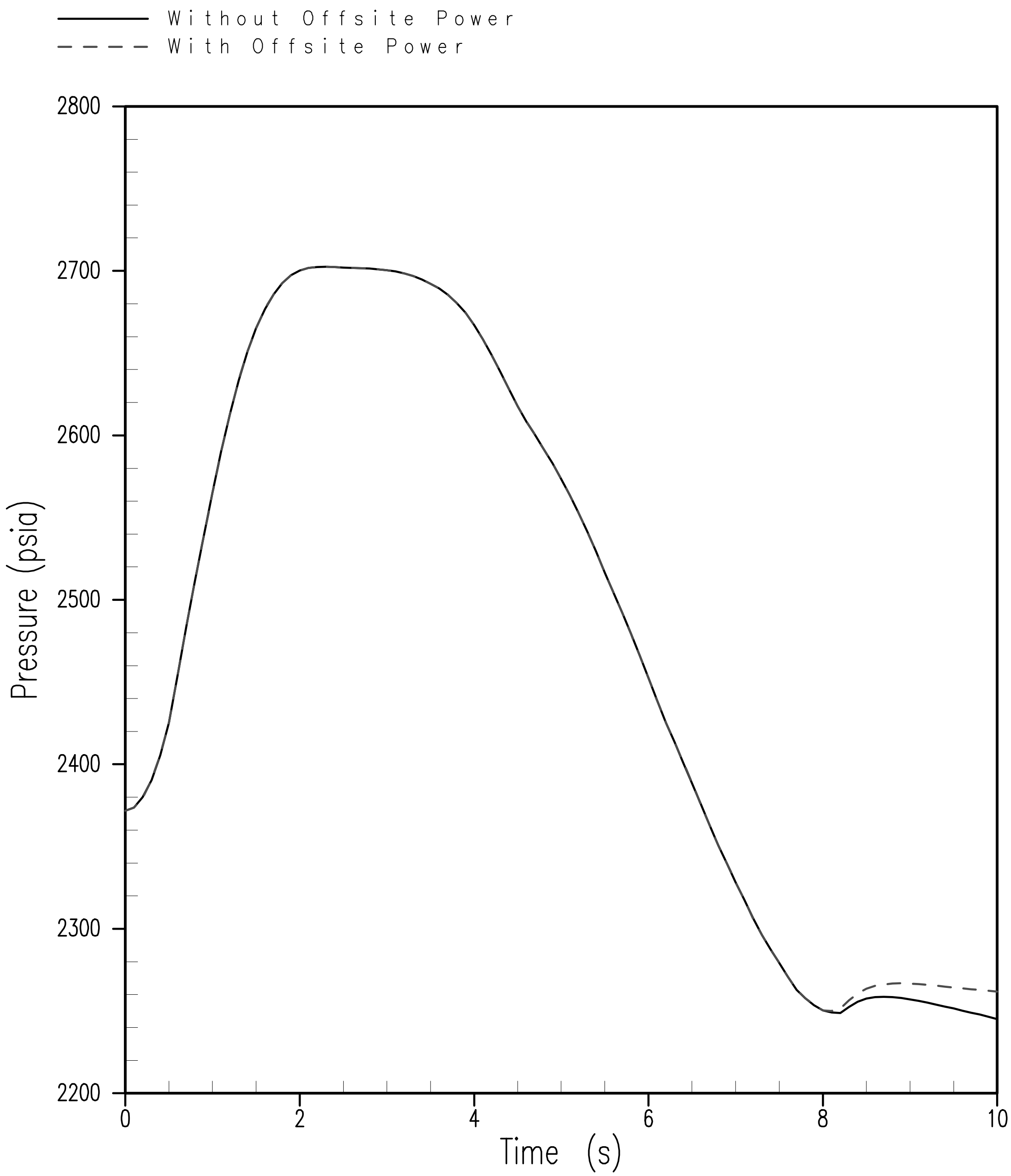

Figure 15.3.3-3

Peak Reactor Coolant Pressure for Four Cold Legs in Operation, One Locked Rotor

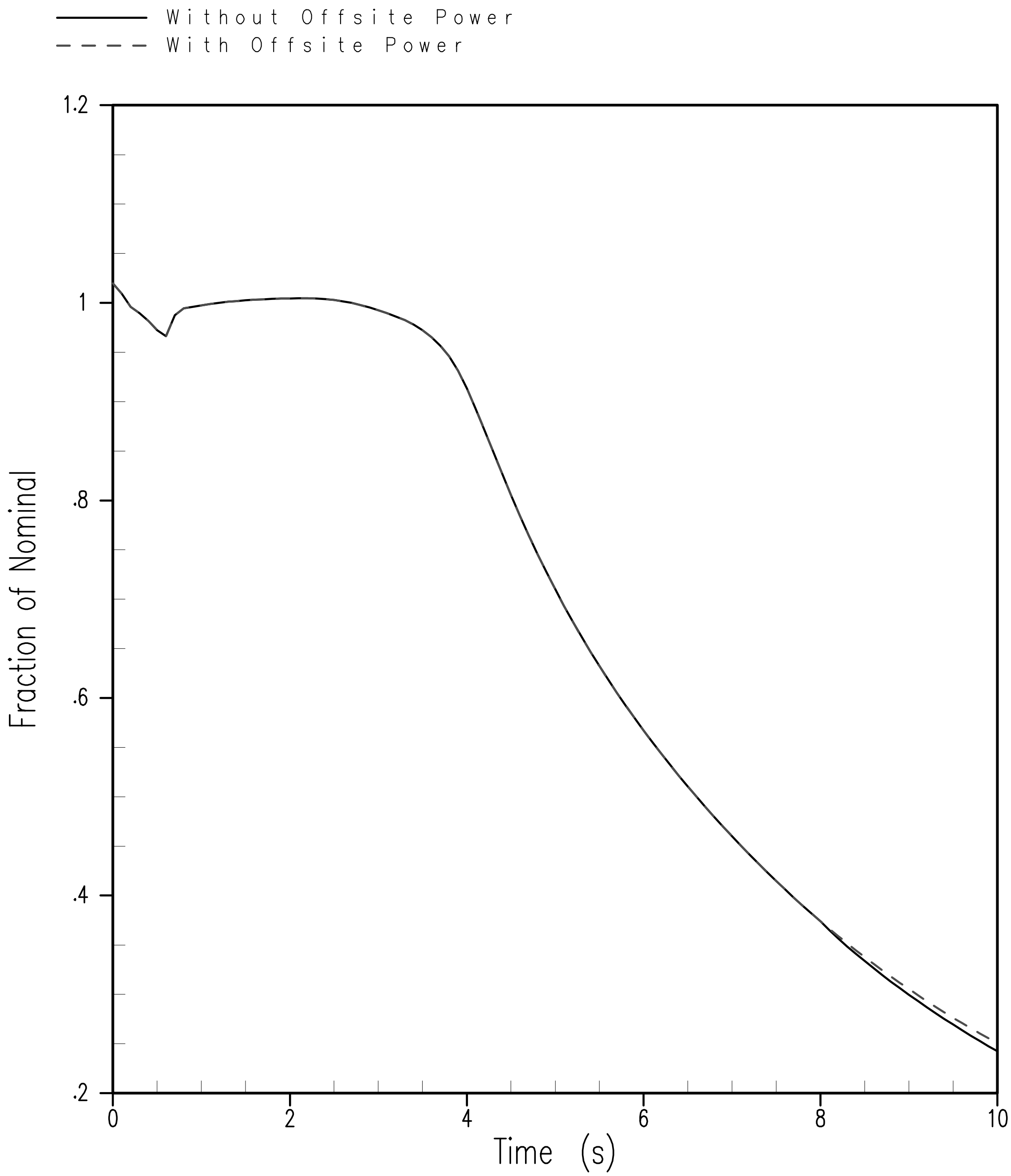

Figure 15.3.3-4

Average Channel Heat Flux Transient for
Four Cold Legs in Operation, One Locked Rotor

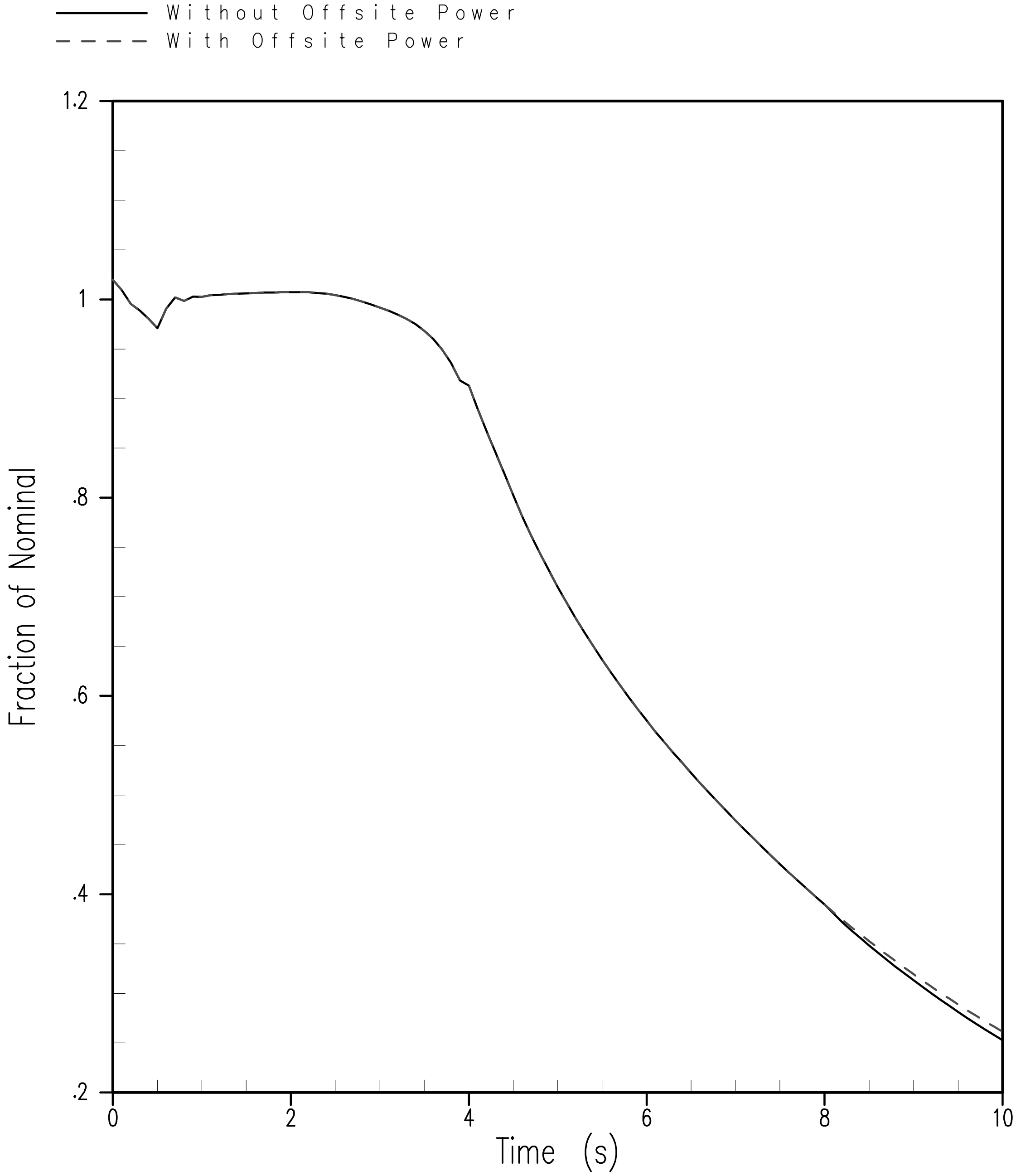

Figure 15.3.3-5

Hot Channel Heat Flux Transient for Four Cold Legs in Operation, One Locked Rotor

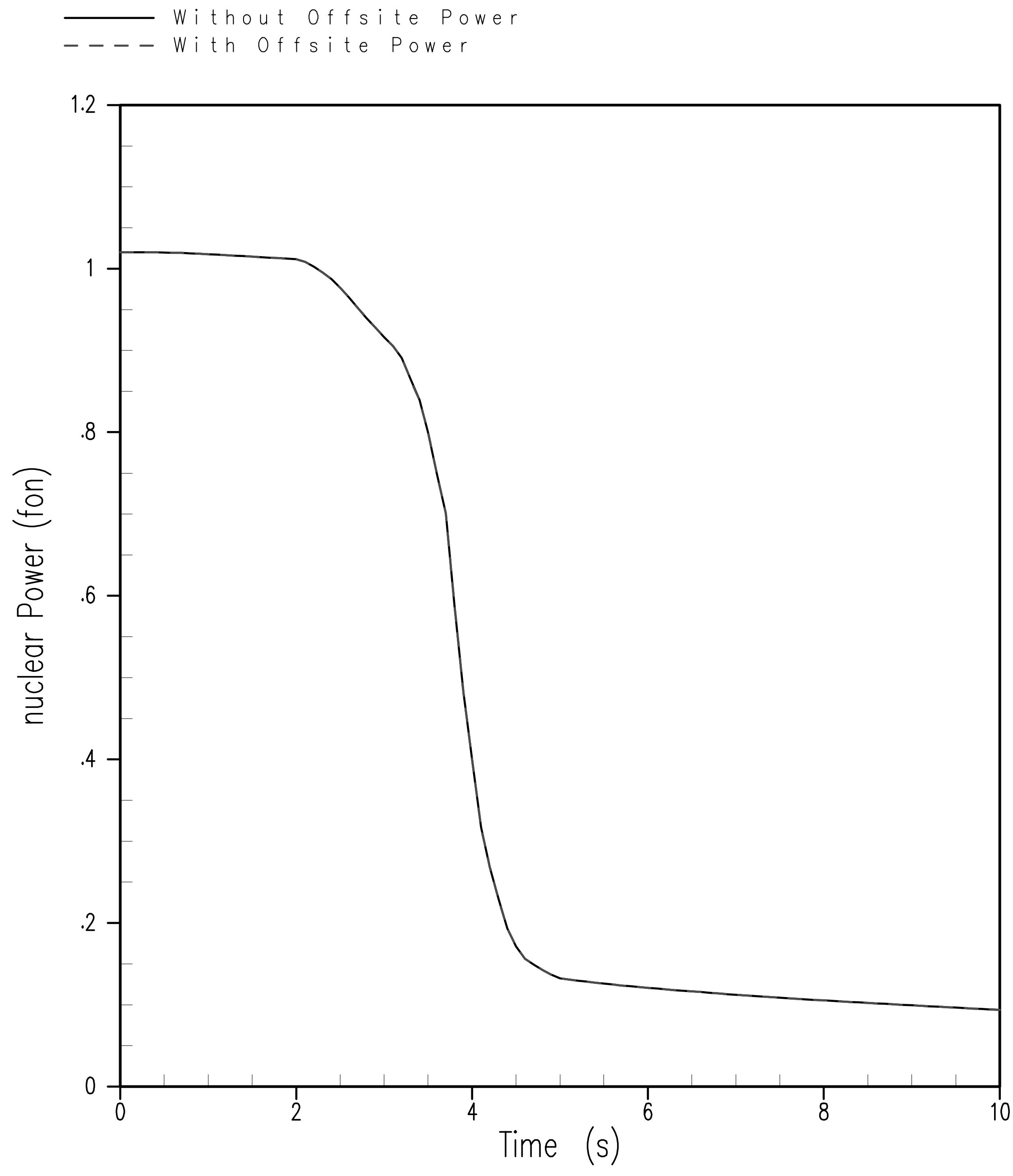

Figure 15.3.3-6

Nuclear Power Transient for
Four Cold Legs in Operation, One Locked Rotor

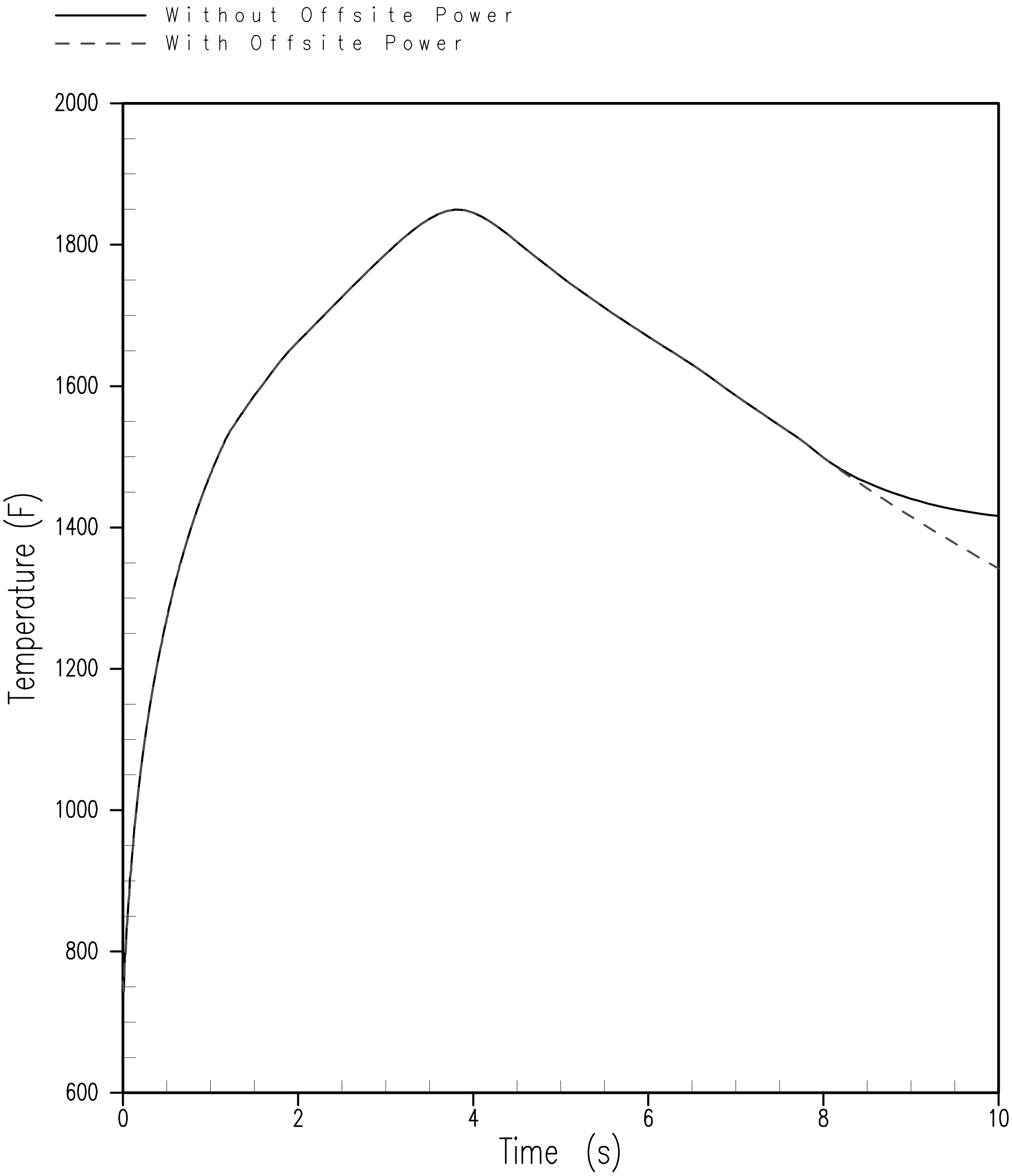

Figure 15.3.3-7

Cladding Inside Temperature Transient for Four Cold Legs in Operation, One Locked Rotor

15.4 Reactivity and Power Distribution Anomalies

A number of faults are postulated that result in reactivity and power distribution anomalies. Reactivity changes could be caused by control rod motion or ejection, boron concentration changes, or addition of cold water to the reactor coolant system. Power distribution changes could be caused by control rod motion, misalignment, or ejection, or by static means such as fuel assembly mislocation. These events are discussed in this section. Analyses are presented for the most limiting of these events.

The following incidents are discussed in this section:

A. Uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition

B. Uncontrolled RCCA bank withdrawal at power

C. RCCA misalignment

D. Startup of an inactive reactor coolant pump at an incorrect temperature

E. A malfunction or failure of the flow controller in a boiling water reactor recirculation loop that results in an increased reactor coolant flow rate (not applicable to AP1000)

F. Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant

G. Inadvertent loading and operation of a fuel assembly in an improper position

H. Spectrum of RCCA ejection accidents

Items A, B, D, and F above are Condition II events, item G is a Condition III event, and item H is a Condition IV event. Item C includes both Conditions II and III events.

The applicable transients in this section have been analyzed. It has been determined that the most severe radiological consequences result from the complete rupture of a control rod drive mechanism housing as discussed in subsection 15.4.8.

Radiological consequences are reported only for the limiting case.

15.4.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-power Startup Condition

15.4.1.1 Identification of Causes and Accident Description

An RCCA withdrawal accident is an uncontrolled addition of reactivity to the reactor core caused by the withdrawal of RCCAs which results in a power excursion. Such a transient can be caused by a malfunction of the reactor control or rod control systems. This can occur with the reactor subcritical, at hot zero power, or at power. The at-power case is discussed in subsection 15.4.2.

Although the reactor is normally brought to power from a subcritical condition by RCCA withdrawal, initial startup procedures with a clean core use boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see subsection 15.4.6).

The RCCA drive mechanisms are grouped into preselected bank configurations. These groups prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled such that no more than two banks are withdrawn at the same time and in their proper withdrawal sequence. The RCCA drive mechanisms are the magnetic latch type, and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed is that occurring with the simultaneous withdrawal of the combination of two sequential RCCA banks having the maximum combined worth at maximum speed.

This event is a Condition II event (a fault of moderate frequency) as defined in subsection 15.0.1.

The neutron flux response to a continuous reactivity insertion is characterized by a fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power excursion limits the power during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient is terminated by the following automatic features of the protection and safety monitoring system:

- Source range high neutron flux reactor trip

  This trip function is actuated when two out of four independent source range channels indicate a neutron flux level above a preselected, manually adjustable setpoint. It may be manually bypassed only after an intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when the coincident two out of four intermediate range channels indicate a flux level below a specified level.

- Intermediate range high neutron flux reactor trip

  This trip function is actuated when two out of four independent, intermediate range channels indicate a flux level above a preselected, manually adjustable setpoint. It may be manually bypassed only after two out of four power range channels are reading above approximately 10 percent of full power. It is automatically reinstated when the coincident two out of four channels indicate a power level below this value.

- Power range high neutron flux reactor trip (low setting)

  This trip function is actuated when two out of four power range channels indicate a power level above approximately 25 percent of full power. It may be manually bypassed when two out of four power range channels indicate a power level above approximately 10 percent of full power. It is automatically reinstated when the coincident two out of four channels indicate a power level below this value.

- Power range high neutron flux reactor trip (high setting)

  This trip function is actuated when two out of four power range channels indicate a power level above a preset setpoint. It is always active.

- High nuclear flux rate reactor trip

  This trip function is actuated when the positive rate of change of neutron flux on two out of four nuclear power range channels indicate a rate above a preset setpoint. The trip may be manually bypassed after the coincident two out of four nuclear power range channels are manually reset.

  In addition, control rod stops on high intermediate range flux level (one out of two) and high power range flux level (one out of four) serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux level trip and the power range flux level trip, respectively.

15.4.1.2 Analysis of Effects and Consequences

15.4.1.2.1 Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: first, an average core nuclear power transient calculation; then, an average core heat transfer calculation; and finally, the departure from nucleate boiling ratio (DNBR) calculation. In the first stage, the average core nuclear calculation is performed using spatial neutron kinetics methods, using the code TWINKLE (Reference 1), to determine the average power generation with time, including the various total core feedback effects (doppler reactivity and moderator reactivity).

In the second stage, the average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN (Reference 2). In the final stage, the average heat flux is used in VIPRE-01 (described in Section 4.4) for the transient DNBR calculation.

Plant characteristics and initial conditions are discussed in subsection 15.0.3. The following assumptions are made to give conservative results for a startup accident:

- Because the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservatively low values, as a function of power, are used (see Table 15.0-2).

- Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. After the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A conservative value is used in the analysis to yield the maximum peak heat flux (see Table 15.0-2).

- The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect and thereby increase the neutron flux peak. The initial effective multiplication factor (k_{eff}) is assumed to be 1.0 because this results in the worst nuclear power transient.

- Reactor trip is assumed to be initiated by the power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10-percent uncertainty increase is assumed for the power range flux trip setpoint, raising it to 35 percent from the nominal value of 25 percent.

  Because the rise in the neutron flux is so rapid, the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. See subsection 15.0.5 for RCCA insertion characteristics.

- The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two sequential RCCA banks having the greatest combined worth at maximum speed (45 inches per minute). Control rod drive mechanism design is discussed in Section 4.6.

- The most limiting axial and radial power shapes, associated with having the two highest combined worth banks in their high-worth position, are assumed in the departure from nucleate boiling (DNB) analysis.

- The initial power level is assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

- Four reactor coolant pumps are assumed to be in operation.

- Pressurizer pressure is assumed to be 50 psi below nominal for steady-state fluctuations and measurement uncertainties.

Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or components adversely affect the consequences of the accident. A loss of offsite power as a consequence of a turbine trip disrupting the grid is not considered because the accident is initiated from a subcritical condition where the plant is not providing power to the grid.

15.4.1.2.2 Results

Figures 15.4.1-1 through 15.4.1-3 show the transient behavior for the uncontrolled RCCA bank withdrawal from subcritical incident. The accident is terminated by reactor trip at 35 percent of nominal power. The reactivity insertion rate used is greater than that calculated for the

two highest-worth sequential rod cluster control banks, both assumed to be in their highest incremental worth region.

Figure 15.4.1-1 shows the average neutron flux transient. The energy release and the fuel temperature increases are relatively small. The heat flux response (of interest for DNB considerations) is also shown in Figure 15.4.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux much less than the full-power nominal value. There is margin to DNB during the transient because the rod surface heat flux remains below the critical heat flux value, and there is a high degree of subcooling at all times in the core. Figure 15.4.1-3 shows the response of the average fuel and cladding temperatures. The minimum DNBR at all times remains above the design limit value (see Section 4.4).

The calculated sequence of events for this accident is shown in Table 15.4-1. With the reactor tripped, the plant returns to a stable condition. Subsequently, the plant may be cooled down further by following normal plant shutdown procedures.

15.4.1.3 Conclusions

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the reactor coolant system are not adversely affected because the combination of thermal power and the coolant temperature results in a DNBR greater than the safety analysis limit value. Thus, no fuel or cladding damage is predicted as a result of DNB.

15.4.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

15.4.2.1 Identification of Causes and Accident Description

Uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Because the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in DNB. Therefore, to avert damage to the fuel cladding, the protection and safety monitoring system is designed to terminate any such transient before the DNBR falls below the design limit (see Section 4.4).

This event is a Condition II incident (a fault of moderate frequency) as defined in subsection 15.0.1.

The automatic features of the protection and safety monitoring system that prevent core damage following the postulated accident include the following:

- Power range neutron flux instrumentation actuates a reactor trip if two out of four channels exceed an overpower setpoint. In particular, the power range neutron flux instrumentation provides the following reactor trip functions:

  1. Reactor trip on high power range neutron flux (high setpoint)
  2. Reactor trip on high power range positive neutron flux rate

The latter trip protects the core when a sudden abnormal increase in power is detected in the power range neutron flux channel in two out of four PMS divisions. It provides protection against reactivity insertion rates accidents at mid and low power, and it is always active.

- Reactor trip is actuated if any two out of four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature, and pressure to protect against DNB.

- Reactor trip is actuated if any two out of four ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with axial power imbalance to prevent the allowable linear heat generation rate (kW/ft) from being exceeded.

- A high pressurizer pressure reactor trip is actuated from any two out of four pressure channels when a set pressure is exceeded. This set pressure is less than the set pressure for the pressurizer safety valves.

- A high pressurizer water level reactor trip is actuated from any two out of four level channels that exceed the setpoint when the reactor power is above approximately 10 percent (permissive-P10).

In addition to the preceding reactor trips, there are the following RCCA withdrawal blocks:

- High neutron flux (two out of four power range)
- Overpower ΔT (two out of four)
- Overtemperature ΔT (two out of four)

The manner in which the combination of overpower and overtemperature ΔT trips provide protection over the full range of reactor coolant system conditions is described in Chapter 7.

Figure 15.0.3-1 presents allowable reactor coolant loop average temperature and ΔT for the design power distribution and flow as a function of primary coolant pressure. The boundaries of operation defined by the overpower ΔT trip and the overtemperature ΔT trip are represented as “protection lines” on this diagram. The protection lines are drawn to include adverse instrumentation and setpoint uncertainties so that under nominal conditions, a trip occurs well within the area bounded by these lines.

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips:

- High neutron flux (fixed setpoint)
- High pressurizer pressure (fixed setpoint)
- Low pressurizer pressure (fixed setpoint)
- Overpower and overtemperature ΔT (variable setpoints)

For meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, an analysis has been performed to evaluate the effects produced by a possible consequential loss of offsite power during the RCCA withdrawal at-power event. In addressing the loss of offsite power issue, the

minimum DNBR cases with full reactor coolant system flow are analyzed assuming that the turbine trip in parallel with the reactor trip causes a subsequent loss of offsite power. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

15.4.2.2 Analysis of Effects and Consequences

15.4.2.2.1 Method of Analysis

This transient is primarily analyzed by the LOFTRAN (References 3 and 11) code. This code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated in Figure 15.0.3-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

For that portion of the RCCA withdrawal at-power analysis that includes a primary coolant flow coastdown caused by the consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analysis. First, the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 2) is then used to calculate the heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR during the transient, using the heat flux from FACTRAN and the flow, inlet core temperature (and pressure) from LOFTRAN.

Plant characteristics and initial conditions are discussed in subsection 15.0.3. In performing a conservative analysis for an uncontrolled RCCA bank withdrawal at-power accident, the following assumptions are made:

- The nominal initial conditions are assumed in accordance with the revised thermal design procedure. Uncertainties in the initial conditions are included in the DNBR limit as described in WCAP- 11397-P-A (Reference 9).

- Two sets of reactivity coefficients are considered:

  Minimum reactivity feedback — A least-negative moderator temperature coefficient of reactivity is assumed, corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed (see Figure 15.0.4-1).

  Maximum reactivity feedback — A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed (see Figure 15.0.4-1).

- The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal full power. The ΔT trips include adverse instrumentation and setpoint uncertainties; the delays for trip actuation are assumed to be the maximum values.

- The RCCA trip insertion characteristic is based on the assumption that the highest-worth assembly is stuck in its fully withdrawn position.
- A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combination of the two control banks, having the maximum combined worth at maximum speed.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in overtemperature ΔT trip setpoint proportional to a decrease in margin to DNB.

In addressing the loss of offsite power issue, the minimum DNBR cases with full reactor coolant system flow are analyzed assuming that the turbine trip in parallel with the reactor trip causes a subsequent loss of offsite power, as described in subsection 15.0.14. The loss of offsite power is modeled to occur 3.0 seconds after the turbine trip. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in these systems or equipment adversely affects the consequences of the accident. A discussion of anticipated transients without scram considerations is presented in Section 15.8.

15.4.2.2.2 Results

Figures 15.4.2-1 through 15.4.2-7 show the transient response for a representative rapid RCCA withdrawal incident starting from full power with offsite power lost as a consequence of turbine trip. Reactor trip on high neutron flux occurs shortly after the start of the accident. Because this is rapid with respect to the thermal time constants of the plant, small changes in temperature and pressure result, and the minimum DNBR is greater than the design limit described in Section 4.4.

The transient response for a representative slow RCCA withdrawal from full power, with offsite power lost as a consequence of turbine trip, is shown in Figures 15.4.2-8 through 15.4.2-14. Reactor trip on overtemperature ΔT occurs after a longer period. The rise in temperature and pressure is consequently larger than for rapid RCCA withdrawal. The minimum DNBR is greater than the design limit value described in Section 4.4.

Figure 15.4.2-15 shows the minimum DNBR as a function of reactivity insertion rate from initial full-power operation for minimum and maximum reactivity feedback. Minimum DNBR, occurs immediately after rod motion and before the loss of offsite power. Two reactor trip functions provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT channels. The minimum DNBR is greater than the design limit value described in Section 4.4.

Figures 15.4.2-15 and 15.4.2-16 show the minimum DNBR as a function of reactivity insertion rate for RCCA withdrawal incidents for minimum and maximum reactivity feedback, starting at 60-percent and 10-percent power, respectively. Minimum DNBR, occurs immediately after rod motion and before the loss of offsite power. The results are similar to the 100-percent power case, except as the initial power is decreased, the range over which the overtemperature ΔT trip is

effective is increased and for the maximum feedback cases the transient is always terminated by the overtemperature ΔT reactor trip. In both cases the DNBR is greater than the design limit value described in Section 4.4.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to protection and safety monitoring system action in initiating a reactor trip.

Referring to Figure 15.4.2-16, for example, it is noted that:

A. For high reactivity insertion rates (between 20 pcm/s and 110 pcm/s), reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. Reactor trip is initiated by overtemperature ΔT for the whole range of reactivity insertion rates for the maximum reactivity feedback cases. For minimum reactivity feedback cases, the neutron flux level in the core rises rapidly for these insertion rates while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to a significant increase in heat flux or water temperature with resultant high minimum DNBRs during the transient. As reactivity insertion rate decreases, core heat flux and coolant temperatures remain more nearly in equilibrium with the neutron flux. Thus, minimum DNBR during the transient decreases with decreasing insertion rate.

B. The overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured reactor coolant system average temperature and pressure. This trip circuit is described in Chapter 7. The average temperature contribution to the circuit is lead-lag compensated to decrease the effect of the thermal capacity of the reactor coolant system in response to power increases.

C. For reactivity insertion rates less than 40 pcm/s for the minimum feedback cases, the rise in reactor coolant system pressure is sufficiently high that the pressurizer safety valve setpoint is reached prior to reactor trip. Opening of this valve limits the rise in reactor coolant pressure as the temperature continues to rise. Because the overtemperature ΔT reactor trip setpoint is based on both temperature and pressure, limiting the reactor coolant pressure by opening the pressurizer safety valve brings about the overtemperature ΔT earlier than if the valve remains closed. For this reason, the overtemperature ΔT setpoint initiates reactor trip at reactivity insertion rates of approximately 20 pcm/s for the minimum feedback cases. For the maximum feedback case, the pressurizer safety valves open also for reactivity insertion rates as high as 110 pcm/s.

D. For the minimum feedback case, with further decrease in reactivity insertion rate in the range between 25 pcm/s and 20 pcm/s, the overtemperature ΔT and high neutron flux trips become equally effective in terminating the transient. For reactivity insertion rates less than approximately 20 pcm/s the overtemperature ΔT trip predominates and the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum DNB) because for these lower reactivity insertion rates, the power increase is slower, the rate of rise of average coolant temperature is slower, and the system lags and delays become less significant.

E. For reactivity insertion rates less than approximately 3 pcm/s for the minimum feedback cases and less than approximately 40 pcm/s for maximum feedback cases, the rise in the reactor coolant temperature is sufficiently high so that the steam generator safety valve setpoint is reached prior to trip. Opening of these valves, which act as an additional heat load of the reactor coolant system, sharply decreases the rate of increase of reactor coolant system average temperature. This decrease in the rate of increase of the average coolant system temperature during the transient is accentuated by the lead-lag compensation. This causes the overtemperature ΔT setpoint to be reached later, with resulting lower minimum DNBRs.

For transients initiated from full power (see Figure 15.4.2-16), both minimum and maximum reactivity feedback, the minimum DNBR occurs for the lower reactivity insertion rates that result in high neutron flux (higher reactivity insertion rate resulting in overtemperature ΔT).

As described in D, at lower reactivity insertion rates the overtemperature ΔT trip predominates and the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum DNB) because for these lower reactivity insertion rates, the power increase is slower, the rate of rise of average coolant temperature is slower, and the system lags and delays become less significant.

Steam generator safety valves never open before the reactor trip, for transients initiated at full power. So there is not the competing effects due to the opening of the pressurizer safety valve and steam generator safety valves described in items C and E. Hence, for both the minimum and maximum feedback cases, the negative peak in DNBR curve due to the steam generator safety valves opening, is not present.

For transients initiated from 10-percent power (see Figure 15.4.2-17) credit has also been taken for the high power range positive neutron flux rate and for the high pressurizer pressure reactor trips.

In fact, due to the low initial power level and the large margin to the high neutron flux and overtemperature ΔT setpoints, the two above reactor trip signals provide an early detection of the abnormal transient. For the minimum reactivity feedback cases, the high power range positive neutron flux provides protection for reactivity insertion rate higher than approximately 20 pcm/s. The reactor trip occurs quite early in the transient and well before steam generator safety valves open. Early trip at low power levels results in high DNBR values. In the range between 22.5 pcm/s and 3.25 pcm/s the reactor is tripped by the high pressurizer pressure reactor trip. Also for this range of reactivity insertion rates, the protection system is able to trip the reactor for power levels well below nominal. Finally, for insertion rates below about 3 pcm/s, core protection is provided once again by the overtemperature ΔT reactor trip. The large step decrease in minimum DNBR is mainly due to the conservative assumption related to the overtemperature ΔT setpoint that does not take into account the axial offset correction. Should the f(ΔI) term be factored in the setpoint definition, the reactor trip would occur much earlier resulting in higher minimum DNBR values.

For the maximum feedback cases, the high pressurizer pressure reactor trip provides protection for reactivity insertion rates between 110 and 30 pcm/s. However, it should be noted that for all of these cases, even assuming no protective actions, the maximum reactivity available from the rod

control banks, from their insertion limit to the fully withdrawn position, is such that an equilibrium core power of about 35 percent of nominal would be attained. This explains the reason for which DNBR is essentially constant from 30 pcm/s to the minimum insertion rate analyzed. The minimum DNBR for this set of cases is attained for the higher reactivity insertion rates for which the maximum overshoot occurs.

Figures 15.4.2-15, 15.4.2-16, and 15.4.2-17 illustrate minimum DNBR calculated for minimum and maximum reactivity feedback.

Because the RCCA withdrawal at-power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant and the core heat flux lags behind the neutron flux response. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel temperature still remains below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the overtemperature ΔT reactor trip before DNB occurs. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak centerline temperature remains below the fuel melting temperature.

The reactor is tripped fast enough during the RCCA bank withdrawal at-power transient that the ability of the primary coolant to remove heat from the fuel rods is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident, with offsite power available, is shown in Table 15.4-1. With the reactor tripped, the plant returns to a stable condition. The plant may be cooled down further by following normal plant shutdown procedures.

The results of the analysis performed modeling a loss of offsite power and the subsequent reactor coolant pump coastdown, show that the minimum DNBR is predicted to occur during the time period of the RCCA withdrawal at-power event prior to the time the flow coastdown begins. Therefore, the minimum DNB ratios provided in Figures 15.4.2-6 and 15.4.2-12 and 15.4.2-15 through 15.4.2-17 are bounding. The reason for this is that because the loss of offsite power is delayed for 3.0 seconds after the turbine trip signal, the RCCAs are inserted well into the core before the reactor coolant system flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once ac power to the reactor coolant pumps is lost.

15.4.2.3 Conclusions

The power range neutron flux instrumentation, overtemperature ΔT and high pressurizer pressure trip functions provide adequate protection over the entire range of possible reactivity insertion rates. The DNB design basis, as defined in Section 4.4, is met for all cases.

15.4.3 Rod Cluster Control Assembly Misalignment (System Malfunction or Operator Error)

15.4.3.1 Identification of Causes and Accident Description

RCCA misoperation accidents include:

- One or more dropped RCCAs within the same group
- Statically misaligned RCCA
- Withdrawal of a single RCCA

Each RCCA has a position indicator channel which displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod-at-bottom signal, which actuates a local alarm and a main control room annunciator. Group demand position is also indicated.

RCCAs are moved in preselected banks, and the banks are moved in a preselected sequence. Each bank of RCCAs is divided into one or two groups of four or five RCCAs each. The rods comprising a group operate in parallel. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation) of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Because the stationary gripper, movable gripper, and lift coils associated with the RCCAs of a rod group are driven in parallel, any single failure which causes rod withdrawal affects the entire group. A single electrical or mechanical failure in the plant control system could, at most, result in dropping one or more RCCAs within the same group. Mechanical failures can cause either RCCA insertion or immobility, but not RCCA withdrawal.

The dropped RCCAs, dropped RCCA bank, and statically misaligned RCCA events are Condition II incidents (incidents of moderate frequency) as defined in subsection 15.0.1. The single RCCA withdrawal event is a Condition III incident, as discussed below.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full-power operation. The operator could withdraw a single RCCA in the control bank because this feature is necessary to retrieve an assembly should one be accidentally dropped. The event analyzed results from multiple wiring failures or multiple significant operator errors and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is considered low such that the limiting consequences may include slight fuel damage.

The event is classified as a Condition III incident consistent with the philosophy and format of American National Standards Institute, ANSI N18.2. By definition, "Condition III occurrences include incidents, any one of which may occur during the lifetime of a particular plant," and "shall not cause more than a small fraction of fuel elements in the reactor to be damaged . . ." (Reference 10).

This selection of criterion is in accordance with General Design Criterion 25, which states, "The protection system shall be designed to assure that specified acceptable fuel design limits are not

exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods." (Emphases have been added.) It has been shown that single failures resulting in RCCA bank withdrawals do not violate specified fuel design limits. Moreover, no single malfunction can result in the withdrawal of a single RCCA. Thus, it is concluded that criterion established for the single rod withdrawal at power is appropriate and in accordance with General Design Criterion 25.

A dropped RCCA or RCCA bank may be detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen by the incore or excore neutron detectors or core exit thermocouples, through online core monitoring
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Misaligned RCCAs are detected by one or more of the following:

- Asymmetric power distribution as seen by the incore or excore neutron detectors or core exit thermocouples, through online core monitoring
- Rod deviation alarm
- Rod position indicators

The resolution of the rod position indicator channel is ±5 percent span (±7.5 inches). A deviation of any RCCA from its group by twice this distance (10 percent of span or 15 inches) does not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 5 percent of span. If the rod deviation alarm is not operable, the operator takes action as required by the Technical Specifications.

If one or more of the rod position indicator channels is out of service, operating instructions are followed to verify the alignment of the nonindicated RCCAs. The operator also takes action as required by the Technical Specifications.

In the extremely unlikely event of multiple electrical failures that result in single RCCA withdrawal, rod deviation and rod control urgent failure are both displayed to the operator, and the rod position indicators indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, results in activation of the same alarm and the same visual indication. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power and an increase in local power density in the core area associated with the RCCA. Automatic protection for this event is provided

by the overtemperature ΔT reactor trip. The Condition III Standard Review Plan Section 15.4.3 evaluation criteria are met; however, due to the increase in local power density, the limits in Figure 15.0.3-1 may be exceeded.

Plant systems and equipment available to mitigate the effects of the various control rod misoperations are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.4.3.2 Analysis of Effects and Consequences

15.4.3.2.1 Dropped RCCAs, Dropped RCCA Bank, and Statically Misaligned RCCA

15.4.3.2.1.1 Method of Analysis

- One or more dropped RCCAs from the same group

  A drop of one or more RCCAs from the same group results in an initial reduction in the core power and a perturbation in the core radial power distribution. Depending on the worth and position of the dropped rods, this may cause the allowable design power peaking factors to be exceeded. Following the drop, the reduced core power and continued steam demand to the turbine causes the reactor coolant temperature to decrease. In the manual control mode, the plant will establish a new equilibrium condition. The new equilibrium condition is reached through reactivity feedback. In the presence of a negative moderator temperature coefficient, the reactor power rises monotonically back to the initial power level at a reduced inlet temperature with no power overshoot. The absence of any power overshoot establishes the automatic operating mode as a limiting case. If the reactor coolant system temperature reduction is very large, the turbine power may not be able to be maintained due to the reduction in the secondary-side steam pressure and the volumetric flow limit of the turbine system. In this case, the equilibrium power level is less than the initial power. In the automatic control mode, the plant control system detects the drop in core power and initiates withdrawal of a control bank. Power overshoot may occur, after which the control system will insert the control bank and return the plant to the initial power level. The magnitude of the power overshoot is a function of the plant control system characteristics, core reactivity coefficients, the dropped rod worth, and the available control bank worth.

  For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN code (References 3 and 11). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures and power level.

  Steady-state nuclear models using the computer codes described in Table 4.1-2 are used to obtain a hot channel factor consistent with the primary system transient conditions and reactor power. By combining the transient primary conditions with the hot channel factor from the nuclear analysis, the departure from nucleate boiling design basis is shown to be met using the VIPRE-01 code.

- Statically misaligned RCCA

  Steady-state power distributions are analyzed using the computer codes as described in Table 4.1-2. The peaking factors are then used as input to the VIPRE-01 code to calculate the DNBR.

15.4.3.2.1.2 Results

- One or more dropped RCCAs

  Figures 15.4.3-1 through 15.4.3-4 show the transient response of the reactor to a dropped rod (or rods) in automatic control. The nuclear power and heat flux drop to a minimum value and recover under the influence of both rod withdrawal and thermal feedback. The prompt decrease in power is governed by the dropped rod worth because the plant control system does not respond during the short rod drop time period. The plant control system detects the reduction in core power and initiates control bank withdrawal to restore the primary side power. Power overshoot occurs after which the core power is restored to the initial power level.

  The primary system conditions are combined with the hot channel factors from the nuclear analysis for the DNB evaluation. Uncertainties in the initial conditions are included in the DNB evaluation as discussed in subsection 15.0.3.2. The calculated minimum DNBR for the limiting case for any single or multiple rod drop from the same group is greater than the design limit value described in Section 4.4. The sequence of events for this limiting case is shown in Table 15.4-1.

  The analysis described previously includes consideration of drops of the RCCA groups which can be selected for insertion as part of the rapid power reduction system. This system is provided to allow the reactor to ride out a complete loss of load from full power without a reactor trip and is described in subsection 7.7.1.10. If these RCCAs are inadvertently dropped (in the absence of a loss-of-load signal), the transient behavior is the same as for the RCCA drop described. The evaluation showed that the DNBR remains above the design limit value as a result of the inadvertent actuation of the rapid power reduction system.

  The consequential loss of offsite power described in subsection 15.0.14 is not limiting for the dropped RCCA event. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR occurs before the reactor coolant pumps begin to coast down.

- Statically misaligned RCCA

  The most severe misalignment situations with respect to DNBR arise from cases in which one RCCA is fully inserted, or where the mechanical shim or axial offset rod banks are inserted up to their insertion limit with one RCCA fully withdrawn while the reactor is at full power. Multiple independent alarms, including a bank insertion limit or rod deviation alarm, alert the operator well before the postulated conditions are approached.

For RCCA misalignments in which the mechanical shim or axial offset banks are inserted to their respective insertion limits, with any one RCCA fully withdrawn, the DNBR remains above the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and reactor coolant system temperature are at their nominal values, but with the increased radial peaking factor associated with the misaligned RCCA. Uncertainties in the initial conditions are included in the DNB evaluation as described in subsection 15.0.3.2.

DNB does not occur for the RCCA misalignment incident, and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature is that corresponding to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which causes fuel melting.

Following the identification of an RCCA group misalignment condition by the operator, the operator takes action as required by the plant Technical Specifications and operating instructions.

15.4.3.2.2 Single Rod Cluster Control Assembly Withdrawal

15.4.3.2.2.1 Method of Analysis

Power distributions within the core are calculated using the computer codes described in Table 4.1-2. The peaking factors are then used by VIPRE-01 to calculate the DNBR for the event. The case of the worst rod withdrawn from the mechanical shim or axial offset bank inserted at the insertion limit, with the reactor initially at full power, is analyzed. This incident is assumed to occur at beginning of life because this results in the minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.4.3.2.2.2 Results

For the single rod withdrawal event, two cases are considered as follows:

A. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature and an increase in the local hot channel factor in the area of the withdrawing RCCA. In the overall system response, this case is similar to those presented in subsection 15.4.2. The increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum DNBR from falling below the safety analysis limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature ΔT trip is expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the safety analysis limit value is 5 percent.

B. If the reactor is in the automatic control mode, the multiple failures that result in the withdrawal of a single RCCA result in the immobility of the other RCCAs in the controlling bank. The transient then proceeds in the same manner as case A.

For such cases, a reactor trip ultimately occurs although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the safety analysis limit value. Following reactor trip, normal shutdown procedures are followed.

The consequential loss of offsite power described in subsection 15.0.14 is not limiting for the single RCCA withdrawal event. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR, for rods where the DNBR did not fall below the design limit value (see Section 4.4) in the cases described, occurs before the reactor coolant pumps begin to coast down.

15.4.3.3 Conclusions

For cases of dropped RCCAs or dropped banks, including inadvertent drops of the RCCAs in those groups selected to be inserted as part of the rapid power reduction system, it is shown that the DNBR remains greater than the safety analysis limit value and, therefore, the DNB design basis is met.

For cases of any one RCCA fully inserted, or the mechanical shim or axial offset banks inserted to their rod insertion limits with any single RCCA in one of those banks fully withdrawn (static misalignment), the DNBR remains greater than the safety analysis limit value (see Section 4.4).

For the case of the accidental withdrawal of a single RCCA, with the reactor in the automatic or manual control mode and initially operating at full power with the mechanical shim or axial offset banks at their insertion limits, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total fuel rods in the core.

15.4.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

The Technical Specifications (3.4.4) require all RCPs to be operating while in Modes 1 and 2. The maximum initial core power level for the startup of an inactive loop transient is approximately zero MWt. Furthermore, the reactor will initially be subcritical by the Technical Specification requirement. There will be no increase in core power, and no automatic or manual protective action is required.

15.4.5 A Malfunction or Failure of the Flow Controller in a Boiling Water Reactor Loop that Results in an Increased Reactor Coolant Flow Rate

This subsection is not applicable to the AP1000.

15.4.6 Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant

15.4.6.1 Identification of Causes and Accident Description

Other than control rod withdrawal, the principal means of positive reactivity insertion to the core is the addition of unborated, primary-grade water from the demineralized water transfer and storage system into the reactor coolant system through the reactor makeup portion of the chemical and volume control system. Normal boron dilution with these systems is manually initiated under

strict administrative controls requiring close operator surveillance. Procedures limit the rate and duration of the dilution. A boric acid blend system is available to allow the operator to match the makeup water boron concentration to that of the reactor coolant system during normal charging.

An inadvertent boron dilution is caused by the failure of the demineralized water transfer and storage system or chemical and volume control system, either by controller, operator or mechanical failure. The chemical and volume control system and demineralized water transfer and storage system are designed to limit, even under various postulated failure modes, the potential rate of dilution to values that, with indication by alarms and instrumentation, allowing sufficient time for automatic or operator response to terminate the dilution.

An inadvertent dilution from the demineralized water transfer and storage system through the chemical and volume control system may be terminated by isolating the makeup pump suction line to the demineralized water transfer and storage system storage tank. Flow from the demineralized water transfer and storage system, which is the source of unborated water, may be terminated by closing isolation valves in the chemical and volume control system. Lost shutdown margin may be regained by opening the isolation valve to the boric acid tank and thus allowing the addition of borated water (greater than 4000 ppm) to the reactor coolant system.

Generally, to dilute, the operator performs two actions:

- Switch control of the makeup from the automatic makeup mode to the dilute mode.
- Start the chemical and volume control system makeup pumps.

Failure to carry out either of those actions prevents initiation of dilution. Because the AP1000 chemical and volume control system makeup pumps do not run continuously (they are expected to be operated once per day to make up for reactor coolant system leakage), a makeup pump is started when the volume control system is placed into dilute mode.

The status of the reactor coolant system makeup is available to the operator by the following:

- Indication of the boric acid and blended flow rates

- Chemical and volume control system makeup pumps status

- Deviation alarms, if the boric acid or blended flow rates deviate by more than the specified tolerance from the preset values

- When reactor is subcritical

  - High flux at shutdown alarm
  - Indicated source range neutron flux count rates
  - Audible source range neutron flux count rate
  - Source range neutron flux-multiplication alarm

- When the reactor is critical

  – Axial flux difference alarm (reactor power ≥ 50 percent rated thermal power)
  – Control rod insertion limit low and low-low alarms
  – Overtemperature ΔT alarm (at power)
  – Overtemperature ΔT reactor trip
  – Power range neutron flux-high, both high and low setpoint reactor trips.

This event is a Condition II incident (a fault of moderate frequency), as defined in subsection 15.0.1.

15.4.6.2 Analysis of Effects and Consequences

Boron dilutions during refueling, cold shutdown, hot shutdown, hot standby, startup, and power modes of operation are considered in this analysis. Conservative values for necessary parameters are used (high reactor coolant system critical boron concentrations, high boron worths, minimum shutdown margins, and lower-than-actual reactor coolant system volumes). These assumptions (see Table 15.4-2) result in conservative determinations of the time available for operator or automatic system response after detection of a dilution transient in progress.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is considered for the boron dilution case initiated from the power mode of operation (Mode 1) with the reactor in manual control. This is the analyzed Mode 1 boron dilution case that produces a reactor and turbine trip (Section 15.4.6.2.6). The loss of offsite power is assumed to occur as a direct result of a turbine trip that would disrupt the grid and produce a consequential loss of offsite ac power. As discussed in subsection 15.0.14, that scenario can occur only with the plant at power and connected to the grid. Therefore, only a boron dilution case initiated from full power will address the consequential loss of offsite power.

15.4.6.2.1 Dilution During Refueling (Mode 6)

An uncontrolled boron dilution transient cannot occur during this mode of operation. Inadvertent dilution is prevented by administrative controls, which isolate the reactor coolant system from the potential source of unborated water by locking closed specified valves in the chemical and volume control system during refueling operations. These valves block the flow paths that allow unborated makeup water to reach the reactor coolant system. Makeup which is required during refueling uses water supplied from the boric acid tank (which contains borated water).

15.4.6.2.2 Dilution During Cold Shutdown (Mode 5)

The following conditions are assumed for inadvertent boron dilution while in this operating mode:

- A dilution flow of 200 gpm of unborated water exists.

- A volume of 2402 ft^3 is a conservative estimate of the minimum active reactor coolant system volume corresponding to the water level at mid-loop in the vessel while on normal residual heat removal. The assumed active volume does not include the volume of the reactor vessel upper head region.

- Control rods are fully inserted, which is the normal condition in cold shutdown and a critical boron concentration of 955 ppm. This is a conservative boron concentration with control rods inserted and allows for the most reactive rod to be stuck in the fully withdrawn position.

- The shutdown margin is equal to 1.6-percent $\Delta k/k$, the minimum value required by the Technical Specifications for the cold shutdown mode. Combined with the preceding, this gives a shutdown boron concentration of 1135 ppm.

- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that when in Mode 5, at least one reactor coolant pump shall be operable, which provides sufficient flow through the system to maintain the system well mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed and an uncontrolled boron dilution transient cannot occur, as discussed in section 15.4.6.2.1.

In the event of an inadvertent boron dilution transient during cold shutdown, the source range nuclear instrumentation detects an increase of 60 percent of the neutron flux by comparing the current source range flux to that of about 50 minutes earlier. Upon detection of the flux increase, an alarm is sounded for the operator, and valves are actuated to terminate the dilution automatically.

Upon any reactor trip signal, source range flux multiplication signal, low input voltage to the Class 1E dc and uninterruptable power supply system battery chargers, or safety injection signal, a safety function automatically isolates the potentially unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. The suction lines for the chemical and volume control system pumps are automatically realigned to draw borated (greater than 4000 ppm) water from the chemical and volume control system boric acid tank. The realignment of the chemical and volume control system valves to terminate the dilution is a safety-related function. The realignment of pump suction to the boric acid tank is a nonsafety-related operation. The chemical and volume control system pumps are nonsafety-related, so their operation is not credited in the analysis. The analysis does consider the initial portion of this boration phase by treating it as a continuing dilution until any unborated water in the chemical and volume control system lines is purged.

The automatic protective actions initiate about 12.03 minutes after the start of dilution. These automatic actions minimize the approach to criticality and maintain the plant in a subcritical condition. After the automatic protection functions take place, the operator may take action to restore the Technical Specification shutdown margin.

15.4.6.2.3 Dilution During Safe Shutdown (Mode 4)

The following conditions are assumed for an inadvertent boron dilution while in this mode:

- A dilution flow of 200 gpm of unborated water exists.

- Reactor coolant system water volume is 2805 ft^3. This is a conservative estimate of the minimum active volume of the reactor coolant system while on normal residual heat removal.

- All control rods are fully inserted, except the most reactive rod which is assumed stuck in the fully withdrawn position, and a conservative critical boron concentration of 898 ppm.

- The shutdown margin is equal to 1.6-percent k/k, the minimum value required by the Technical Specifications for the hot shutdown mode. This gives a shutdown boron concentration of 1083 ppm.

- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that when in Mode 4, at least one reactor coolant pump shall be operable, which provides sufficient flow through the system to maintain the system well-mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed and an uncontrolled boron dilution transient cannot occur, as discussed in section 15.4.6.2.1.

In the event of an inadvertent boron dilution transient during safe shutdown, the source range nuclear instrumentation detects an increase of 60 percent of the neutron flux, automatically initiates valve movement to terminate the dilution, and sounds an alarm.

As in Mode 5, the safety analysis considers the potential penalty of the subsequent nonsafety-related boration function by accounting for the purge volume associated with the chemical and volume control system piping. The protective actions initiate about 12.3 minutes after start of dilution. No operator action is required to terminate this transient.

15.4.6.2.4 Dilution During Hot Standby (Mode 3)

The following conditions are assumed for an inadvertent boron dilution while in this mode:

- A dilution flow of 200 gpm of unborated water exists.

- The reactor coolant system volume is 7300 ft^3. This is a conservative estimate of the minimum active volume of the reactor coolant system with the reactor coolant system filled and vented and one reactor coolant pump running.

- Critical boron concentration is 655 ppm. This is a conservative boron concentration assuming control rods are fully inserted minus the most reactive rod, which is assumed stuck in the fully withdrawn position.

- The shutdown margin is equal to 1.6-percent k/k, the minimum value required by the Technical Specifications for the hot standby mode. This gives a shutdown boron concentration of 867 ppm.

- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that when in Mode 3, at least one reactor coolant pump shall be operable, which provides sufficient flow through the system to maintain the system well mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed and an uncontrolled boron dilution transient cannot occur, as discussed in section 15.4.6.2.1.

In the event of an inadvertent boron dilution transient in hot standby, the source range nuclear instrumentation detects an increase of 60 percent of the neutron flux, automatically initiates valve movement to terminate the dilution, and sounds an alarm.

As in the analyses for Modes 4 and 5, the only consideration of the boration function in safety analysis is to account for the additional dilution effect due to the purge volume associated with the chemical and volume control system piping. Protective actions initiate about 56.3 minutes after start of dilution. No operator action is required to terminate this transient.

15.4.6.2.5 Dilution During Startup (Mode 2)

The plant is in the startup mode only for startup testing at the beginning of each cycle. During this mode of operation, rod control is in manual. Normal actions taken to change power level, either up or down, require operator actuation. The Technical Specifications require an available shutdown margin of 1.6-percent $\Delta k/k$ and four reactor coolant pumps operating. Other conditions assumed are the following:

- There is a dilution flow of 200 gpm of unborated water.
- Minimum reactor coolant system water volume is 8126 ft^3. This is a very conservative estimate of the active reactor coolant system volume, minus the pressurizer volume.
- An initial maximum critical boron concentration, corresponding to the rods inserted to the insertion limits, is 1327 ppm. The minimum change in boron concentration from this initial condition to a hot zero power critical condition with all rods inserted is 1088 ppm. Full rod insertion, minus the most reactive stuck rod, occurs because of reactor trip.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual control. For a normal approach to criticality, the operator manually initiates a limited dilution and then manually withdraws the control rods, a process that takes several hours. The Technical Specifications require that the operator determine the estimated critical position of the control rods prior to approaching criticality and thus provide confidence that the reactor does not go critical with the control rods below the insertion limits. Once critical, the power escalation is slow enough to allow the operator to manually block the source range reactor trip after receiving the P-6 permissive signal from the intermediate range detectors (nominally at 10^5 cps). Too fast a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action results in a reactor trip and immediate shutdown of the reactor.

Upon any reactor trip signal, source range flux multiplication signal, low input voltage to the Class 1E dc and uninterruptable power supply system battery chargers, or a safety injection signal, a safety-related function automatically isolates the potentially unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. Additionally, the suction lines for the chemical and volume control system pumps are automatically realigned to draw borated water from the chemical and volume control system boric acid tank.

Because the realignment of the suction for the chemical and volume control system pumps to the boric acid tank is a nonsafety-related operation, the only consideration given to the reboration phase of the event in the safety analysis is the unborated chemical and volume control system purge volume. Events are shown in Table 15.4-1.

After reactor trip, the dilution would have to continue for approximately 383 minutes to overcome the available shutdown margin. Even assuming that the nonsafety-related boration operation does not occur, the unborated water that may remain in the purge volume of the chemical and volume control system is not sufficient to return the reactor to criticality. Therefore, the automatic termination of the dilution flow from the demineralized water transfer and storage system prevents a post-trip return to criticality.

15.4.6.2.6 Dilution During Full Power Operation (Mode 1)

The plant may be operated at power two ways: automatic T_{avg}/rod control and under operator control. The Technical Specifications require an available shutdown margin of 1.6-percent $\Delta k/k$ and four reactor coolant pumps operating. With the plant at power and the reactor coolant system at pressure, the dilution rate is limited by the capacity of the chemical and volume control system makeup pumps. The analysis is performed assuming two chemical and volume control system pumps are in operation, even though normal operation is with one pump. Conditions assumed for a dilution in this mode are the following:

- There is a dilution flow of 200 gpm of unborated water.

- Minimum reactor coolant system water volume is 8126 ft^3. This is a very conservative estimate of the active reactor coolant system volume, minus the pressurizer volume.

- An initial maximum critical boron concentration, corresponding to the rods inserted to the insertion limits, is 1080 ppm. The minimum change in boron concentration from this initial condition to a hot zero power critical condition with all rods inserted is 841 ppm. Full rod insertion, minus the most reactive stuck rod, occurs due to reactor trip.

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise causes the reactor to reach the overtemperature ΔT trip setpoint resulting in a reactor trip. Upon any reactor trip signal, a safety-related function automatically isolates the unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. Additionally, the suction lines for the chemical and volume control system pumps are automatically realigned to draw borated water from the chemical and volume control system boric acid tank.

Because the realignment of the suction for the chemical and volume control system pumps to the boric acid tank is a nonsafety-related operation, the only consideration given to the reboration phase of the event in the safety analysis is the unborated purge volume.

After reactor trip, the dilution would have to continue for at least 325 minutes to overcome the available shutdown margin. The unborated water that may remain in the purge volume of the chemical and volume control system does not return the reactor to criticality. Therefore, the

automatic termination of the dilution flow from the demineralized water transfer and storage system precludes a post-trip return to criticality.

Should a consequential loss of offsite power occur after reactor and turbine trip, it does not alter the fact that the dilution event has been terminated by automatic protection features. As indicated previously, the reactor trip signal that occurs in parallel with the turbine trip will actuate a safety-related function that automatically isolates the unborated water from the demineralized water system and thereby terminates the dilution. A subsequent loss of offsite power will cause the chemical and volume control system pumps to shut down. Should power and chemical and volume control system flow be restored, the unborated water that may remain in the purge volume of the chemical and volume control system will still not return the reactor to criticality.

The boron dilution transient in this case is essentially the equivalent to an uncontrolled rod withdrawal at power (see Section 15.4.2). The maximum reactivity insertion rate for a boron dilution transient is conservatively estimated to be in the range of 0.5 to 0.8 pcm per second and is within the range of insertion rates analyzed for uncontrolled rod withdrawal at power. Before reaching the overtemperature ΔT reactor trip, the operator receives an alarm on overtemperature ΔT and an overtemperature ΔT turbine runback.

With the reactor in automatic rod control, the pressurizer level controller limits the dilution flow rate to the maximum letdown rate. If a dilution rate in excess of the letdown rate is present, the pressurizer level controller throttles charging flow down to match letdown rate. For the safety analysis, a conservative dilution flow rate of 200 gpm is assumed. With the reactor in automatic rod control, a boron dilution results in a power and temperature increase in such a way that the rod controller attempts to compensate by slow insertion of the control rods. This action by the controller results in at least three alarms to the operator:

A. Rod insertion limit - low level alarm
B. Rod insertion limit - low-low level alarm if insertion continues
C. Axial flux difference alarm (ΔI outside of the target band)

Given the many alarms, indications, and the inherent slow process of dilution at power, the operator has sufficient time for action. The operator has at least 348 minutes from the rod insertion limit low-low alarm until shutdown margin is lost at beginning of cycle. The time is significantly longer at end of cycle because of the low initial boron concentration.

Because the analysis for the boron dilution event with the reactor in automatic rod control does not predict a reactor and turbine trip, considering the consequential loss of offsite power for this case is not needed.

The preceding results demonstrate that in all modes of operation, an inadvertent boron dilution is prevented or responded to by automatic functions, or sufficient time is available for operator action to terminate the transient. Following termination of the dilution flow and initiation of boration, the reactor is in a stable condition.

15.4.6.3 Conclusions

Inadvertent boron dilution events are prevented during refueling and automatically terminated during cold shutdown, safe shutdown, and hot standby modes. Inadvertent boron dilution events during startup or power operation, if not detected and terminated by the operators, result in an automatic reactor trip. Following reactor trip, automatic termination of the dilution occurs and post-trip return to criticality is prevented.

15.4.7 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position

15.4.7.1 Identification of Causes and Accident Description

Fuel and core loading errors can inadvertently occur, such as those arising from the inadvertent loading of one or more fuel assemblies into improper positions, having a fuel rod with one or more pellets of the wrong enrichment, or having a full fuel assembly with pellets of the wrong enrichment. This leads to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. Also included among possible core-loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

An error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes more peaked than those calculated with the correct enrichments. A 5-percent uncertainty margin is included in the design value of power peaking factor assumed in the analysis of Condition I and Condition II transients. The online core monitoring system is used to verify power shapes at the start of life and is capable of revealing fuel assembly enrichment errors or loading errors that cause power shapes to be peaked in excess of the design value. Power-distribution-related measurements are incorporated into the evaluation of calculated power distribution information using the incore instrumentation processing algorithms contained within the online monitoring system. The processing algorithms contained within the online monitoring system are functionally identical to those historically used for the evaluation of power distributions measurements in Westinghouse pressurized water reactors.

Each fuel assembly is marked with an identification number and loaded in accordance with a core-loading diagram to reduce the probability of core loading errors. During core loading, the identification number is checked before each assembly is moved into the core. Serial numbers read during fuel movement are subsequently recorded on the loading diagram as a further check on proper placement after the loading is completed.

The power distortion due to a combination of misplaced fuel assemblies could significantly increase peaking factors and is readily observable with the online core monitoring system. The fixed incore instrumentation within the instrumented fuel assembly locations is augmented with core exit thermocouples. There is a high probability that these thermocouples would also indicate any abnormally high coolant temperature rise. Incore flux measurements are taken during the startup subsequent to every refueling operation.

This event is a Condition III incident (an infrequent fault) as defined in subsection 15.0.1.

15.4.7.2 Analysis of Effects and Consequences

15.4.7.2.1 Method of Analysis

Steady-state power distributions in the x-y plane of the core are calculated at 30-percent rated thermal power using the three-dimensional nodal code ANC (Reference 7). Representative power distributions in the x-y plane for a correctly loaded core are described in Chapter 4.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown in the incore detector locations. (See Figures 15.4.7-1 through 15.4.7-4.)

15.4.7.2.2 Results

The following core loading error cases are analyzed:

Case A:

Case in which a Region 1 assembly is interchanged with a Region 3 assembly. The particular case considered is the interchange of two assemblies near the periphery of the core (see Figure 15.4.7-1).

Case B:

Case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly. For the particular case considered, the interchange is assumed to take place close to the core center and with burnable poison rods located in the correct Region 2 position, but in a Region 1 assembly mistakenly loaded in the Region 2 position (see Figure 15.4.7-2).

Case C:

Enrichment error – Case in which a Region 2 fuel assembly is loaded in the core central position (see Figure 15.4.7-3).

Case D:

Case in which a Region 2 fuel assembly instead of a Region 1 assembly is loaded near the core periphery (see Figure 15.4.7-4).

15.4.7.3 Conclusions

Fuel assembly enrichment errors are prevented by administrative procedures implemented in fabrication.

In the event that a single pin or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced DNBR and increased fuel and cladding temperatures are limited to the incorrectly loaded pin or pins and perhaps the immediately adjacent pins.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects are either readily detected by the online core monitoring system or cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

15.4.8 Spectrum of Rod Cluster Control Assembly Ejection Accidents

15.4.8.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of an RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.8.1.1 Design Precautions and Protection

15.4.8.1.1.1 Mechanical Design

The mechanical design is discussed in Section 4.6. Mechanical design and quality control procedures intended to prevent the possibility of an RCCA drive mechanism housing failure are listed below:

- Each control rod drive mechanism housing is completely assembled and shop tested at 4100 psi.

- The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head. The housings are checked during the hydrotest of the completed reactor coolant system.

- Stress levels in the mechanism are not affected by anticipated system transients at power or by the thermal movement of the coolant loops. Moments induced by the safe shutdown earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class 1 components.

- The latch mechanism housing and rod travel housing are each a single length of forged stainless steel. This material exhibits excellent notch toughness at temperatures that are encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional confidence that gross failure of the housing does not occur. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are threaded joints reinforced by canopy-type rod welds, which are subject to periodic inspections.

15.4.8.1.1.2 Nuclear Design

If a rupture of an RCCA drive mechanism housing is postulated, the operation using chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the power control (or mechanical shim) RCCAs inserted only far enough to permit load follow. The axial offset RCCAs are positioned so that the targeted axial offset can be met throughout core life. Reactivity changes caused by core depletion and xenon transients are normally compensated for by boron changes and the mechanical shim banks, respectively. Further, the location and grouping of the power control and axial offset RCCAs are selected with consideration for an RCCA ejection accident. Therefore, should an RCCA be ejected from its normal position during full-power operation, a less severe reactivity excursion than analyzed is expected.

It may occasionally be desirable to operate with larger than normal insertions. For this reason, a power control and axial offset rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit provides adequate shutdown capability and an acceptable power distribution. The position of the RCCAs is continuously indicated in the main control room. An alarm occurs if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. Operating instructions require boration at the low level alarm and emergency boration at the low-low level alarm.

15.4.8.1.1.3 Reactor Protection

The reactor protection in the event of a rod ejection accident is described in WCAP-7588, Revision 1A (Reference 4). The protection for this accident is provided by the high neutron flux trip (high and low setting) and the high rate of neutron flux increase trip. These protection functions are described in Section 7.2.

15.4.8.1.1.4 Effects on Adjacent Housings

Failures of an RCCA mechanism housing, due to either longitudinal or circumferential cracking, does not cause damage to adjacent housings. The control rod drive mechanism is described in subsection 3.9.4.1.1.

15.4.8.1.1.5 Effects of Rod Travel Housing Longitudinal Failures

If a longitudinal failure of the rod travel housing occurs, the region of the position indicator assembly opposite the break is stressed by the reactor coolant pressure of 2250 psia. The most probable leakage path is provided by the radial deformation of the position indicator coil assembly, resulting in the growth of axial flow passages between the rod travel housing and the hollow tube along which the coil assemblies are mounted.

If failure of the position indicator coil assembly occurs, the resulting free radial jet from the failed housing could cause it to bend and contact adjacent rod housings. If the adjacent housings are on the periphery, they might bend outward from their bases. The housing material is quite ductile; plastic hinging without cracking is expected. Housings adjacent to a failed housing in locations other than the periphery would not bend due to the rigidity of multiple adjacent housings.

15.4.8.1.1.6 Effect of Rod Travel Housing Circumferential Failures

If circumferential failure of a rod travel housing occurs, the broken-off section of the housing is ejected vertically because the driving force is vertical and the position indicator coil assembly and the drive shaft tend to guide the broken-off piece upward during its travel. Travel is limited by the missile shield and thereby limits the projectile acceleration. When the projectile reaches the missile shield, it partially penetrates the shield dissipating its kinetic energy. The water jet from the break continues to push the broken-off piece against the missile shield.

If the broken-off piece of the rod travel housing is short enough to clear the break when fully ejected, it rebounds after impact with the missile shield. The top end plates of the position indicator coil assemblies prevent the broken piece from directly hitting the rod travel housing of a second drive mechanism. Even if a direct hit by the rebounding piece occurs, the low kinetic energy of the rebounding projectile is not expected to cause significant damage (sufficient to cause failure of an adjacent housing).

15.4.8.1.1.7 Consequences

The probability of damage to an adjacent housing is considered remote. If damage is postulated, it is not expected to lead to a more severe transient because RCCAs are inserted in the core in symmetric patterns and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal. This is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

15.4.8.1.1.8 Summary

Failure of a control rod housing, due either to longitudinal or circumferential cracking, does not cause damage to adjacent housings that increase the severity of the initial accident.

15.4.8.1.2 Limiting Criteria

This event is a Condition IV incident (ANSI N18.2). See subsection 15.0.1 for a discussion of ANS classification. Because of the extremely low probability of an RCCA ejection accident, some fuel damage is considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project (Reference 5). Extensive tests of uranium dioxide (UO_2) zirconium-clad fuel rods representative of those in pressurized water reactor cores such as AP1000 have demonstrated failure thresholds in the range of 240 to 257 cal/g. Other rods of a slightly different design have exhibited failure as low as 225 cal/g. These results differ significantly from the TREAT (Reference 6) results, which indicated a failure threshold of 280 cal/g. Limited results indicate that this threshold decreases by about 10 percent with fuel burnup. The cladding failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods.

Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/g for unirradiated rods and 200 cal/g for irradiated rods.

Catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/g.

Regulatory Guide 1.77 criteria are applied to provide confidence that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are the following:

- Average fuel pellet enthalpy at the hot spot is below 200 cal/g (360 btu/lb) for irradiated fuel. This bounds non-irradiated fuel, which has a slightly higher enthalpy limit.

- Peak reactor coolant pressure is less than that which could cause stresses to exceed the "Service Limit C" as defined in the ASME code.

- Fuel melting is limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of the first criterion.

15.4.8.2 Analysis of Effects and Consequences

Method of Analysis

The calculation of the RCCA ejection transients is performed in two stages: first, an average core channel calculation and then, a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time, including the various total core feedback effects (Doppler reactivity and moderator reactivity). Enthalpy and temperature transients at the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is conservatively assumed to persist throughout the transient.

A discussion of the method of analysis appears in WCAP-7588, Revision 1A (Reference 4).

Average Core Analysis

The spatial kinetics computer code TWINKLE (Reference 1) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in 1, 2, or 3 spatial dimensions (rectangular coordinates) for 6 delayed neutron groups and up to 2000 spatial points. The computer code includes a multiregion, transient fuel-clad-coolant heat transfer model for the calculation of pointwise Doppler and moderator feedback effects. In this analysis, the code is used as a one-dimensional axial kinetics code because it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. Because the radial dimension is missing, it is necessary to use conservative methods (described as follows) of calculating the ejected rod worth and hot channel factor. Further description of TWINKLE appears in subsection 15.0.11.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal value multiplied by the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the

transient value in 0.1 second, the time for full ejection of the rod. The assumption is made that the hot spots before and after ejection are coincident. This is conservative because the peak after ejection occurs in or adjacent to the assembly with the ejected rod, and before ejection, the power in this region is depressed.

The hot spot analysis is performed using the fuel and cladding transient heat transfer computer code FACTRAN (Reference 2). This computer code calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and material properties are represented as functions of temperature. A parabolic radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB and the Bishop-Sandburg-Tong correlation (Reference 8) to determine the film boiling coefficient after DNB. The Bishop-Sandburg-Tong correlation is conservatively used, assuming zero-bulk fluid quality. The DNBR is not calculated. Instead, the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient is calculated by the code. It is adjusted to force the full power, steady-state temperature distribution to agree with the fuel heat transfer design codes. Further description of FACTRAN appears in subsection 15.0.11.

System Overpressure Analysis

There is little likelihood of fuel dispersal into the coolant. The pressure surge may be calculated on the basis of conventional heat transfer from the fuel and prompt heat absorption by the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a (Section 4.4) calculation is performed to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient, taking into account fluid transport in the reactor coolant system and heat transfer to the steam generators. For conservatism, no credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

15.4.8.2.1 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. Table 15.4-3 presents the important parameters used in this analysis.

15.4.8.2.1.1 Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either three-dimensional static methods or by a synthesis method using one-dimensional and two-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate safety analysis margins are added to the ejected rod worth and hot channel factors to account for calculational uncertainties, including an allowance for nuclear peaking due to densification.

Power distributions before and after ejection for a worst case can be found in WCAP-7588, Revision 1A (Reference 4). During plant startup physics testing, rod worths and power distributions have been measured in the zero-power configuration and compared to values used in the analysis. The ejected rod worth and power peaking factors are consistently overpredicted in the analysis.

15.4.8.2.1.2 Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. This means that the reactivity feedback is larger than that indicated by a simple single channel analysis.

Physics calculations are carried out for temperature changes with a flat temperature distribution and with a large number of axial and radial temperature distributions. Reactivity changes are compared, and effective reactivity feedback weighting factors are shown to be conservative. These weighting factors take the form of multipliers that, when applied to single-channel feedbacks, correct them to effective whole-core feedbacks for the appropriate flux shape.

In this analysis, because a one-dimensional (axial) spatial kinetics method is used, axial reactivity weighting is not necessary if the initial condition matches the ejected rod configuration. In addition, no reactivity weighting is applied to the moderator feedback.

A conservative radial reactivity weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time, accounting for the missing spatial dimension. These reactivity weighting factors are shown to be conservative compared to three-dimensional analysis (Reference 5).

15.4.8.2.1.3 Moderator and Doppler Coefficients

The critical boron concentrations at the beginning of cycle and end of cycle are adjusted in the nuclear code to obtain moderator density coefficient curves that are conservative compared to actual design conditions for the plant. No weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one-dimensional, steady-state computer code with a Doppler weighting factor of one. The Doppler defect used is given in subsection 15.0.4. The Doppler weighting factor increases under accident conditions.

15.4.8.2.1.4 Delayed Neutron Fraction, β_{eff}

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.70 percent at beginning of cycle and 0.50 percent at end of cycle for the first cycle. The accident is sensitive to β_{eff} if the ejected rod worth is equal to or greater than β_{eff} as in zero-power transients. To allow for future cycles, pessimistic estimates of β_{eff} of 0.49 percent at beginning of cycle and 0.44 percent at end of cycle are used in the analysis.

15.4.8.2.1.5 Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 15.4-3 and includes the effect of one stuck RCCA. These values are reduced by the ejected rod reactivity. The shutdown reactivity is simulated by dropping a rod of the required worth into the core. The start of rod motion occurs 0.9 second after the high neutron flux trip setpoint is reached. This delay is assumed to consist of 0.583 second for the instrument channel to produce a signal, 0.167 second for the trip breakers to open, and 0.15 second for the coil to release the rods. A curve of trip rod insertion versus time is used, which assumes that insertion to the dashpot does not occur until 2.47 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over 1 second after the trip setpoint is reached before significant shutdown reactivity is inserted into the core. This conservatism is important for the hot full power accidents.

The minimum design shutdown margin available at hot zero power may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Calculations show that the effect of two stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1-percent Δk. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor is subcritical when the core returns to hot zero power.

15.4.8.2.1.6 Reactor Protection

As discussed in subsection 15.4.8.1.1.3, reactor protection for a rod ejection is provided by the high neutron flux trip (high and low setting) and the high rate of neutron flux increase trip. These protection functions are part of the protection and safety monitoring system. No single failure of the protection and safety monitoring system negates the protection functions required for the rod ejection accident or adversely affects the consequences of the accident.

15.4.8.2.1.7 Results

Because the control rod insertion limits for the AP1000 are multidimensional, a significant number of rodded configurations are evaluated to determine the most limiting cases, (that is, those cases that produced the least amount of margin to the Standard Review Plan Section 15.4.8 evaluation acceptance criteria). The hot zero power cases and hot full power cases assume that the mechanical shim and axial offset control RCCAs are inserted to their insertion limits before the event. The limiting RCCA ejection cases, for both the beginning and end of cycle at zero and full power, are presented next.

- Beginning of cycle, full power

  The limiting ejected rod worth and hot channel factor are conservatively assumed to be 0.37-percent Δk and 4.9, respectively. The peak hot spot cladding average temperature is 2265°F. The peak hot spot fuel center temperature reaches melting at 4900°F. However, melting is restricted to less than 10 percent of the pellet at the hot spot.

- Beginning of cycle, zero power

  For this condition, the limiting ejected rod worth and hot channel factor are conservatively assumed to be 0.65-percent Δk and 12.0, respectively. The peak hot spot cladding average temperature is 1907°F, and the peak hot spot fuel center temperature is 3018°F.

- End of cycle, full power

  The ejected rod worth and hot channel factor are conservatively assumed to be 0.30-percent Δk and 6.0, respectively. The peak hot spot cladding average temperature is 2151°F. The peak hot spot fuel temperature reaches melting at 4800°F. However, melting is restricted to less than 10 percent of the pellet at the hot spot.

- End of cycle, zero power

  The ejected rod worth and hot channel factor for this case are conservatively assumed to be 0.75-percent Δk and 19.6, respectively. The peak hot spot cladding average temperature is 2122°F, and the peak hot spot fuel center temperature is 3263°F.

A summary of the preceding cases is given in Table 15.4-3. The nuclear power and fuel and cladding temperature transients for the limiting cases are presented in Figures 15.4.8-1 through 15.4.8-4.

The calculated sequence of events for the limiting case rod ejection accidents, as shown in Figures 15.4.8-1 through 15.4.8-4, is presented in Table 15.4-1. Reactor trip occurs early in the transients, after which the nuclear power excursion is terminated.

The ejection of an RCCA constitutes a break in the reactor coolant system, located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents (LOCAs) are discussed in subsection 15.6.5. Following the RCCA ejection, the plant response is the same as a LOCA.

The consequential loss of offsite power described in subsection 15.0.14 is not limiting for the enthalpy and temperature transients resulting from an RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the peak fuel and cladding temperatures occur before the reactor coolant pumps begin to coast down.

15.4.8.2.1.8 Fission Product Release

It is assumed that fission products are released from the gaps of all rods entering DNB. In the cases considered, less than 10 percent of the rods are assumed to enter DNB based on a detailed three-dimensional THINC analysis (Reference 4). Although limited (less than 10 percent) fuel melting at the hot spot is allowed for the full-power cases, in practice, melting is not expected because the analysis conservatively assumes that the hot spots before and after ejection are coincident.

The consequential loss of offsite power described in subsection 15.0.14 is not limiting for the calculation of the number of rods assumed to enter DNB for the RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR, for rods where the DNBR did not fall below the design limit (see Section 4.4) in the cases described, occurs before the reactor coolant pumps begin to coast down.

15.4.8.2.1.9 Pressure Surge

A calculation of the pressure surge for an ejection worth of about one dollar at beginning of cycle, hot full power, demonstrates that the peak pressure does not exceed that which would cause the stress to exceed the Service Level C Limit as described in the ASME Code, Section III. Because the severity of the analysis does not exceed the worst-case analysis, the accident for this plant does not result in an excessive pressure rise or further damage to the reactor coolant system.

The consequential loss of offsite power described in subsection 15.0.14 is not limiting for the pressure surge transient resulting from an RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the peak system pressure occurs before the reactor coolant pumps begin to coast down.

15.4.8.2.1.10 Lattice Deformations

A large temperature gradient exists in the region of the hot spot. Because the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion, tending to bow the midpoint of the rods toward the hotter side of the rod.

Calculations indicate that this bowing results in a negative reactivity effect at the hot spot because the core is undermoderated, and bowing tends to increase the undermoderation at the hot spot. In practice, no significant bowing is anticipated because the structural rigidity of the core is sufficient to withstand the forces produced.

Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that crossflow is sufficient to produce lattice deformation. Even if massive and rapid boiling, sufficient to distort the lattices, is hypothetically postulated, the large void fraction in the hot spot region produces a reduction in the total core moderator to fuel ratio and a large reduction in this ratio at the hot spot. The net effect is therefore a negative feedback.

In conclusion, no credible mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

15.4.8.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated rod ejection accident assumes that the reactor is operating with the design basis fuel defect level (0.25 percent of power produced by fuel rods containing cladding defects) and that leaking steam generator tubes result in a buildup of activity in the secondary coolant.

As a result of the accident, 10 percent of the fuel rods are assumed to be damaged (see subsection 15.4.8.2.1.8) such that the activity contained in the fuel-cladding gap is released to the reactor coolant. In addition, a small fraction of fuel is assumed to melt and release core inventory to the reactor coolant.

Activity released to the containment via the spill from the reactor vessel head is assumed to be available for release to the environment because of containment leakage. Activity carried over to the secondary side due to primary-to-secondary leakage is available for release to the environment through the steam line safety or power-operated relief valves.

15.4.8.3.1 Source Term

The significant radionuclide releases due to the rod ejection accident are the iodines, alkali metals, and noble gases. The reactor coolant iodine source term assumes a pre-existing iodine spike. The initial reactor coolant noble gas and alkali metal concentrations are assumed to be those associated with the design fuel defect level. These initial reactor coolant activities are of secondary importance compared to the release of fission products from the portion of the core assumed to fail.

Based on NUREG-1465 (Reference 12), the fission product gap fraction is 3 percent of fuel inventory. For this analysis, the gap fraction is increased to 10 percent of the inventory for iodine and noble gases and 12 percent for alkali metals. Also, to address the fact that the failed fuel rods may have been operating at power levels above the core average, the source term is increased by the lead rod radial peaking factor.

Even though no fuel centerline melting is expected, a conservative upper limit for fuel melting was determined to be 0.25 percent of the core based on the following assumptions:

1. No more than 50 percent of the rods experiencing clad damage will experience centerline melting. (Based on 10 percent of rods failing, this is 5 percent of the core.)

2. Due to the power distribution within the core, no more than 50 percent of the axial length of the affected fuel rods will experience melting. (This reduces the equivalent number of rods experiencing melting to 2.5 percent of the core.)

3. Of rods experiencing centerline melting, only a conservative maximum of the innermost 10 percent of the fuel volume will actually melt. (Based on 2.5 percent of the rods experiencing melting, the resulting fraction of the core experiencing melting is 0.25 percent.)

All of the noble gases and half of the iodines and alkali metals are assumed to be released from the melted fuel.

The initial secondary coolant activity is assumed to be 10 percent of the maximum equilibrium primary coolant activity for iodines and alkali metals.

15.4.8.3.2 Release Pathways

There are three components to the accident releases:

- The activity initially in the secondary coolant is available for release as long as steam releases continue.

- The reactor coolant leaking into the steam generators is assumed to mix with the secondary coolant. The activity from the primary coolant mixes with the secondary coolant and, as steam is released, a portion of the iodine and alkali metal in the coolant is released. The fraction of activity released is defined by the assumed flashing fraction and the partition coefficient assumed for the steam generator. The noble gas activity entering the secondary side is released to the environment. These releases are terminated when the steam releases stop.

- The activity from the reactor coolant system and the core is released to the containment atmosphere and is available for leakage to the environment through the assumed design basis containment leakage.

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.4.8.3.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.4.8.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.4-4.

15.4.8.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of conservatisms:

- Although fuel damage is assumed to occur as a result of the accident, no fuel damage is anticipated.

- The reactor coolant activities are based on an assumed fuel defect level of 0.25 percent; whereas, the expected fuel defect level is far less than this (see Section 11.1).

- The leakage of reactor coolant into the secondary system, at 300 gallons per day, is conservative. The leakage is normally a small fraction of this.

- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

- The leakage from containment is assumed to continue for a full 30 days. It is expected that containment pressure is reduced to the point that leakage is negligible before this time.

15.4.8.3.6 Doses

Using the assumptions from Table 15.4-4, the calculated total effective dose equivalent (TEDE) doses are determined to be less than 2.9 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and less than 5.5 rem at the low population zone outer boundary. These doses are well within the dose guideline of 25 rem total effective dose equivalent identified in 10 CFR Part 50.34. The phrase "well within" is taken as being 25 percent or less.

At the time the rod ejection accident occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE, and when this is added to the dose calculated for the rod ejection accident, the resulting total dose remains less than 2 rem TEDE.

15.4.9 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.4.10 References

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11. "AP1000 Code Applicability Report," WCAP-15644-P (Proprietary) and WCAP-15644-NP (Nonproprietary), Revision 2, March 2004.

12. Soffer, L. et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

Table 15.4-1 (Sheet 1 of 3)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
Uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition	Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0.0
	Power range high neutron flux (low setting) setpoint reached	10.4
	Peak nuclear power occurs	10.6
	Rods begin to fall into core	11.3
	Peak heat flux occurs	12.7
	Minimum DNBR occurs	12.7
	Peak average clad temperature occurs	13.3
	Peak average fuel temperature occurs	13.4
One or more dropped RCCAs	Rods drop	0.0
	Control system initiates control bank withdrawal	0.4
	Peak nuclear power occurs	274.9
	Minimum DNBR occurs	277.9
Uncontrolled RCCA bank withdrawal at power		
1. Case A	Initiation of uncontrolled RCCA withdrawal at a high-reactivity insertion rate (75 pcm/s)	0.0
	Power range high neutron flux high trip point reached	6.6
	Rods begin to fall into core	7.5
	Minimum DNBR occurs	7.7
	Loss of ac power occurs	10.2
2. Case B	Initiation of uncontrolled RCCA withdrawal at a small reactivity insertion rate (3 pcm/s)	0.0
	Overtemperature ΔT setpoint reached	508.1
	Rods begin to fall into core	510.1
	Minimum DNBR occurs	510.4
	Loss of ac power occurs	512.8

Table 15.4-1 (Sheet 2 of 3)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
Chemical and volume control system malfunction that results in a decrease in the boron concentration in the rector coolant		
1. Dilution during startup	Power range – low setpoint reactor trip due to dilution	0.0
	Dilution automatically terminated by demineralized water transfer and storage system isolation	215.0
2. Dilution during full-power Operation		
a. Automatic reactor control	Operator receives low-low rod insertion limit alarm due to dilution	0.0
	Shutdown margin lost	19,680
b. Manual reactor control	Initiate dilution	0.0
	Reactor trip on overtemperature ΔT due to dilution	180.0
	Dilution automatically terminated by demineralized water transfer and storage system isolation	395.0
RCCA ejection accident		
1. Beginning of cycle, full power	Initiation of rod ejection	0.00
	Power range high neutron flux (high setting) setpoint reached	0.03
	Peak nuclear power occurs	0.14
	Rods begin to fall into core	0.93
	Peak cladding temperature occurs	2.36
	Peak heat flux occurs	2.37
	Peak fuel center temperature occurs	4.54

Table 15.4-1 (Sheet 3 of 3)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
2. Beginning of cycle, zero power	Initiation of rod ejection	0.00
	Power range high neutron flux (low setting) setpoint reached	0.37
	Peak nuclear power occurs	0.44
	Rods begin to fall into core	1.27
	Peak heat flux occurs	1.53
	Peak cladding temperature occurs	2.55
	Peak fuel center temperature occurs	3.32
3. End of cycle, full power	Initiation of rod ejection	0.00
	Power range high neutron flux (high setting) setpoint reached	0.035
	Peak nuclear power occurs	0.14
	Rods begin to fall into core	0.94
	Peak cladding temperature occurs	2.36
	Peak heat flux occurs	2.37
	Peak fuel center temperature occurs	4.34
4. End of cycle, zero power	Initiation of rod ejection	0.00
	Power range high neutron flux (low setting) setpoint reached	0.23
	Peak nuclear power occurs	0.27
	Rods begin to fall into core	1.13
	Peak cladding temperature occurs	1.83
	Peak heat flux occurs	1.85
	Peak fuel center temperature occurs	2.94

Table 15.4-2

PARAMETERS

Assumed Dilution Flowrates	
Mode	**Flow Rate (gal/min)**
1 through 5	200

Volume		
Mode	**Volume (ft^3)**	**Volume (gal)**
1 and 2	8126	60,786
3	7300	54,607
4	2805	20,982
5	2402	17,968

Table 15.4-3

PARAMETERS USED IN THE ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Time in Life	HZP[1] Beginning	HFP[2] Beginning	HZP End	HFP End
Power level (%)	0	102	0	102
Ejected rod worth (%Δk)	0.65	0.37	0.75	0.30
Delayed neutron fraction (%)	0.49	0.49	0.44	0.44
Feedback reactivity weighting	2.155	1.22	2.9	1.35
Trip reactivity (%Δk)	2.0	4.0	2.0	4.0
F_q before rod ejection	–	2.6	–	2.6
F_q after rod ejection	12.0	4.9	19.6	6.0
Number of operational pumps	2	4	2	4
Maximum fuel pellet average temperature (°F)	2573	4118	2848	3926
Maximum fuel center temperature (°F)	3018	4974	3263	4871
Maximum cladding average temperature (°F)	1907	2265	2122	2151
Maximum fuel stored energy (cal/g)	104	181	117	170
Percent of fuel melted at hot spot	0	<10	0	<10

Notes:
1. HZP – Hot zero power
2. HFP – Hot full power

Table 15.4-4 (Sheet 1 of 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A ROD EJECTION ACCIDENT

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)[a]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	10% of reactor coolant concentrations at maximum equilibrium conditions
Radial peaking factor (for determination of activity in failed/melted fuel)	1.65
Fuel cladding failure	
– Fraction of fuel rods assumed to fail	0.1
– Fission product gap fractions	
Iodines and noble gases	0.1
Alkali metals	0.12
Core melting	
– Fraction of core melting	0.0025
– Fraction of activity released	
Iodines and alkali metals	0.5
Noble gases	1.0
Iodine chemical form (%)	
– Elemental	4.85
– Organic	0.15
– Particulate	95.0
Core activity	See Table 15A-3 in Appendix 15A
Nuclide data	See Table 15A-4 in Appendix 15A
Reactor coolant mass (lb)	3.7 E+05

Note:

a. The assumption of a pre-existing iodine spike is a conservative assumption for the initial reactor coolant activity. However, compared to the activity assumed to be released from damaged fuel, it is not significant.

Table 15.4-4 (Sheet 2 of 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A ROD EJECTION ACCIDENT

Condenser	Not available
Duration of accident (days)	30
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in Appendix 15A
Secondary system release path	
– Primary to secondary leak rate (lb/hr)	104.3[(a)]
– Leak flashing fraction (%)	4.0[(b)]
– Secondary coolant mass (lb)	6.06 E+05
– Duration of steam release from secondary system (sec)	1800
– Steam released from secondary system (lb)	1.08 E+05
– Partition coefficient in steam generators	
• Iodine	0.01
• Alkali metals	0.001
Containment leakage release path	
– Containment leak rate (% per day)	
• 0-24 hr	0.10
• >24 hr	0.05
– Airborne activity removal coefficients (hr^{-1})	
• Elemental iodine	1.7[(c)]
• Organic iodine	0
• Particulate iodine or alkali metals	0.1
– Decontamination factor limit for elemental iodine removal	200
– Time to reach the decontamination factor limit for elemental iodine (hr)	3.1

Notes:

a. Equivalent to 300 gpd cooled liquid at 62.4 lb/ft^3.
b. No credit for iodine partitioning is taken for flashed leakage.
c. From Appendix 15B.

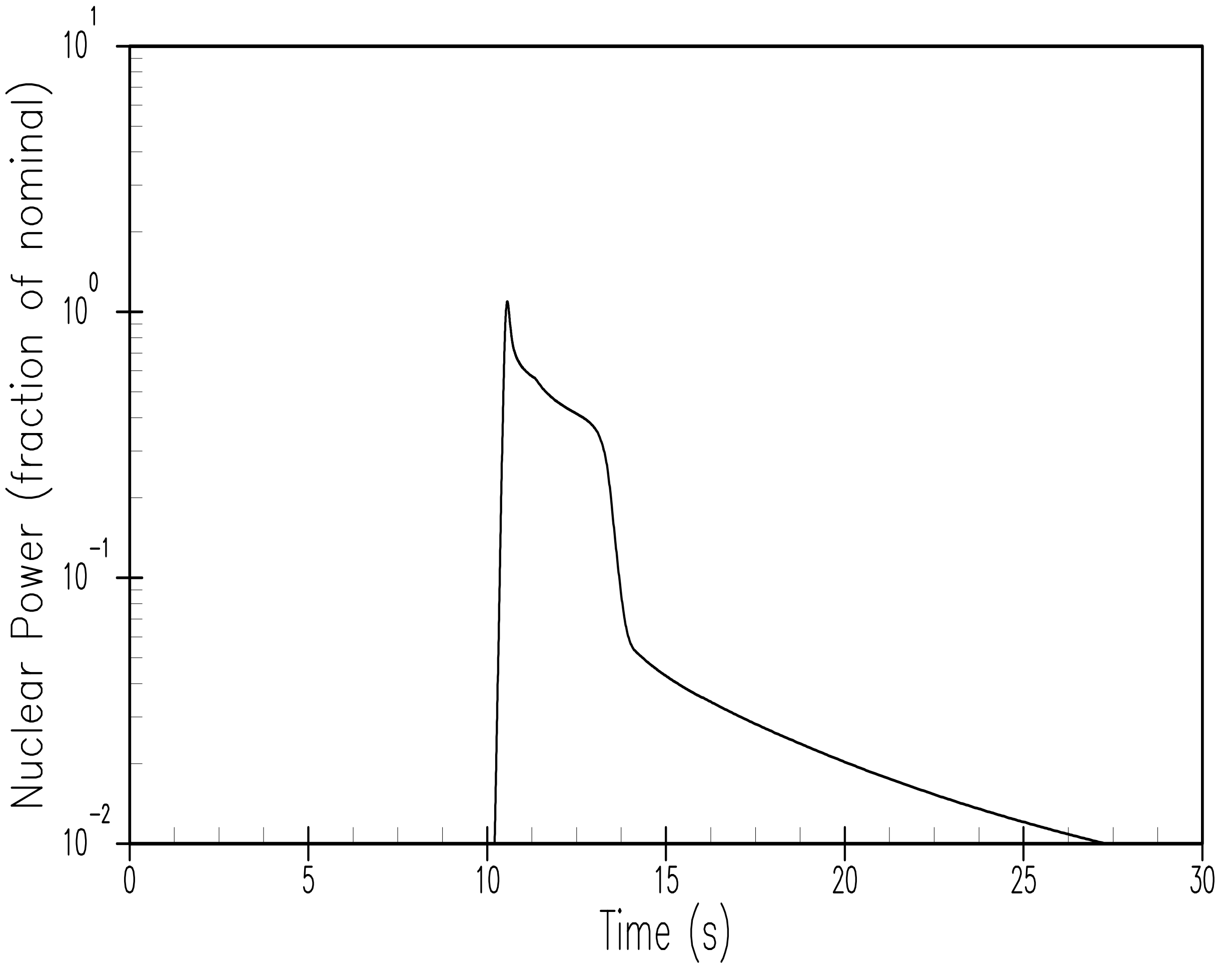

Figure 15.4.1-1

RCCA Withdrawal from Subcritical Nuclear Power

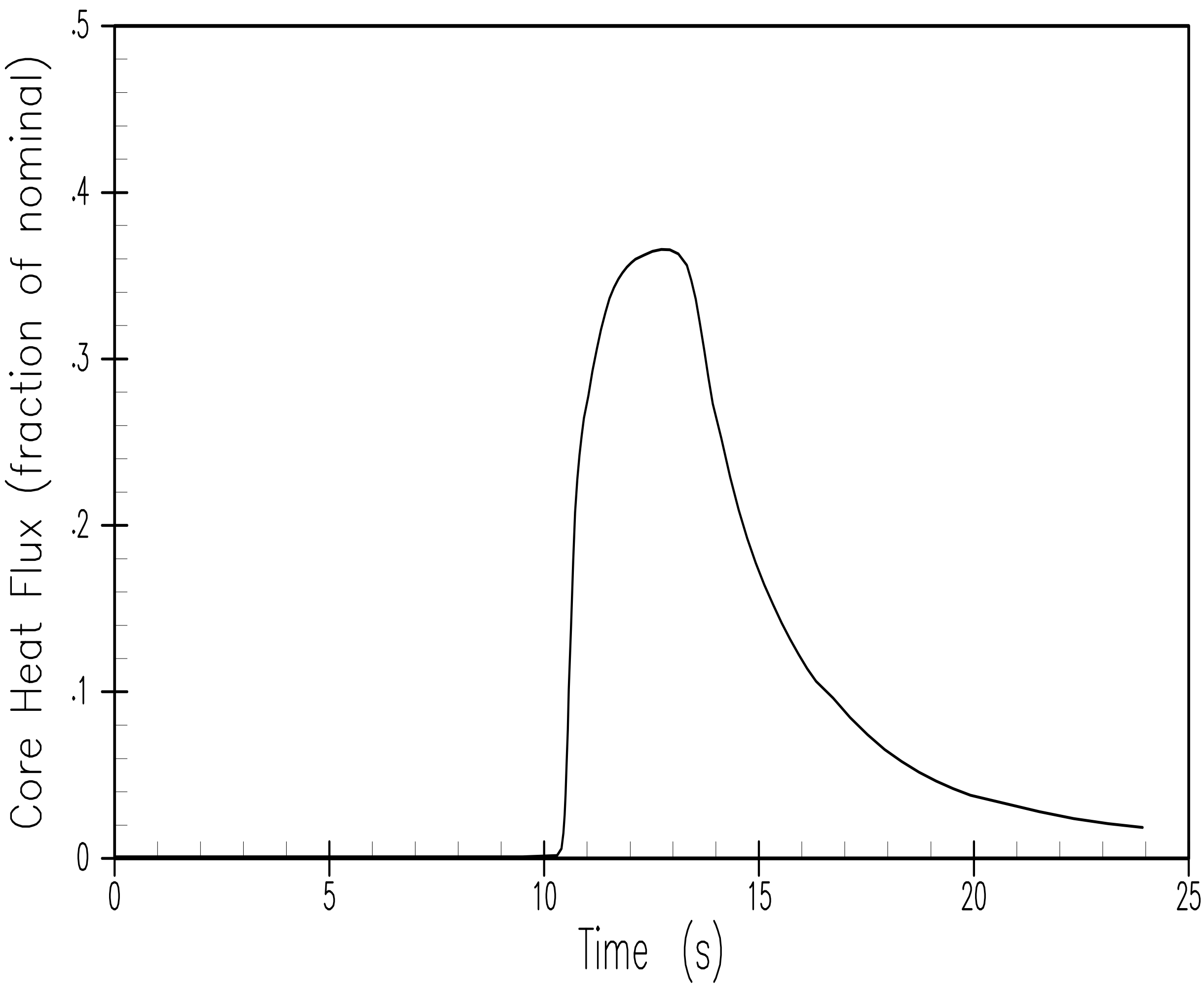

Figure 15.4.1-2

RCCA Withdrawal from Subcritical
Average Channel Core Heat Flux

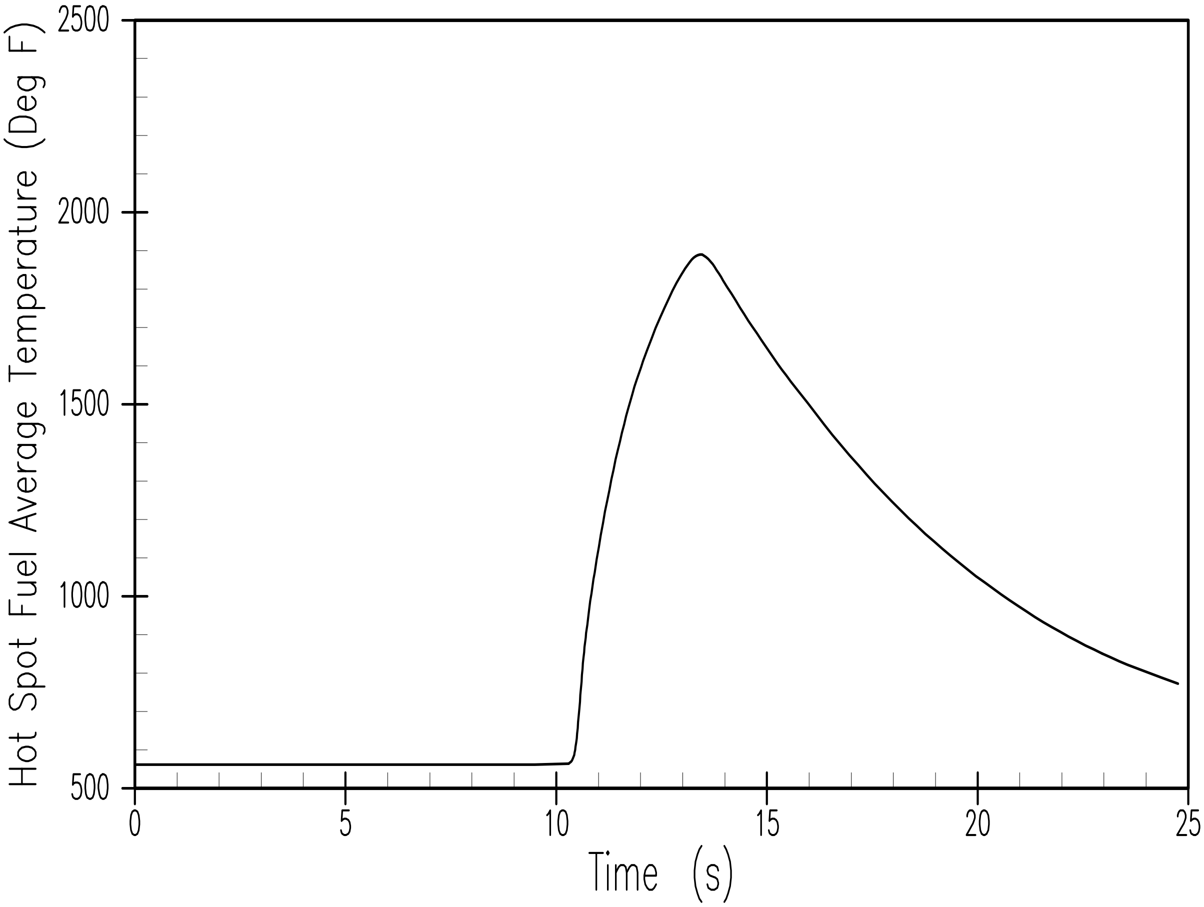

Figure 15.4.1-3 (Sheet 1 of 2)

RCCA Withdrawal from Subcritical
Hot Spot Fuel Average Temperature

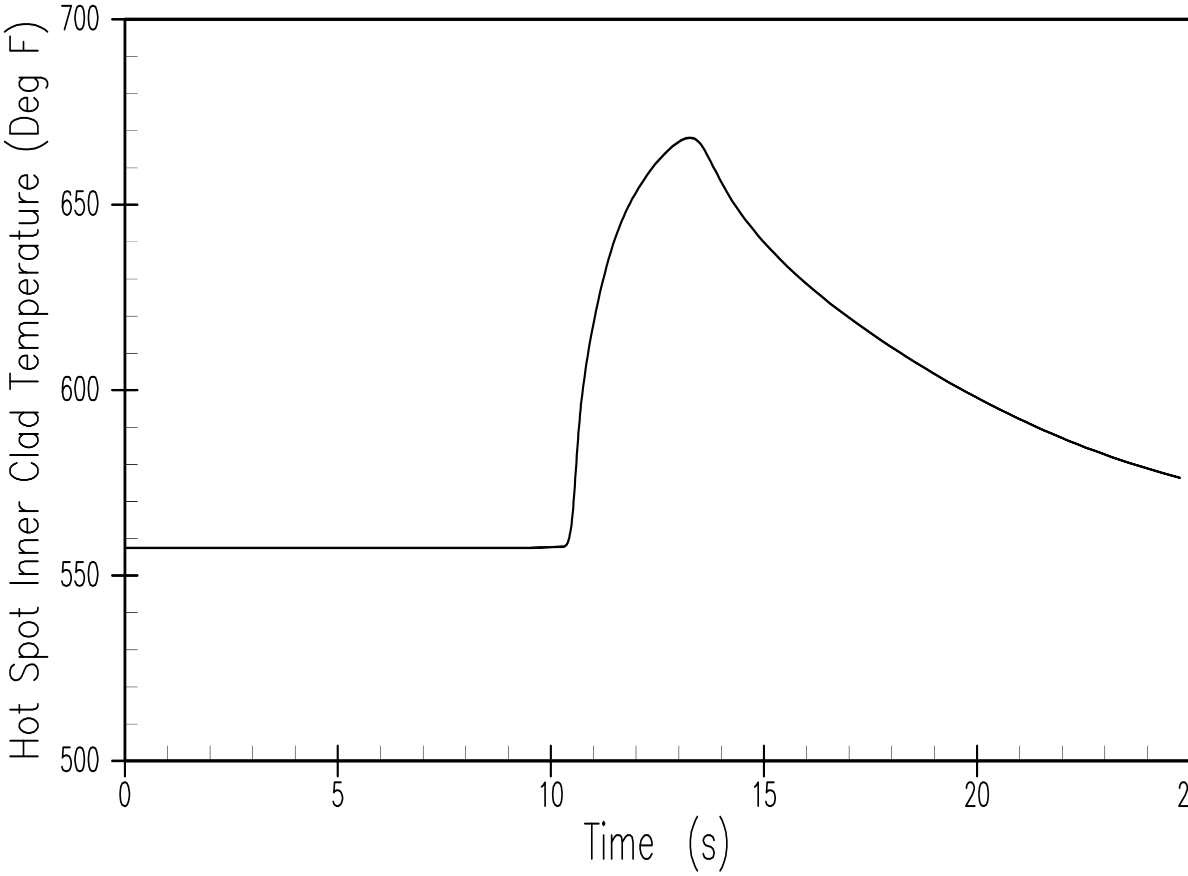

Figure 15.4.1-3 (Sheet 2 of 2)

RCCA Withdrawal from Subcritical
Hot Spot Cladding Inner Temperature

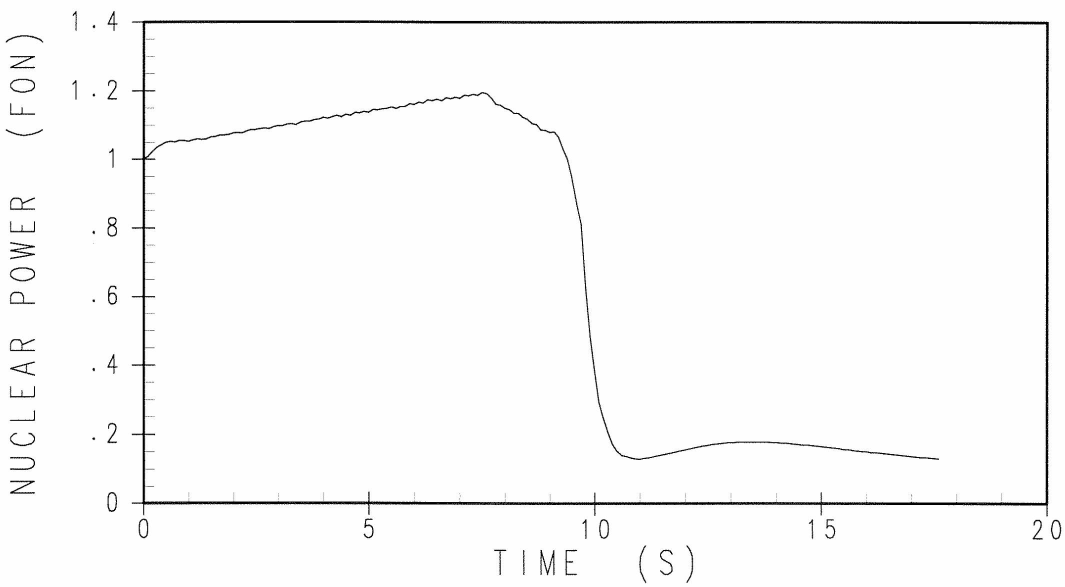

Figure 15.4.2-1

Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

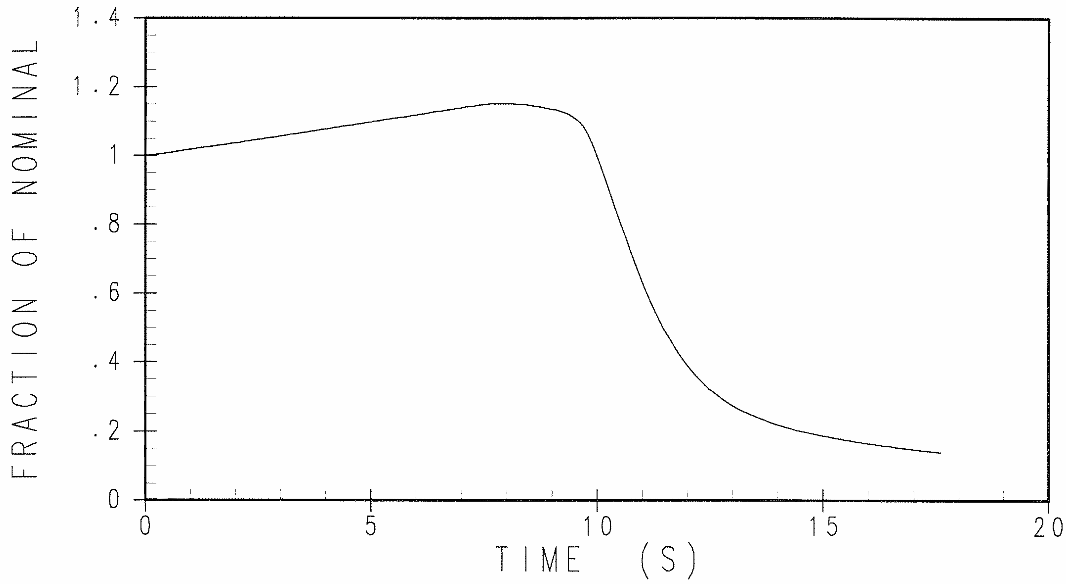

Figure 15.4.2-2

Thermal Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

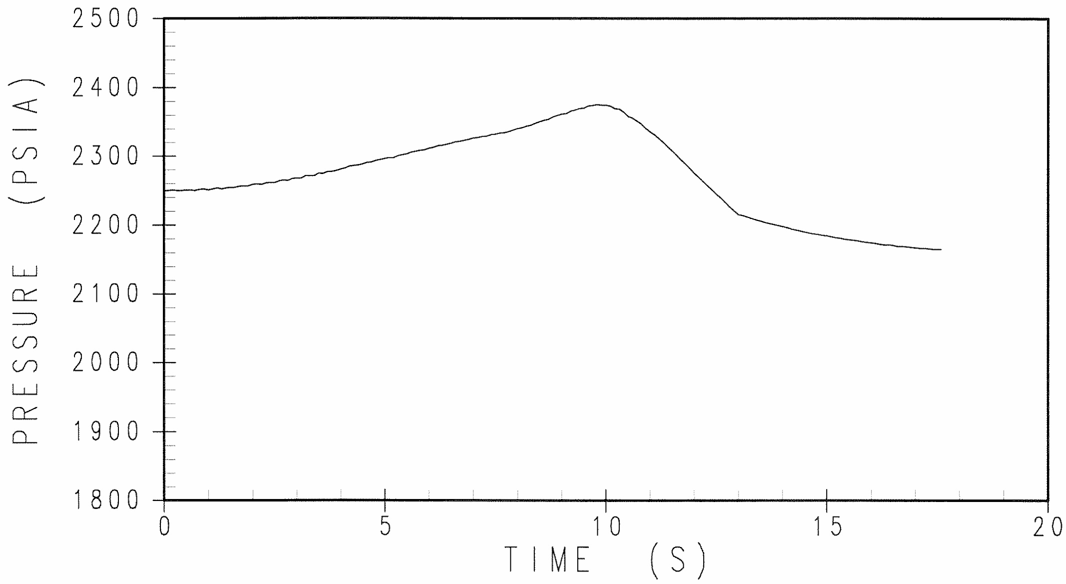

Figure 15.4.2-3

Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

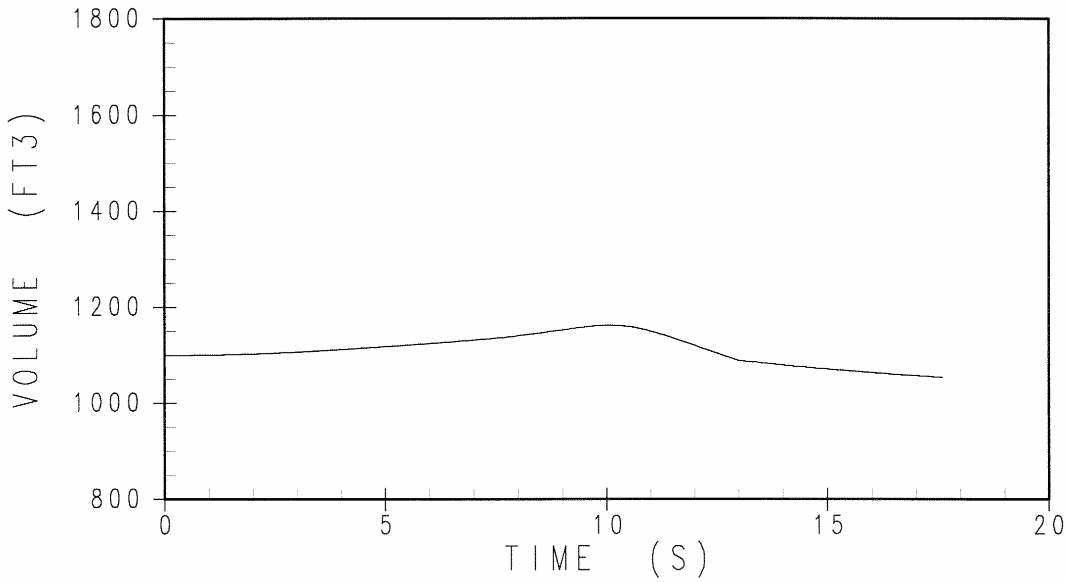

Figure 15.4.2-4

Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

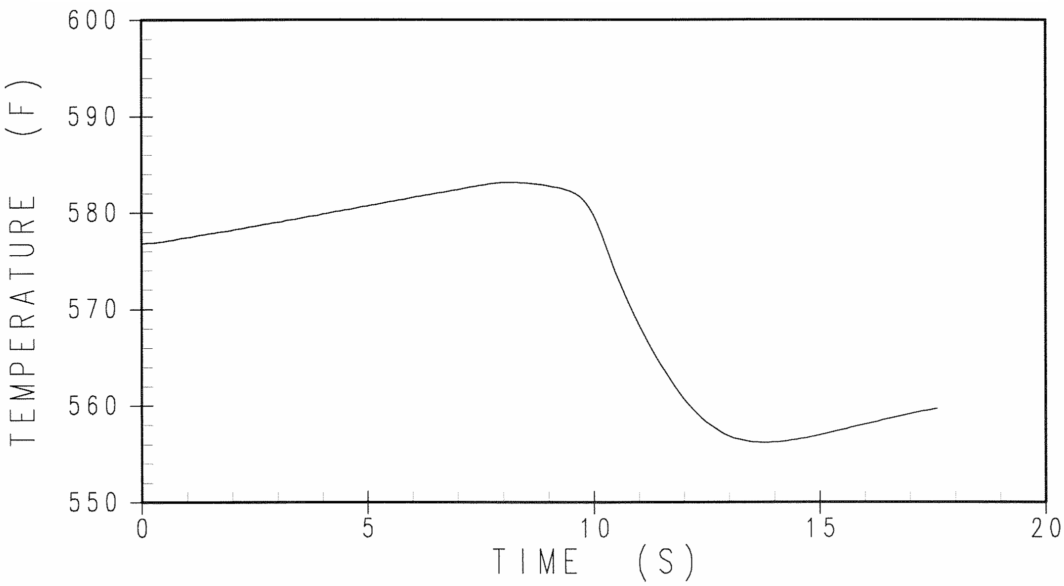

Figure 15.4.2-5

Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

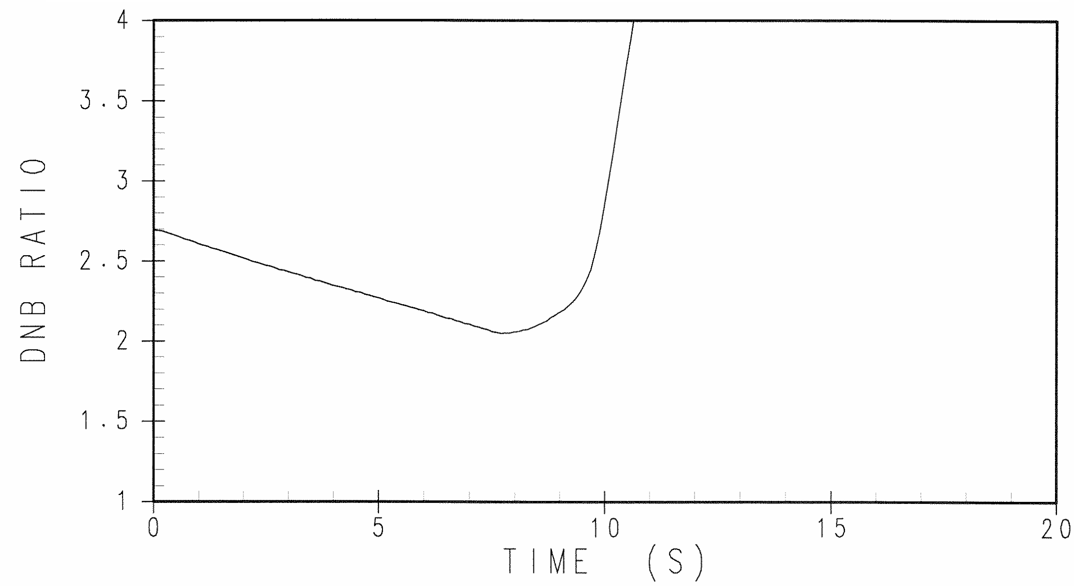

Figure 15.4.2-6

DNBR Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

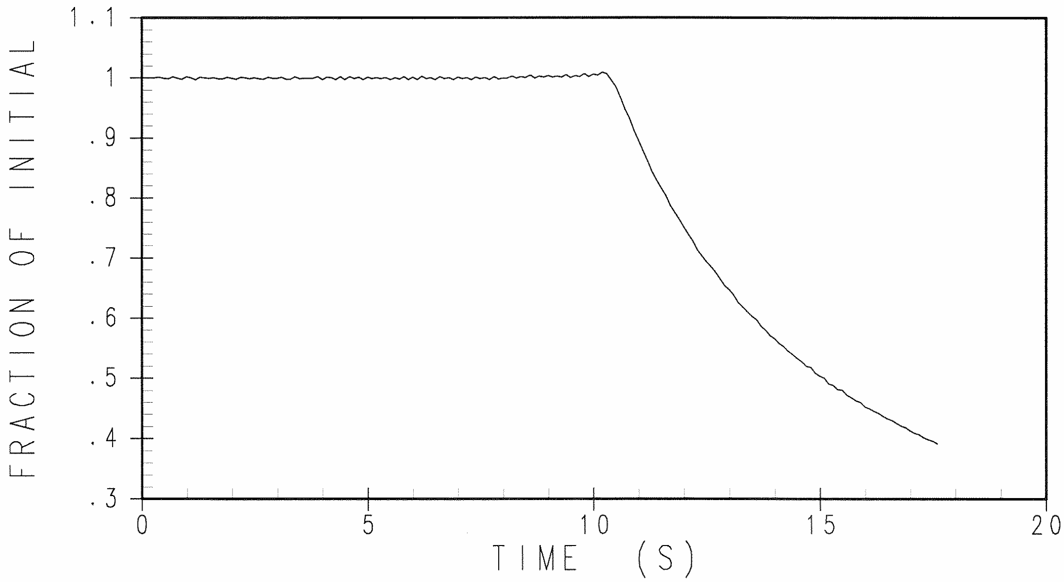

Figure 15.4.2-7

Core Mass Flow Rate Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (75 pcm/s)

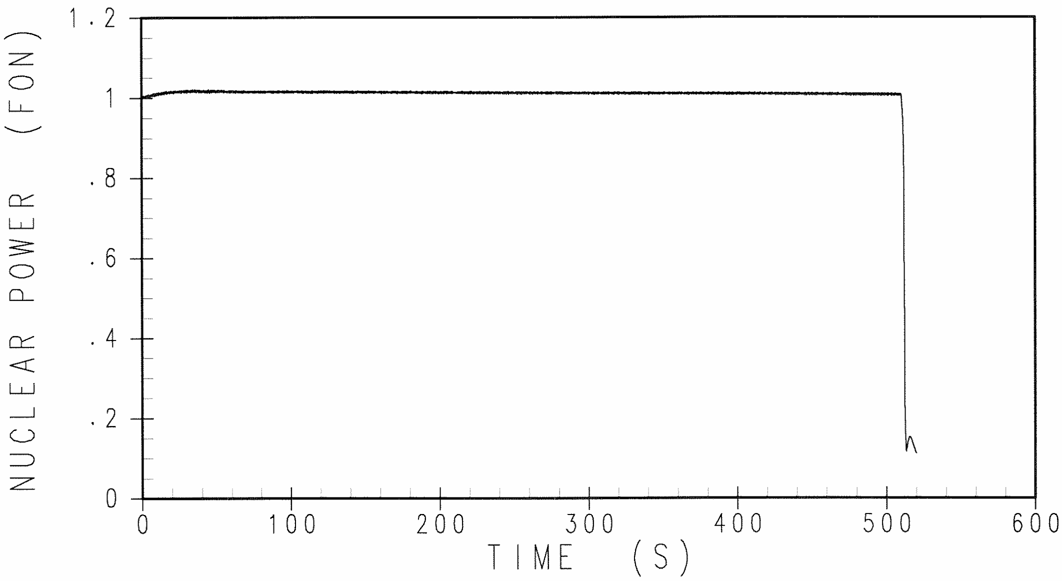

Figure 15.4.2-8

Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

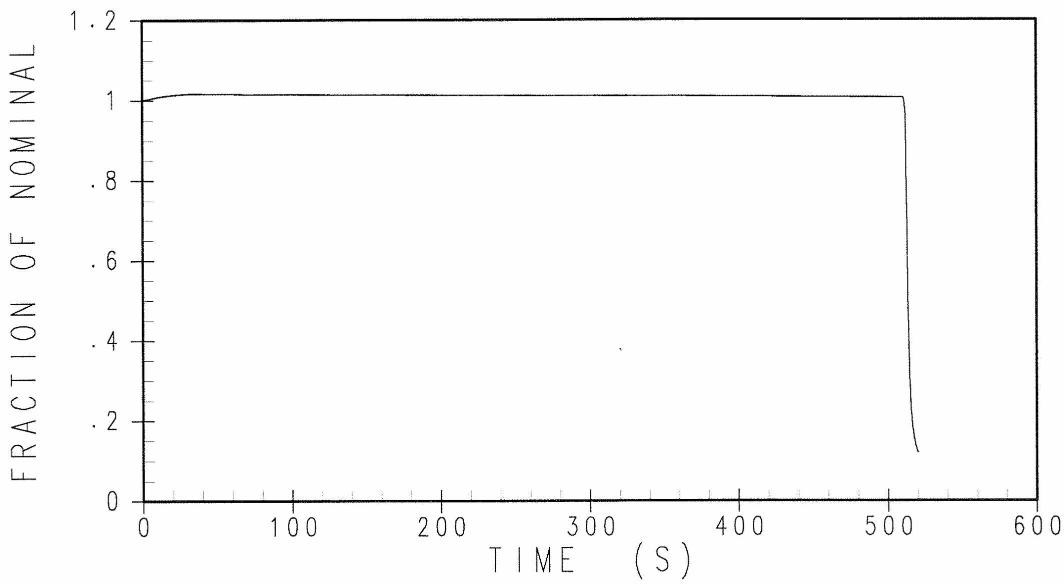

Figure 15.4.2-9

Thermal Flux Transient for an
Uncontrolled RCCA Bank Withdrawal from Full Power
With Maximum Reactivity Feedback (3 pcm/s)

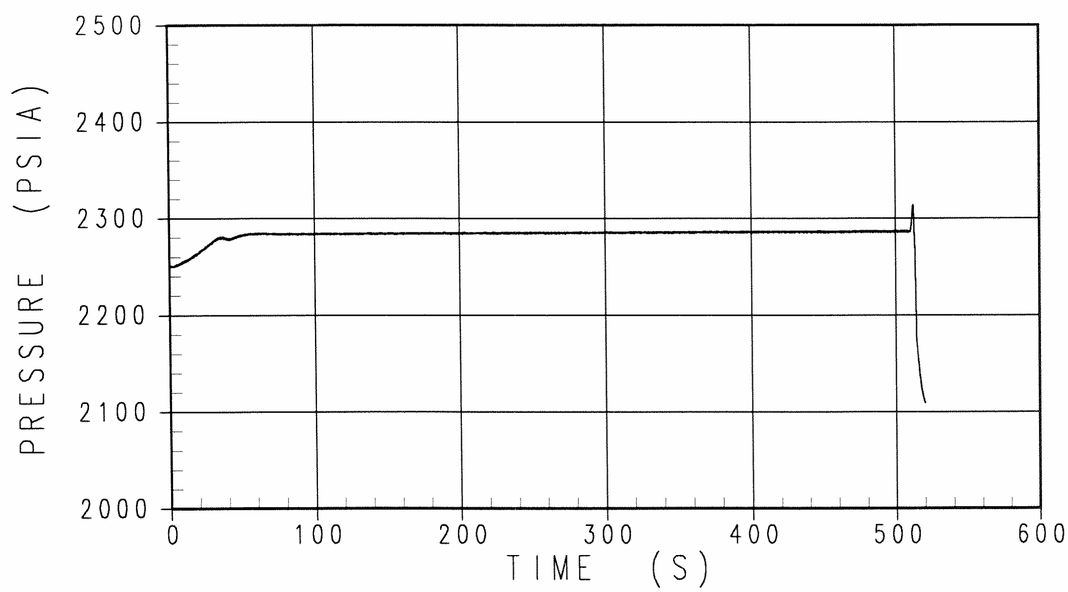

Figure 15.4.2-10

Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

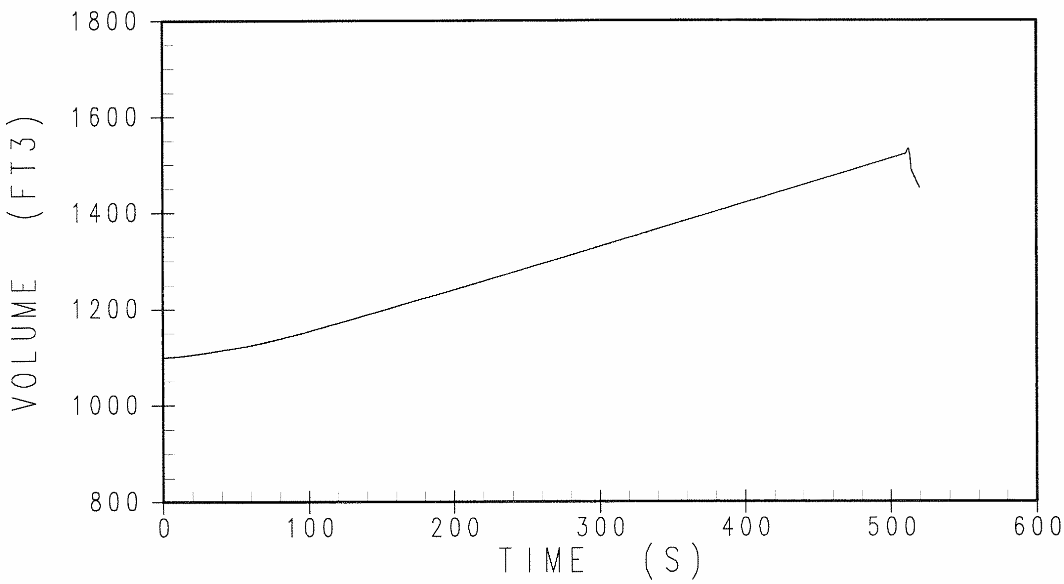

Figure 15.4.2-11

Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

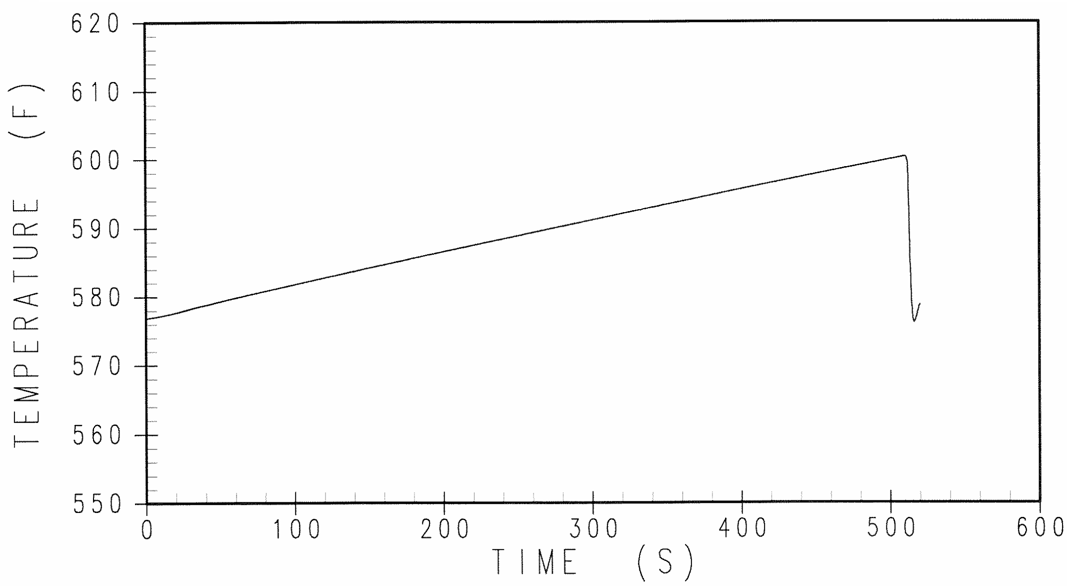

Figure 15.4.2-12

Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

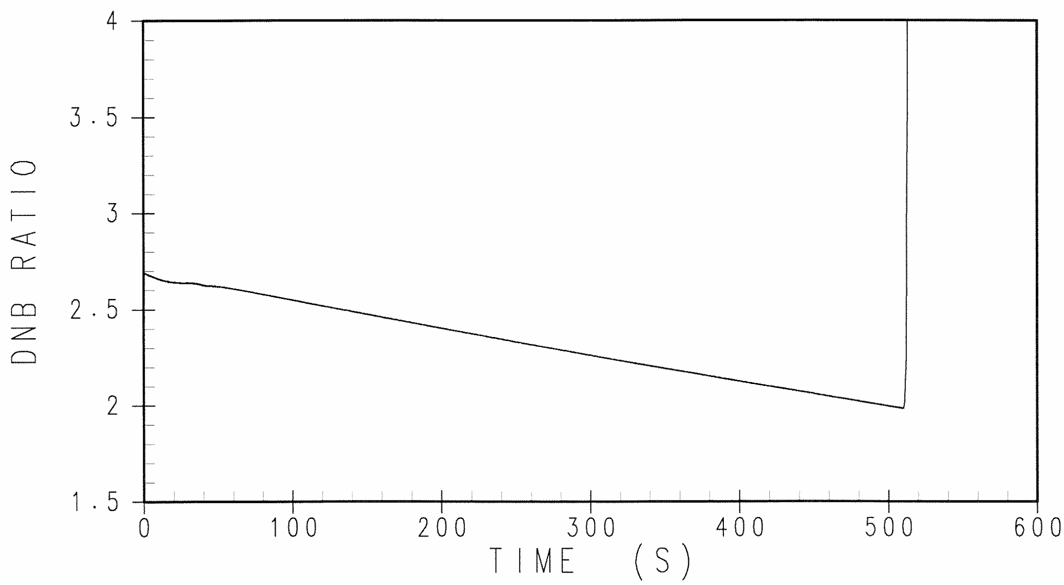

Figure 15.4.2-13

DNBR Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

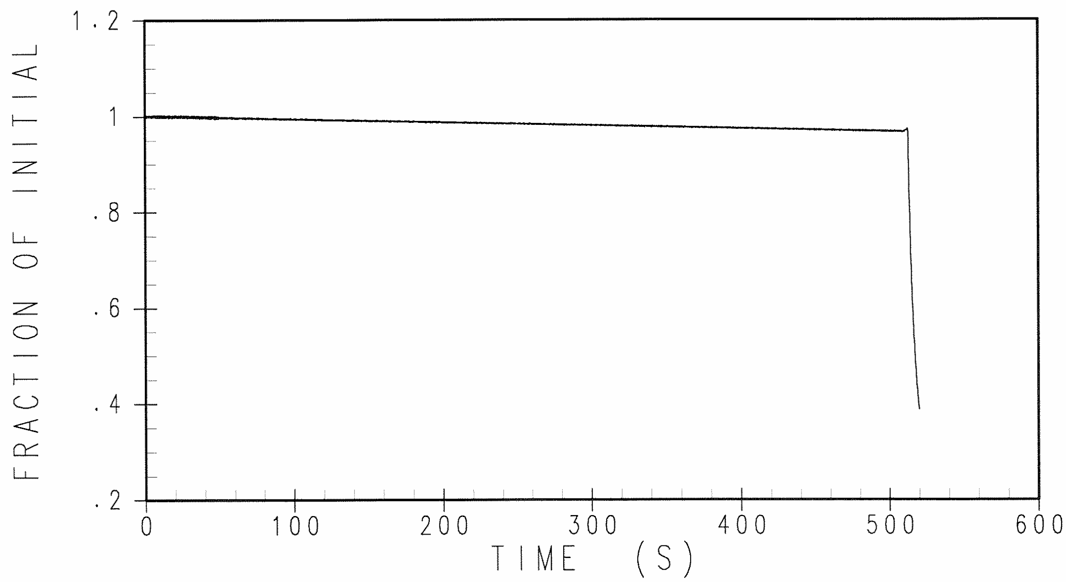

Figure 15.4.2-14

Core Mass Flow Rate Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (3 pcm/s)

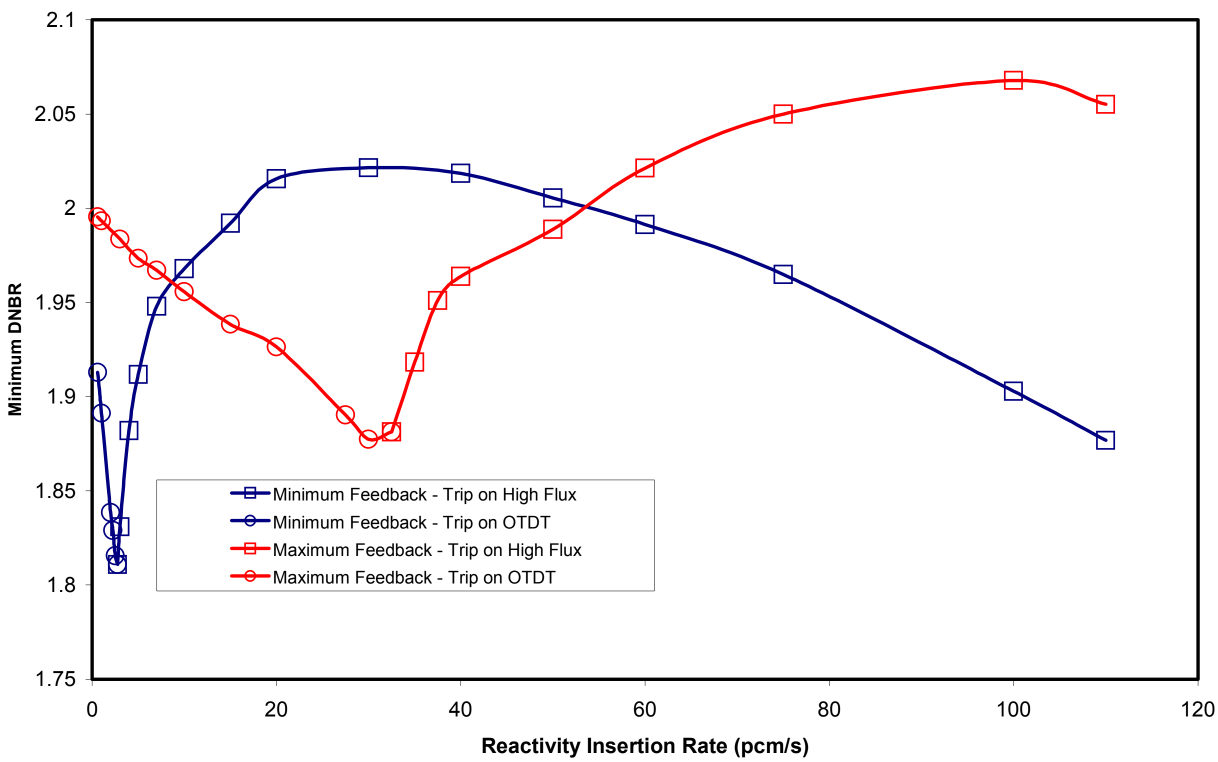

Figure 15.4.2-15

Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 100-percent Power

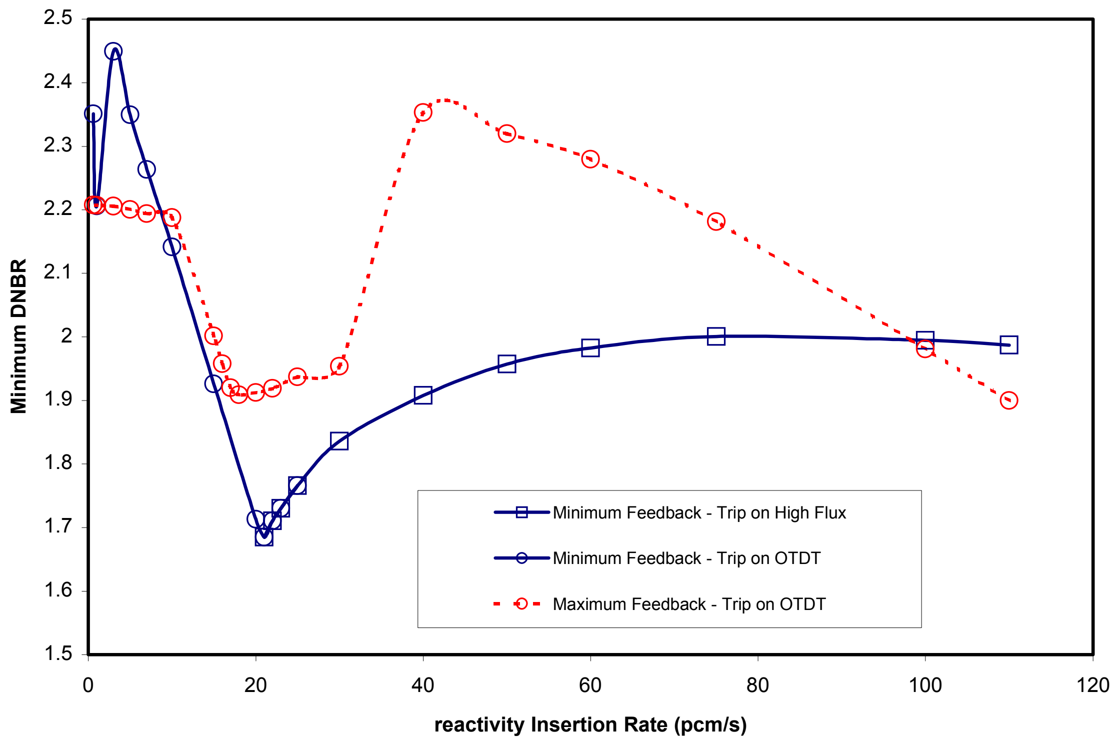

Figure 15.4.2-16

Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 60-percent Power

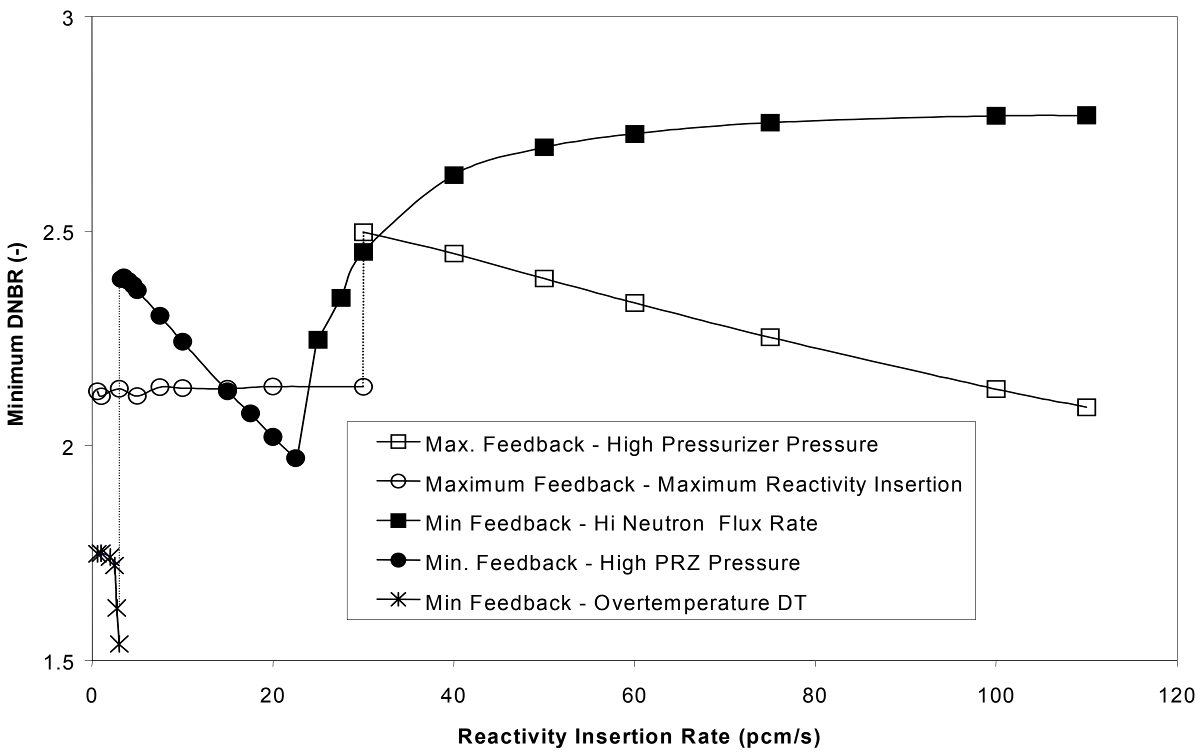

Figure 15.4.2-17

Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 10-percent Power

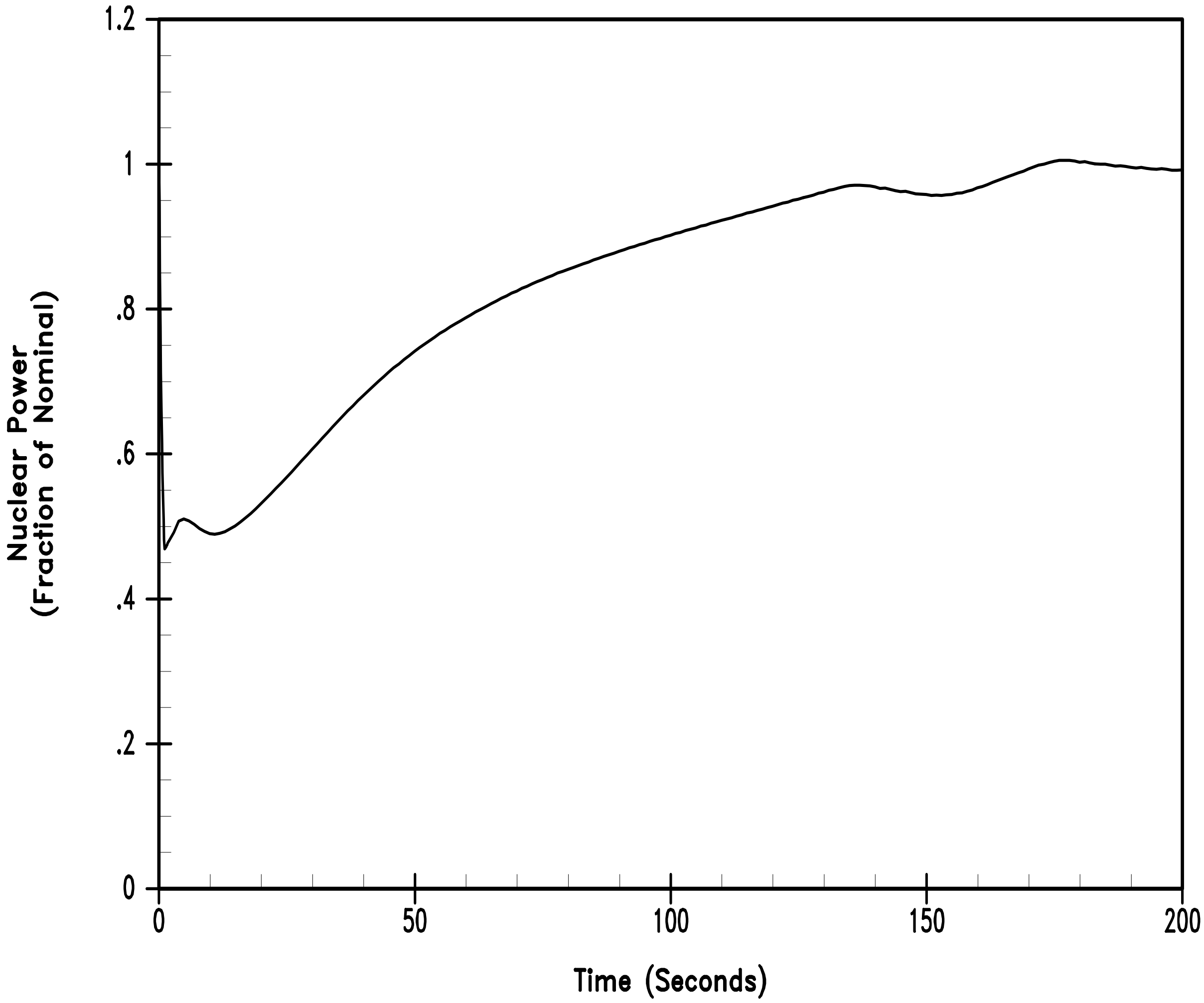

Figure 15.4.3-1

Nuclear Power Transient for Dropped RCCA

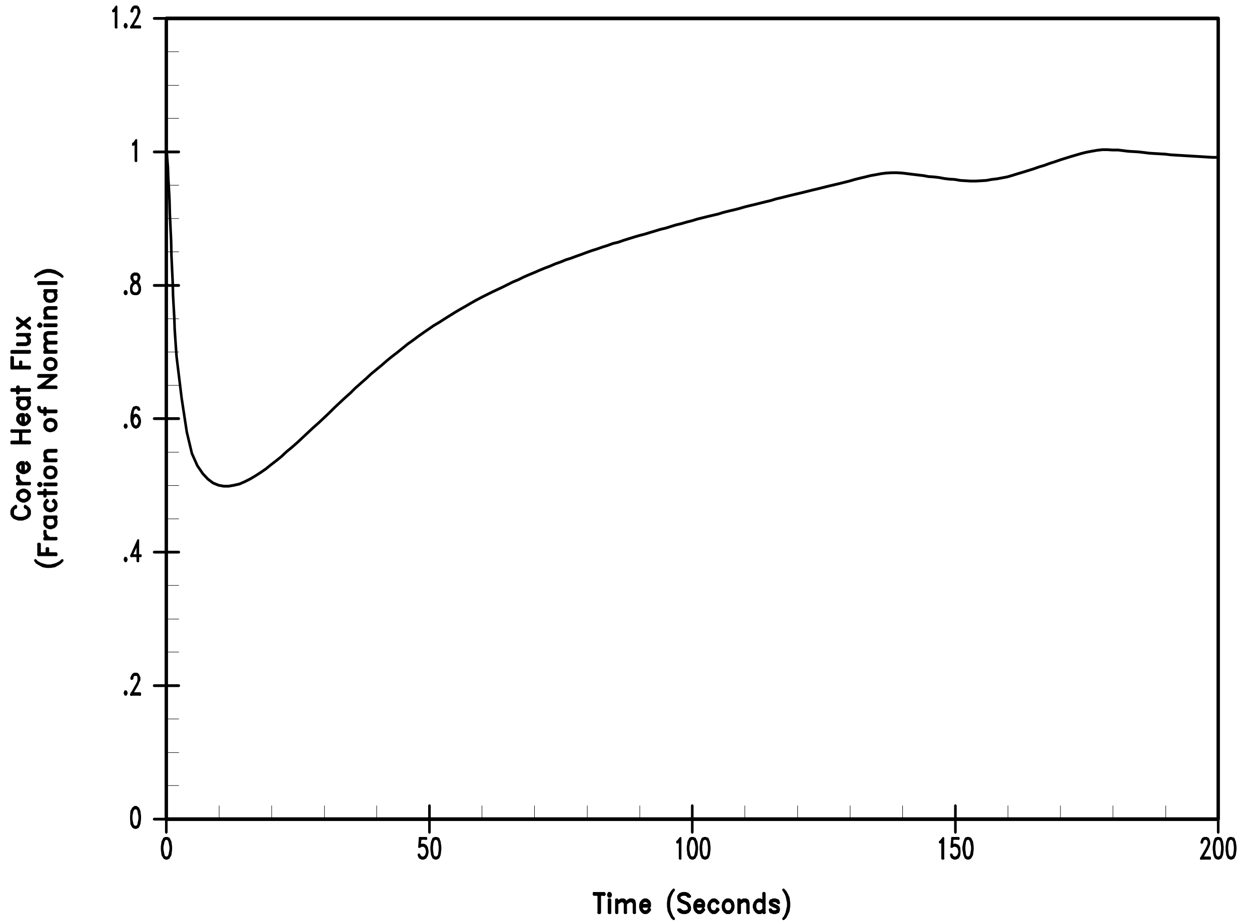

Figure 15.4.3-2

Core Heat Flux Transient for Dropped RCCA

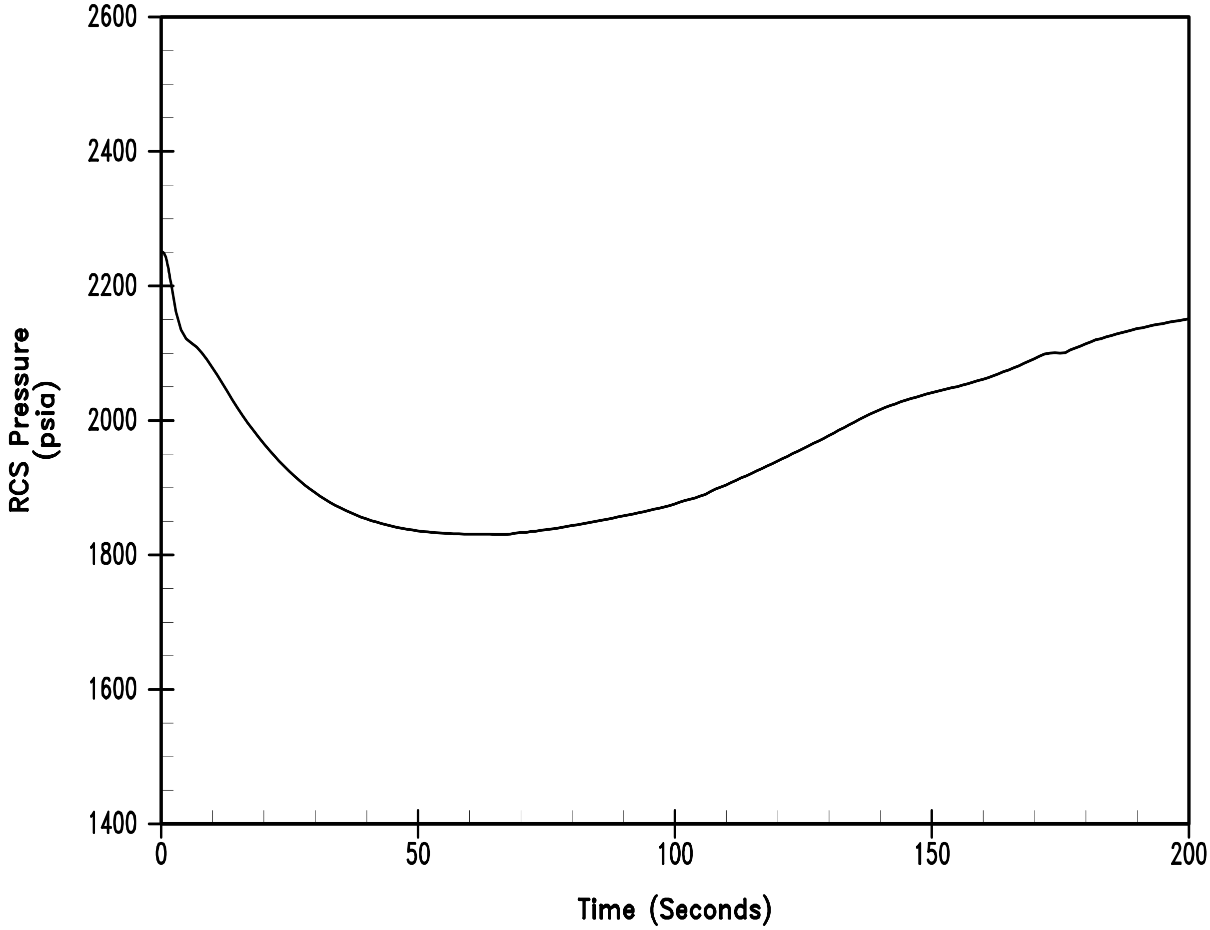

Figure 15.4.3-3

Reactor Coolant System Pressure Transient for Dropped RCCA

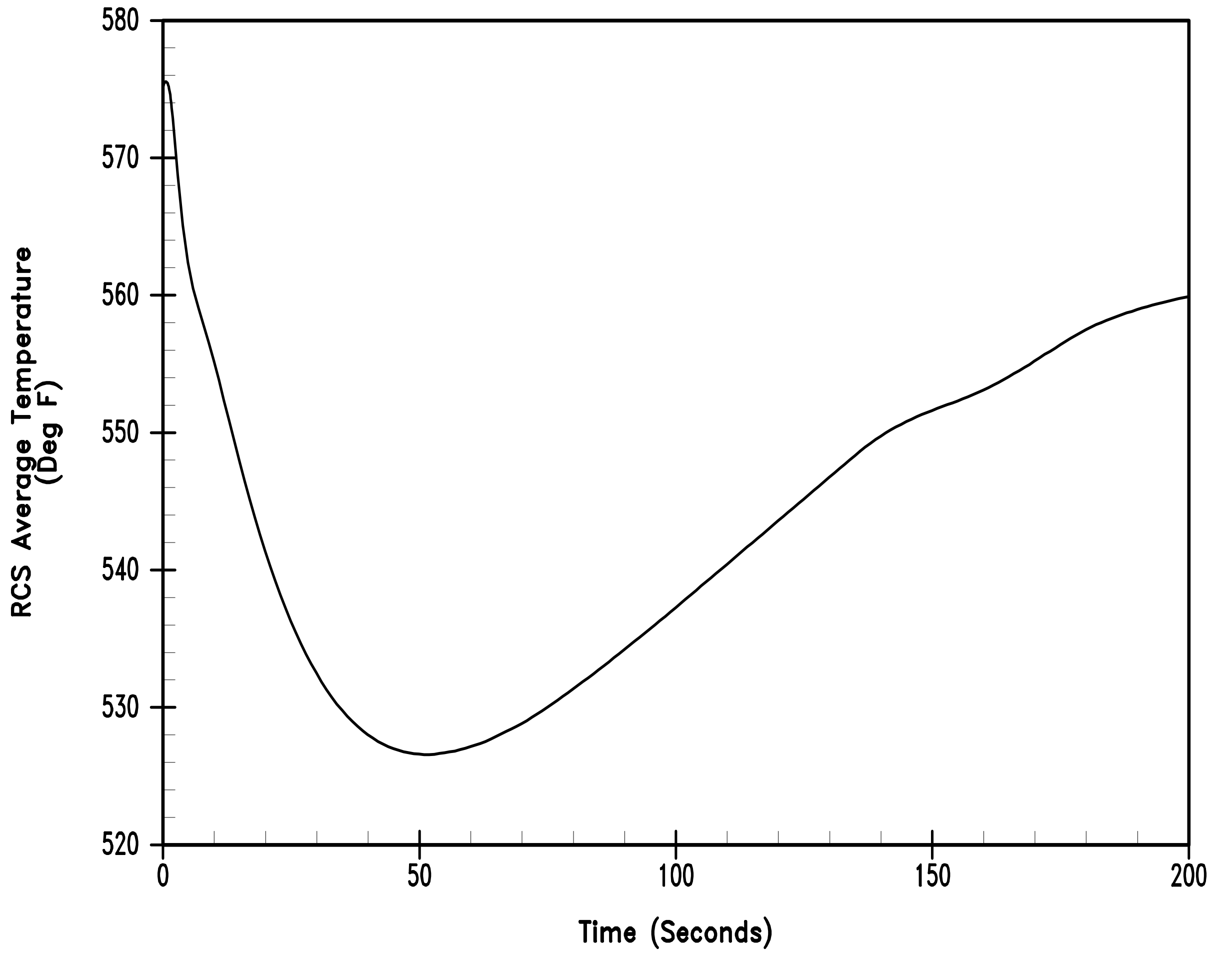

Figure 15.4.3-4

RCS Average Temperature Transient for Dropped RCCA

180°

		R	P	N	M	L	K	J	H	G	F	E	D	C	B	A	
1																	
2						-2.4		-2.3		-2.1		-1.8					
3																	
4				-2.3		-2.3		-2.1		-1.9		-1.4		-0.8			
5																	
6				-2.3		-2.1		-1.6		-1.0		-0.4		0.0			
7			-2.2												0.9		
8	90°			-2.0		-1.7		-0.9		0.4		1.6		1.7			360°
9			-2.0												2.6		
10				-1.7		-1.2		-0.2		2.6		6.2		4.8			
11												X					
12				-1.5		-1.1		0.0		2.5		6.3		6.9			
13																	
14						-0.9		-0.2		0.4		X -16.3					
15																	

0°

Figure 15.4.7-1

Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 3 Assembly

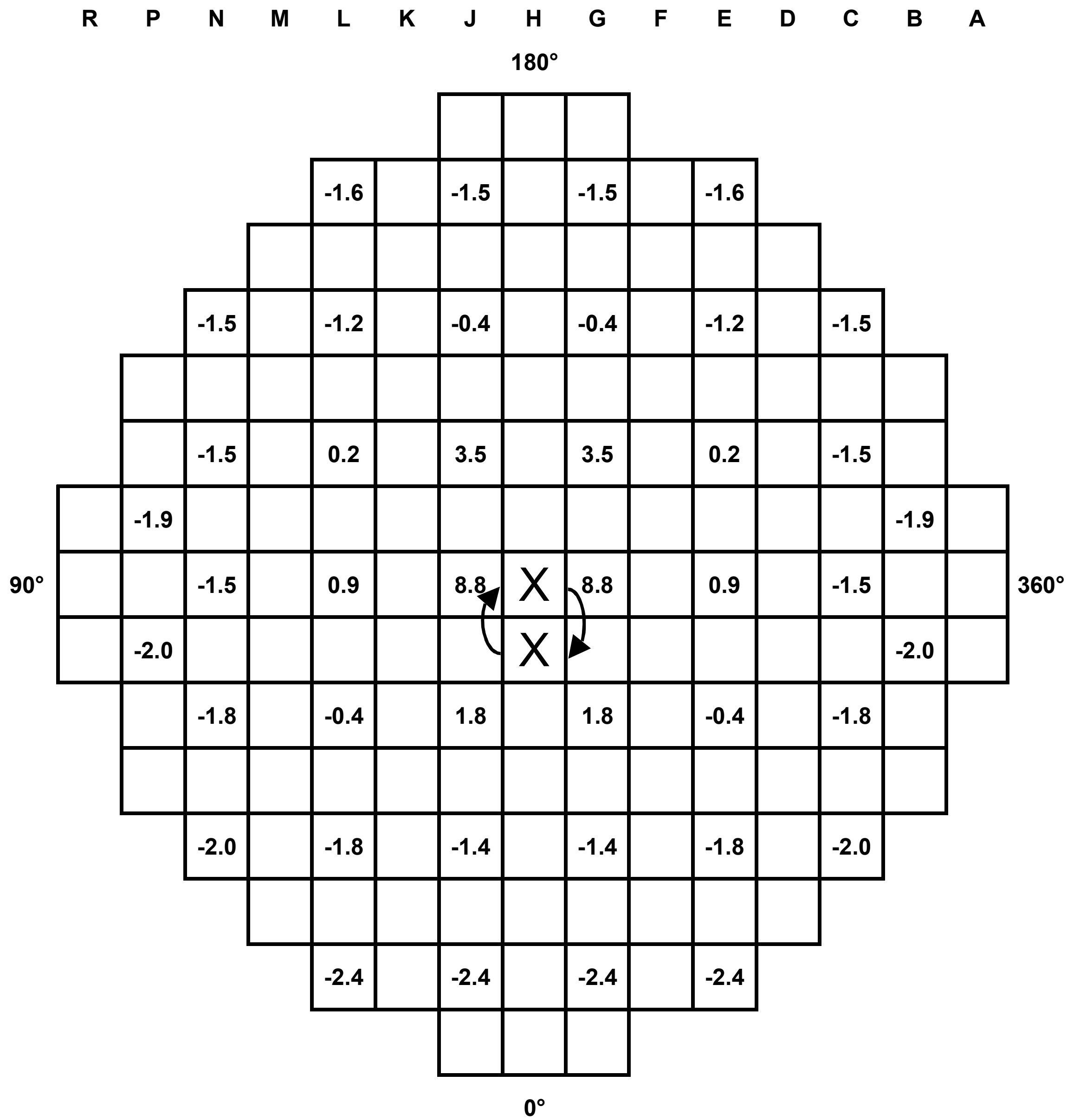

Figure 15.4.7-2

Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 2 Assembly with the BP Rods Transferred to Region 1 Assembly

180°

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1															
2					-2.2		-2.2		-2.2		-2.2				
3															
4			-2.1		-1.7		-1.1		-1.1		-1.7		-2.1		
5															
6			-2.0		-0.3		3.2		3.2		-0.3		-2.0		
7		-2.2												-2.2	
8			-1.9		0.8		9.9	X	9.9		0.8		-1.9		
9		-2.2												-2.2	
10			-2.0		-0.3		3.2		3.2		-0.3		-2.0		
11															
12			-2.1		-1.7		-1.1		-1.1		-1.7		-2.1		
13															
14					-2.2		-2.2		-2.2		-2.2				
15															

90° (left, row 8) 360° (right, row 8)

0°

Figure 15.4.7-3

Representative Percent Change in Local Assembly Average Power for Enrichment Error (Region 2 Assembly Loaded into Core Central Position)

180°

		R	P	N	M	L	K	J	H	G	F	E	D	C	B	A	
1																	
2						-6.9		-6.9		-6.6		-6.0					
3																	
4				-6.7		-6.7		-6.5		-6.0		-5.0		-3.6			
5																	
6				-6.4		-6.2		-5.5		-4.2		-2.8		-1.4			
7			-6.1												1.1		
8	90°			-5.8		-5.2		-3.7		-1.3		1.6		3.2			360°
9			-5.6												6.9		
10				-5.0		-3.8		-1.4		3.3		11.1		13.8			
11																	
12				-4.1		-2.4		0.6		7.4		26.3	X	39.7			
13																	
14						-1.1		2.0		7.5		20.5					
15																	

0°

Figure 15.4.7-4

Representative Percent Change in Local Assembly Average Power for Loading Region 2 Assembly into Region 1 Position Near Core Periphery

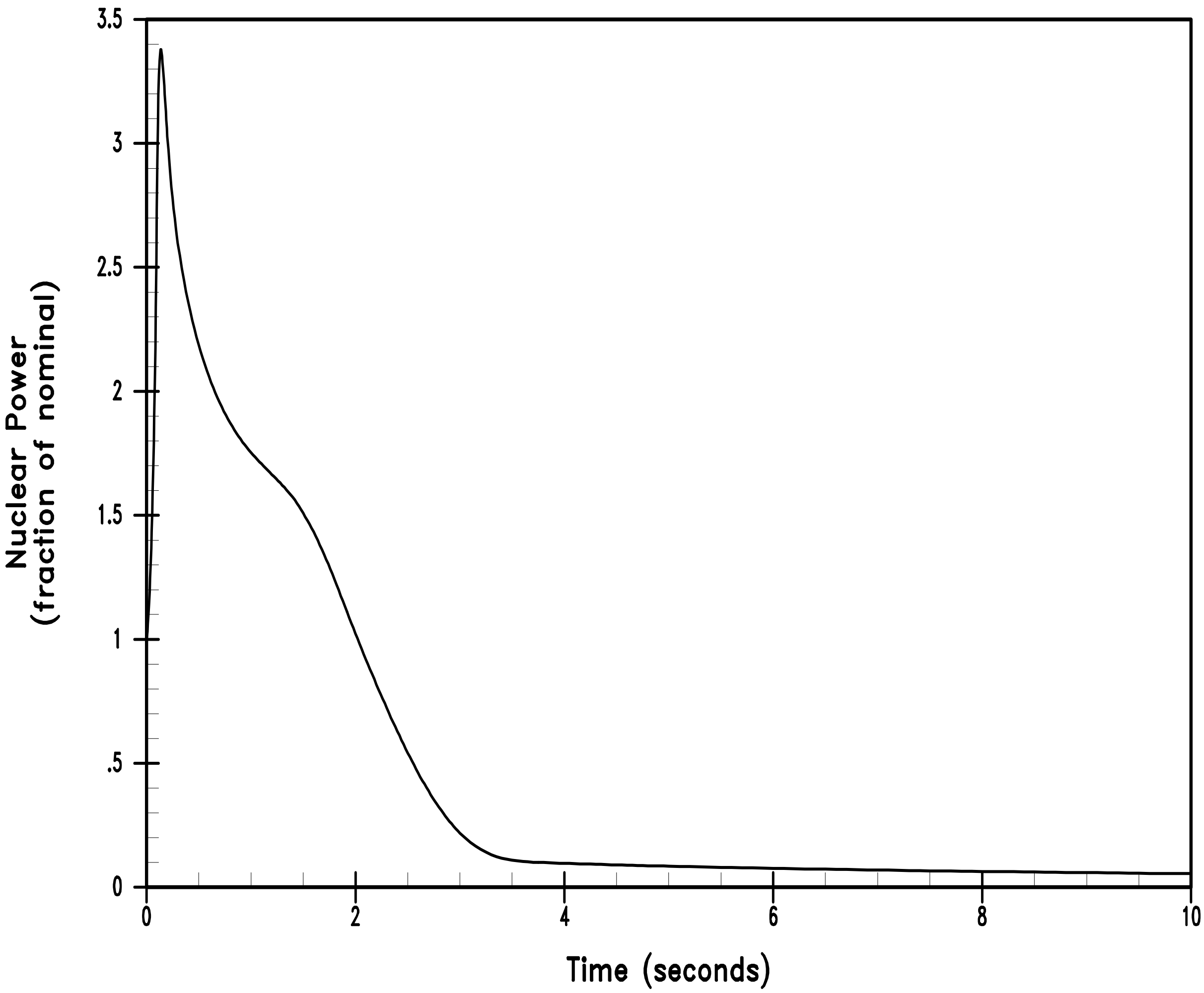

Figure 15.4.8-1

Nuclear Power Transient Versus Time at Beginning of Life, Full Power

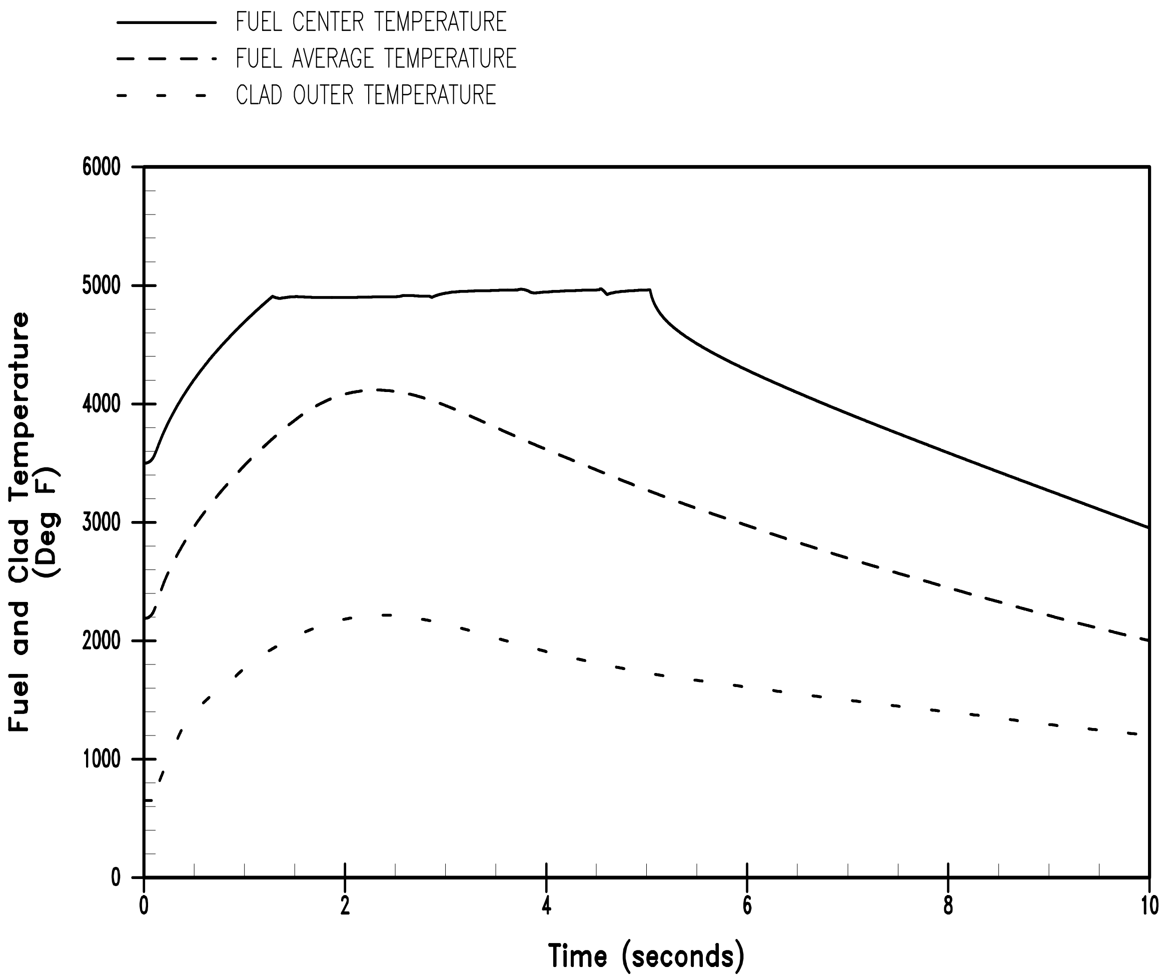

Figure 15.4.8-2

Hot Spot Fuel, Average Fuel, and Outer Cladding Temperature Versus Time at Beginning of Life, Full Power

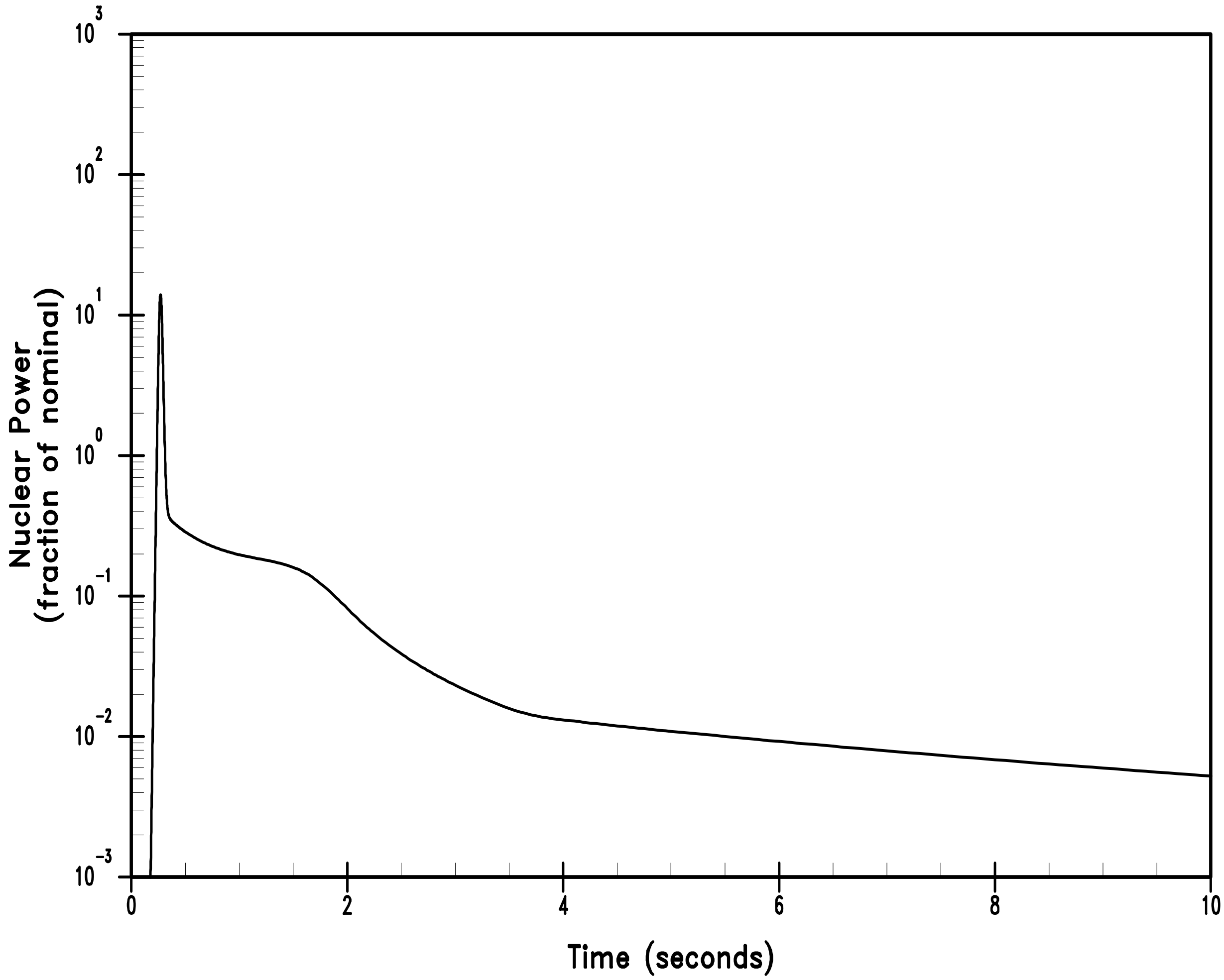

Figure 15.4.8-3

Nuclear Power Transient Versus Time at End of Life, Zero Power

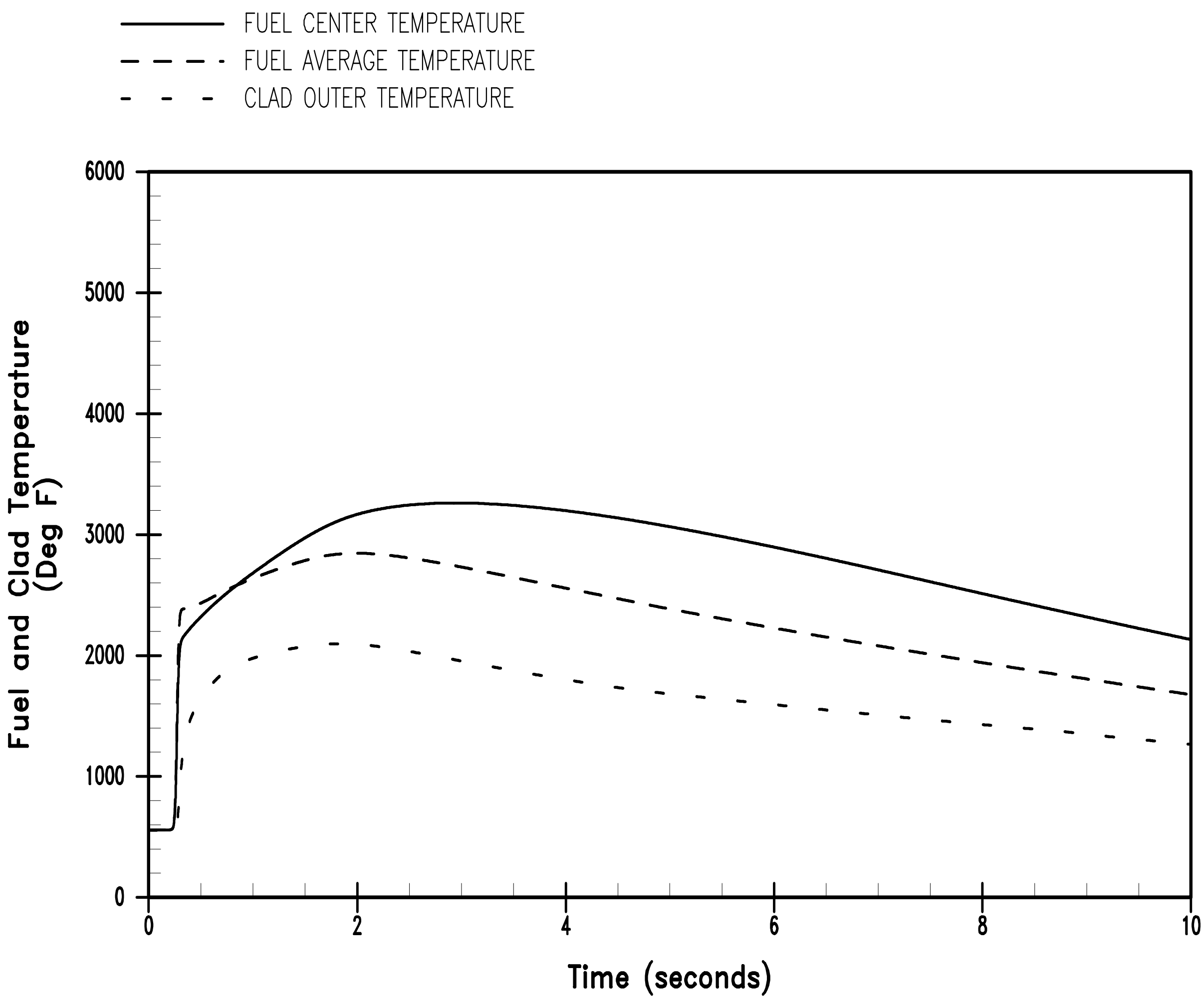

Figure 15.4.8-4

Hot Spot Fuel, Average Fuel, and Outer Cladding Temperature Versus Time at End of Life, Zero Power

15.5 Increase in Reactor Coolant Inventory

This section presents a discussion and analysis of the following events:

- Inadvertent operation of the core makeup tanks during power operation
- Chemical and volume control system malfunction that increases reactor coolant inventory

These Condition II events cause an increase in reactor coolant inventory.

15.5.1 Inadvertent Operation of the Core Makeup Tanks During Power Operation

15.5.1.1 Identification of the Causes and Accident Description

Spurious core makeup tank operation at power could be caused by an operator error, a false electrical actuation signal, or a valve malfunction. A spurious signal may originate from any of the safeguards (“S”) actuation channels as described in Section 7.3. The AP1000 protection logic is such that a single failure cannot actuate both core makeup tanks without also actuating the passive residual heat removal (PRHR) heat exchanger. A scenario such as this is the spurious “S” signal event. However, if one core makeup tank is inadvertently actuated by a single failure, the event may progress with the plant at power until a reactor trip is reached. For the plant under automatic rod control, a reactor trip on high-3 pressurizer water level reactor trip is expected to occur followed by the PRHR actuation and eventually by an “S” signal, which would then actuate the second core makeup tank. When a consequential loss of offsite power is assumed, this event is more conservative than the spurious “S” signal event.

The inadvertent opening of the core makeup tank discharge valves, due to operator error or valve failure, results in significant core makeup tank injection flow leading to a boration similar to that resulting from a chemical and volume control system malfunction event. If the automatic rod control system is operable, it will begin to withdraw rods from the core to counteract the reactivity effects of the boration. As a result, the core makeup tank will continue injection and slowly raise the pressurizer level until the high-3 pressurizer level trip setpoint is reached. In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of reactor trip. The primary effect of this assumption is the coastdown of the reactor coolant pumps. The core makeup tank injection will increase as the steam generator outlet temperature increases resulting in a lower density in the CMT balance line. This event will then proceed similarly to a spurious “S” signal or chemical and volume control system malfunction event. However, this event is more limiting primarily due to the higher pressurizer level at the time of reactor trip and to the significant heat up of the injected fluid during the pre-trip phase of the accident. Thus, the inadvertent core makeup tank actuation event with a consequential loss of offsite power is analyzed here.

Upon receipt of the high-3 pressurizer level reactor trip signal, the reactor is tripped; then the turbine is immediately tripped, and after a 3-second delay, a consequential loss of offsite power is assumed. The basis for the 3-second delay is described in subsection 15.0.14. The high-3 pressurizer level signal also actuates the PRHR heat exchanger and blocks the pressurizer heaters, but a 15-second delay is built in to prevent unnecessary actuation of the PRHR heat exchanger if offsite power is maintained.

Following reactor trip, the reactor power drops and the average reactor coolant system temperature decreases with subsequent coolant shrinkage. However, due to the assumed loss of offsite power, the reactor coolant cold leg temperature, in the loop without PRHR, increases and the core makeup tank starts injecting cold water into the reactor coolant system at a much higher rate. The primary coolant system shrinkage is counteracted by the core makeup tank injection, and the pressurizer water volume starts to increase because of the heatup of the cold injected fluid by the decay heat. The high-3 pressurizer level setpoint is once again reached, and after a 15-second delay, the signal is sent to actuate the PRHR heat exchanger and block the pressurizer heaters.

Eventually, the core makeup tank heats up and the gravity-driven recirculation is significantly reduced. The PRHR heat exchanger continues to extract heat from the reactor coolant system, and the pressurizer water volume starts to decrease. Ultimately, the core makeup tank stops recirculating, the PRHR heat removal matches decay heat and the reactor coolant system cooldown begins eventually leading to a “S” signal on a Low T_{cold} setpoint.

The cold injection flow from the second CMT initially results in a fast decrease in temperature and shrinkage of the reactor coolant. However, as the temperature decreases, the PRHR heat removal capability diminishes and a moderate heat up occurs followed by the increase of pressurizer water level. The second CMT injection rate is much lower than that experienced during the first part of the transient from the first CMT. Due to the colder cold leg temperatures, the density in balance line is much higher than during the first part of the transient, resulting in a reduction of the total buoyancy driving head. Ultimately, the PRHR heat removal once again matches the decay heat and the final reactor coolant system cooldown begins.

This event is a Condition II incident (a fault of moderate frequency) as defined in subsection 15.0.1.

15.5.1.2 Analysis of Effects and Consequences

The plant response to an inadvertent core makeup tank actuation is analyzed by using a modified version of the computer program LOFTRAN described in subsection 15.0.11.2. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, PRHR heat exchanger, and core makeup tank. The program computes pertinent plant variables, including temperatures, pressures, and power level.

Reactor power and average temperature drop immediately following the trip, and the operating conditions never approach the core limits. The PRHR heat exchanger removes the long-term decay heat and prevents possible reactor coolant system overpressurization or loss of reactor coolant system water.

Core makeup tank and PRHR system performance is conservatively simulated. Core makeup tank enthalpies have been maximized. This is conservative because it minimizes the cooling provided by the core makeup tanks as flow recirculates and thereby increases the peak pressurizer water volume during the transient. Core makeup tank injection and balance lines pressure drop is minimized. This maximizes the core makeup tank flow injected in the primary system. During this event, the core makeup tanks remain filled with water. The volume of injection flow leaving the

core makeup tanks is offset by an equal volume of recirculation flow that enters the core makeup tanks via the balance lines. PRHR heat transfer capability has been minimized.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

The limiting case presented here bounds cases that model explicit operator action 60 minutes after reactor trip. The assumptions for this case are as follows:

- Initial operating conditions

  The initial reactor power is assumed to be 102 percent of nominal. The initial pressurizer pressure is assumed to be 50 psi below nominal. The initial reactor coolant system average temperature is assumed to be 7°F below nominal.

- Control systems

  The pressurizer spray system and automatic rod control system are conservatively assumed to operate. The pressurizer heaters are automatically blocked on a high-3 pressurizer level signal, so they cannot add heat to the system during the period of thermal expansion that produces the peak pressurizer water volume. Thus, the pressurizer heaters are assumed to be inoperable during this event. Other control systems are conservatively not assumed to function during the transient. Cases with the turbine bypass (steam dump) and feedwater control systems working result in lower secondary and primary temperatures and in greater margin to overfilling.

- Moderator and Doppler coefficients of reactivity

  A least-negative moderator temperature coefficient, a Low (absolute value) Doppler power coefficient, and a maximum boron worth are assumed. With these minimum feedback parameters and the operability of the pressurizer spray system and automatic rod control system assumed, the reactivity effects of the boron injection from the core makeup tanks is counteracted. As a result, the high-3 pressurizer signal is the first reactor trip signal generated during the transient.

- Boron injection

  The transient is initiated by an inadvertent opening of the discharge valves of one of the two core makeup tanks. The core makeup tank injects 3400 ppm borated water.

- Protection and safety monitoring system actuations

  Reactor trip is initiated by the high-3 pressurizer level signal.

  The core decay heat is removed by the PRHR heat exchanger. The worst single failure is assumed to occur in the outlet line of the PRHR heat exchanger. One of the two parallel isolation valves is assumed to fail to open.

Plant systems and equipment available to mitigate the effect of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.5.1.3 Results

Figures 15.5.1-1 through 15.5.1-11 show the transient response to the inadvertent operation of one of the two core makeup tanks during power operation. The inadvertent opening of the core makeup tank discharge valves occurs at 10 seconds. As the core makeup tank continues to add inventory to the primary system, the pressurizer level begins to increase until the high-3 pressurizer level reactor trip setpoint is reached at about 520.7 seconds. After a 2-second delay, the neutron flux starts decreasing due to the reactor trip, which is immediately followed by the turbine trip. Following reactor trip, the reactor power drops and the average reactor coolant system temperature decreases with subsequent coolant shrinkage. However, due to the assumed loss of offsite power, the reactor coolant pumps trip at about 525.4 seconds. The cold leg temperature increases and the core makeup tank starts injecting cold water into the reactor coolant system at a much higher rate due to the increased driving head resulting from the density decreases in balance line. The primary coolant system shrinkage is counteracted by the core makeup tank injection, and the pressurizer water volume starts to increase because of the heatup of the cold injected fluid by the decay heat. The high-3 pressurizer level setpoint is once again reached at about 541.9 seconds, and after a 15-second delay, the signal is sent to actuate the PRHR heat exchanger and block the pressurizer heaters. Following a conservative 17-second delay, the valves are assumed to open to actuate the PRHR heat exchanger at about 573.9 seconds.

After reactor trip, the pressure in the primary and secondary systems increases initially due to the assumed unavailability of the nonsafety-related control systems. The primary and secondary system pressures eventually decrease as the PRHR system removes decay heat. The core makeup tank works in recirculation mode, meaning it is always filled with water because cold borated water injected through the injection line is replaced by hot water coming from the cold leg (balance lines). At approximately 5,000 seconds, the PRHR heat flux matches the core decay heat. However, the pressurizer level continues to slowly increase until the core makeup tank recirculation is decreased sufficiently to significantly limit the mass addition to the RCS.

At 5,880 seconds, the pressurizer safety valves close. At about 6,600 seconds, the pressurizer water volume stops increasing. At about 12,354 seconds, the Low T_{cold} “S” setpoint is reached and the second CMT is actuated. The pressurizer level initially shrinks due to the addition of cold borated water. As the core makeup tank continues to add inventory to the primary system, the pressurizer level begins to increase. At approximately 13,300 seconds, the first core makeup tank essentially stops recirculating. The PRHR heat flux decreases below decay heat and a moderate heat up is experienced by the plant. Finally, at 21,800 seconds, the PRHR heat transfer matches the decay heat and the final cooldown commences.

Figure 15.5.1-6 shows the departure from nucleate boiling ratio (DNBR) until the time of reactor coolant trip and subsequent flow coastdown due to the loss of offsite power. At this time, core power and heat flux have diminished sufficiently, due to the reactor trip, that DNBR is well above the design limit value defined in Section 4.4.

The calculated sequence of events is shown in Table 15.5-1.

The limiting case presented here bounds all cases that model explicit operator action 30 minutes after reactor trip. For such events, the operator would take action to reduce the increase in coolant inventory. As the pressurizer water level would increase above the high pressurizer water level that normally isolates chemical and volume control system makeup, the normal letdown line could be placed into service to reduce the increase in coolant inventory. If letdown could not be placed into service, the operator could use the safety related reactor vessel head vent valves to reduce the increase in coolant inventory. For these events, following the procedures outlined in the Emergency Response Guidelines AFR-I.1, there is sufficient time for the operator to mitigate the consequences of this event, and the results of such an event have a greater margin to pressurizer overfill than that presented in this analysis.

15.5.1.4 Conclusions

The results of this analysis show that inadvertent operation of the core makeup tanks during power operation does not adversely affect the core, the reactor coolant system, or the steam system. The PRHR heat removal capacity is such that reactor coolant water is not relieved from the pressurizer safety valves. DNBR always remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values.

15.5.2 Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

15.5.2.1 Identification of Causes and Accident Description

An increase of reactor coolant inventory, which results from addition of cold unborated water to the reactor coolant system, is analyzed in subsection 15.4.6.

In this subsection 15.5.2, the increase of reactor coolant system inventory due to the addition of borated water is analyzed.

The increase of reactor coolant system coolant inventory may be due to the spurious operation of one or both of the chemical and volume control system pumps or by the closure of the letdown path. If the chemical and volume control system is injecting highly borated water into the reactor coolant system, the reactor experiences a negative reactivity excursion due to the injected boron, causing a decrease in reactor power and subsequent coolant shrinkage. The load decreases due to the effect of reduced steam pressure after the turbine throttle valve fully opens.

At high chemical and volume control system boron concentration, low reactivity feedback conditions, and reactor in manual rod control, an “S” signal will be generated by either the low T_{cold} or low steamline pressure setpoints before the chemical and volume control system can inject a significant amount of water into the reactor coolant system. In this case, the chemical and volume control system malfunction event proceeds similarly to, and is only slightly more limiting than, a spurious “S” signal event. If the automatic rod control is modeled and the pressurizer spray functions properly to prevent a high pressure reactor trip signal, no “S” signals are generated and this specific event is terminated by automatic isolation of the chemical and volume control system on the safety-related high-2 pressurizer level setpoint.

Under typical operating conditions for the AP1000, the boron concentration of the injected chemical and volume control system water is equal to that of the reactor coolant system. If the chemical and volume control system is functioning in this manner and the pressurizer spray system functions properly to prevent a high pressure reactor trip signal, no "S" signals are generated and this specific event is also terminated by automatic isolation of the chemical and volume control system on the safety-related high-2 pressurizer level setpoint.

While these scenarios are the most probable outcomes of a chemical and volume control system malfunction, several combinations of boron concentration, feedback conditions, and plant system interactions have been identified which can result in more limiting scenarios with respect to pressurizer overfill. The key factors that make this event more limiting than a spurious "S" signal event are that the reactor coolant system is at a lower average temperature, higher pressure, and a higher pressurizer level at the time an "S" signal is generated. These factors produce a greater volume of higher density water and, thus, a larger reactor coolant system mass at the time of the "S" signal. In addition, at lower reactor coolant system average temperature, the PRHR is less effective in removing decay heat, which results in greater expansion of the cold water injected by the core makeup tanks.

The limiting analysis scenario minimizes reactor coolant system average temperature, maximizes reactor coolant system mass, and maximizes pressurizer water volume at the time of an "S" signal. This scenario is as follows:

- Both of the chemical and volume control system pumps spuriously begin delivering flow at a boron concentration slightly higher than that of the reactor coolant system. (Assuming that a chemical and volume control system malfunction results in both chemical and volume control system pumps delivering flow is a conservative assumption. One chemical and volume control system pump is automatically controlled and one is manually controlled.)

- The nonsafety-related pressurizer spray is assumed to be available, so that a high pressurizer pressure reactor trip is prevented.

Due to the boron addition in the core, the plant cools down until an "S" signal is generated on low cold leg temperature. On the "S" signal, the reactor is tripped, the reactor coolant pumps are tripped, the pressurizer heaters are blocked, and the main feedwater lines, steam lines, and chemical and volume control system are isolated. After a conservative 17-second delay, the PRHR heat exchanger is actuated and the core makeup tank discharge valves are opened.

Normally, the reactor coolant pumps would be tripped 15 seconds after the receipt of the "S" signal. However, to meet the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of reactor trip. The primary effect of this assumption is the coastdown of the reactor coolant pumps. Immediately following reactor trip, the turbine is tripped, and after a 3-second delay, a consequential loss of offsite power is assumed. The basis for the 3-second delay is described in subsection 15.0.14. As a result, the reactor coolant pumps are conservatively assumed to trip about 10 seconds before they would otherwise trip due to the "S" signal.

This event is a Condition II incident (a fault of moderate frequency) as defined in subsection 15.0.1.

15.5.2.2 Analysis of Effects and Consequences

The malfunction of the chemical and volume control system is analyzed by using a modified version of the computer program LOFTRAN (Reference 1). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, PRHR heat exchanger, and core makeup tank. The program computes pertinent plant variables including temperatures, pressures, and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits. The PRHR heat exchanger removes the long-term decay heat to prevent possible reactor coolant system overpressurization or loss of reactor coolant system water.

Using an iterative analysis process, the boron concentration is chosen such that this limiting case bounds the cases that model explicit operator action 30 minutes after the reactor trip.

The assumptions are as follows:

- Initial operating conditions

  The initial reactor power is assumed to be 102 percent of nominal. The initial pressurizer pressure is assumed to be 50 psi above nominal. The initial reactor coolant system average temperature is assumed to be 6.5°F above nominal.

- Moderator and Doppler coefficients of reactivity

  A least-negative moderator temperature coefficient, a low (absolute value) Doppler power coefficient, and a maximum boron worth are assumed. For a different set of reactivity feedback parameters, a different chemical and volume control system boron concentration can result in an identical transient.

- Reactor control

  Rod control is not modeled.

- Pressurizer heaters

  The pressurizer heaters are automatically blocked on an “S” signal, and do not add heat to the system during the period of fluid thermal expansion that produces the peak pressurizer water volume. Thus, the pressurizer heaters are assumed to be inoperable during this event.

- Pressurizer spray

  The spray system controls the pressurizer pressure so that a high pressurizer pressure reactor trip is prevented.

- Boron injection

  After 10 seconds at steady state, the chemical and volume control system pumps start injecting borated water, which is slightly above the reactor coolant system boron concentration. Upon receipt of an “S” signal, the chemical and volume control system pumps are isolated and the core makeup tanks begin injecting 3400 ppm borated water.

- Turbine load

  The turbine load is assumed constant until the governor drives the throttle valve wide open. Then the turbine load drops as steam pressure drops.

- Protection and safety monitoring system actuations

  If the automatic rod control system is modeled and the pressurizer spray system functions properly, no reactor trip signal is expected to occur. Instead, the event is terminated by automatic isolation of the chemical and volume control system on the safety grade high-2 pressurizer level setpoint. If the automatic rod control system is not active and the pressurizer spray system is assumed to be available, reactor trip may be initiated on either low T_{cold} “S” or a low steamline pressure “S” signal.

  The core decay heat is removed by the PRHR heat exchanger. The worst single failure is assumed to occur in the outlet line of the PRHR heat exchanger. One of the two parallel isolation valves is assumed to fail to open.

  Plant systems and equipment available to mitigate the effect of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.5.2.3 Results

Figures 15.5.2-1 through 15.5.2-11 show the transient response to a chemical and volume control system malfunction that results in an increase of reactor coolant system inventory. Neutron flux slowly decreases due to boron injection, but steam flow does not decrease until later in the transient when the turbine throttle valves are wide open.

As the chemical and volume control system injection flow increases reactor coolant system inventory, pressurizer water volume begins increasing while the primary system is cooling down. At about 1,009 seconds, the low T_{cold} setpoint is reached, the reactor trips, and the control rods start moving into the core.

Immediately following reactor trip, the turbine is tripped and after a 3-second delay, a consequential loss of offsite power is assumed and the reactor coolant pumps trip. The basis for the 3-second delay is described in subsection 15.0.14. Soon after reactor trip, the pressurizer heaters are blocked and the main feedwater lines, steam lines, and chemical and volume control system are isolated. After a conservative 17-second delay, the PRHR heat exchanger is actuated and the core makeup tank discharge valves are opened. The core makeup tanks work in

recirculation mode, meaning they are always filled with water because cold borated water injected through the injection lines is replaced by hot water coming from the cold leg balance lines.

The operation of the PRHR heat exchanger and the core makeup tanks cools down the plant. Due to the swelling of the core makeup tank water, the pressurizer level is still increasing. As the reactor coolant system average temperature goes below 490°F, the cooling effect due to the core makeup tanks is decreasing. In this condition, the PRHR heat exchanger cannot remove the entire decay heat. Reactor coolant system temperature tends to increase until an equilibrium between decay heat power and heat absorbed by the PRHR heat exchanger is reached.

When the PRHR heat flux matches the core decay heat, the pressurizer water volume stops increasing, and the pressurizer safety valves close. Then the core makeup tanks essentially stop injecting.

Figure 15.5.2-6 shows the DNBR until the time of reactor coolant pump trip and subsequent flow coastdown due to the loss of offsite power. At this time, core power and heat flux have diminished sufficiently, due to the reactor trip, that DNBR is well above the design limit value defined in Section 4.4.

The calculated sequence of events is shown in Table 15.5-1.

The limiting case presented here bounds all cases that model explicit operator action 30 minutes after reactor trip. For such events, the operator could take action to reduce the increase in coolant inventory. As the pressurizer water level would increase above the high pressurizer water level that normally isolates chemical and volume control system makeup, the normal letdown line could be placed into service to reduce the increase in coolant inventory. If letdown could not be placed into service, the operator would use the safety-related reactor vessel head vent valves to reduce the increase in coolant inventory. For these events, following the procedures outlined in the AP1000 Emergency Response Guidelines AFR-I.1, there is sufficient time for the operator to mitigate the consequences of this event, and the results of such an event have a greater margin to pressurizer overfill than that presented in this analysis.

15.5.2.4 Conclusions

The results of this analysis show that a chemical and volume control system malfunction does not adversely affect the core, the reactor coolant system, or the steam system. The PRHR heat removal capacity is such that reactor coolant water is not relieved from the pressurizer safety valves. DNBR remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values.

If the automatic rod control system and the pressurizer spray systems are assumed to function, no reactor trip signal is expected to occur. Instead, the event is terminated by automatic isolation of the chemical and volume control system on the safety grade high pressurizer level setpoint. If manual rod control is assumed and the pressurizer spray system is assumed to be unavailable, reactor trip may be initiated on either a high pressurizer pressure, low T_{cold} “S”, or a low steamline pressure “S” signal.

15.5.3 Boiling Water Reactor Transients

This subsection is not applicable to the AP1000.

15.5.4 Combined License Information

This subsection has no requirement for additional information to be provided in support of the Combined License application.

15.5.5 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

Table 15.5-1 (Sheet 1 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN AN INCREASE IN REACTOR COOLANT INVENTORY

Accident	Event	Time (seconds)
Inadvertent operation of the core makeup tanks during power operation	Core makeup tank discharge valves open	10
	High-3 pressurizer level setpoint reached	520.7
	Rod motion begins	522.7
	Loss of offsite power	525.4
	Reactor coolant pumps trip	525.4
	High-3 pressurizer level setpoint reached	541.9
	PRHR heat exchanger actuated	573.9
	Pressurizer safety valves open	574.0
	Pressurizer safety valves close	594.0
	Pressurizer safety valves open	1,312
	Pressurizer safety valves close	5,880
	Low T_{cold} “S” setpoint is reached	12,354
	Second CMT starts recirculating	12,361
	First Core makeup tank stops recirculating	13,300
	Main steam and feed lines are isolated	12,366
	Pressurizer safety valves open	14,960
	Pressurizer safety valves close	20,140
	Peak pressurizer water volume occurs	20,480
	PRHR matches decay heat	21,800
	Second Core makeup tank stops recirculating	30,900

Table 15.5-1 (Sheet 2 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN AN INCREASE IN REACTOR COOLANT INVENTORY

Accident	Event	Time (seconds)
Chemical and volume control system malfunction that increases reactor coolant inventory	Chemical and volume control system charging pumps start	10
	Low T_{cold} "S" signal is reached	1,088
	Rod motion begins	1,090
	Loss of offsite power	1,093
	Reactor coolant pumps trip	1,093
	Main steam and feed lines are isolated	1,100
	Chemical and volume control system charging pumps are isolated	1,100
	Core makeup tank discharge valves open	1,100
	PRHR heat exchanger actuated	1,105
	Pressurizer safety valves open	1,424
	PRHR matches decay heat	14,720
	Pressurizer safety valves close	15,088
	Peak pressurizer water volume occurs	15,262
	Core makeup tanks stop recirculating	20,200

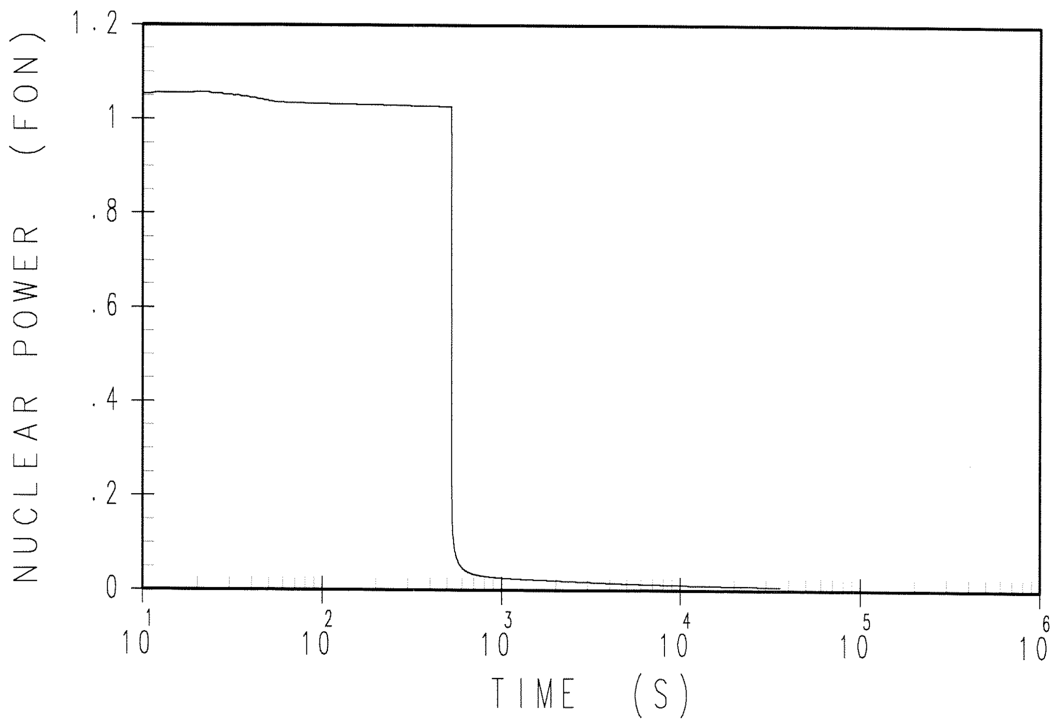

Figure 15.5.1-1

Core Nuclear Power Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

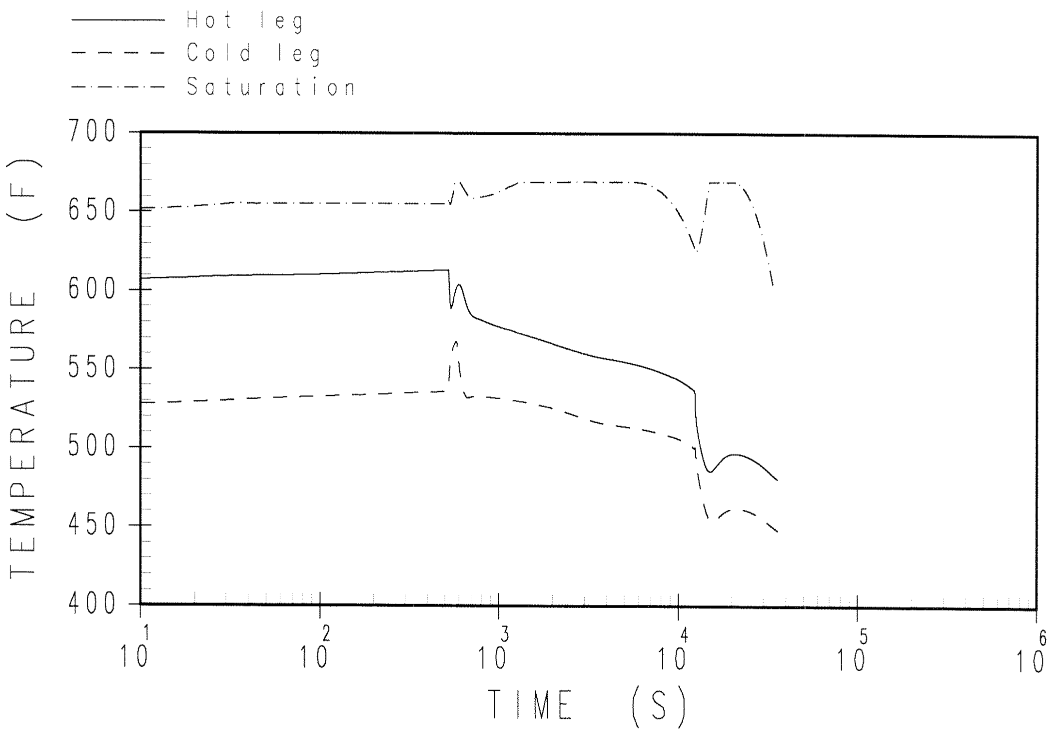

Figure 15.5.1-2

RCS Temperature Transient in Loop Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

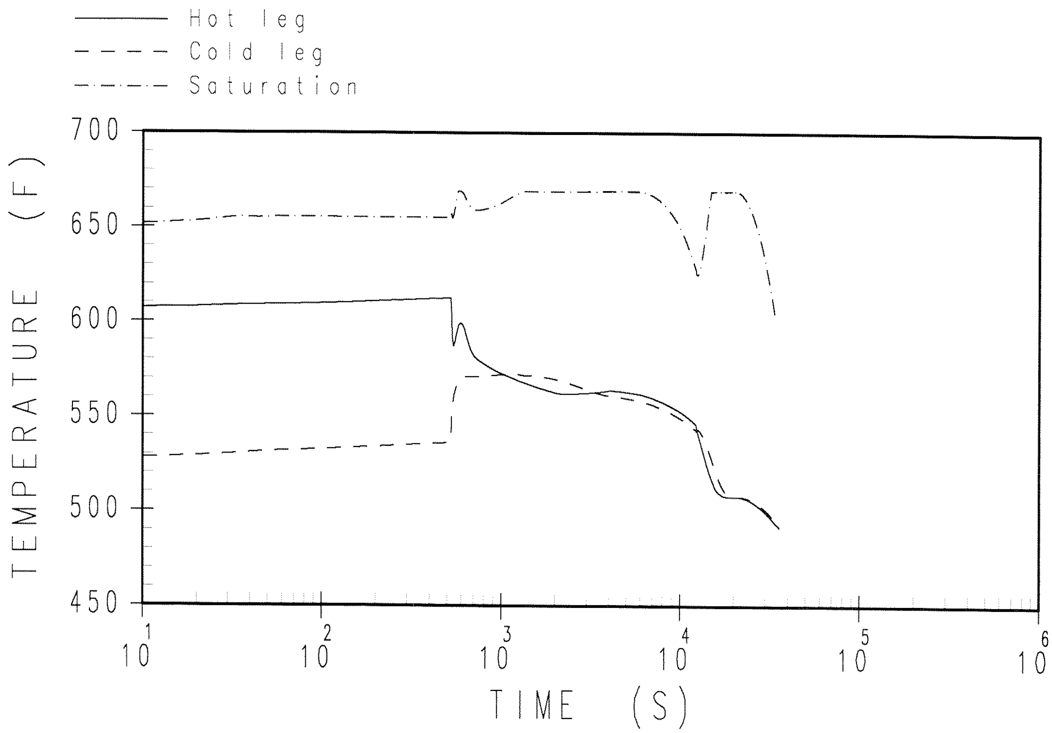

Figure 15.5.1-3

RCS Temperature Transient in Loop Not Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

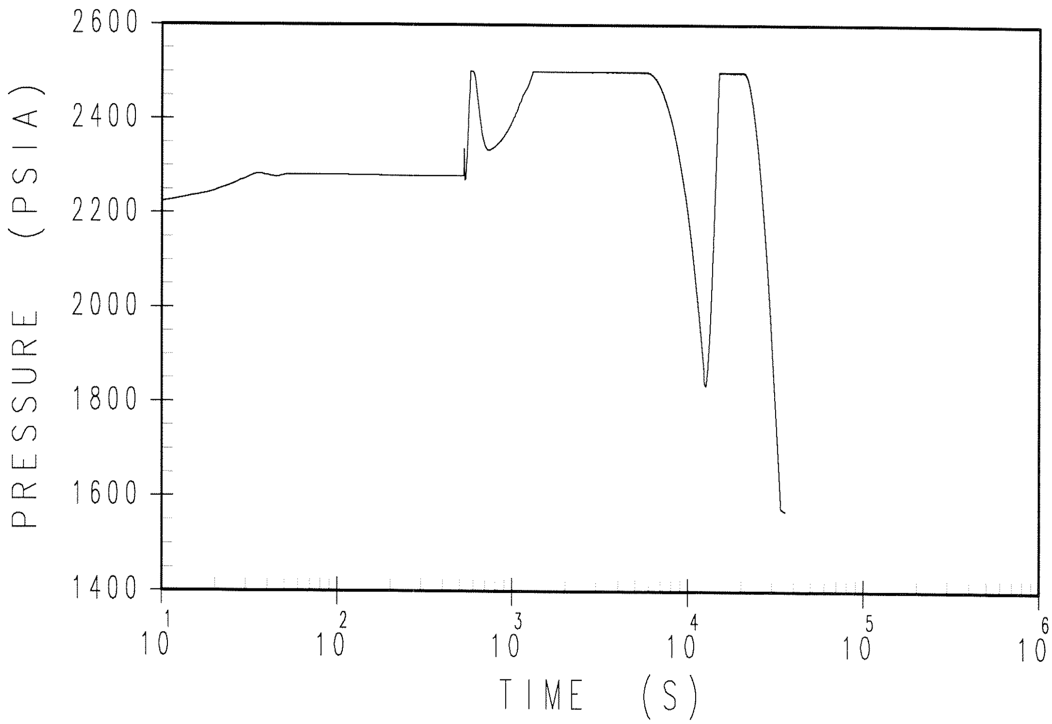

Figure 15.5.1-4

Pressurizer Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

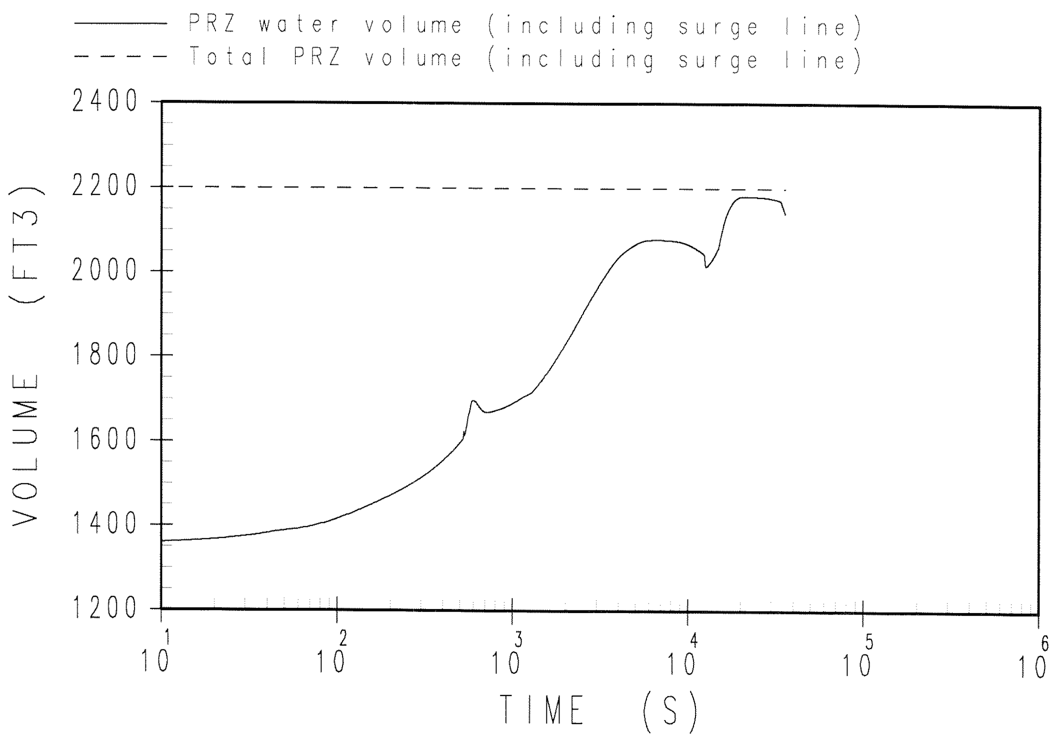

Figure 15.5.1-5

Pressurizer Water Volume Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

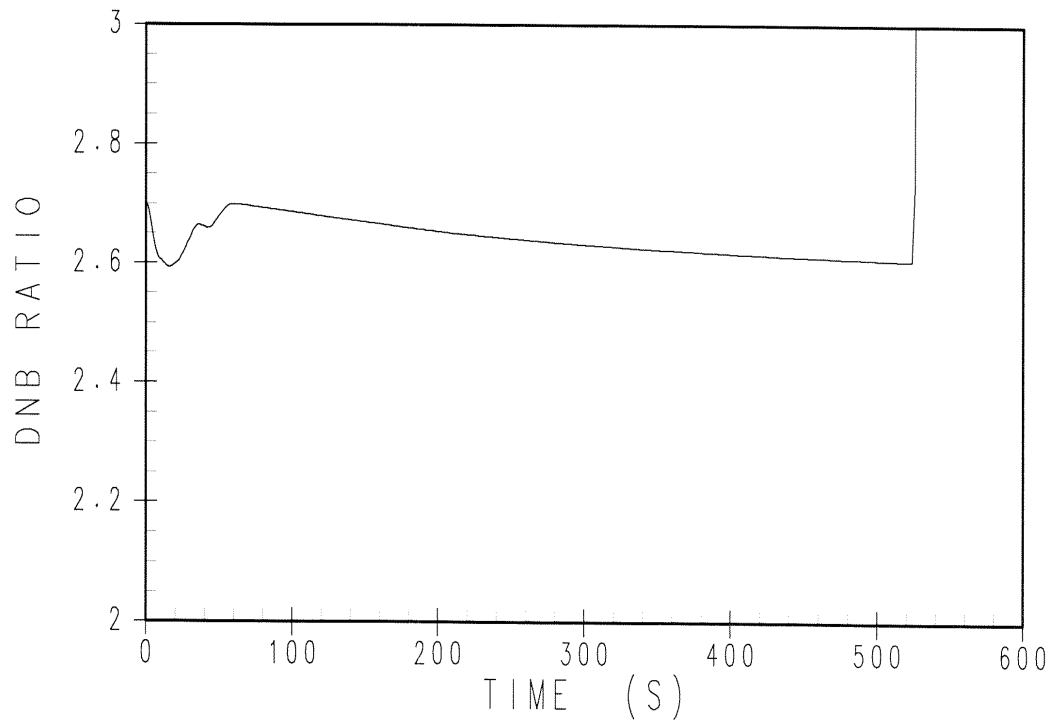

Figure 15.5.1-6

DNBR Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

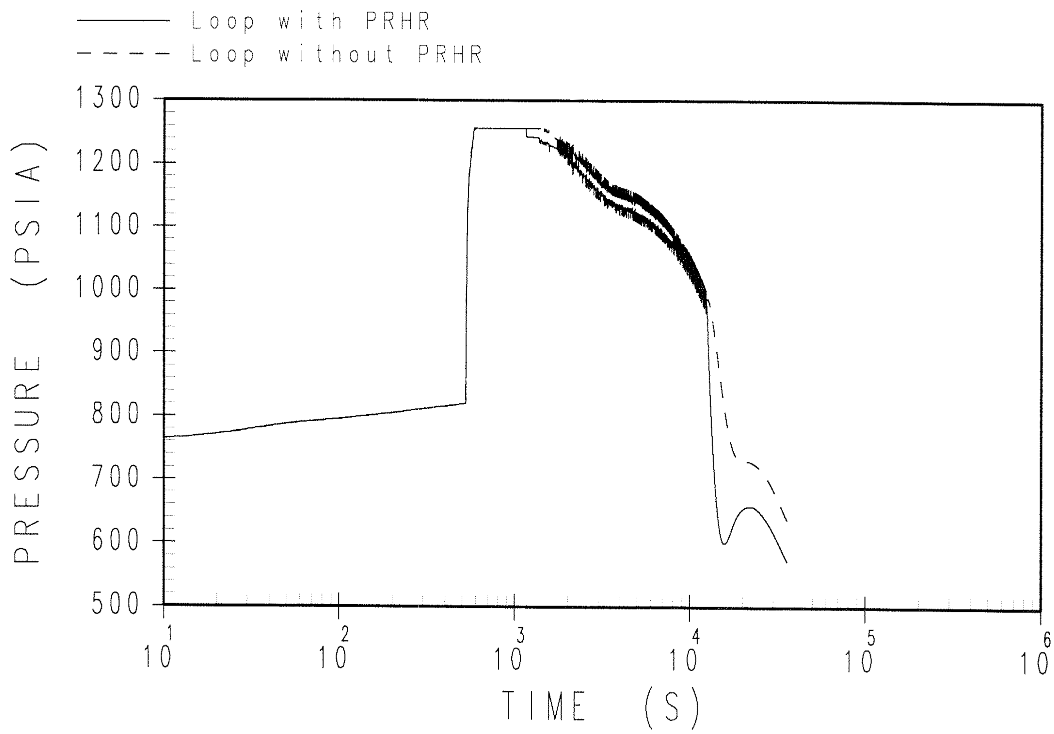

Figure 15.5.1-7

Steam Generator Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

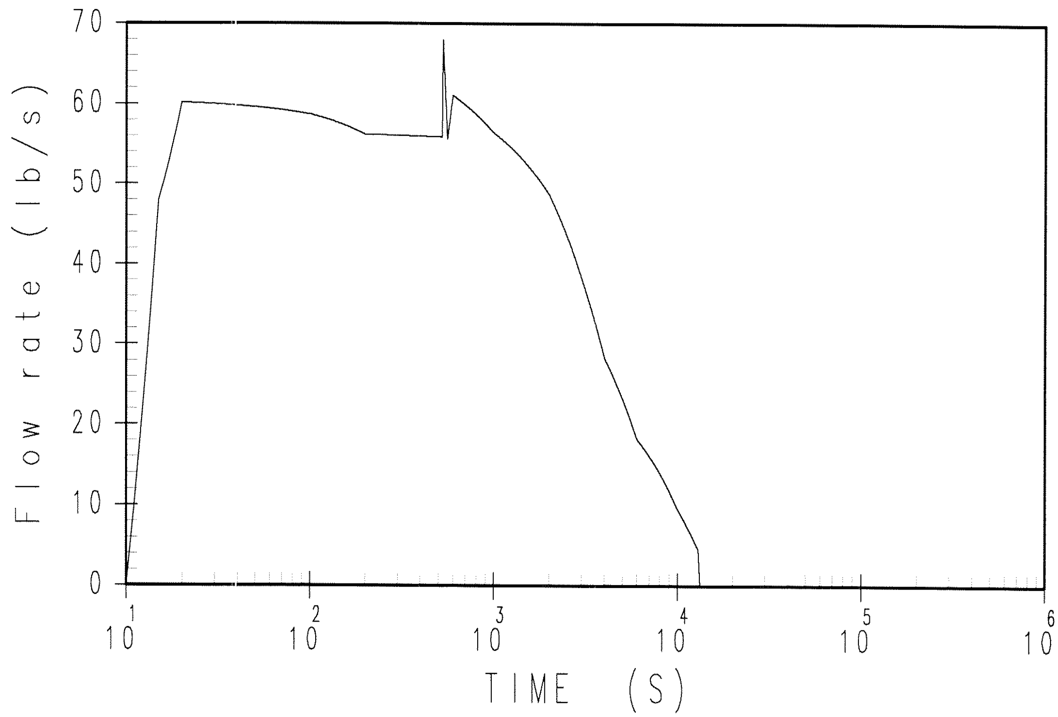

Figure 15.5.1-8

Inadvertent Actuated CMT Flow Rate Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

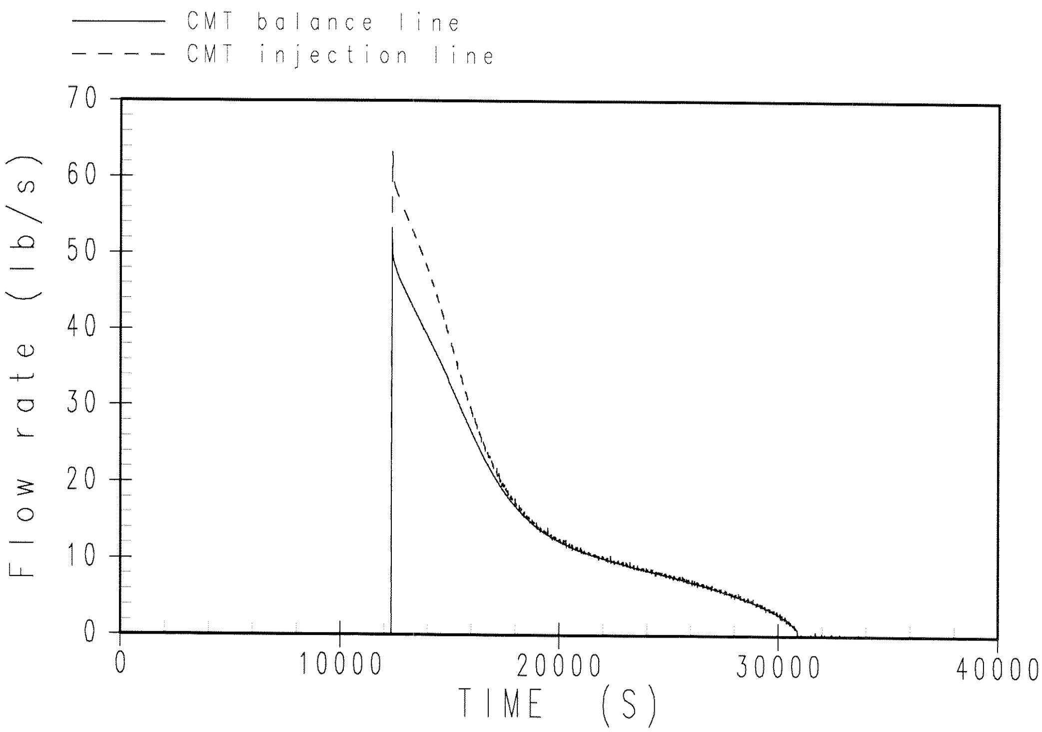

Figure 15.5.1-9

Intact CMT Flow Rate Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

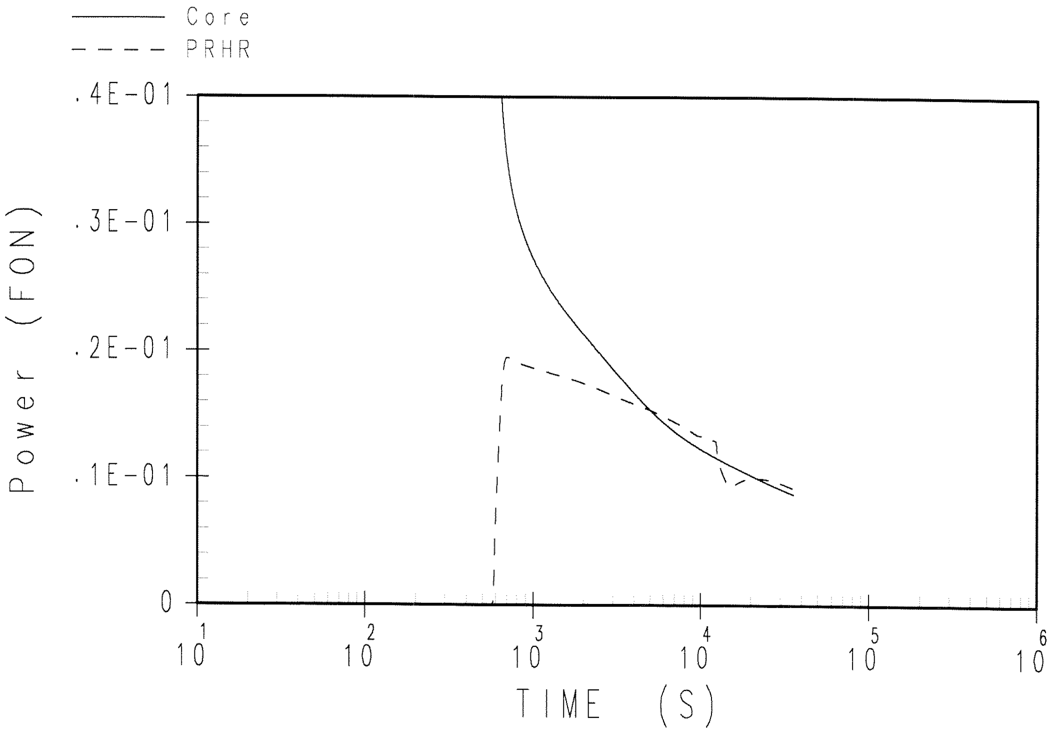

Figure 15.5.1-10

PRHR and Core Heat Flux Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

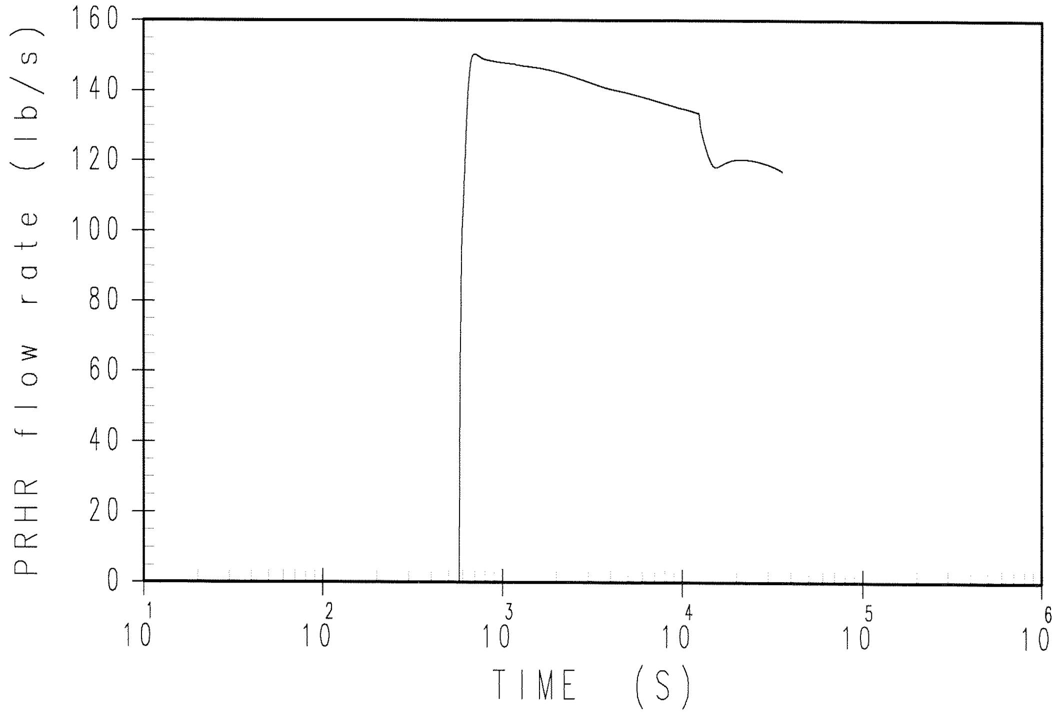

Figure 15.5.1-11

PRHR Flow Rate Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

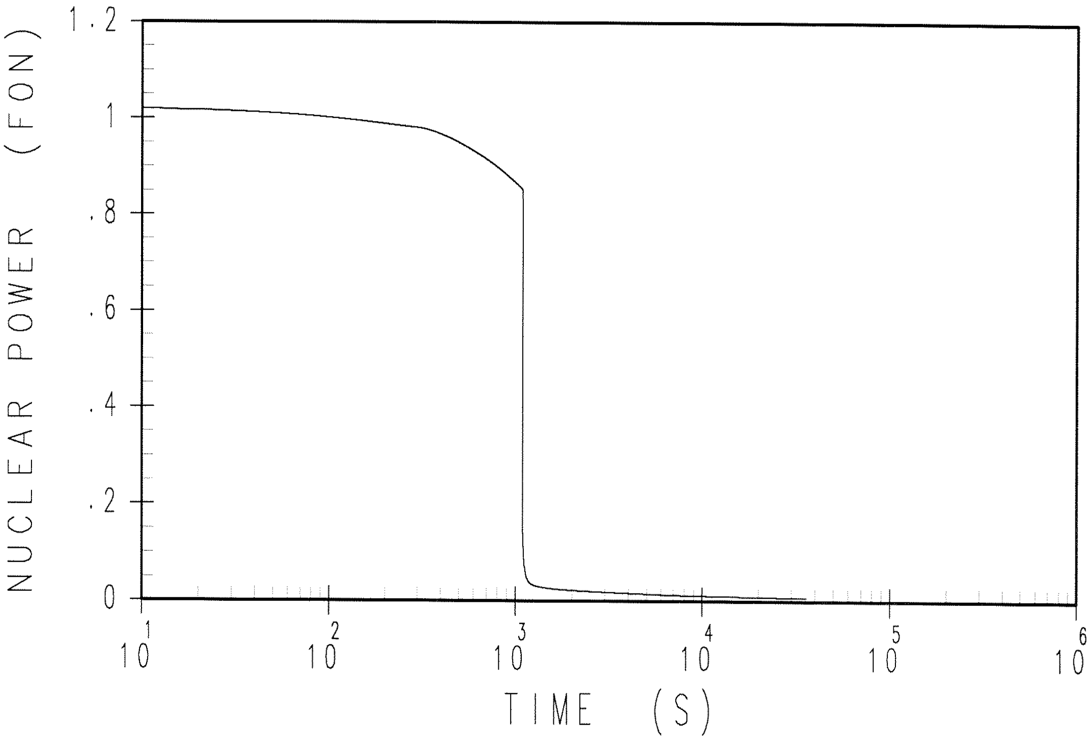

Figure 15.5.2-1

Core Nuclear Power Transient for Chemical and Volume Control System Malfunction

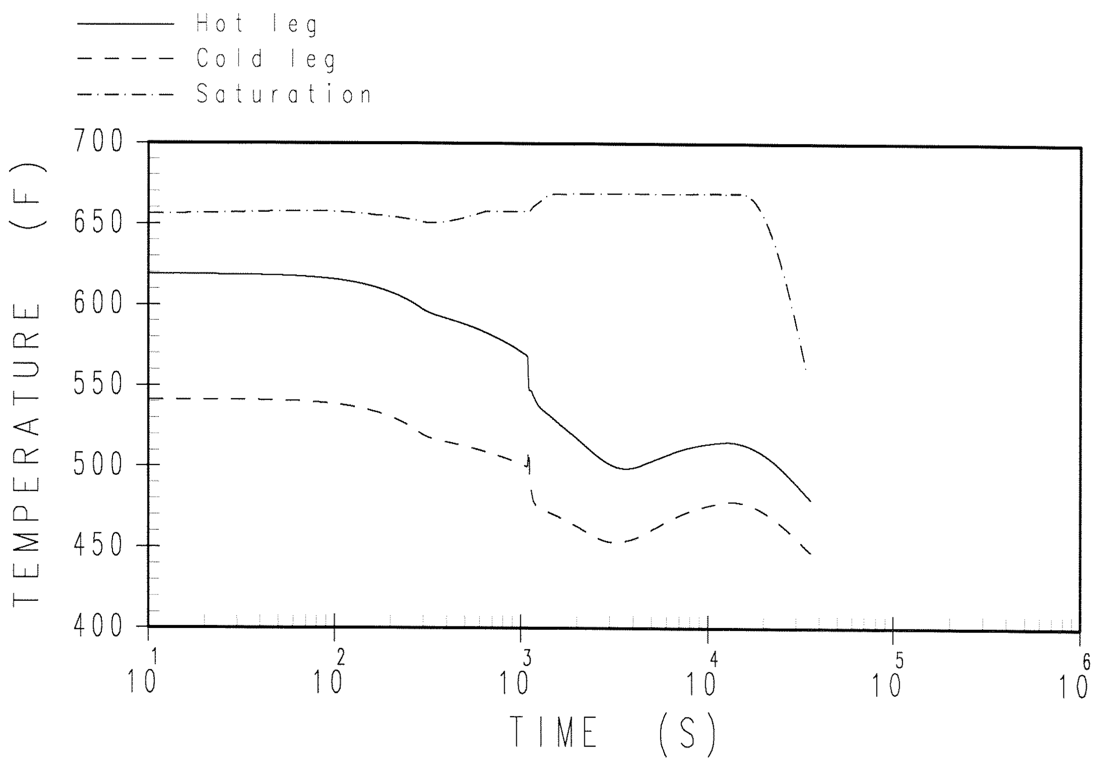

Figure 15.5.2-2

RCS Temperature Transient in Loop Containing the PRHR for Chemical and Volume Control System Malfunction

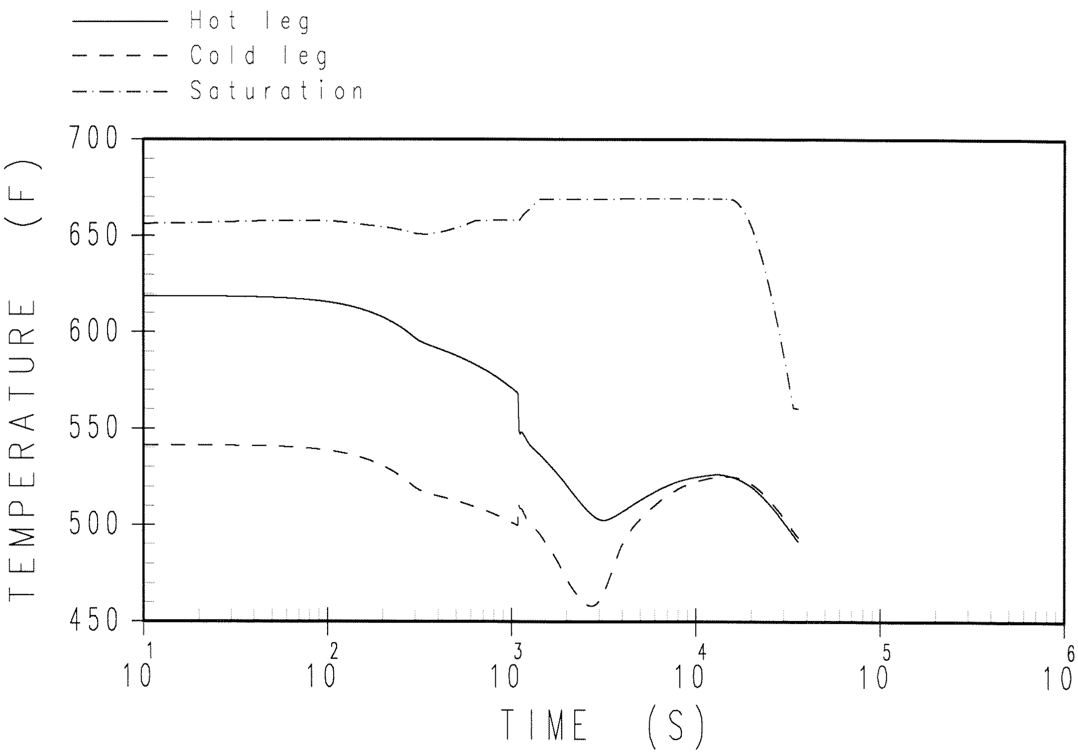

Figure 15.5.2-3

RCS Temperature Transient in Loop Not Containing the PRHR for Chemical and Volume Control System Malfunction

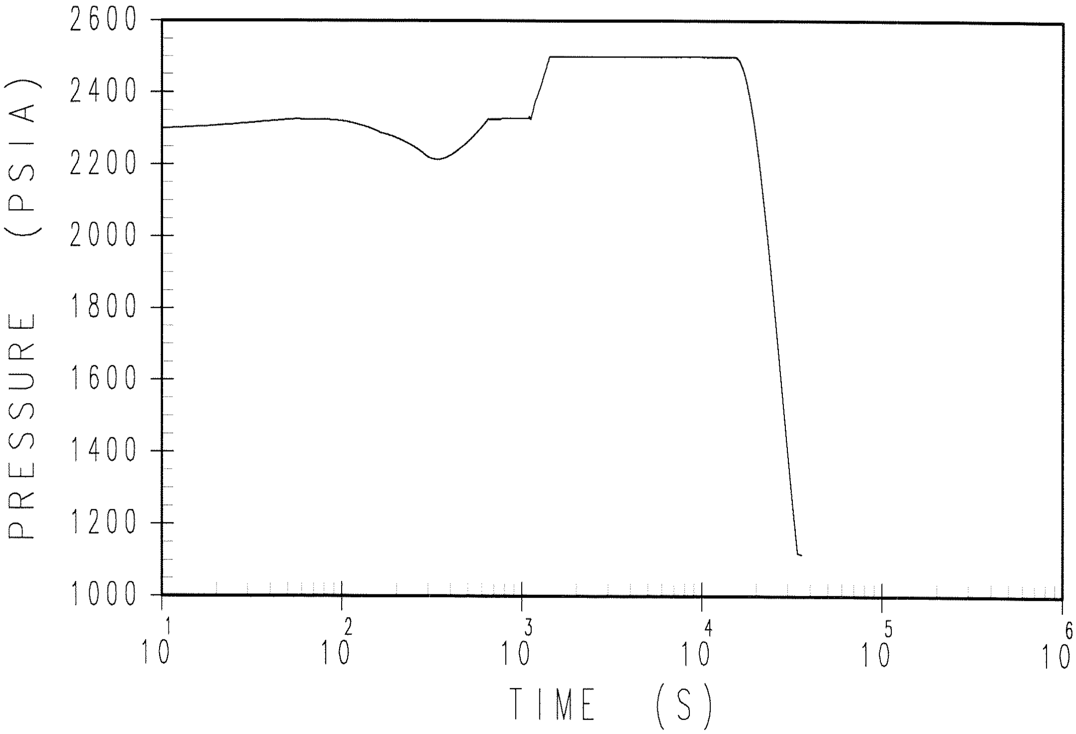

Figure 15.5.2-4

Pressurizer Pressure Transient for Chemical and Volume Control System Malfunction

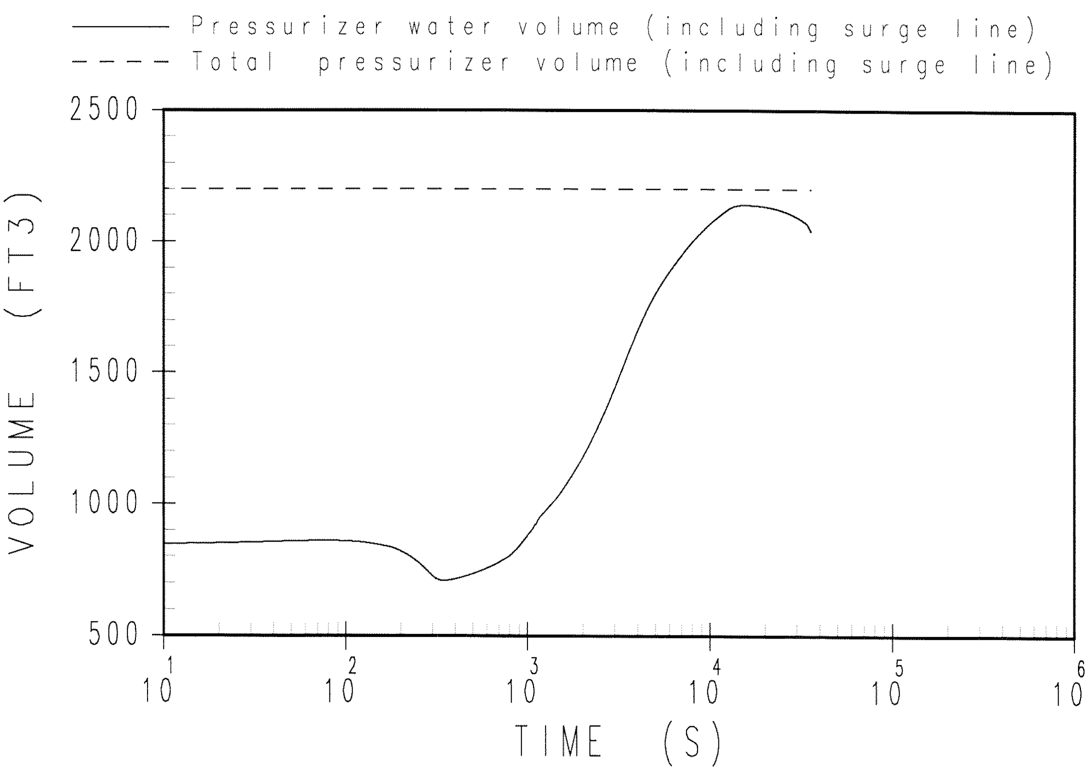

Figure 15.5.2-5

Pressurizer Water Volume Transient for Chemical and Volume Control System Malfunction

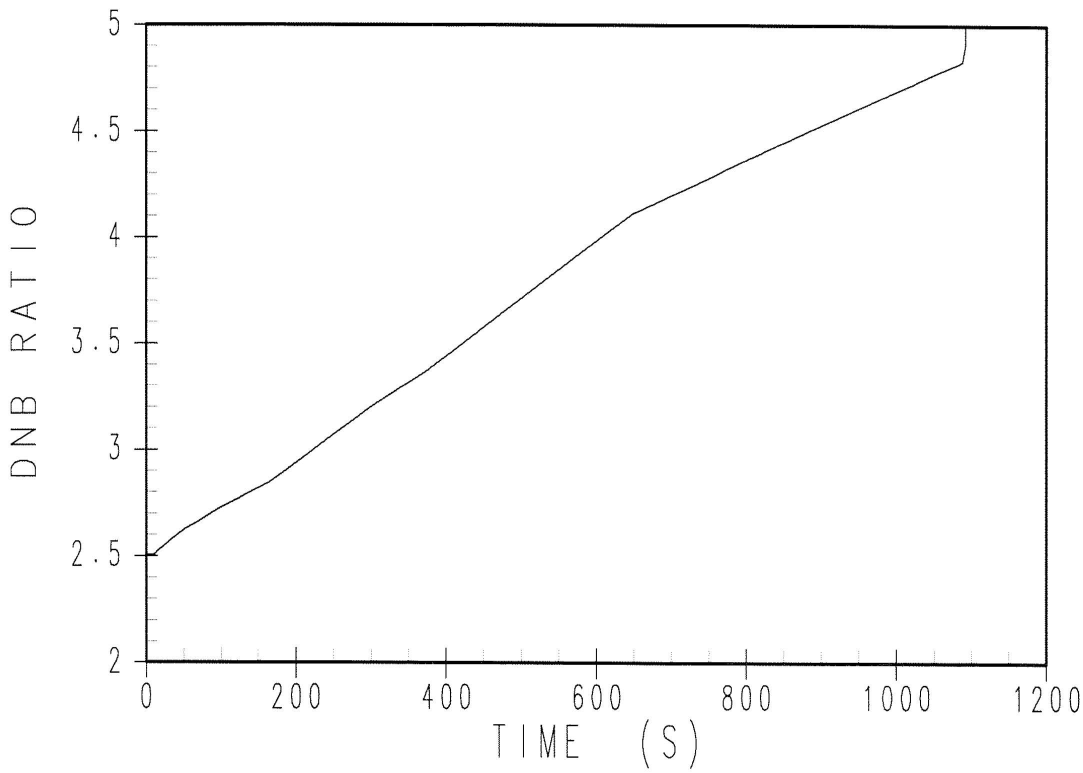

Figure 15.5.2-6

DNBR Transient for Chemical and Volume Control System Malfunction

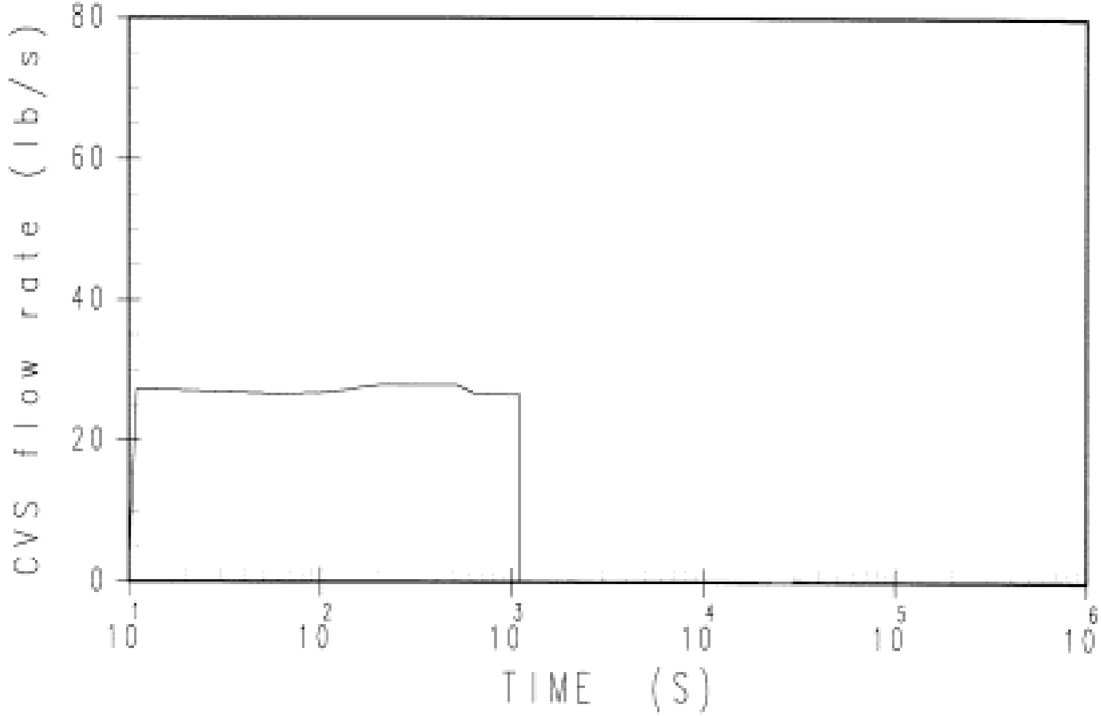

Figure 15.5.2-7

CVS Flow Rate Transient
for Chemical and Volume Control System Malfunction

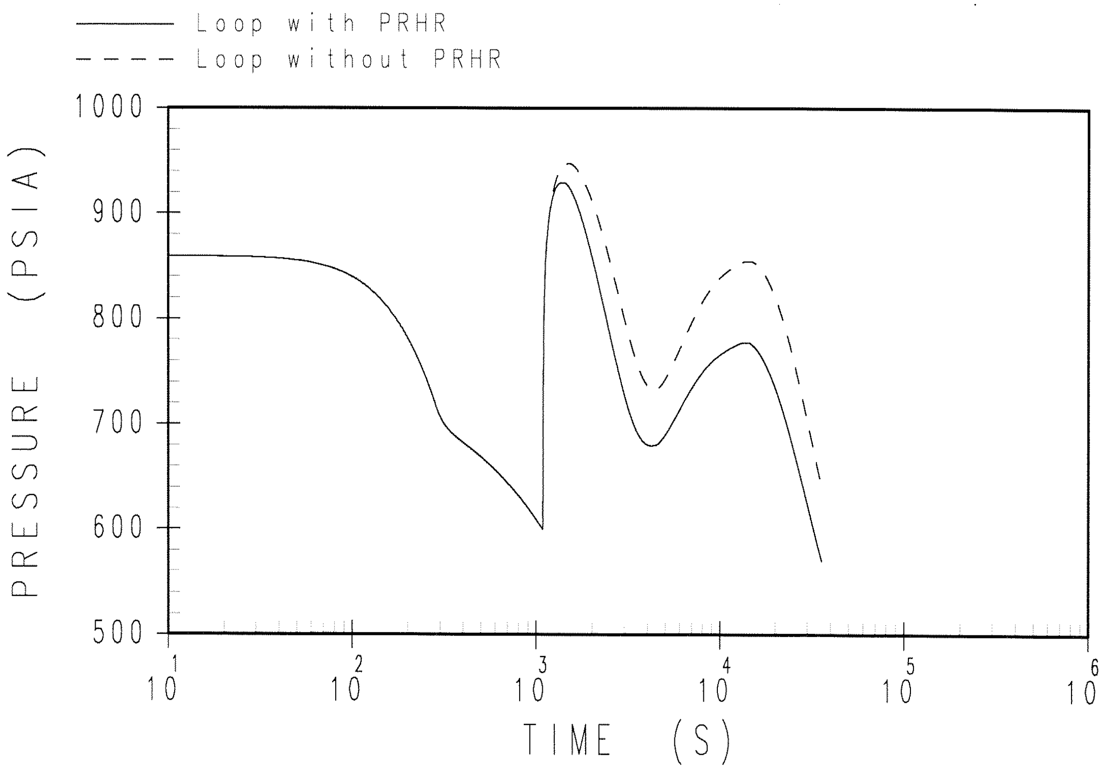

Figure 15.5.2-8

Steam Generator Pressure Transient
for Chemical and Volume Control System Malfunction

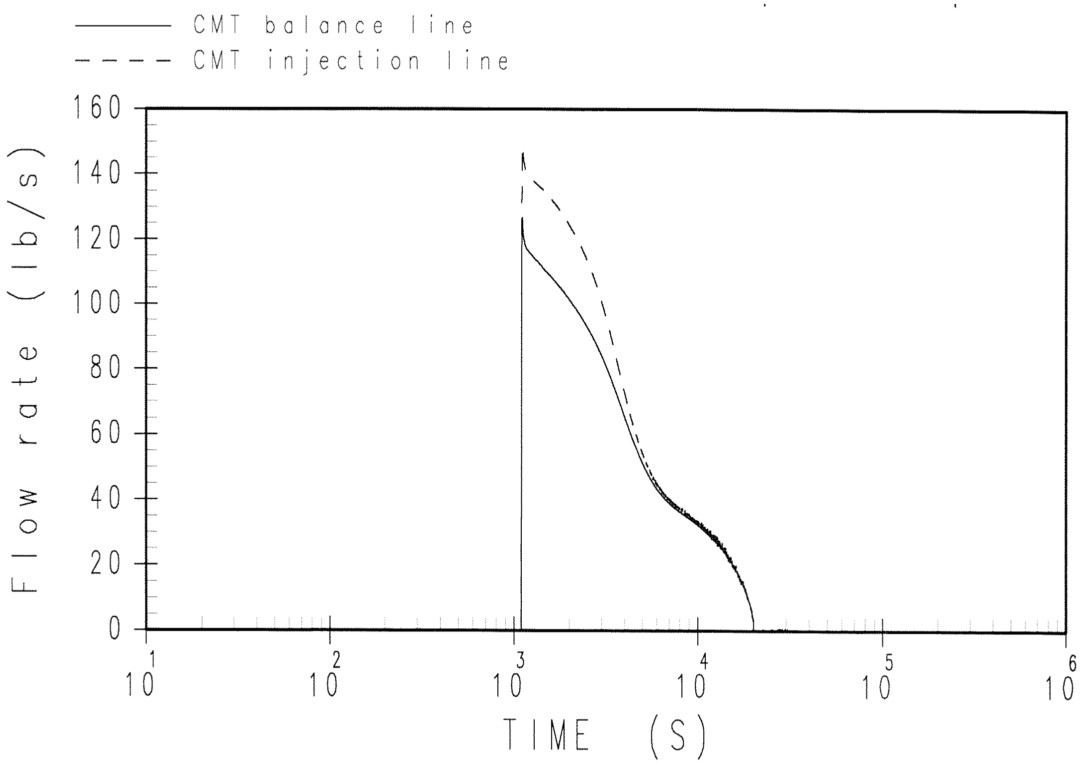

Figure 15.5.2-9

CMT Injection Line and Balance Line Flow Transient for Chemical and Volume Control System Malfunction

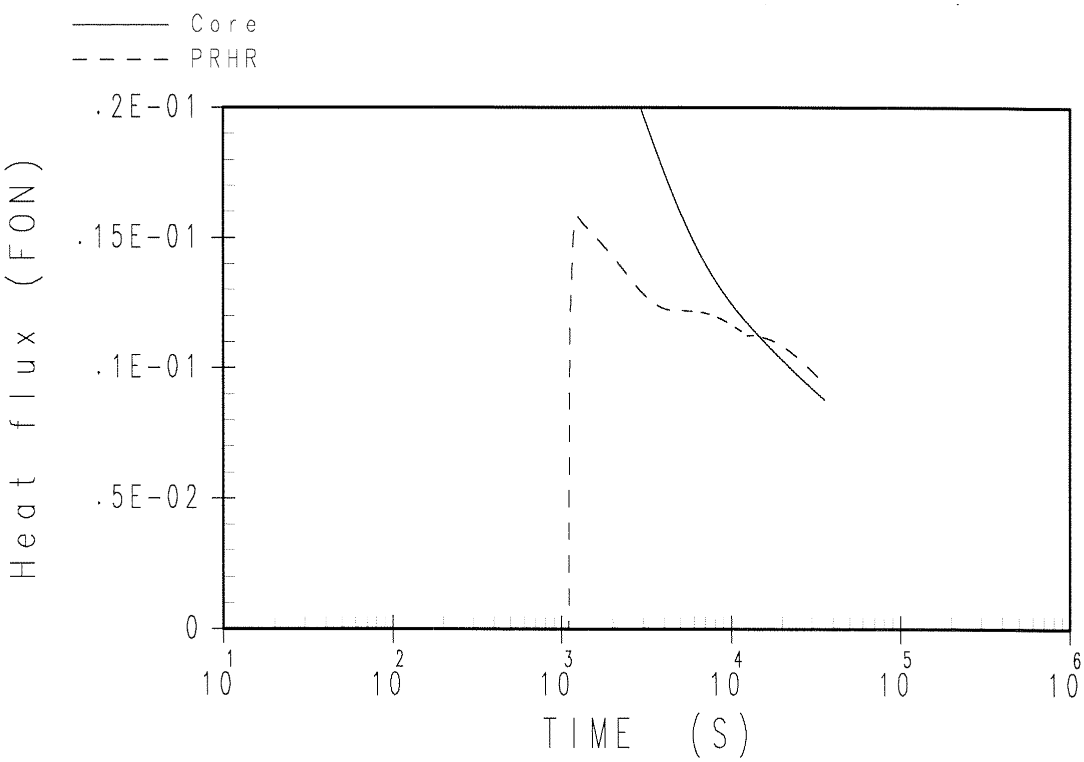

Figure 15.5.2-10

PRHR and Core Heat Flux Transient for Chemical and Volume Control System Malfunction

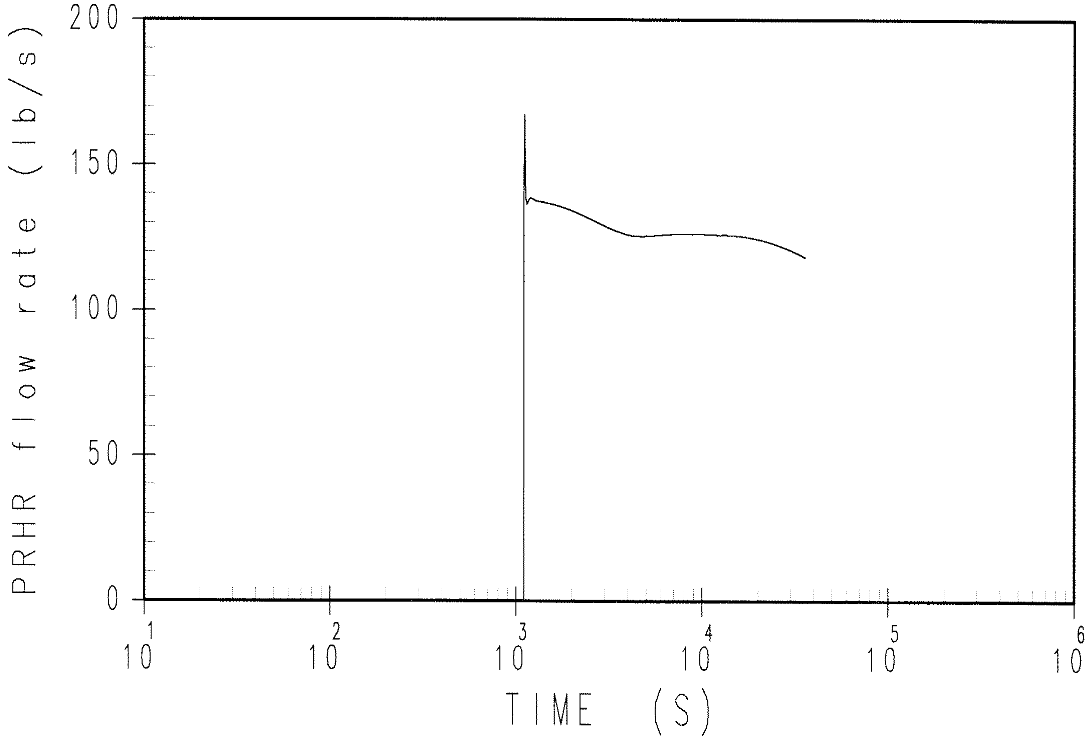

Figure 15.5.2-11

PRHR Flow Rate Transient
for Chemical and Volume Control System Malfunction

15.6 Decrease in Reactor Coolant Inventory

This section discusses the following events that result in a decrease in reactor coolant inventory:

- An inadvertent opening of a pressurizer safety valve or inadvertent operation of the automatic depressurization system (ADS)
- A break in an instrument line or other lines from the reactor coolant pressure boundary that penetrate the containment
- A steam generator tube failure
- A loss-of-coolant accident (LOCA) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary

The applicable accidents in this category have been analyzed. It has been determined that the most severe radiological consequences result from the major LOCA described in subsection 15.6.5. The LOCA, chemical and volume control system letdown line break outside the containment and the steam generator tube rupture (SGTR) accident are analyzed for radiological consequences. Other accidents described in this section are bounded by these accidents.

15.6.1 Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the ADS

15.6.1.1 Identification of Causes and Accident Description

Two types of inadvertent depressurization are discussed in this section. One covers all inadvertent operation of ADS valves. The other covers inadvertent opening of a pressurizer safety valve.

An inadvertent depressurization of the reactor coolant system can occur as a result of an inadvertent opening of a pressurizer safety valve or ADS valves. Initially, the event results in a rapidly decreasing reactor coolant system pressure. The pressure decrease causes a decrease in power via the moderator density feedback. The average coolant temperature decreases slowly, but the pressurizer level increases until reactor trip.

The reactor may be tripped by the following reactor protection system signals:

- Overtemperature ΔT
- Pressurizer low pressure

The ADS is designed such that inadvertent operation of the ADS is classified as a Condition III event, an infrequent fault.

An inadvertent opening of a pressurizer safety valve is a Condition II event, a fault of moderate frequency.

The ADS system consists of four stages of depressurization valves. The ADS stages are interlocked; for example, Stage 1 is initiated first and subsequent stages are not actuated until previous stages have been actuated. Each stage includes two redundant parallel valve paths such

that no single failure prevents operation of the ADS stage when it is called upon to actuate and the spurious opening of a single ADS valve does not initiate ADS flow. To actuate the ADS manually from the main control room, the operators actuate two separate controls positioned at some distance apart on the main control board. Therefore, one unintended operator action does not cause ADS actuation.

ADS Stage 1 has a design opening time of 25 seconds and an effective flow area of 7 in^2 (maximum). ADS Stages 2 and 3 have design opening times of 70 seconds and an effective flow area of 26 in^2 (maximum).

In each ADS path are two valves in series such that no mechanical failure could result in an inadvertent operation of an ADS stage. The ADS Stage 4 squib valves cannot be opened while the reactor coolant system is at nominal operating pressure.

For this analysis, multiple failures and or errors are assumed which actuate both Stage 1 ADS paths. Although ADS Stages 2 and 3 have larger depressurization valves, the opening time of the Stage 1 depressurization valves is faster. This results in the most severe reactor coolant system depressurization due to ADS operation with the reactor at power.

Inadvertent opening of a pressurizer safety valve can only be postulated due to a mechanical failure. Although a pressurizer safety valve is smaller than the combined two Stage 1 ADS valves, the pressurizer safety valve is postulated to open in a short time.

Therefore, analyses are presented in this section for the inadvertent opening of a pressurizer safety valve and the inadvertent opening of two paths of Stage 1 of the ADS. These analyses are performed to demonstrate that the departure from nucleate boiling ratio (DNBR) does not decrease below the design limit values (see Section 4.4) while the reactor is at power.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, analyses have been performed to evaluate the effects produced by a possible consequential loss of offsite power during inadvertent reactor coolant system depressurization events. As discussed in subsection 15.0.14, the loss of offsite power is considered as a direct consequence of a turbine trip occurring while the plant is operating at power. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

15.6.1.2 Analysis of Effects and Consequences

15.6.1.2.1 Method of Analysis

The accidental depressurization transient is analyzed by using the computer code LOFTRAN (References 14 and 15). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, main steam isolation valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

For reactor coolant system depressurization analyses that include a primary coolant flow coastdown caused by a consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analyses. First the LOFTRAN code is used to perform the plant

system transient. The FACTRAN code (Reference 18) is then used to calculate the core heat flux based on nuclear power and reactor coolant flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR using heat flux from FACTRAN and flow from LOFTRAN.

Plant characteristics and initial conditions are discussed in subsection 15.0.3. The following assumptions are made to give conservative results in calculating the DNBR during the transient:

- Initial conditions are discussed in subsection 15.0.3. Uncertainties in initial conditions are included in the DNBR limit as discussed in WCAP-11397-P-A (Reference 16).

- A least negative moderator temperature coefficient is assumed. The spatial effect of voids resulting from local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

- A large (absolute value) Doppler coefficient of reactivity is used such that the resulting amount of positive feedback is conservatively high to retard any power decrease.

Plant systems and equipment necessary to mitigate the effects of reactor coolant system depressurization are discussed in subsection 15.0.8 and are listed in Table 15.0-6.

Normal reactor control systems are not required to function. The rod control system is assumed to be in the automatic mode to maintain the core at full power until the reactor trip protection function is reached. This is a worst case assumption. The reactor protection system functions to trip the reactor on the appropriate signal. No single active failure prevents the reactor protection system from functioning properly.

15.6.1.2.2 Results

The system response to an inadvertent opening of a pressurizer safety valve is shown in Figures 15.6.1-1 through 15.6.1-5. The figures show the results for cases with and without offsite power available. The calculated sequence of events for both inadvertent opening of a pressurizer safety valve scenarios are shown in Table 15.6.1-1.

A pressurizer safety valve is assumed to step open at the start of the event. The reactor coolant system then depressurizes until the overtemperature ΔT reactor trip setpoint is reached. Figure 15.6.1-3 shows the pressurizer pressure transient.

In the case where offsite power is lost, ac power is assumed to be lost 3 seconds after a turbine trip signal occurs. At this time, the reactor coolant pumps are assumed to start coasting down and reactor coolant system flow begins decreasing (Figure 15.6.1-5). The availability of offsite power has minimal impact on the pressure transient during the period of interest.

Prior to tripping of the reactor, the core power remains relatively constant (Figure 15.6.1-1). The minimum DNBR during the event occurs shortly after the rods begin to be inserted into the core (Figure 15.6.1-2). In the case where offsite power is lost, reactor trip has already been initiated and core heat flux has started decreasing when the reactor coolant system flow reduction starts. The DNBR continues to increase when reactor coolant system flow begins to decrease due to the

loss of offsite power. Therefore, the minimum DNBR occurs at the same time for cases with and without offsite power available. The DNBR remains above the design limit values as discussed in Section 4.4 throughout the transient.

The system response for inadvertent operation of the ADS is shown in Figures 15.6.1-6 through 15.6.1-10. The figures show the results for cases with and without offsite power available. The sequences of events are provided in Table 15.6.1-1. The responses for inadvertent operation of the ADS are very similar to those obtained for inadvertent opening of a pressurizer safety valve.

15.6.1.3 Conclusion

The results of the analysis show that the overtemperature ΔT reactor protection system signal provides adequate protection against the reactor coolant system depressurization events. The calculated DNBR remains above the design limit defined in Section 4.4. The long-term plant responses due to a stuck-open ADS valve or pressurizer safety valve, which cannot be isolated, is bounded by the small-break LOCA analysis.

15.6.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

The small lines carrying primary coolant outside containment are the reactor coolant system sample line and the discharge line from the chemical and volume control system to the liquid radwaste system. These lines are used only periodically. No instrument lines carry primary coolant outside the containment.

When excess primary coolant is generated because of boron dilution operations, the chemical and volume control system purification flow is diverted out of containment to the liquid radwaste system. Before passing outside containment, the flow stream passes through the chemical and volume control system heat exchangers and mixed bed demineralizer. The flow leaving the containment is at a temperature of less than 140°F and has been cleaned by the demineralizer. The flow out a postulated break in this line is limited to the chemical and volume control system purification flow rate of 100 gpm. Considering the low temperature of the flow and the reduced iodine activity because of demineralization, this event is not analyzed. The postulated sample line break is more limiting.

The sample line isolation valves inside and outside containment are open only when sampling. The failure of the sample line is postulated to occur between the isolation valve outside the containment and the sample panel. Because the isolation valves are open only when sampling, the loss of sample flow provides indication of the break to plant personnel. In addition, a break in a sample line results in activity release and a resulting actuation of area and air radiation monitors. The loss of coolant reduces the pressurizer level and creates a demand for makeup to the reactor coolant system. Upon indication of a sample line break, the operator would take action to isolate the break.

The sample line includes a flow restrictor at the point of sample to limit the break flow to less than 130 gpm. The liquid sampling lines are 1/4 inch tubing which further restricts the break flow of a sampling line outside containment. Offsite doses are based on a conservative break flow of 130 gpm with isolation after 30 minutes.

15.6.2.1 Source Term

The only significant radionuclide releases are the iodines and the noble gases. The analysis assumes that the reactor coolant iodine is at the maximum Technical Specification level for continuous operation. In addition, it is assumed that an iodine spike occurs at the time of the accident. The reactor coolant noble gas activities are assumed to be those associated with the design basis fuel defect level.

15.6.2.2 Release Pathway

The reactor coolant that is spilled from the break is assumed to be at high temperature and pressure. A large portion of the flow flashes to steam, and the iodine in the flashed liquid is assumed to become airborne.

The iodine and noble gases are assumed to be released directly to the environment with no credit for depletion, although a large fraction of the airborne iodine is expected to deposit on building surfaces. No credit is assumed for radioactive decay after release.

15.6.2.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.6.2.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.6.2-1.

15.6.2.5 Identification of Conservatisms

The assumptions used contain the following significant conservatisms:

- The reactor coolant activities are based on a fuel defect level of 0.25 percent; whereas, the expected fuel defect level is far less than this (see Section 11.1).
- It is unlikely that the conservatively selected meteorological conditions would be present at the time of the accident.

15.6.2.6 Doses

Using the assumptions from Table 15.6.2-1, the calculated total effective dose equivalent (TEDE) doses are determined to be < 1.7 rem at the exclusion area boundary and < 1.1 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase “a small fraction” is taken as being ten percent or less.

At the time the accident occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose

because pool boiling would not occur until after 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the dose calculated for the small line break outside containment, the resulting total dose remains less than 1.3 rem TEDE.

15.6.3 Steam Generator Tube Rupture

15.6.3.1 Identification of Cause and Accident Description

15.6.3.1.1 Introduction

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited number of defective fuel rods within the allowance of the Technical Specifications. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or a failure of the condenser steam dump, discharge of radioactivity to the atmosphere takes place via the steam generator power-operated relief valves or the safety valves.

The assumption of a complete tube severance is conservative because the steam generator tube material (Alloy 690) is a corrosion-resistant and ductile material. The more probable mode of tube failure is one or more smaller leaks of undetermined origin. Activity in the secondary side is subject to continual surveillance, and an accumulation of such leaks, which exceeds the limits established in the Technical Specifications, is not permitted during operation.

The AP1000 design provides automatic protective actions to mitigate the consequences of an SGTR. The automatic actions include reactor trip, actuation of the passive residual heat removal (PRHR) heat exchanger, initiation of core makeup tank flow, termination of pressurizer heater operation, and isolation of chemical and volume control system flow and startup feedwater flow on high steam generator level. These protective actions result in automatic cooldown and depressurization of the reactor coolant system, termination of the break flow and release of steam to the atmosphere, and long-term maintenance of stable conditions in the reactor coolant system. These protection systems serve to prevent steam generator overfill (see discussion in subsections 15.6.3.1.2 and 15.6.3.1.3) and to maintain offsite radiation doses within the allowable guideline values for a design basis SGTR. The operator may take actions that would provide a more rapid mitigation of the consequences of an SGTR.

Because of the series of alarms described next, the operator can readily determine when an SGTR occurs, identify and isolate the ruptured steam generator, and complete the required recovery actions to stabilize the plant and terminate the primary-to-secondary break flow. The recovery procedures are completed on a time scale that terminates break flow to the secondary system before steam generator overfill occurs and limits the offsite doses to acceptable levels without actuation of the ADS. Indications and controls are provided to enable the operator to carry out these functions.

15.6.3.1.2 Sequence of Events for a Steam Generator Tube Rupture

The following sequence of events occur following an SGTR:

- Pressurizer low pressure and low level alarms are actuated and chemical and volume control system makeup flow and pressurizer heater heat addition starts or increases in an attempt to maintain pressurizer level and pressure. On the secondary side, main feedwater flow to the affected steam generator is reduced because the primary-to-secondary break flow increases steam generator level.

- The condenser air removal discharge radiation monitor, steam generator blowdown radiation monitor, and/or main steam line radiation monitor alarm indicate an increase in radioactivity in the secondary system.

- Continued loss of reactor coolant inventory leads to a reactor trip generated by a low pressurizer pressure or over-temperature ΔT signal. Following reactor trip, the SGTR leads to a decrease in reactor coolant pressure and pressurizer level, counteracted by chemical and volume control system flow and pressurizer heater operation. A safeguards (“S”) signal that provides core makeup tank and PRHR heat exchanger actuation is initiated by low pressurizer pressure or low-2 pressurizer level. The “S” signal automatically terminates the normal feedwater supply and trips the reactor coolant pumps. The power to the pressurizer heaters is also terminated. Startup feedwater flow is initiated on a low steam generator narrow range level signal and controls the steam generator levels to the narrow range low-level setpoint.

- The reactor trip automatically trips the turbine, and if offsite power is available, the steam dump valves open permitting steam dump to the condenser. In the event of a loss of offsite power or loss of the condenser, the steam dump valves automatically close to protect the condenser. The steam generator pressure rapidly increases resulting in steam discharge to the atmosphere through the steam generator power-operated relief valves and/or the safety valves.

- Following reactor trip and core makeup tank and PRHR actuation, the PRHR heat exchanger operation – combined with startup feedwater flow, borated core makeup tank flow, and chemical and volume control system flow – provides a heat sink that absorbs the decay heat. This reduces the amount of steam generated in the steam generators and steam bypass to the condenser. In the case of loss of offsite power, this reduces steam relief to the atmosphere.

- Injection of the chemical and volume control system and core makeup tank flow stabilizes reactor coolant system pressure and pressurizer water level, and the reactor coolant system pressure trends toward an equilibrium value, where the total injected flow rate equals the break flow rate.

15.6.3.1.3 Steam Generator Tube Rupture Automatic Recovery Actions

The AP1000 incorporates several protection system and passive design features that automatically terminate a steam generator tube leak and stabilize the reactor coolant system, in the highly

unlikely event that the operators do not perform recovery actions. Following an SGTR, the injecting chemical and volume control system flow (and pressurizer heater heat addition if the pressure control system is operating) maintains the primary-to-secondary break flow and the ruptured steam generator secondary level increases as break flow accumulates in the steam generator. Eventually, the ruptured steam generator secondary level reaches the high-2 steam generator narrow range level setpoint, which is near the top of the narrow range level span.

The AP1000 protection system automatically provides several safety-related actions to cool down and depressurize the reactor coolant system, terminate the break flow and steam release to the atmosphere, and stabilize the reactor coolant system in a safe condition. The safety-related actions include initiation of the PRHR system heat exchanger, isolation of the chemical and volume control system pumps and pressurizer heaters, and isolation of the startup feedwater pumps. In addition, the protection and safety monitoring system provides a safety-related signal to trip the redundant, nonsafety related pressurizer heater breakers.

Actuating the PRHR heat exchanger transfers core decay heat to the in-containment reactor water storage tank (IRWST) and initiates a cooldown (and a consequential depressurization) of the reactor coolant system.

Isolation of the chemical and volume control system pumps and pressurizer heaters minimizes the repressurization of the primary system. This allows primary pressure to equilibrate with the secondary pressure, which effectively terminates the primary-to-secondary break flow. Because the core makeup tank continues to inject when needed to provide boration following isolation of the chemical and volume control system pumps, isolating the chemical and volume control system pumps does not present a safety concern.

Isolation of the startup feedwater provides protection against a failure of the startup feedwater control system, which could potentially result in the ruptured steam generator being overfilled.

With decay heat removal by the PRHR heat exchanger, steam generator steaming through the power-operated relief valves ceases and steam generator secondary level is maintained.

15.6.3.1.4 Steam Generator Tube Rupture Assuming Operator Recovery Actions

In the event of an SGTR, the operators can diagnose the accident and perform recovery actions to stabilize the plant, terminate the primary-to-secondary leakage, and proceed with orderly shutdown of the reactor before actuation of the automatic protection systems. The operator actions for SGTR recovery are provided in the plant emergency operating procedures. The major operator actions include the following:

- Identify the ruptured steam generator – The ruptured steam generator can be identified by an unexpected increase in steam generator narrow range level or a high radiation indication from any main steam line monitor, steam generator blowdown line monitor, or steam generator sample.

- Isolate the ruptured steam generator – Once the steam generator with the ruptured tube is identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured steam generator.

- Cooldown of the reactor coolant system using the intact steam generator or the PRHR system – After isolation of the ruptured steam generator, the reactor coolant system is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured steam generator pressure. This provides adequate subcooling in the reactor coolant system after depressurization of the reactor coolant system to the ruptured steam generator pressure in subsequent actions.

- Depressurize the reactor coolant system to restore reactor coolant inventory – When the cooldown is completed, the chemical and volume control system and core makeup tank injection flow increases the reactor coolant system pressure until break flow matches the total injection flow. Consequently, these flows must be terminated or controlled to stop primary-to-secondary leakage. However, adequate reactor coolant inventory must first be provided. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after the injection flow is stopped.

Because leakage from the primary side continues after the injection flow is stopped, until reactor coolant system and ruptured steam generator pressures equalize, the reactor coolant system is depressurized to provide sufficient inventory to verify that the pressurizer level remains on span after the pressures equalize.

- Termination of the injection flow to stop primary to secondary leakage – The previous actions establish adequate reactor coolant system subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to verify that injection flow is no longer needed. When these actions are completed, core makeup tank and chemical and volume control system flow is stopped to terminate primary-to-secondary leakage. Primary-to-secondary leakage continues after the injection flow is stopped until the reactor coolant system and ruptured steam generator pressures equalize. Chemical and volume control system makeup flow, letdown, pressurizer heaters, and decay heat removal via the intact steam generator or the PRHR heat exchanger are then controlled to prevent repressurization of the reactor coolant system and reinitiation of leakage into the ruptured steam generator.

Following the injection flow termination, the plant conditions stabilize and the primary-to-secondary break flow terminates. At this time, a series of operator actions is performed to prepare the plant for cooldown to cold shutdown conditions. The actions taken depend on the available plant systems and the plan for further plant repair and operation.

15.6.3.2 Analysis of Effects and Consequences

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. An analysis is performed to demonstrate that the offsite radiological consequences resulting from an SGTR are within the allowable guidelines.

One of the concerns for an SGTR is the possibility of steam generator overfill because this can potentially result in a significant increase in the offsite radiological consequences. Automatic protection and passive design features are incorporated into the AP1000 design to automatically terminate the break flow to prevent overfill during an SGTR. These features include actuation of

the PRHR system, isolation of chemical and volume control system flow, and isolation of startup feedwater.

An analysis is performed, without modeling expected operator actions to isolate the ruptured steam generator and cool down and depressurize the reactor coolant system, to demonstrate the role that the AP1000 design features have in preventing steam generator overfill. The limiting single failure for the overfill analysis is assumed to be the failure of the startup feedwater control valve to throttle flow when nominal steam generator level is reached. Other conservative assumptions that maximize steam generator secondary volume (such as high initial steam generator level, minimum initial reactor coolant system pressure, loss of offsite power, maximum chemical and volume control system injection flow, maximum pressurizer heater addition, maximum startup feedwater flow, and minimum startup feedwater delay time) are also assumed.

The results of this analysis demonstrate the effectiveness of the AP1000 protection system and passive system design features and support the conclusion that an SGTR event would not result in steam generator overfill.

For determining the offsite radiological consequences, an SGTR analysis is performed assuming the limiting single failure and limiting initial conditions relative to offsite doses. Because steam generator overfill is prevented for the AP1000, the results of this analysis represent the limiting radiological consequences for an SGTR.

A thermal-hydraulic analysis is performed to determine the plant response for a design basis SGTR, the integrated primary-to-secondary break flow, and the mass releases from the ruptured and intact steam generators to the condenser and to the atmosphere. This information is then used to calculate the radioactivity release to the environment and the resulting radiological consequences.

15.6.3.2.1 Method of Analysis

15.6.3.2.1.1 Computer Program

The plant response following an SGTR until the primary-to-secondary break flow is terminated is analyzed with the LOFTTR2 program (Reference 21). The LOFTTR2 program is modified to model the PRHR system, core makeup tanks, and protection system actions appropriate for the AP1000. These modifications to LOFTTR2 are described in WCAP-14234, Revision 1 (Reference 14).

15.6.3.2.1.2 Analysis Assumptions

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. The location of the break on the cold leg side of the steam generator results in higher initial primary-to-secondary leakage than a break on the hot side of the steam generator.

The reactor is assumed to be operating at full power at the time of the accident, and the initial secondary mass is assumed to correspond to operation at nominal steam generator mass minus an allowance for uncertainties. Offsite power is assumed to be lost and the rods are assumed to be

inserted at the start of the event because continued operation of the reactor coolant pumps has been determined to reduce flashing of primary-to-secondary break flow and, consequently, lower offsite radiological doses. Maximum chemical and volume control system flows and pressurizer heater heat addition are assumed immediately (even though offsite power is not available) to conservatively maximize primary-to-secondary leakage. The steam dump system is assumed to be inoperable, consistent with the loss of offsite power assumption, because this results in steam release from the steam generator power-operated relief valves to the atmosphere following reactor trip. The chemical and volume control system and pressurizer heater modeling is conservatively chosen to delay the low pressurizer pressure "S" and the low-2 pressurizer level signal and associated protection system actions.

The limiting single failure is assumed to be the failure of the ruptured steam generator power-operated relief valve. Failure of this valve in the open position causes an uncontrolled depressurization of the ruptured steam generator, which increases primary-to-secondary leakage and the mass release to the atmosphere.

It is assumed that the ruptured steam generator power-operated relief valve fails open when the low-2 pressurizer level signal is generated. This results in the maximum integrated flashed primary-to-secondary break flow.

The valve is subsequently isolated when the associated block valve is automatically closed on a low steam line pressure protection system signal.

No operator actions are modeled in this limiting analysis, and the plant protection system provides the protection for the plant. Not modeling operator actions is conservative because the operators are expected to have sufficient time to recover from the accident and supplement the automatic protection system. In particular, the operator would take action to reduce the primary pressure before the high-2 steam generator level chemical and volume control system shutoff signal is generated. It is also expected that the operator can close the block valve to the ruptured steam generator power-operated relief valve in much shorter time than the automatic protection signal. The operators can quickly diagnose a power-operated relief valve failure based on the rapid depressurization of the steam generator and increase in steam flow. They can then close the block valve from the control panel.

Consistent with the assumed loss of offsite power, the main feedwater pumps coast down and no startup feedwater is assumed to conservatively minimize steam generator secondary inventory and thus maximize secondary activity concentration and steam release.

15.6.3.2.1.3 Results

The sequence of events for this transient is presented in Table 15.6.3-1. The system responses to the SGTR accident are shown in Figures 15.6.3-1 to 15.6.3-10.

Offsite power is lost concurrent with the rupture of the tube. The reactor trips due to the loss of offsite power. The main feedwater pumps are assumed to coast down following reactor trip. The startup feedwater pumps are conservatively assumed not to start. Following the tube rupture, reactor coolant flows from the primary into the secondary side of the faulted steam generator. In response to this loss of reactor coolant, pressurizer level and reactor coolant system pressure

decreases as shown in Figures 15.6.3-1 and 15.6.3-2. As a result of the decreasing pressurizer level and pressure, two chemical and volume control system pumps are automatically initiated to provide makeup flow and the pressurizer heaters turn on.

After reactor trip, core power rapidly decreases to decay heat levels and the core inlet to outlet temperature differential decreases. The turbine stop valves close, and steam flow to the turbine is terminated. The steam dump system is conservatively assumed to be inoperable. The secondary side pressure increases rapidly after reactor trip until the steam generator power-operated relief valves (and safety valves, if their setpoints are reached) lift to dissipate the energy, as shown in Figure 15.6.3-3.

Maximum heat addition to the pressurizer from the pressurizer heaters increases the primary pressure.

As the leak flow continues to deplete primary inventory, low pressurizer level “S” and core makeup tank and PRHR actuation signals are reached. Power to the pressurizer heaters is shut off so that they will not provide additional heat to the primary should the pressurizer level return. The ruptured steam generator power-operated relief valve is assumed to fail open at this time.

The failure causes the intact and ruptured steam generators to rapidly depressurize (Figure 15.6.3-3). This results in an initial increase in primary-to-secondary leakage and a decrease in the reactor coolant system temperatures. Both the intact and ruptured steam generators depressurize because the steam generators communicate through the open steam line isolation valves.

The decrease in the reactor coolant system temperature results in a decrease in the pressurizer level and reactor coolant system pressure (Figures 15.6.3-1 and 15.6.3-2). Depressurization of the primary and secondary systems continues until the low steam line pressure setpoint is reached. As a result, the steam line isolation valves and intact and ruptured steam generator power-operated relief block valves are closed.

Following closure of the block valves, the primary and secondary pressures and the ruptured steam generator secondary water volume and mass increase as break flow accumulates. This increase continues until the steam generator secondary level reaches the high-2 narrow range level when the chemical and volume control system pump is isolated.

With continued reactor coolant system cooldown, depressurization provided by the PRHR heat exchanger, and with the chemical and volume control system isolated, primary system pressure eventually falls to match the secondary pressure. The break flow terminates as shown in Figure 15.6.3-5, and the system is stabilized in a safe condition. As shown in Figure 15.6.3-8, steam release through the intact loop, unfaulted power-operated relief valve does not occur following PRHR initiation because the PRHR is capable of removing the core decay heat.

As shown in Figure 15.6.3-9, the core makeup tank flow trends toward zero because the gravity head diminishes as the core makeup tank temperature approaches the reactor coolant system temperature due to the continued balance line flow. The core makeup tank remains full, and ADS actuation does not occur.

The ruptured steam generator water volume is shown in Figure 15.6.3-6. The water volume in the ruptured steam generator when the break flow is terminated is significantly less than the total steam generator volume of 8868 ft^3.

The design basis SGTR event does not result in fuel failures. In the event of an SGTR, the reactor coolant system depressurizes due to the primary-to-secondary leakage through the ruptured steam generator tube. This depressurization reduces the calculated DNBR. The depressurization prior to reactor trip for the SGTR has been compared to the depressurization for the reactor coolant system depressurization accidents analyzed in subsection 15.6.1. The rate of depressurization is much slower for the SGTR than for the reactor coolant system depressurization accidents. Following reactor trip, the DNBR increases rapidly. Thus, the conclusion of subsection 15.6.1, that the calculated DNBR remains above the limit, is extended to the SGTR analysis, justifying the assumption of no failed fuel.

15.6.3.2.1.4 Mass Releases

The mass release of an SGTR event is determined for use in evaluating the exclusion area boundary and low population zone radiation exposure. The steam releases from the ruptured and intact steam generators and the primary-to-secondary leakage into the ruptured steam generator are determined from the LOFTTR2 results for the period from the initiation of the accident until the leakage is terminated.

Following reactor trip, the releases to the atmosphere are through the steam generator power-operated relief valves (and steam generator safety valves for a short period). Steam relief through the power-operated relief valves continues until the PRHR is automatically initiated and core decay heat is transferred to the IRWST. The mass releases for the SGTR event are presented in Table 15.6.3-2.

15.6.3.3 Radiological Consequences

The evaluation of the radiological consequences of the postulated SGTR assumes that the reactor is operating with the design basis fuel defect level (0.25 percent of power produced by fuel rods containing cladding defects) and that leaking steam generator tubes result in a buildup of activity in the secondary coolant.

Following the rupture, any noble gases carried from the primary coolant into the ruptured steam generator via the break flow are released directly to the environment. The iodine and alkali metal activity entering the secondary side is also available for release, with the amount of release dependent on the flashing fraction of the reactor coolant and on the partition coefficient in the steam generator. In addition to the activity released through the ruptured loop, there is also a small amount of activity released through the intact loop.

15.6.3.3.1 Source Term

The significant radionuclide releases from the SGTR are the noble gases, alkali metals and the iodines that become airborne and are released to the environment as a result of the accident.

The analysis considers two different reactor coolant iodine source terms, both of which consider the iodine spiking phenomenon. In one case, the initial iodine concentrations are assumed to be those associated with the equilibrium operating limits for primary coolant iodine activity. The iodine spike is assumed to be initiated by the accident with the spike causing an increasing level of iodine in the reactor coolant.

The second case assumes that the iodine spike occurs before the accident and that the maximum reactor coolant iodine concentration exists at the time the accident occurs.

The reactor coolant noble gas and alkali metal concentrations are assumed to be those associated with the design fuel defect level.

The secondary coolant iodine and alkali metal activity is assumed to be 10 percent of the maximum equilibrium primary coolant activity.

15.6.3.3.2 Release Pathways

The noble gas activity contained in the reactor coolant that leaks into the intact steam generator and enters the ruptured steam generator through the break is assumed to be released immediately as long as a pathway to the environment exists. There are three components to the modeling of iodine and alkali metal releases:

- Intact loop steaming, with credit for partitioning of iodines and alkali metals (includes continued primary-to-secondary leakage at the maximum rate allowable by the Technical Specifications)

- Ruptured loop steaming, with credit for partitioning of iodines and alkali metals (includes modeling of increasing activity in the secondary coolant due to the break flow)

- Release of flashed reactor coolant through the ruptured loop, with no credit for scrubbing (this conservatively assumes that break location is at the top of the tube bundle)

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion of iodines by ground deposition during transport offsite.

15.6.3.3.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.6.3.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.6.3-3.

15.6.3.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of significant conservatisms, such as:

- The reactor coolant activities are based on a fuel defect level of 0.25 percent; whereas, the expected fuel defect level is far less (see Section 11.1).
- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.6.3.3.6 Doses

Using the assumptions from Table 15.6.3-3, the calculated TEDE doses for the case in which the iodine spike is assumed to be initiated by the accident are determined to be less than 0.9 rem at the exclusion area boundary for the limiting 2-hour interval (0-2 hours) and less than 0.8 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A “small fraction” is defined, consistent with the Standard Review Plan, as being ten percent or less.

For the case in which the SGTR is assumed to occur coincident with a pre-existing iodine spike, the TEDE doses are determined to be less than 1.8 rem at the exclusion area boundary for the limiting 2-hour interval (0 to 2 hours) and less than 1.3 rem at the low population zone outer boundary. These doses are within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34.

At the time the accident occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour exclusion area boundary dose because pool boiling would not occur until after 2.0 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the doses calculated for the steam generator tube rupture, the resulting total doses remain as reported above.

15.6.3.4 Conclusions

The results of the SGTR analysis show that the overfill protection logic and the passive system design features provide protection to prevent steam generator overfill. Following an SGTR accident, the operators can identify and isolate the faulted steam generator and complete the required actions to terminate the primary-to-secondary break flow before steam generator overfill or ADS actuation occurs.

Even when no operator actions are assumed, the AP1000 protection system and passive design features initiate automatic actions that can terminate a steam generator tube leak and stabilize the reactor coolant system in a safe condition while preventing steam generator overfill and ADS actuation.

The resulting offsite radiological doses for the limiting case analyzed are within the dose acceptance limits.

15.6.4 Spectrum of Boiling Water Reactor Steam System Piping Failures Outside of Containment

This section is not applicable to the AP1000.

15.6.5 Loss-of-coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

15.6.5.1 Identification of Causes and Frequency Classification

A LOCA is the result of a pipe rupture of the reactor coolant system pressure boundary. For the analyses reported here, a major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0 ft^2. This event is considered a Condition IV event (a limiting fault) because it is not expected to occur during the lifetime of the plant but is postulated as a conservative design basis (see subsection 15.0.1).

A minor pipe break (small break), as considered in this subsection, is defined as a rupture of the reactor coolant pressure boundary (Section 5.2) with a total cross-sectional area less than 1.0 ft^2 in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure. This is considered a Condition III event because it is an infrequent fault that may occur during the life of the plant.

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) as follows:

- The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
- Localized cladding oxidation shall not exceed 17 percent of the total cladding thickness before oxidation.
- The amount of hydrogen generated from fuel element cladding reacting chemically with water or steam shall not exceed 1 percent of the total amount if all metal cladding were to react.
- The core remains amenable to cooling for any calculated change in core geometry.
- The core temperature is maintained at a low value, and decay heat is removed for the extended period of time required by the long-lived radioactivity remaining in the core.

These criteria are established to provide significant margin in emergency core cooling system performance following a LOCA.

For the AP1000, the small breaks (less than 1.0 ft^2) yield results with more margin than large breaks.

15.6.5.2 Basis and Methodology for LOCA Analyses

Should a major break occur, depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure trip setpoint is reached. A safeguards actuation (“S”) signal is generated when the appropriate setpoint is reached. These measures limit the consequences of the accident in two ways:

- Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat. Insertion of control rods to shut down the reactor is neglected in the large-break analysis.
- Injection of borated water provides core cooling and prevents excessive cladding temperatures.

The acceptability of the computer codes approved for AP600 LOCA analyses for the AP1000 application is documented in Reference 24.

15.6.5.2.1 Description of Large-break LOCA Transient

Before the break occurs, the unit is in an equilibrium condition in which the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay stored energy in the fuel, hot internals, and vessel continues to be transferred to the reactor coolant. At the beginning of the blowdown phase, the entire reactor coolant system contains subcooled liquid, which transfers heat from the core by forced convection with some fully developed nucleate boiling. After the break, the core heat transfer is based upon local fluid conditions. Transition boiling and dispersed flow film boiling are the major heat transfer mechanisms.

The heat transfer between the reactor coolant system and the secondary system may be in either direction, depending upon the relative temperatures. In the case of continued heat addition to the secondary, secondary system pressure increases and the main steam safety valves may lift to limit the pressure. The safety injection signal actuates a feedwater isolation signal, which isolates normal feedwater flow by closing the main feedwater isolation valves.

The reactor coolant pumps trip automatically during the accident following an “S” signal. The effects of pump coastdown are included in the blowdown. The blowdown phase of the transient ends when the reactor coolant system pressure (initially assumed at 2250 psia) falls to a value approaching that of the containment atmosphere.

When the “S” signal occurs, the core makeup tank valves in the cold leg pressure balance line are opened. The core makeup tank begins to inject subcooled borated water into the reactor vessel through the direct vessel injection lines.

Subsection 15.6.5.4C presents calculations that show the effective post-LOCA long-term cooling of the AP1000 by passive means.

15.6.5.2.2 Description of Small-break LOCA Transient

The AP1000 includes passive safety features to prevent or minimize core uncovery during small-break LOCAs. The passive safety design approach of the AP1000 is to depressurize the reactor coolant system if the break or leak is greater than the makeup capability of the charging system. By depressurizing the reactor system, large volumes of borated water in the accumulators and in the IRWST become available for cooling the core. This analysis demonstrates that, with a single failure, the passive systems are capable of depressurizing the reactor coolant system while maintaining acceptable core conditions and establishing stable delivery of cooling water from the IRWST.

During a small-break LOCA, the AP1000 reactor coolant system depressurizes to the pressurizer low-pressure setpoint, actuating a reactor trip signal. The passive core cooling system is aligned for delivery following the generation of an “S” signal when the pressurizer low-pressure setpoint is reached. The passive core cooling system includes two core makeup tanks, two accumulators, a large IRWST, and the PRHR heat exchanger.

The core makeup tanks operate at reactor coolant system pressure. They provide high-pressure safety injection in the event of a small-break LOCA. The core makeup tanks share a common discharge line with the accumulators and IRWST; they are filled with borated water to provide core shutdown margin. The injection of the core makeup tanks is provided by gravity head of the colder water in the core makeup tanks. The core makeup tanks are located above the reactor coolant loops, and each is equipped with a pressure balancing line from a cold leg to the top of the tank.

The pressurized accumulators provide additional borated water to the reactor coolant system in the event of a LOCA. Nominally, these 2000-ft^3 tanks are filled with 1700 ft^3 of water and 300 ft^3 of nitrogen at an initial pressure of 700 psig. Once sufficient reactor coolant system depressurization occurs, either as a result of a LOCA or the actuation of the ADS, accumulator injection commences.

The IRWST provides an additional source of water for long-term core cooling. To attain injection from the IRWST, the reactor coolant system pressure must be lowered to approximately 13 psi above containment pressure. For this pressure to be achieved during a small-break LOCA, the ADS system is initiated.

The ADS consists of a series of valves, connected to the pressurizer and hot legs, which provide a phased depressurization of the reactor coolant system. As the reactor system loses inventory through the break, the core makeup tanks provide flow to the reactor vessel. When the level in the core makeup tank drops to the 67.5-percent level, the ADS valves open to accelerate the reactor coolant system depressurization rate. The ADS Stage 1 4-inch valves open at the 67.5-percent level; the 8-inch Stage 2 and the 8-inch Stage 3 valves open in a timed sequence thereafter. The flow from the first three stages of the ADS is discharged into the IRWST through a sparger system. The fourth stages of the ADS are connected to the reactor coolant system hot legs and discharge to containment atmosphere. The ADS Stage 4 valves are activated when the core makeup tank level reaches the 20-percent level.

As the reactor coolant system depressurizes and mass is lost out the break, mass is added to the reactor vessel from the core makeup tanks and the accumulators. When the system is depressurized below the IRWST delivery pressure, flow from the IRWST continues to maintain the core in a coolable state. Calculations described in subsection 15.6.5.4B indicate that acceptable core cooling is provided for the small-break LOCA transients. Subsection 15.6.5.4C calculations show that effective post-LOCA core cooling is provided in the long term by passive means.

15.6.5.3 Radiological Consequences

Although the analysis of the core response during a LOCA (see subsection 15.6.5.4) shows that core integrity is maintained, for the evaluation of the radiological consequences of the accident, it is assumed that major core degradation and melting occur.

The dose calculations take into account the release of activity by way of the containment purge line prior to its isolation near the beginning of the accident and the release of activity resulting from containment leakage. Purge of the containment for hydrogen control is not an intended mode of operation and is not considered in the dose analysis. While the normal residual heat removal system is capable of post-LOCA cooling, it is not a safety-related system and may not be available following the accident. If it is operable, it would be used only if the source term is not far above the normal shutdown primary coolant source term. It is assumed that core cooling is accomplished by the passive core cooling system, which does not pass coolant outside of containment. Thus, there is no recirculation leakage release path to be modeled.

15.6.5.3.1 Source Term

The release of activity to the containment consists of two parts. The initial release is the activity contained in the reactor coolant system. This is followed by the release of core activity.

15.6.5.3.1.1 Primary Coolant Release

The reactor coolant is assumed to have activity levels consistent with operation at the Technical Specification limits of 280 μCi/gm dose equivalent Xe-133 and 1.0 μCi/gm dose equivalent I-131.

Based on NUREG-1465 (Reference 19), for a plant using leak-before-break methodology, the release of coolant into the containment can be assumed to last for 10 minutes. The AP1000 is a leak-before-break plant, and the water in the reactor coolant system is assumed to blow down into the containment over a period of 10 minutes. The flow rate is assumed to be constant over the 10-minute period. As the reactor coolant enters the containment, the noble gases and half of the iodine activity are assumed to be released into the containment atmosphere.

15.6.5.3.1.2 Core Release

The release of activity from the fuel takes place in two stages as summarized in Table 15.6.5-1. First is the gap release which is assumed to occur at the end of the primary coolant release phase (i.e., at ten minutes into the accident) and continue over a period of half an hour. The second stage is that of the in-vessel core melt in which the bulk of the activity releases associated with the

accident occur. The source term model is based on NUREG-1465 and Regulatory Guide 1.183 (Reference 20).

The core fission product inventory at the time of the accident is based on operation near the end of a fuel cycle at 102-percent power and is provided in Table 15A-3 of Appendix 15A. Consistent with NUREG-1465, there are three groups of nuclides considered in the gap activity releases: noble gases, iodines, and alkali metals (cesium and rubidium). For the core melt phase, there are five additional nuclide groups for a total of eight. The five additional nuclide groups are the tellurium group, the noble metals group, the cerium group, the lanthanide group, and barium and strontium. The specific nuclides included in the source term are as shown in Table 15A-3.

Gap Activity Release

Consistent with NUREG-1465 guidance for a plant using leak-before-break methodology, the gap release phase begins after the primary coolant release phase ends at ten minutes and has a duration of 0.5 hour.

In-vessel Core Release

After the gap activity release phase, there is an in-vessel release phase which lasts for 1.3 hours and which releases activity to the containment due to core melting. The fractions of the core activity released to the containment atmosphere during this phase are from NUREG-1465:

Noble gases	0.95
Iodines	0.35
Alkali metals	0.25
Tellurium group	0.05
Noble metals	0.0025
Ba and Sr	0.02
Cerium group	0.0005
Lanthanide group	0.0002

Consistent with NUREG-1465, the releases are assumed to occur at a constant rate over the 1.3-hour phase duration.

15.6.5.3.1.3 Iodine Form

The iodine form is consistent with the NUREG-1465 model. The model shows the iodine to be predominantly in the form of nonvolatile cesium iodide with a small fraction existing as elemental iodine. Additionally, the model assumes that a portion of the elemental iodine reacts with organic materials in the containment to form organic iodine compounds. The resulting iodine species split is as follows:

- Particulate 0.95
- Elemental 0.0485
- Organic 0.0015

If the post-LOCA cooling solution has a pH of less than 6.0, part of the cesium iodide may be converted to the elemental iodine form. The passive core cooling system provides sufficient trisodium phosphate to the post-LOCA cooling solution to maintain the solution pH at 7.0 or greater following a LOCA (see subsection 6.3.2.1.4).

15.6.5.3.2 In-containment Activity Removal Processes

The AP1000 does not include active systems for the removal of activity from the containment atmosphere. The containment atmosphere is depleted of elemental iodine and of particulates as a result of natural processes within the containment.

Elemental iodine is removed by deposition onto surfaces. Particulates are removed by sedimentation, diffusiophoresis (deposition driven by steam condensation), and thermophoresis (deposition driven by heat transfer). No removal of organic iodine is assumed. Appendix 15B provides a discussion of the models and assumptions used in calculating the removal coefficients.

15.6.5.3.3 Release Pathways

The release pathways are the containment purge line and containment leakage. The activity releases are assumed to be ground level releases.

During the initial part of the accident, before the containment is isolated, it is assumed that containment purge is in operation and that activity is released through this pathway until the purge valves are closed. No credit is taken for the filters in the purge exhaust line.

The majority of the releases due to the LOCA are the result of containment leakage. The containment is assumed to leak at its design leak rate for the first 24 hours and at half that rate for the remainder of the analysis period.

15.6.5.3.4 Offsite Dose Calculation Models

The offsite dose calculation models are provided in Appendix 15A. The models address the determination of the TEDE doses from the combined acute doses and the committed effective dose equivalent doses.

The exclusion area boundary dose is calculated for the 2-hour period over which the highest doses would be accrued by an individual located at the exclusion area boundary. Because of the delays associated with the core damage for this accident, the first 2 hours of the accident are not the worst 2-hour interval for accumulating a dose.

The low population zone boundary dose is calculated for the nominal 30-day duration of the accident.

For both the exclusion area boundary and low population zone dose determinations, the calculated doses are compared to the dose guideline of 25 rem TEDE from 10 CFR Part 50.34.

15.6.5.3.5 Main Control Room Dose Model

There are two approaches that may be used for modeling the activity entering the main control room. If power is available, the normal heating, ventilation, and air-conditioning (HVAC) system will switch over to a supplemental filtration mode (Section 9.4). The normal HVAC system is not a safety-class system but provides defense in depth.

Alternatively, if the normal HVAC is inoperable or, if operable, the supplemental filtration train does not function properly resulting in increasing levels of airborne iodine in the main control room, the emergency habitability system (Section 6.4) would be actuated when high iodine activity is detected. The emergency habitability system provides passive pressurization of the main control room from a bottled air supply to prevent inleakage of contaminated air to the main control room. There is a 72-hour supply of air in the emergency habitability system. After this time, the main control room is assumed to be opened and unfiltered air is drawn into the main control room by way of an ancillary fan. After 7 days, offsite support is assumed to be available to reestablish operability of the control room habitability system by replenishing the compressed air supply. As a defense-in-depth measure, the nonsafety-related normal control room HVAC would be brought back into operation with the supplemental filtration train if power is available.

The main control room is accessed by a vestibule entrance, which restricts the volume of contaminated air that can enter the main control room from ingress and egress. The equivalent inflow of unfiltered air due to expected ingress/egress has been determined to be 5.0 cfm.

Activity entering the main control room is assumed to be uniformly dispersed. No credit is taken for the removal of airborne activity in the main control room although elemental iodine and particulates would be removed by deposition and sedimentation.

The main control room dose calculation models are provided in Appendix 15A for the determination of doses resulting from activity which enters the main control room envelope.

15.6.5.3.6 Analytical Assumptions and Parameters

The analytical assumptions and parameters used in the radiological consequences analysis are listed in Table 15.6.5-2.

15.6.5.3.7 Identification of Conservatisms

The LOCA radiological consequences analysis assumptions include a number of conservatisms. Some of these conservatisms are discussed in the following subsections.

15.6.5.3.7.1 Primary Coolant Source Term

The source term is based on operation with the design fuel defect level of 0.25 percent; whereas, the expected fuel defect level is far less.

15.6.5.3.7.2 Core Release Source Term

The assumed core melt is a major conservatism associated with the analysis. In the event of a postulated LOCA, no major core damage is expected. Release of activity from the core is limited to a fraction of the core gap activity.

15.6.5.3.7.3 Atmospheric Dispersion Factors

The atmospheric dispersion factors assumed to be present during the course of the accident are conservatively selected. Actual meteorological conditions are expected to result in significantly higher dispersion of the released activity.

15.6.5.3.8 LOCA Doses

15.6.5.3.8.1 Offsite Doses

The doses calculated for the exclusion area boundary and the low population zone boundary are listed in Table 15.6.5-3. The doses are within the 10 CFR 50.34 dose guideline of 25 rem TEDE.

The reported exclusion area boundary doses are for the time period of 1.4 to 3.4 hours. This is the 2-hour interval that has the highest calculated doses. The dose that would be incurred over the first 2 hours of the accident is well below the reported dose.

At the time the LOCA occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because pool boiling would not occur until after 8 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the dose calculated for the LOCA, the resulting total dose remains less than that reported in Table 15.6.5-3.

15.6.5.3.8.2 Doses to Operators in the Main Control Room

The doses calculated for the main control room personnel due to airborne activity entering the main control room are listed in Table 15.6.5-3. Also listed on Table 15.6.5-3 are the doses due to direct shine from the activity in the adjacent buildings and sky-shine from the radiation that streams out the top of the containment shield building and is reflected back down by air-scattering. The total of the three dose paths is within the dose criteria of 5 rem TEDE as defined in GDC 19.

As discussed above for the offsite doses, there is the potential for a dose to the operators in the main control room due to iodine releases from postulated spent fuel boiling. The calculated dose from this source is less than 0.01 rem TEDE and, when this is added to the dose calculated for the LOCA, the resulting total dose remains less than that reported in Table 15.6.5-3.

15.6.5.4 Core and System Performance

Subsection 15.6.5.4A describes the large-break LOCA analysis methodology and results. Subsections 15.6.5.4B.1.0 through 15.6.5.4B.4.0 describe the small-break LOCA analysis methodology and results.

15.6.5.4A Large-break LOCA Analysis Methodology and Results

Westinghouse applies the WCOBRA/TRAC computer code to perform best-estimate large-break LOCA analyses in compliance with 10 CFR 50 (Reference 5). WCOBRA/TRAC is a thermal-hydraulic computer code that calculates realistic fluid conditions in a PWR during the blowdown and reflood of a postulated large-break LOCA. The methodology used for the AP1000 analysis is documented in WCAP-12945-P-A and WCAP-14171, Revision 2 (References 10 and 11).

The NRC staff has reviewed and approved the best-estimate LOCA methodology documented in Reference 10 for estimating the 95th percentile PCT (Reference 8) for three-loop and four-loop Westinghouse pressurized water reactors (PWRs). In the methodology approved for three- and four-loop Westinghouse PWRs, three major components of uncertainty are considered. The initial conditions uncertainty component addresses variations and uncertainties in the initial fluid conditions in the reactor coolant system and the emergency core cooling system boundary conditions. The power distribution uncertainty component addresses variations and uncertainties in power-related parameters, such as peaking factors and axial power distributions. The model uncertainty component addresses uncertainties in the code models that affect the overall system transient ("global" models), as well as those which affect the hot rod only ("local" models). The WCOBRA/TRAC code is used to calculate the effects of initial conditions, power distributions, and global models, and the HOTSPOT code is used to calculate the effects of local models. Biases and uncertainties due to the assumption that the initial conditions, power distribution, and model uncertainty components can be linearly combined are quantified and accounted for.

In addition to the code uncertainty estimates quantified in the model uncertainty component, a separate code uncertainty has been estimated based on direct comparisons of WCOBRA/TRAC predictions to experimental data. This estimate is considered in the appropriate step of the methodology used to develop the overall uncertainty. Finally, the uncertainty of the experimental data has been quantified. This uncertainty is also considered in the appropriate step of methodology used to develop the overall uncertainty.

A simplification of this methodology was approved for the AP600 in Reference 3. The parameters important to the initial conditions and power distribution uncertainty components are set to bounding values established by sensitivity studies. The model uncertainty component is quantified in the same way as for three- and four-loop plants, in cases where the other parameters are set to their bounding values. The code uncertainty estimate based on direct comparisons with data and the uncertainty in the experimental data itself, is also considered in the overall uncertainty estimate. A discussion of the AP600 large-break LOCA uncertainty methodology is given in WCAP-14171, Revision 2 (Reference 11). As stipulated in the Reference 3 approval, a PCT bias is included in the 95th percentile blowdown and reflood PCT results to account for the sensitivity to eliminating the operation of the CMT and PRHR from the WCOBRA/TRAC calculation.

For the AP1000 large-break LOCA analysis, the best-estimate LOCA analysis methodology approved for AP600 by the NRC Staff is applied as described in Reference 11. The plant boundary conditions for WCOBRA/TRAC, including the initial operating conditions and the core power distribution, are bounded in a conservative manner based on initial sensitivity studies investigating the range of AP1000 possible values. The modeling bias and uncertainty is then evaluated. This component accounts for uncertainties in the ability of the WCOBRA/TRAC code to accurately predict important phenomena affecting the overall system response ("global" parameters) and the local fuel rod response ("local" parameters). The code and model bias is the difference between the reference transient PCT, which assumes nominal values for the global and local parameters, and the average PCT, taking into account the possible values of global and local parameters.

The post-LOCA long-term core cooling and core boron concentration analyses discussed in subsection 15.6.5.4C are applicable to the large-break LOCA transient.

15.6.5.4A.1 General Description of WCOBRA/TRAC Modeling

WCOBRA/TRAC is the best-estimate thermal-hydraulic computer code used to calculate realistic fluid conditions in the PWR during blowdown and reflood of a postulated large-break LOCA.

The WCOBRA/TRAC Code Qualification Document (Reference 10) contains a complete description of the code models and justifies their applicability to PWR large-break LOCA analysis.

Table 15.6.5-4 lists the AP1000-specific parameters identified for use in the large-break LOCA analysis. WCOBRA/TRAC studies were performed for AP600 to establish sensitivities to parameter variations. A spectrum of large-break LOCA sensitivity cases considered different values of the AP600 initial condition and power distribution parameters; ranges of parameters in the studies performed for the AP600 are reported in Reference 7. Some of these parameter studies were performed again for AP1000 to evaluate the effect of changes in key initial plant conditions over their expected range of operation. These studies included effects of ranging T_{avg}, steam generator tube plugging, core burnup, and hot assembly location. The calculated results were used to identify bounding conditions, which are then used in the AP1000 reference transient.

The WCOBRA/TRAC vessel nodalization is developed from plant design drawings to divide the vessel into 10 vertical sections. The bottom of section 1 is the inside vessel bottom, and the top of section 10 is the inside top of the vessel upper head. In addition to the major downcomer and core flow paths, the modeled bypass flow paths are the upper head cooling spray, guide thimbles, and core bypass. After defining the elevations for each section, a noding scheme is defined for the WCOBRA/TRAC model as shown in WCAP-14171, Revision 2 (Reference 11). WCOBRA/TRAC assumes a vertical flow path for vertically stacked channels, unless specified otherwise in the input. Positive flow for the vertically connected channels (and cells) is upward. Several of the 10 sections are divided vertically into 2 or more levels; these levels are referred to as cells within a channel.

The WCOBRA/TRAC loop model represents the major primary, secondary, and passive safety systems components. Both loops are explicitly modeled, including the hot leg, the steam

generator, and the two cold legs and associated pumps. The loop designated "2" has the pressurizer and the PRHR system connections, and loop "1" cold legs have the core makeup tank pressure balance line connections. The reactor coolant pump models contain the AP1000 homologous curves together with appropriate two-phase head and torque multipliers and degradation data. AP1000 values for pump coastdown characteristics are also applied. The passive safety features are modeled using design data for elevations, liquid volumes, and line losses. Because the ADS is not actuated until long after the time of PCT in large-break LOCA events, it is not modeled in detail.

15.6.5.4A.2 Steady-state Calculation

A WCOBRA/TRAC LOCA calculation is initiated from a point at which the flows, temperatures, powers, and pressures are at their approximate steady-state values before the postulated break occurs. Steady-state WCOBRA/TRAC calculations are run for a brief time period to verify that the calculated conditions are steady and that the desired reactor conditions are achieved.

The values used to set the steady-state plant conditions reflect the AP1000 parameters for reactor coolant pump flows, core power, and steam generator tube plugging levels. The fuel parameters provide the steady-state fuel temperatures, pressures, and gap conductances as a function of fuel burnup and linear power. The calculated fuel temperatures from WCOBRA/TRAC are adjusted to match the specified fuel data by adjusting the gap heat transfer coefficient between the pellet and the cladding. Once the vessel fluid temperatures, flows, pressures, loop pressure drop, and core parameters are in agreement with the desired values and are steady, a suitable initial condition is achieved.

15.6.5.4A.3 Signal Logic for Large-break LOCA

The reactor trip signal occurs due to compensated pressurizer pressure within the first second of the large-break transient. Because control rod insertion is not modeled in WCOBRA/TRAC, no effects on reactivity ensue. A safeguards "S" signal occurs due to containment high pressure at 2.2 seconds of large-break LOCA transients.

As a consequence of this signal, after appropriate delays, the PRHR and core makeup tank isolation valves open and containment isolation occurs. The rapid depressurization of the primary system during a large-break LOCA leads to the initiation of accumulator injection early in the large-break transient. The accumulator flow diminishes core makeup tank delivery to such an extent that the core makeup tank level does not approach the ADS Stage 1 valve actuation point until after the accumulator tank is empty. The accumulator empties long after the blowdown portion of the large-break LOCA transient is complete. Actuation of the ADS on CMT water level does not occur until long after the AP1000 PCT is calculated to occur.

15.6.5.4A.4 Transient Calculation

Once the steady-state calculation is found to be acceptable, the transient calculation is initiated. The semi-implicit pipe break model is added to the desired break location. The containment backpressure is specified consistent with WCAP-14171, Revision 2 (Reference 11) methodology. The steady-state calculation is restarted with the above changes to begin the transient.

The calculation is continued until the fuel rods are quenched. Passive safety injection flow into the vessel from the accumulators is larger than the break flow for as long as the accumulators discharge.

Table 15.6.5-5 shows a general sequence of events following a large cold-leg break LOCA and the relationship of these events to the blowdown and reflood portion of the transient.

15.6.5.4A.5 Large-break LOCA Analysis Results

For the AP1000 large-break LOCA analysis, the best-estimate LOCA analysis methodology approved for AP600 is applied as follows. The plant boundary conditions for WCOBRA/TRAC, including the initial operating conditions and the core power distribution, are bounded in a conservative manner based on the sensitivity studies that investigated the range of AP600 possible values. Studies were reperformed for AP1000 to establish the bounding values for the AP1000 reference transient.

Conceptually, the following equation defines the effect on the reference transient PCT of the uncertainties due to global model parameter variations:

$$PCT_i = PCT_{REF,i} + \Delta PCT_{MOD,i}$$

where,

$PCT_{REF,i}$ = Reference transient PCT: The reference transient PCT is calculated using WCOBRA/TRAC at the bounding initial conditions and distribution for blowdown (i = 1) and reflood (i = 2).

$\Delta PCT_{MOD,i}$ = Model bias and uncertainty: This component accounts for uncertainties in the ability of the WCOBRA/TRAC code to accurately predict important phenomena affecting the overall system response (“global” parameters) and the local fuel rod response (“local” parameters). The code and model bias is the difference between the reference transient PCT, which assumes nominal values for the global and local parameters, and the average PCT, taking into account the possible values of global and local parameters. The global model matrix for AP1000 is presented in Reference 11.

Reference 3 indicates the application restrictions on the AP600 methodology. The AP1000 large-break LOCA analysis has complied with those restrictions. The global model matrix of calculations and the final 95-percent uncertainty calculations have been performed for AP1000. The reference transient was reanalyzed to address the sensitivity to the modeling of the CMT and PRHR. A case in which the CMT was isolated from the rest of the AP1000 was analyzed, and the calculated PCT was lower than the reference transient PCT. Also, a case in which the PRHR was isolated from the rest of the AP1000 was analyzed, and the calculated PCT was lower than the reference transient result. Further, local and core-wide cladding oxidation values have been determined using the Reference 10 approved methodology.

Figures 15.6.5.4A-1 through 15.6.5.4A-12 present the parameters of principal interest for the Reference Case DECLG break analysis. Values of the following parameters are presented:

- The highest calculated cladding temperature at any elevation for the five fuel rods modeled
- Hot rod cladding temperature transient at the limiting elevation for PCT
- Core fluid mass flows at top of core for the fuel assemblies modeled in WCOBRA/TRAC
- Core pressure
- Break flow rates
- Core and downcomer collapsed liquid levels
- Accumulator water flow rate
- Intact loop core makeup tank flow rate

Cold-leg breaks are analyzed because the hot-leg break location is nonlimiting in the large-break LOCA best-estimate methodology. The DECLG break was shown to be more limiting than the limiting size split break.

In all cases analyzed, the bounding core design values of Fq (2.60) and FdH (1.65) are applied to the hot rod, and 102 percent of nominal core power is assumed.

15.6.5.4A.6 Description of AP1000 Large-Break LOCA Transient

A description of the reference transient DECLG break with bounding initial and boundary conditions follows. The sequence of events is presented in Table 15.6.5-6. The break was modeled to occur in one of the cold legs in the loop containing the core makeup tanks. Shortly after the break opens, the vessel rapidly depressurizes and the core flow quickly reverses. The hot assembly fuel rods dry out and begin to heat up (Figures 15.6.5.4A-1 and 15.6.5.4A-2) during the flow reversal (Figure 15.6.5.4A-3). In Figure 15.6.5.4A-3, FGM is the vapor flow rate at the top of the hot assembly, FEM is the entrained liquid drop flow rate at that location, and FLM is the continuous liquid flow rate at that location.

In Figure 15.6.5.4A-1, Rod 1 refers to the hot rod at the maximum allowed linear heat rate, Rod 2 represents the average rod in the hot assembly that contains the hot rod, Rod 3 represents the open hole/support column rod, Rod 4 represents the guide tube rod, and Rod 5 represents the peripheral fuel assembly rod.

The steam generator secondaries are assumed to be isolated immediately at the inception of the break to maximize their stored energy. The massive size of the break causes an immediate, rapid pressurization of the containment. At 2.2 seconds of the transient, credit is taken for receipt of an "S" signal due to high-2 containment pressure. Applying the pertinent signal processing delay means that the valves isolating the core makeup tanks from the direct vessel injection line and the PRHR begin to open at 4.2 seconds into the transient. The reactor coolant pumps are presumed to trip immediately following the break. Core shutdown occurs due to voiding; no credit is taken for the control rod reactivity effect.

The system depressurizes rapidly (Figure 15.6.5.4A-4) as the initial mass inventory is depleted due to break flow. The pressurizer drains completely approximately 25 seconds into the transient, and accumulator injection commences 15 seconds into the transient (Figure 15.6.5.4A-5).

Accumulator actuation shuts off core makeup tank flow (Figure 15.6.5.4A-6), which has been delivering since the isolation valve opened. The CMT liquid level remains well above the ADS Stage 1 actuation setpoint throughout the AP1000 DECLG LOCA cladding temperature excursion, even though CMT injection begins again at 215 seconds.

The dynamics of the reference transient are shown in terms of the flow rates of liquid, vapor, and entrained liquid at the top of the core (Figures 15.6.5.4A-7 through 15.6.5.4A-9) for the peripheral, open hole/support column average power interior, and guide tube average power interior assemblies (the corresponding figure for the hot assembly is Figure 15.6.5.4A-3). The variables plotted are the same as those in Figure 15.6.5.4A-3 for the respective assemblies.

Figures 15.6.5.4A-8 and 15.6.5.4A-9 illustrate the impact of upper head drain through the guide tubes and upper core plate holes, respectively, on core flow. While liquid remains in the upper head above the top of the guide tubes, the guide tubes (Figure 15.6.5.4A-8) are the preferred path for draining of liquid into the upper plenum. Top of core liquid flow is relatively stagnant for the first few seconds; once the upper head begins to flash, liquid drains directly down the guide tubes and that fraction that is able to penetrate into the core does so, at a maximum flow rate exceeding 2000 lbm/sec of total liquid flow between 5 and 18 seconds. At that point, the flow entering the guide tubes in the upper head is largely steam; residual liquid is supplied to the guide tube fuel assemblies at a constant or decreasing rate out to 42 seconds.

Figure 15.6.5.4A-9 presents the open hole/support column assembly top of core flow behavior. In contrast to the guide tubes, flow of liquid down into the core open hole/support column locations does not become significant until about 9 seconds of the reference transient. Between 11 and 18 seconds, the combined flow of continuous and entrained liquid is 600 to 1500 lbm/sec; the entrained liquid flow continues to be significant until 30 seconds. After 10 seconds of transient, the downflow pattern in the open hole/support column locations and the guide tubes is established to the extent that vapor downflow is also predicted. Thus, there exists good flow of liquid into the top of the core at these locations from before 10 seconds to after 20 seconds. The flow in the open hole and guide tube assemblies is sufficient to quench the fuel in each respective assembly (Rod 3 and Rod 4 respectively in Figure 15.6.5.4A-1).

Liquid downflow is delayed into the hot assembly. By 10 seconds into the transient, liquid that has built up in the global region above the upper core plate begins to flow through the plate at the hot assembly location and then proceeds into the core (Figure 15.6.5.4A-3). Significant flow of continuous and/or entrained droplet liquid into the hot assembly exists from 10 to 22 seconds. The liquid flow is not enough to quench the hot rod and hot assembly rod at all elevations (Figure 15.6.5.4A-1), although effective cooling is achieved.

Figure 15.6.5.4A-7 demonstrates that liquid downflow exists through the top of the peripheral core assemblies from 2 seconds through about 26 seconds in the reference DECLG transient. The power of the fuel in this region is almost identical to that in the open hole and guide tube locations, so the cladding temperature profiles are similar.

About 15 seconds into the transient, the accumulator begins to inject water into the upper downcomer region, most of which is initially bypassed to the break. At approximately 25 seconds, accumulator water begins to flow into the lower plenum. Break flow rates through the loop

(Figure 15.6.5.4A-10) and vessel (Figure 15.6.5.4A-11) sides of the break diminish as the transient progresses. At approximately 70 seconds, the lower plenum fills to the point that water begins to reflood the core from below. The void fraction at the core bottom begins to decrease, and as time passes, core cooling increases substantially. The cladding temperature begins to decrease once the core water level has risen high enough in the core. Figure 15.6.5.4A-12 presents the collapsed liquid levels in the core referenced to the bottom elevation of the active fuel (solid line) and downcomer (dashed line) referenced to the bottom of the reactor vessel.

15.6.5.4A.7 Global Model Sensitivity Studies and Uncertainty Evaluation

The global model run matrix developed for the approved best-estimate LOCA methodology was analyzed to evaluate the effect of broken loop resistance, break discharge coefficient, and condensation rate on the PCT for the guillotine break. These parameters were varied singly and in combination to obtain a data base that could be used for response surface generation. The run matrix and ranges of the break flow parameters are described in WCAP-14171, Revision 2 (Reference 11). The bounding power shape and initial conditions identified for AP1000 by sensitivity study are used.

Further, studies of split breaks with areas equal to between 1.4 and 1.8 times the cold-leg area were performed to identify the limiting split-break area. The calculated results from these additional split breaks are summarized in Table 15.6.5-7.

The calculated results were used to develop a response surface by regression analysis. This is then used in the uncertainty evaluation to predict the PCT uncertainty component resulting from uncertainties in global model parameters, $\Delta PCT_{MOD,i}$. An uncertainty evaluation is performed solely for the global model parameters because the initial condition and power distribution parameters are bounded.

The PCT equation as presented before requires evaluation of the element of uncertainty associated with the $\Delta PCT_{MOD,i}$ term. Separate initial PCT frequency distributions are constructed as follows for the guillotine break and the limiting split break size:

1. Generate a random value of the ΔPCT element
2. Calculate the resulting PCT
3. Repeat the process many times to generate a histogram of PCTs

The results of this assessment indicated the DECLG (guillotine) break is limiting for the AP1000.

To account for the uncertainty due to statistical approximation methods, several global model runs are imposed to identify the PCT-based code uncertainty for a final Monte Carlo simulation of the guillotine break PCT. Results obtained in the determination of the 95th percentile PCT are presented in Table 15.6.5-8.

15.6.5.4A.8 Large-Break LOCA Conclusions

In accordance with 10 CFR 50.46, the conclusions of the best-estimate large-break LOCA analysis are that there is a high level probability that the following criteria are met.

1. The calculated maximum fuel element cladding temperature (i.e., peak cladding temperature (PCT)) will not exceed 2200°F.

2. The calculated total oxidation of the cladding (i.e., maximum cladding oxidation) will nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam (i.e., maximum hydrogen generation) will not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. The calculated changes in core geometry are such that the core remains amenable to cooling.

   Note that criterion 4 has historically been satisfied by adherence to criteria 1 and 2, and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. Criteria 1 and 2 are satisfied for best-estimate large-break LOCA applications. The approved methodology specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the assemblies in the low power channel as defined in the WCOBRA/TRAC model. This situation has not been calculated to occur for the AP1000. Therefore, acceptance criterion 4 is satisfied.

5. After successful initial operation of the emergency core cooling system (ECCS), the core temperature will be maintained at an acceptably low value and decay heat will be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

   Criterion 5 is satisfied if a coolable core geometry is maintained and the core is cooled continuously following the LOCA. The AP1000 passive core cooling system provides effective core cooling following a large-break LOCA event, even assuming the limiting single failure of a core makeup tank delivery line isolation valve. The large-break LOCA transient has been extended beyond fuel rod quench until 1800 seconds, a time at which the CMT liquid level has decreased to the low-2 setpoint that actuates the fourth-stage ADS valves and IRWST injection. A significant increase in safety injection flow rate occurs when the IRWST becomes active. The analysis performed demonstrates that CMT injection is sufficient to maintain the mass inventory in the core and downcomer, from the period of fuel rod quench until IRWST injection. The AP1000 passive core cooling system provides effective post-LOCA long-term core cooling.

Table 15.6.5-8 presents the calculated 50th and 95th percentile PCT, maximum cladding oxidation, maximum hydrogen generation, and core cooling results.

Based on the analysis, the Westinghouse Best-Estimate Large-Break LOCA methodology has shown that the acceptance criteria of 10 CFR 50.46 are satisfied for AP1000.

15.6.5.4B Small-break LOCA Analyses

Should a small break LOCA occur, depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal occurs when the pressurizer

low-pressure trip setpoint is reached. An "S" signal is generated when the appropriate setpoint is reached. These measures limit the consequences of the accident in two ways:

- Reactor trip leads to a rapid reduction of power to a residual level corresponding to fission product decay heat by the insertion of control rods to shut down the reactor.

- Injection of borated water provides core cooling and prevents excessive cladding temperatures.

15.6.5.4B.1 Description of Small-break LOCA Transient

The AP1000 plant design includes passive safety features to prevent or minimize core uncovery during small-break LOCAs. The passive safety design approach of the AP1000 is to depressurize the reactor coolant system if the break or leak is greater than the capability of the makeup system or if the nonsafety makeup system fails to perform. By depressurizing the reactor system, large volumes of borated water in the accumulators and in the IRWST become available for cooling the core. This analysis demonstrates that, with a single failure, the passive systems are capable of depressurizing the reactor coolant system while maintaining acceptable core conditions and establishing stable delivery of cooling water from the IRWST.

During a small-break LOCA, the AP1000 reactor coolant system depressurizes to the pressurizer low-pressure setpoint, actuating a reactor trip signal. The passive core cooling system is aligned for delivery following the generation of an "S" signal when the pressurizer low-pressure setpoint is reached. The passive core cooling system includes two core makeup tanks, two accumulators, a large IRWST, and the PRHR heat exchanger.

The core makeup tanks operate at reactor coolant system pressure. They provide high-pressure safety injection in the event of a small-break LOCA. The core makeup tanks share a common discharge line with the accumulators and IRWST; they are filled with borated water to provide core shutdown margin. Gravity head of the colder water in the core makeup tanks provides the injection of the core makeup tanks. The core makeup tanks are located above the reactor coolant loops, and each is equipped with a pressure balancing line from a cold leg to the top of the tank.

The pressurized accumulators provide additional borated water to the reactor coolant system in the event of a LOCA. Nominally, these 2000-ft^3 tanks are filled with 1700 ft^3 of water and 300 ft^3 of nitrogen at an initial pressure of 700 psig. Once sufficient reactor coolant system depressurization occurs, either as a result of a LOCA or the actuation of the ADS, accumulator injection begins.

The IRWST at a minimum provides an additional 78,900 ft^3 of water for long-term core cooling. To attain injection from the IRWST, the reactor coolant system pressure must be lowered to approximately 13 psi above containment pressure. For this pressure to be achieved during a small-break LOCA, the actuation of the ADS valves is required.

The ADS consists of a series of valves, connected to the pressurizer and hot legs, which provide a phased depressurization of the reactor coolant system. As the reactor system loses inventory through the break, the core makeup tanks provide flow to the reactor vessel. When the level in the core makeup tank drops to the 67.5-percent level, the ADS valves open to accelerate the reactor coolant system depressurization rate. The ADS Stage 1 4-inch valves open at the 67.5-percent

level; the 8-inch Stage 2 and the 8-inch Stage 3 valves open in a timed sequence thereafter. The flow from the first three stages of the ADS is discharged into the IRWST through a sparger system. The fourth stages of the ADS are connected to the reactor coolant system hot legs and discharge to containment atmosphere. The ADS Stage 4 valves are activated when the core makeup tank level reaches the 20-percent level.

As the reactor system depressurizes and mass is lost out the break, mass is added to the reactor vessel from the core makeup tanks and the accumulators. When the system is depressurized below the IRWST delivery pressure, flow from the IRWST continues to maintain the core in a coolable state. Calculations described in this section indicate that acceptable core cooling is provided for the small-break LOCA transients.

15.6.5.4B.2 Small-break LOCA Analysis Methodology

Small-break LOCA response is evaluated for AP1000 with an evaluation model that conforms to 10 CFR 50 Appendix K. The elements of the AP1000 small-break LOCA evaluation model are the following:

- NOTRUMP computer code
- NOTRUMP homogeneous sensitivity model
- Critical heat flux assessment during accumulator injection

15.6.5.4B.2.1 NOTRUMP Computer Code

The NOTRUMP computer code is used in the analysis of LOCAs due to small-breaks in the reactor coolant system. The NOTRUMP computer code is a one-dimensional, general network code, which includes a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. The version of NOTRUMP used in AP1000 small-break LOCA calculations has been validated against applicable passive plant test data (Reference 22). The code has limited capability in modeling upper plenum and hot leg entrainment and did not predict the core collapsed level during the accumulator injection phase adequately. The NOTRUMP homogeneous sensitivity model (discussed in subsection 15.6.5.4B.2.2) and the critical heat flux assessment during the accumulator injection phase (discussed in subsection 15.6.5.4B.2.3) supplement the base NOTRUMP analysis to demonstrate the adequacy of the design.

In NOTRUMP, the reactor coolant system is nodalized into volumes interconnected by flow paths. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum applied throughout the system. A description of NOTRUMP is given in References 12 and 13. The AP600 modeling approach, described in Reference 17, is also used to develop the AP1000 model; NOTRUMP's applicability to AP1000 is documented in Reference 24.

The use of NOTRUMP in the analysis involves the representation of the reactor core as heated control volumes with an associated bubble rise model to permit a transient mixture height

calculation. The multi-node capability of the program enables an explicit and detailed spatial representation of various system components. Table 15.6.5-9 lists important input parameters and initial conditions of the analysis.

A steady-state input deck for the AP1000 was set up to comply, where appropriate, with the standard small-break LOCA Evaluation Model methodology. Major features of the modeling of the AP1000 follow:

- Accumulators are modeled at an initial pressure of 715 psia.

- The flow through the ADS links is modeled using the Henry-Fauske, the homogeneous equilibrium (HEM), and the Murdock/Baumann critical flow models. The Henry-Fauske correlation is used for low-quality two-phrase flow, and the HEM model, for high-quality flow, with a transition between the two beginning at 10-percent static quality. The Murdock-Bauman model is used if the ADS flow path is venting superheated steam.

- Isolation and check valves used in the passive safety systems are modeled.

- The IRWST is modeled as two connected fluid nodes. The lower node is connected to the direct vessel injection line and is the source of injection water to the DVI lines driven by gravity head. The upper node acts as a sink for the ADS flow from the pressurizer and as a heat sink for the PRHR heat exchanger. These nodes are modeled as having an initial temperature of 120°F, a pressure of 14.7 psia, and the nominal full-power operation level of 28.8 feet. Therefore, the minimum head for IRWST injection is assumed. For the DEDVI simulations, a conservative 20 psia containment pressure was used based on containment pressurization calculations performed with the WGOTHIC containment model.

- The PRHR system is modeled in accordance with the guidance provided in References 22 and 24. The PRHR isolation valve is modeled as opening with the maximum delay after the generation of an “S” signal to conservatively deny the cooling capability of the heat exchanger to the reactor coolant system for an extended period.

- The core power is initially set to 102 percent of the nominal core power. The reactor trip signal occurs when the pressurizer pressure falls below 1800 psia. A conservative delay time is modeled between the reactor trip signal and reactor trip. Decay heat is modeled according to the ANS-1971 (Reference 2) standard, with 20-percent uncertainty added.

- The “S” signal is generated when the pressurizer pressure falls below 1700 psia. The isolation valves on the core makeup tank injection lines begin to open after the signal setpoint is reached; the valves are then assumed to open linearly. The main feedwater isolation valves are ramped closed between 2 and 7 seconds after the “S” signal. The reactor coolant pumps are tripped 6.0 seconds after the “S” signal.

- The ADS actuation signals are generated on low core makeup tank levels and the ADS timer delays. A list of the ADS parameters is given in Table 15.6.5-10 for AP1000. ADS Stages 1, 2, and 3 are modeled as discharging through spargers submerged in the IRWST at the appropriate depth.

- The pressure in the boundary node modeling of the containment is 14.7 psia in all NOTRUMP cases except the DEDVI line break, which used 20.0 psia.

- The steam generator secondary is isolated 6 seconds after the reactor trip signal, due to closure of the turbine stop valves. The main steam safety valves actuate and remove energy from the steam generator secondary when pressure reaches 1235 psia.

Active single failures of the passive safeguards systems are considered. The limiting failure is judged to be one out of four ADS Stage 4 valves failing to open on demand, the failure that most severely impacts depressurization capability. The safety design approach of the AP1000 is to depressurize the reactor coolant system to the containment pressure in an orderly fashion such that the large reservoir of water stored in the IRWST is available for core cooling. The mass inventory plots provided for the breaks show the minimum inventory condition generally occurs at the start of IRWST injection. Penalizing the depressurization is the most conservative approach in postulating the single failure for such breaks.

The small-break LOCA spectrum analyzed for AP1000 includes a break that exhibits a minimum reactor vessel inventory early in the transient, before the accumulators become active: the 10-inch cold leg break. In this transient, the early mass inventory decrease is terminated by injection flow from the intact accumulator, and depressurization through the break enables accumulator injection to begin with no contribution from the actuation of ADS Stages 1, 2, and 3. For consistency, the conservative failure of one of the ADS Stage 4 valves located off the PRHR inlet pipe, which adversely affects the depressurization necessary to achieve IRWST injection in small-break LOCAs, is assumed in all cases. Sensitivity analysis shows that assuming failure of one ADS Stage 4 valve on the non-PRHR loop does not significantly impact core cooling.

15.6.5.4B.2.1.1 AP1000 Model-Detailed Noding

Refer to Reference 17 for details of the AP600 NOTRUMP modeling. The AP1000 model was developed in the same fashion with modifications to the AP600 model introduced as follows. A modification performed for AP1000 was the addition of two core nodes one foot each in length to reflect the added active fuel length of this design. The ADS-4 flow path resistances were increased to accommodate shortcomings in NOTRUMP identified during the integral test facility simulations, namely, the lack of a detailed momentum flux model in the ADS-4 discharge paths. A detailed calculation of the energy and momentum equations is performed for the ADS-4 piping over a range of flow and pressure conditions to provide a benchmark for the NOTRUMP ADS-4 flow path resistance. The methodology used to determine the resistance increase is described in Reference 24. By increasing the ADS-4 resistances, the onset of IRWST injection is more appropriately calculated. This methodology directly addresses the effect of momentum flux in ADS-4. The ADS-4 resistance increase utilized is computed for the NOTRUMP analyses in this section to be a 70 percent ADS-4 flow path resistance increase.

15.6.5.4B.2.1.2 Plant Initial Conditions/Steady-State

A steady-state calculation is performed prior to initiating the transient portion of the calculation.

Table 15.6.5-9 contains the most important initial conditions for the transient calculations. The behaviors of the primary pressure and pressurizer level, steam generator pressures, and the core flow rate are stable at the end of the 100-second steady-state calculation.

15.6.5.4B.2.2 NOTRUMP Homogeneous Sensitivity Model

In order to address the uncertainties associated with entrainment in the upper plenum and hot leg following ADS-4 operation, a sensitivity study is performed with the limiting break with respect to these phenomena, effectively maximizing the amount of entrainment downstream of the core. This methodology is described and the results are presented for the double-ended direct vessel injection (DEDVI) line break in detail in Reference 24.

[*In order to maximize the entrainment downstream of the core for the limiting break with respect to entrainment, NOTRUMP is run with the regions of the upper plenum, hot leg, and ADS-4 lines in a homogeneous fluid condition, with slip = 1, to demonstrate that even with maximum entrainment, the 10 CFR 50.46 criteria are met.*]*

15.6.5.4B.2.3 Critical Heat Flux Assessment During Accumulator Injection

[*An assessment is performed of the peak core heat flux with respect to the critical heat flux during the later ADS depressurization time period for a double-ended rupture of the direct vessel injection line. This time period corresponds to the accumulator injection phase of the transient. The predicted average mass flux at the core inlet and the reactor pressure from the NOTRUMP computer code base model analysis are used as input parameters to critical heat flux correlation as described in Reference 30. The requirements of 10 CFR 50.46 are met provided the maximum heat flux is less than the critical heat flux calculated by the correlation.*]* NOTRUMP has been shown (Reference 24) to adequately predict mass flux and pressure for integral systems tests.

The predicted mass flux at the core inlet is on the average constant and corresponds to 7.2 lbm ft^{-2} s^{-1} (~35 kg m^{-2} s^{-1}). The key thermal-hydraulic parameters at different times during the ADS depressurization time period are summarized in following table.

Time (sec)	UP Pressure (kPa)	UP Pressure (psia)	Mass Flux (kg/m^2s)	Average Heat Flux (kW/m^2)
400	1293	190	35	20.2
500	646	95	35	19.1
570	340	50	35	18.5
600	272	40	35	18.2

For the critical heat flux assessment, the peak core heat flux is applied to simulate the hot assembly condition in a conservative manner. No credit is taken for increased flow in the hot assembly that is known to occur in rod bundles.

* NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The correlation applied for this assessment is from vertical tube data (Reference 30) and recognizes two regimes depending on the mass flux. The main difference between the two is the mass flux dependence. They are as follows:

$$q^*_{CL} = q^*_{CF} + 0.01351\left(D^*\right)^{-0.473}(L/D)^{-0.533}\left|G^*\right|^{1.45} \quad \text{for low } G^*$$

and,

$$q^*_{CH} = q^*_{CF} + 0.05664\left(D^*\right)^{-0.247}(L/D)^{-0.501}\left|G^*\right|^{0.77} \quad \text{for high } G^*$$

The first term of above correlations is,

$$q^*_{CF} = 1.61\left(\frac{A}{Ah}\right)\frac{\left(D^*\right)^{0.5}}{\left[1+\left(\frac{\rho_g}{\rho_l}\right)^{0.25}\right]^2}$$

where A is the flow area and Ah is the heated area.

The dimensionless CHF is calculated as,

$$q^*_{CHF} = \min(q^*_{CL}, q^*_{CH})$$

Dimensionless CHF, G, and D are defined as,

$$q^*_{CHF} = \frac{q''_{CHF}}{h_{fg}\sqrt{\lambda\rho_g g\Delta\rho}}$$

$$G^* = \frac{G}{\sqrt{\lambda\rho_g g\Delta\rho}}$$

$$D^* = \frac{D}{\lambda}$$

where λ is the length scale of the Taylor instability:

$$\lambda = \sqrt{\frac{\sigma}{g\Delta\rho}}$$

Conservative application of this correlation with the AP1000 parameters indicates that the peak AP1000 heat flux during this period is at least 40 percent below the predicted critical heat flux.

This CHF assessment addresses core cooling during a time period where the NOTRUMP computer code may not conservatively predict the core average void fraction. The requirements of 10 CFR 50.46 are met during this period since this CHF assessment indicates peak core heat flux is less than critical heat flux. Cladding temperatures will remain near the coolant saturation temperature, well below the 10 CFR 50.46 peak cladding temperature limit.

15.6.5.4B.3 Small-break LOCA Analysis Results

Several small-break LOCA transients are analyzed using NOTRUMP, and the results of these calculations are presented. The results demonstrate that the minimum reactor coolant system mass inventory condition occurs for the relatively large system pipe breaks. Smaller breaks exhibit a greater margin-to-core uncovery.

15.6.5.4B.3.1 Introduction

The small-break LOCA safety design approach for AP1000 is to provide for a controlled depressurization of the primary system if the break cannot be terminated, or if the nonsafety-related charging system is postulated to be lost or cannot maintain acceptable plant conditions. Nonsafety-related systems are not modeled in this design basis analysis; the testing conducted in the SPES-2 facility has indicated that the mass inventory condition during small LOCAs is significantly improved when these nonsafety-related systems operate. The core makeup tank level activates primary system depressurization. The core makeup tank provides makeup to help compensate for the postulated break in the reactor coolant system. As the core makeup tank level drops, Stages 1 through 4 of the ADS valves are ramped open in sequence. The ADS valve descriptions for the AP1000 plant design are presented in Table 15.6.5-10. The reactor coolant system depressurizes due to the break and the ADS valves, while subcooled water from the core makeup tanks and accumulators enters the reactor vessel downcomer to maintain system inventory and keep the core covered. Design basis maximum values of passive core cooling system resistances are applied to obtain a conservative prediction of system behavior during the small LOCA events.

During controlled depressurization via the ADS, the accumulators and core makeup tanks maintain system inventory for small-break LOCAs. Once the reactor coolant system depressurizes, injection from the IRWST maintains long-term core cooling. For continued injection from the IRWST, the reactor coolant system must remain depressurized. To conservatively model this condition, design maximum resistance values are specified for the IRWST delivery lines.

A series of small-break LOCA calculations are performed to assess the AP1000 passive safety system design performance. In these calculations, the decay heat used is the ANS-1971 (Reference 2) plus 20 percent for uncertainty as specified in 10 CFR 50, Appendix K (Reference 1). This maximizes the core steam generation to be vented. The breaks analyzed in this document include the following:

Inadvertent ADS Actuation

A “no-break” small-break LOCA calculation that uses an inadvertent opening of the 4-inch nominal size ADS Stage 1 valves is a situation that minimizes the venting capability of the reactor coolant system. Only the ADS valve vent area is available; no additional vent area exists due to a

break. This case examines whether sufficient vent area is available to completely depressurize the reactor coolant system and achieve injection from the IRWST without core uncovery. The worst single failure for this situation is a failure of one of four ADS Stage 4 valves connected to either of the two hot legs. The ADS Stage 4 valve is the largest ADS valve, and it vents directly to the containment with no additional backpressure from the spargers being submerged in the IRWST.

2-inch Break in a Cold Leg with Core Makeup Tank Balance Line Connections

The small size of the break leads to a long period of recirculatory flow from the cold leg into the core makeup tank. This delays the formation of a vapor space in the core makeup tank and therefore the actuation of the ADS.

Double-ended Rupture of the Direct Vessel Injection Line

The injection line break evaluates the ability of the plant to recover from a moderately sized break with only half of the total emergency core cooling system capacity available. The vessel side of the break of the DEDVI line break is 4 inches in equivalent diameter. The double-ended nature of this break means that there are effectively two breaks modeled:

- Downcomer to containment. The direct vessel injection nozzle includes a venturi, which limits the available break area.
- Direct vessel injection line into containment from the cold leg balance line and the broken loop core makeup tank.

The containment pressure was conservatively assumed to pressurize to 20 psia. This pressure was selected based on iterative execution of the NOTRUMP and WGOTHIC codes. The NOTRUMP code provides the mass and energy releases from the AP1000 DEDVI break to the AP1000 WGOTHIC containment model while the WGOTHIC code calculates the containment pressure response. The containment pressure assumed in the NOTRUMP simulations was conservatively selected from the generated pressure history curves obtained from the WGOTHIC runs.

The peak core heat flux during the accumulator injection period is assessed relative to the predicted critical heat flux as discussed in subsection 15.6.5.4B.2.3.

An additional injection line break case is analyzed assuming containment pressure is at 14.7 psia.

Double-ended Rupture of the Direct Vessel Injection Line Entrainment Sensitivity

The sensitivity case is performed to assess the effect of higher than expected entrainment in the upper plenum and hot legs on the overall system response and core cooling.

10-inch Cold Leg Break

This break models a break size that approaches the upper limit size for small-break LOCAs.

15.6.5.4B.3.2 Transient Results

The transient results are presented in tables and figures for the key AP1000 parameters of interest in the following sections.

15.6.5.4B.3.3 Inadvertent Actuation of Automatic Depressurization System

An inadvertent ADS signal is spuriously generated and the 4-inch ADS valves open. The plant, which is operating at 102-percent power, is depressurized via the ADS alone. Only safety-related systems are assumed to operate in this and other small-break LOCA cases. Additional ADS valves open; after a 70-second delay, the ADS Stage 2 8-inch valves open, and after an additional 120 seconds, the ADS Stage 3 valves open. At the 20-percent core makeup tank level, the ADS Stage 4A valve, which is connected to the hot leg, receives a signal to open. After a 60-second delay, both Stage 4B valves (one connected to the hot leg and the other connected to the PRHR inlet pipe) open. The path that fails to open as the assumed single active failure is the Stage 4A valve off the PRHR inlet pipe. The reactor steady-state initial conditions assumed can be found in Table 15.6.5-9. The sequence of events for the transient is given in Table 15.6.5-11.

The transient is initiated by the opening of the two ADS Stage 1 paths. Reactor trip, reactor coolant pump trip, and safety injection signals are generated via pressurizer low-pressure signals with appropriate delays. After generation of the reactor trip signal, the turbine stop valves begin to close. The main feedwater isolation valves begin to close 2 seconds after the "S" signal pressure setpoint is reached. The opening of the ADS valves and the reduction in core power due to reactor trip causes the primary pressure to fall rapidly (Figure 15.6.5.4B-1). Flow of fluid toward the open ADS paths causes the pressurizer to fill rapidly (Figure 15.6.5.4B-2), and the ADS flow becomes two-phase (Figures 15.6.5.4B-3 and -4). The safety injection signal opens the valves isolating the core makeup tanks and circulation of cold water begins (Figures 15.6.5.4B-5 and -6). The mixture level (Figures 15.6.5.4B-7 and -8) in the core makeup tanks is relatively constant until the accumulators inject (Figures 15.6.5.4B-10 and -11). The reactor coolant pumps begin to coast down due to an automatic trip signal following a 6.0-second delay.

Continued mass flow through the ADS Stage 1, 2, and 3 valves drains the upper parts of the circuit. The steam generator tube cold leg sides start to drain, followed by the drop in mixture levels in the hot leg sides. As the ADS Stage 2 and 3 paths begin to open, increased ADS flow causes the primary pressure to fall rapidly (Figure 15.6.5.4B-1). Following the emptying of the steam generator tube cold leg sides, the cold legs have drained and a mixture level forms in the downcomer (Figure 15.6.5.4B-9).

The primary pressure falls below the pressure in the accumulators thus causing the accumulator check valves to open and accumulator delivery to begin (Figures 15.6.5.4B-10 and -11). The accumulators, and then the core makeup tanks inject until they empty. The ADS flow falls off as the primary pressure decreases. The flow from the accumulators raise the mixture levels in the upper plenum and downcomer (Figures 15.6.5.4B-16 and 15.6.5.4B-9).

As the levels in the core makeup tanks reach the ADS Stage 4 setpoint, one out of two paths are opened from the top of the hot leg (loop 1) and begin discharging fluid. After 30 seconds, the second path in loop one opens, as does a loop 2 Stage 4 path. Activating the Stage 4 paths leads to

reduced flow through ADS Stages 1, 2, and 3. The reduced flow allows the pressurizer level to fall, and these stages begin to discharge only steam. Once the core makeup tanks are empty, delivery ceases (Figures 15.6.5.4B-7 and -8). Once the reactor coolant system pressure has fallen sufficiently due to the ADS Stage 4 discharge, (Figure 15.6.5.4B-12) gravity drain from the IRWST begins (Figures 15.6.5.4B-13 and -14). At 5000 seconds, the calculation is considered complete; IRWST delivery exceeds the ADS flows (which are removing the decay heat), and the reactor coolant system inventory is slowly rising (Figure 15.6.5.4B-15). Core uncovery does not occur and the upper plenum mixture level remains well above the core elevation throughout (Figure 15.6.5.4B-16).

The inadvertent opening of the ADS Stage 1 transient confirms the minimum venting area capability to depressurize the reactor coolant system to the IRWST pressure. The analysis indicates that the ADS sizing is sufficient to depressurize the reactor coolant system assuming the worst single failure as the failure of a Stage 4 ADS path to open and decay heat equal to the 10 CFR 50 Appendix K (Reference 1) value of the ANS-1971 Standard (Reference 2) plus 20 percent, which over estimates the core steam generation rate. Even under these limiting conditions, IRWST injection is obtained, and the core remains covered such that no cladding heatup occurs.

15.6.5.4B.3.4 2-inch Cold Leg Break in the Core Makeup Tank Loop

This case models a 2-inch break occurring in the bottom of cold leg connected to the balance line of CMT-1. The reactor steady-state initial conditions assumed for this transient can be found in Table 15.6.5-9. The event times for this transient are given in Table 15.6.5-12.

The break opens at time zero, and the pressurizer pressure begins to fall as shown in Figure 15.6.5.4B-17 as mass is lost out the break. The pressurizer mixture level initially decreases as given in Figure 15.6.5.4B-18. The break fluid flow is shown in Figures 15.6.5.4B-32 and -33. The pressurizer pressure falls below the reactor trip set point, causing the reactor to trip (after the appropriate time delay) and causing isolation of the steam generator steam lines. The core makeup tank isolation valves on both delivery lines and the PRHR delivery line isolation valve open after an “S” signal occurs (with appropriate delays); the reactor coolant pumps trip after an “S” with a 6.0-second delay. The reactor coolant system is cooled by natural circulation with the steam generators removing the energy through their safety valves (as well as by the break) and via the PRHR. Once the core makeup tank isolation valves open, the core makeup tanks begin to inject borated water into the reactor coolant system as shown in Figures 15.6.5.4B-22 and -23.

As time proceeds, the loops drain to the reactor vessel. The mixture level in the downcomer begins to drop as seen in Figure 15.6.5.4B-30, and the core remains completely covered. The core makeup tank reaches the 67.5-percent level, and after an appropriate delay, the ADS Stage 1 valves open. When the ADS is actuated, the mixture level increases in the pressurizer (Figure 15.6.5.4B-18) because an opening has been created at the top of the pressurizer. After these valves open, a more rapid depressurization occurs as seen in Figure 15.6.5.4B-17; the accumulator setpoint is reached and the accumulators begin to inject. The injection flow from the core makeup tanks are shown in Figures 15.6.5.4B-22 and -23, and from the accumulators, in Figures 15.6.5.4B-24 and -25.

As Figures 15.6.5.4B-22 and -23 indicate, when the accumulators begin to inject, the flow from both core makeup tanks is reduced, and the flow is temporarily stopped due to the pressurization of the core makeup tanks injection lines by the accumulators.

The ADS Stage 2 valves, maintaining the depressurization rate as shown in Figure 15.6.5.4B-17. ADS Stage 3 valves open, thereby increasing the system venting capability. The ADS Stage 4 valves open when the core makeup tank water level is reduced to 20 percent. Figures 15.6.5.4B-28 and -31 indicate the instantaneous liquid and integrated total mass discharged from the ADS Stage 4 valves. After the ADS Stage 4 path opens, the pressurizer begins to drain mixture into the hot legs as seen in Figure 15.6.5.4B-18. The Figure 15.6.5.4B-29 mass inventory plot considers the primary inventory to be the reactor coolant system proper, including the pressurizer; the mass present in the passive safety system components is not included at time zero. Once the downcomer pressure drops below the IRWST injection pressure, flow enters the reactor vessel from the IRWST. The mixture level in the reactor vessel is approximately at the hot leg elevation as shown in Figure 15.6.5.4B-30 throughout this transient; the core never uncovers, and the peak cladding temperature occurs for this transient at the inception of the event. The 2-inch break cases exhibit large margin-to-core uncovery.

15.6.5.4B.3.5 Direct Vessel Injection Line Break

This case models the double-ended rupture of the DVI line at the nozzle into the downcomer. The broken loop injection system (consisting of an accumulator, a core makeup tank, and an IRWST delivery line) is modeled to spill completely out the DVI side of the break. The steady-state reactor coolant system conditions for this transient are shown in Table 15.6.5-9. Design maximum resistances are applied to the inlet and outlet lines of that core makeup tank to conservatively minimize intact loop core makeup tank delivery through the time of minimum reactor coolant system mass inventory. Minimum resistances are applied to the broken loop IRWST injection line to maximize the spill to containment, thus minimizing the reactor coolant system mass inventory. This case uses a containment backpressure defined to be a constant 20 psia. While not exactly reflecting the containment pressure history that occurs as a result of the DVI line break, it represents a conservatively low estimate of the expected containment pressure response during a DEDVI transient. The containment pressurizes for a DEDVI break as a result of the break mass and energy releases in addition to the ADS-4 discharge paths that vent directly to the containment atmosphere.

The containment pressurization was calculated using the mass and energy releases from the NOTRUMP small-break LOCA code in the WGOTHIC containment model. Mass and energy releases from both sides of the DVI break (both vessel side and DVI side) and ADS-4 valve discharges were provided in a tabular form to the WGOTHIC AP1000 model used to compute containment pressurization for the long-term cooling analysis.

The event times for this transient are shown in Table 15.6.5-13. The break is assumed to open instantaneously at 0 seconds. The accumulator on the broken loop starts to discharge via the DVI line to the containment. Figure 15.6.5.4B-36 shows the subcooled discharge from the downcomer nozzle, which causes a rapid reactor coolant system (RCS) depressurization (Figure 15.6.5.4B-38). A reactor trip signal is generated, followed by generation of the “S” signal. Following a delay, the isolation valves on the core makeup tank and PRHR delivery lines begin to

open. The "S" signal also causes closure of the main feedwater isolation valves after a 2-second delay and trips the reactor coolant pumps after a 6-second delay. The opening of the core makeup tank isolation valves allows the broken loop core makeup tank to discharge directly to the containment (Figure 15.6.5.4B-39), and a small circulatory flow develops through the intact loop core makeup tank (Figure 15.6.5.4B-40).

As the pressure falls, the reactor coolant system fluid saturates, and a mixture level forms in the upper plenum and then falls to the hot leg elevation (Figure 15.6.5.4B-41). The upper parts of the reactor coolant system start to drain, and a mixture level forms in the downcomer (Figure 15.6.5.4B-42) and falls below the elevation of the break. Two-phase discharge, then vapor flow occurs from the downcomer side of the break (Figure 15.6.5.4B-37).

In the core makeup tank connected to the broken loop, a level forms and starts to fall. The ADS Stage 1 setpoint is reached, and the ADS Stage 1 valves open after the signal delay time elapses. The ensuing steam discharge from the top of the pressurizer (Figure 15.6.5.4B-43) increases the reactor coolant system depressurization rate. The depressurization rate is also increased due to the steam discharge from the downcomer to the containment (Figure 15.6.5.4B-37) as the downcomer mixture level falls below the DVI nozzle (Figure 15.6.5.4B-42).

During the initial portion of the DEDVI break, only liquid flows out the top of the core (Figure 15.6.5.4B-45). Soon, steam flows out also (Figure 15.6.5.4B-46) because the void fraction in the core increases (Figure 15.6.5.4B-44). The break in the downcomer draws fluid from the bottom of the core (Figure 15.6.5.4B-47) and insufficient liquid remains in the core and upper plenum to sustain the mixture level. The mixture level therefore starts to decrease (Figure 15.6.5.4B-41). The mixture level falls to a minimum and then starts to recover, as flow re-enters the core from the downcomer (Figure 15.6.5.4B-41 compared to -47).

The ADS Stage 2 valves open after the appropriate time delay between the actuation of the first two stages of the ADS. The intact loop accumulator starts to inject into the downcomer (Figure 15.6.5.4B-50) causing the mixture level in the downcomer to slowly rise (Figure 15.6.5.4B-42). The mixture level also increases within the upper plenum.

The ADS Stage 3 valves open upon completion of the time delay of 120 seconds between the actuation of Stages 2 and 3 of the ADS. The broken loop core makeup tank level reaches the ADS Stage 4 setpoint, but the ADS Stage 4 valves do not open until the minimum time delay between the actuation of ADS Stages 3 and 4 occurs. Two-phase discharge ensues through three of the four Stage 4 paths (Figures 15.6.5.4B-48 and -49). The broken loop core makeup tank and accumulator empty rapidly.

The fluid level at the top of the intact loop core makeup tank starts to decrease slowly (Figure 15.6.5.4B-52) because injection from the tank has begun (Figure 15.6.5.4B-40). The intact loop accumulator has emptied (Figure 15.6.5.4B-50) and the reduced pressure in the injection line allows the core makeup tank to inject continuously.

During the period of accumulator injection, the downcomer mixture level rises slowly (Figure 15.6.5.4B-42). Figure 15.6.5.4B-53 presents the RCS mass inventory. With only intact loop core makeup tank injection available for a period of time, the downcomer level once again

falls and core boil-off increases the rate of reactor coolant system inventory depletion until sufficient CMT/IRWST injection flow can be introduced. However, the level in the upper plenum is maintained near the hot leg elevation (Figure 15.6.5.4B-41) throughout the remainder of the transient.

Once the pressure in the broken DVI line falls below that in the IRWST, the water from the tank is spilled to the containment.

Stable, but decreasing, injection continues from the intact loop core makeup tank as the reactor coolant system pressure declines slowly. The reactor coolant system pressure continues to fall until it drops below that of the IRWST and injection begins (Figure 15.6.5.4B-51). With the reduced initial RCS inventory recovery from the accumulators and only a single intact injection path available for the DEDVI line break, the minimum inventory occurs near the initiation of IRWST injection flow. After injection flow greater than the sum of the break and ADS flows exists, a slow rise in the reactor coolant system inventory (Figure 15.6.5.4B-53) occurs. Since no core uncovery is predicted for this scenario, no cladding heatup occurs.

The critical heat flux assessment described in subsection 15.6.5.4B.2.3 addresses core cooling during a time period where the NOTRUMP computer code may not conservatively predict the core average void fraction. The requirements of 10 CFR 50.46 are met during this period since this CHF assessment indicates peak core heat flux is less than critical heat flux. Cladding temperatures will remain near the coolant saturation temperature, well below the 10 CFR 50.46 peak cladding temperature limit.

Another DEDVI line break analysis is performed that is the same as the case discussed above except that containment pressure is assumed to be at 14.7 psia. Table 15.6.5-13A provides the time sequence of events for this analysis. Figures 15.6.5.4B-36A through -55A provide the transient results for this analysis. The transient is like the case at 20 psia except that IRWST injection occurs somewhat later due to the lower containment pressure.

15.6.5.4B.3.6 10-inch Cold Leg Break

This case models a 10-inch break occurring in the bottom of a cold leg connected to the balance line of CMT-1. The reactor steady-state initial conditions assumed for this transient are found in Table 15.6.5-9. The event times for this transient are given in Table 15.6.5-14.

The break opens at time zero, and the pressurizer pressure begins to fall, as shown in Figure 15.6.5.4B-56, as mass is lost out the break. The pressurizer mixture level initially decreases as given in Figure 15.6.5.4B-57. The break fluid flow is shown in Figures 15.6.5.4B-75 and -76 for the liquid and vapor components respectively. The pressurizer pressure falls below the reactor trip set point. This causes the reactor to trip (after the appropriate time delay) and isolation of the steam generator steam lines. The core makeup tank isolation valves on both delivery lines and the PRHR delivery line isolation valve open after an “S” signal occurs (with appropriate delays); the reactor coolant pumps trip after an “S” with a 6.0-second delay. The reactor coolant system is cooled by natural circulation with energy being removed by the steam generator safety valves, the core, and the PRHR heat exchanger. Once the core makeup tank isolation valves open, the core

makeup tanks begin to inject borated water into the reactor coolant system as shown in Figures 15.6.5.4B-61 and -62.

As time proceeds, the loops drain to the reactor vessel. The mixture level in the downcomer begins to drop as seen in Figure 15.6.5.4B-60, and the core remains completely covered. Due to the size and location of the break involved, the accumulator setpoint is reached prior to the core makeup tanks transitioning from recirculation to injection mode. The flows from the core makeup tanks are shown in Figures 15.6.5.4B-61 and -62, and from the accumulators, in Figures 15.6.5.4B-63 and -64. The response of core makeup tank 1 is offset compared to that of core makeup tank 2 as a result of the break size/location being modeled. Core makeup tank 2 reaches the 67.5-percent level first, and after an appropriate delay, the ADS Stage 1 valves open. When the ADS is actuated, the mixture level increases in the pressurizer (Figure 15.6.5.4B-57) because an opening has been created at the top of the pressurizer. After these valves open, a more rapid depressurization occurs as seen in Figure 15.6.5.4B-56.

During the initial portion of the 10-inch break, both liquid and steam flow out the top of the core (Figures 15.6.5.4B-71 and -72) as the void fraction in the core increases (Figure 15.6.5.4B-73). The break in the cold leg draws fluid from the bottom of the core, and insufficient liquid remains in the core and upper plenum to sustain the mixture level. The mixture level, therefore, starts to decrease (Figure 15.6.5.4B-69). The mixture level falls to a minimum and then starts to recover as accumulator flows enter the downcomer (Figures 15.6.5.4B-63 and -64). During this time period (~75-125 seconds), a portion of the core exhibits the potential for core dryout to occur without the prediction of a traditional core uncovery period (for example, core two-phase mixture level dropping into the active fuel region). To conservatively account for this potential core dryout period, a composite core mixture level was created which collapses to the minimum of the actual core/upper plenum two-phase mixture level and the bottom of the lowest core node that exceeds the core dryout onset conditions. A 90-percent quality limit was chosen as the indicator of the onset of core dryout indicative of the critical heat flux (as predicted by Griffith's modification of the Zuber equation, in References 28 and 29); dryout is assumed at core qualities above this value. The resulting composite core mixture level resulting from this approach can be seen in Figure 15.6.5.4B-70. To conservatively estimate the effects of this dryout period, an adiabatic heat-up calculation was performed, and the resulting peak cladding temperature is determined to be approximately 1370°F. Even under these conservative adiabatic heat-up assumptions, the AP1000 plant design exhibits large margins to the 10 CFR 50.46 Appendix-K limits for the 10-inch break.

As Figures 15.6.5.4B-61 and -62 indicate, when the accumulators begin to inject, the flow from both core makeup tanks is reduced and the flow is temporarily stopped due to the pressurization of the injection lines of the core makeup tanks by the accumulators. The opening of ADS Stage 2 valves maintains the depressurization rate as shown in Figure 15.6.5.4B-56. ADS Stage 3 valves subsequently open. This increases the system venting capability. The ADS Stage 4 valves open when the core makeup tank water level is reduced to 20 percent. Figures 15.6.5.4B-67 and -74 indicate the instantaneous liquid and integrated total mass discharged from the ADS Stage 4 valves. After the ADS Stage 4 path opens, the pressurizer begins to drain mixture into the hot legs as seen in Figure 15.6.5.4B-57. The Figure 15.6.5.4B-68 mass inventory plot considers the primary inventory to be the reactor coolant system proper, including the pressurizer; the mass present in the passive safety system components is not included. Once the downcomer pressure

drops below the IRWST injection pressure, flow enters the reactor vessel from the IRWST. The mixture level in the reactor vessel is approximately at the hot leg elevation as shown in Figure 15.6.5.4B-69 throughout this transient; the core never uncovers, even though the period of potential core dryout was predicted to occur during the initial blowdown period. Even when the core dryout is conservatively accounted for, large margins to the 10 CFR 50.46 Appendix-K limits of 2200°F exist.

15.6.5.4B.3.7 Direct Vessel Injection Line Break (Entrainment Sensitivity)

In order to assess the potential impact of higher than expected entrainment in the upper plenum and hot legs on the overall system response and core cooling, an AP1000 plant sensitivity run was performed. The sensitivity case was performed with the DEDVI line break simulation as described in the following. The simulation is identical to the base DEDVI line simulation presented in subsection 15.6.5.4B.3.5 until ADS-4 actuation, at which time the higher than expected entrainment is included in the analysis by assuming homogenous conditions in the regions downstream of the core. In addition, since homogenous treatment of these regions will eliminate the pressure drop effect of the accumulated mass stored in the upper plenum, the NOTRUMP model was conservatively adjusted to account for this effect following the transition of the ADS-4 flow paths to noncritical conditions.

Figure 15.6.5.4B-79 presents a comparison of the upper downcomer pressure between the base and sensitivity cases. The sensitivity case results in higher upper downcomer pressure and subsequently results in delayed IRWST injection (Figure 15.6.5.4B-80). This can also be observed in the intact DVI line flow, which comprises all intact injection flow components (that is, accumulator, CMT, and IRWST) per Figure 15.6.5.4B-81, and the pressurizer mixture level response (Figure 15.6.5.4B-90), which follows the change in pressure response. As expected, the initial ADS-4 liquid discharge is much higher (Figure 15.6.5.4B-82) until the inventory, which resided in the upper plenum and hot leg regions, depletes (Figure 15.6.5.4B-83). The net effect is a decrease in the ADS-4 vapor discharge rate (Figure 15.6.5.4B-84) and subsequently higher RCS pressures.

Due to the elimination of the inventory stored in the upper plenum, the downcomer mass is also reduced (Figure 15.6.5.4B-85). Since the static head that existed in the upper plenum is eliminated when the model is made homogenous, the downcomer mixture is subsequently driven into the core as the static heads equilibrate. This results in the core region mass increasing initially due to the introduction of cold downcomer fluid to the core region (Figure 15.6.5.4B-86). The net effect of the sensitivity case is that the vessel inventory is substantially decreased over the base model simulation (Figure 15.6.5.4B-87); however, this inventory is sufficient to provide adequate core cooling because the ADS-4 continually draws liquid flow through the core (Figure 15.6.5.4B-82). Even though there is no liquid storage in the upper plenum for the homogenous case (Figure 15.6.5.4B-88), the core collapsed liquid level (Figure 15.6.5.4B-89) is not impacted significantly.

This sensitivity demonstrates that the AP1000 plant response is relatively insensitive to upper plenum and hot leg entrainment. Even with the assumption of homogenous fluid nodes above the core, adequate core cooling is demonstrated. No significant core uncovery/heatup is predicted for this scenario.

15.6.5.4B.4 Conclusions

The small-break LOCA analyses performed show that the performance of the AP1000 plant design to small-break LOCA scenarios is excellent and that the passive safeguards systems in the AP1000 are sufficient to mitigate LOCAs. Specifically, it is concluded that:

- The primary side can be depressurized by the ADS to allow stable injection into the core.
- Injection from the core makeup tanks, accumulators, and IRWST prevents excessive cladding heatup for small-break LOCAs analyzed, including double-ended ruptures in the passive safeguards system lines. The peak AP1000 heat flux during the accumulator injection period is below the predicted critical heat flux.
- The effect of increasing upper plenum/hot leg entrainment does not significantly affect plant safety margins.

The analyses performed demonstrate that the 10 CFR 50.46 Acceptance Criteria are met by the AP1000. Summarizing the small-break LOCA spectrum:

Break Location/Diameter	AP1000 Minimum RCS Inventory	Peak Cladding Temperature
Inadvertent ADS	105,800	(1)
2-inch cold leg break	106,620	(1)
10-inch cold leg break	78,160	<1370°F
DEDVI	113,710	(1)
DEDVI (Entrainment Study)	~81,000	(1)

The 10-inch cold leg break exhibits the limiting minimum inventory condition that occurs during the initial blowdown period and is terminated by accumulator injection. The AP1000 design is such that the minimum inventory occurs just prior to IRWST injection for all breaks except the 10-inch cold leg break. All breaks simulated in the break spectrum produce results that demonstrate significant margin to peak cladding temperature regulatory limits.

15.6.5.4C Post-LOCA Long-Term Cooling

15.6.5.4C.1 Long-Term Cooling Analysis Methodology

The AP1000 safety-related systems are designed to provide adequate cooling of the reactor indefinitely. Initially, this is achieved by discharging water from the IRWST into the vessel. When the low-3 level setpoint is reached in the IRWST, the containment recirculation subsystem isolation valves open and water from the containment reactor coolant system (RCS) compartment can flow into the vessel through the PXS piping. The water in containment rises in temperature

(1) There is no core heatup as a result of this transient. PCT occurs at transient initiation.

toward the saturation temperature. Long-term heat removal from the reactor and containment is by heat transfer through the containment shell to atmosphere.

The purpose of the long-term cooling analysis is to demonstrate that the passive systems provide adequate emergency core cooling system performance during the IRWST injection/containment recirculation time scale. The long-term cooling analysis is performed using the WCOBRA/TRAC computer code to verify that the passive injection system is providing sufficient flow to the reactor vessel to cool the core and to preclude boron precipitation.

The AP1000 long-term cooling analysis is supported by the series of tests at the Oregon State University AP600 APEX Test Facility. This test facility is designed to represent the AP600 reactor safety-related systems and nonsafety-related systems at quarter-scale during long-term cooling. The data obtained during testing at this facility has been shown to apply to the AP1000 (Reference 25). These tests were modeled using WCOBRA/TRAC with an equivalent noding scheme to that used for AP600 (Reference 17) in order to validate the code for long-term cooling analysis.

Reference 24 provides details of the AP1000 WCOBRA/TRAC modeling. The coarse reactor vessel modeling used for AP600 has been replaced with a detailed noding like that applied in the large-break LOCA analyses described in subsection 15.6.5.4A. The reactor vessel noding used in the AP1000 long-term cooling analyses in core and upper plenum regions is equivalent to that used in full-scale test simulations (see Reference 24).

A DEDVI line break is analyzed because it is the most limiting long-term cooling case in the relationship between decay power and available liquid driving head. Because the IRWST spills directly onto the containment floor in a DEDVI break, this event has the highest core decay power when the transfer to sump injection is initiated. In postulated DEDVI break cases, the compartment water level exceeds the elevation at which the DVI line enters the reactor vessel, so water can flow from the containment into the reactor vessel through the broken DVI line; this in-flow of water through the broken DVI line assists in the heat removal from the core. The steam produced by boiling in the core vents to the containment through the ADS valves and condenses on the inner surface of the steel containment vessel. The condensate is collected and drains to the IRWST to become available for injection into the reactor coolant system. The WCOBRA/TRAC analysis presented analyzes the DEDVI small-break LOCA event from a time (3000 seconds) at which IRWST injection is fully established to beyond the time of containment recirculation. During this time, the head of water to drive the flow into the vessel for IRWST injection decreases from the initial level to its lowest value at the containment recirculation switchover time. PXS Room B is the location of the break in the DVI line. At this break location, liquid level in containment at the time of recirculation is a minimum.

A continuous analysis of the post-LOCA long term cooling is provided from the time of stable IRWST injection through the time of sump recirculation for the DEDVI break. Maximum design resistances are applied in WCOBRA/TRAC for both the ADS Stage 4 flow paths and the IRWST injection and containment recirculation flow paths.

The break modeled is a double-ended guillotine rupture of one of the direct vessel injection lines. The long-term cooling phase begins after the simultaneous opening of the isolation valves in the

IRWST DVI lines and the opening of ADS Stage 4 squib valves, when flow injection from the IRWST has been fully established. Initial conditions are taken from the NOTRUMP DEDVI case at 20 psia containment pressure reported in subsection 15.6.5.4B.

15.6.5.4C.2 DEDVI Line Break with ADS Stage 4 Single Failure, Passive Core Cooling System Only Case; Continuous Case

This subsection presents the results of a DEDVI line break analysis during IRWST injection phase continuing into sump recirculation. Initial conditions at the start of the case are prescribed based on the NOTRUMP DEDVI break results to allow a calculation to begin shortly after IRWST injection begins in the small break long-term cooling transient. The WCOBRA/TRAC calculation is then allowed to proceed until a quasi-steady-state is achieved. At this time, the predicted results are independent of the assumed initial conditions. This calculation uses boundary conditions taken from a WGOTHIC analysis of this event. During the calculation, which is carried out for 10,000 seconds until a quasi-steady-state sump recirculation condition has been established, the IRWST water level is decreased continuously until the sump recirculation setpoint is reached.

In the analysis, one of the two ADS Stage 4 valves in the PRHR loop is assumed to have failed. The initial reactor coolant system liquid inventory and temperatures are determined from the NOTRUMP calculation. The core makeup tanks do not contribute to the DVI injection during this phase of the transient. Steam generator secondary side conditions are taken from the NOTRUMP calculation (at the beginning of long-term cooling). The reactor coolant pumps are tripped and not rotating.

The levels and temperatures of the liquid in the containment sump and the containment pressure are based on WGOTHIC calculations of the conservative minimum pressure during this long-term cooling transient, including operation of the containment fan coolers. Small changes in the RCS compartment level do not have a major effect on the predicted core collapsed liquid level or on the predicted flow rate through the core. The minimum compartment floodup level for this break scenario is 107.8 feet or greater.

In this transient, the IRWST provides a hydraulic head sufficient to drive water into the downcomer through the intact DVI nozzle. Also, water flows into the downcomer from the broken DVI line once the liquid level in the compartment with the broken line is adequate to support flow. The water flows down the downcomer and up through the core, into the upper plenum. Steam produced in the core and liquid flow out of the reactor coolant system via the ADS Stage 4 valves. There is little flow out of ADS Stages 1, 2, and 3 even when the IRWST liquid level falls below the sparger elevation, so they are not modeled in this calculation. The venting provided by the ADS-4 paths enables the liquid flow through the core to maintain core cooling.

Approximately 500 seconds of WCOBRA/TRAC calculation are required to establish the quasi-steady-state condition associated with IRWST injection at the start of long-term cooling and so are ignored in the following discussion. The hot leg levels are such that during the IRWST injection phase the quality of the ADS Stage 4 mass flows varies as water is carried out of the hot legs. This periodically increases the pressure drop across the ADS Stage 4 valves and the upper plenum pressure. The higher pressure in the upper plenum reduces the injection flow. This cycle

of pressure variations due to changing void fractions in the flow through ADS Stage 4 is consistent with test observations and is expected to recur often during long-term cooling.

The head of water in the IRWST causes a flow of subcooled water into the downcomer at an approximate rate of 170 lbm/s through the intact DVI nozzle at the start of long-term cooling. The downcomer level at the end of the code initiation (the start of long-term cooling) is about 18.0 feet (Figure 15.6.5.4C-1). Note that the time scale of this and other figures in subsection 15.6.5.4C.2 is offset by 2500 seconds; that is, a time of 500 seconds on the Figure 15.6.5.4C-1 axis equals 3000 seconds transient time for the DEDVI break. All of the injection water flows down the downcomer and up through the core. The accumulators have been fully discharged before the start of the time window and do not contribute to the DVI flow.

Boiling in the core produces steam and a two-phase mixture, which flows into the upper plenum. The core is 14 feet high, and the core average collapsed liquid level (Figure 15.6.5.4C-2) is shown from the start of long-term cooling. The boiling process causes a variable rate of steam production and resulting pressure changes, which in turn causes oscillations in the liquid flow rate at the bottom of the core and also variations in the core collapsed level and the flow rates of liquid and vapor out of the top of the core. In the WCOBRA/TRAC noding, the core is divided both axially and radially as described in Reference 24. The void fractions in the top two cells of the hot assembly are shown as Figures 15.6.5.4C-3 and -4. The average void fraction of these upper core cells is about 0.8 during long-term cooling, during IRWST injection, and into the containment recirculation period. There is a continuous flow of two-phase fluid into the hot legs, and mainly vapor flow toward the ADS Stage 4 valve occurs at the top of the pipe. The collapsed liquid level in the hot leg varies between 0.8 feet to 1.6 feet (Figure 15.6.5.4C-5). The hot legs on average are more than 50-percent full. Vapor and liquid flows at the top of the core are shown in Figures 15.6.5.4C-6 and 15.6.5.4C-7, the upper plenum collapsed liquid level in Figure 15.6.5.4C-8. Figures 15.6.5.4C-9 and 15.6.5.4C-10 are ADS stage 4 mass flowrates.

The pressure in the upper plenum is shown in Figure 15.6.5.4C-11. The upper plenum pressure fluctuation that occurs is due to the ADS Stage 4 water discharge. The PCT of the hot rod follows saturation temperature (Figure 15.6.5.4C-12), which demonstrates that no uncovery and no cladding temperature excursion occurs. A small pressure drop is calculated across the reactor vessel, and injection rates through the DVI lines into the vessel are presented in Figures 15.6.5.4C-13 and -14. Figure 15.6.5.4C-14 shows the flow is outward through the broken DVI line at the start of the long-term cooling period, and it increases to a maximum average value of about 52 lbm/s after the compartment water level has increased above the nozzle elevation to permit liquid injection into the reactor vessel. In contrast, the intact DVI line flow falls from 170 lbm/s with a full IRWST to about 65 lbm/s flow from the containment at the end of the calculation. The recirculation core liquid throughput is more than adequate to preclude any boron buildup on the fuel.

Figures 15.6.5.4C-1A through -14A present the sensitivity of long-term cooling performance to a bounding containment pressure of 14.7 psia. The DEDVI break in the PXS “B” Room case is restarted at 6500 seconds to assess in a window mode calculation the effect of this reduced containment pressure at the most limiting time in the transient, the switchover to containment recirculation. The initial 700 seconds of the window establish the reactor vessel pressure condition that is consistent with the 14.7 psia containment pressure. After 7200 seconds, the

WCOBRA/TRAC calculation provides the transient behavior of the AP1000 at the reduced containment pressure.

15.6.5.4C.3 DEDVI Break and Wall-to-Wall Floodup; Containment Recirculation

This subsection presents a DEDVI line break analysis with wall-to-wall flooding due to leakage between compartments, using the window mode methodology. All containment free volume beneath the level of the liquid is assumed filled in this calculation to generate the minimum water level condition during containment recirculation. The time identified for this calculation is 14 days into the event, and the core power is calculated accordingly. The initial conditions at the start of the window are consistent with the analysis described in subsection 15.6.5.4C.2. Containment recirculation is simulated during the time window. The calculation is carried out over a time period long enough to establish a quasi-steady-state solution; after 400 seconds of problem time, the flow dynamics are quasi-steady-state and the predicted results are independent of the assumed initial conditions. The liquid level is simulated constant at 28.2 feet above the bottom inside surface of the reactor vessel (refer to Figure 15.0.3-2 for AP1000 reference plant elevations) during the time window, and the liquid temperatures in the containment sump and the PXS “B” room are 196°F and 182°F, respectively. The containment pressure is conservatively assumed to be 14.7 psia. The single failure of an ADS Stage 4 flow path is assumed as in the subsection 15.6.5.4C.2 case.

Focusing on the post 400-second time interval of this case, the containment liquid provides a hydraulic head sufficient to drive water into the downcomer through the DVI nozzles. The water introduced into the downcomer flows down the downcomer and up through the core, into the upper plenum. Steam produced in the core entrains liquid and flows out of the reactor coolant system via the ADS Stage 4 valves. The DVI flow and the venting provided by the ADS paths provide a liquid flow through the core that enables the core to remain cool.

The downcomer collapsed liquid level (Figure 15.6.5.4C-15) varies between 23 and 25 feet during the analysis. Pressure spikes produced by boiling in the core can cause the mass flow of the DVI flow rates shown in Figures 15.6.5.4C-27 and -28 into the vessel to fluctuate upward and downward.

Boiling in the core produces steam and a two-phase mixture, which flows out of the core into the upper plenum. The core is 14 feet high, and the core collapsed liquid level (Figure 15.6.5.4C-16) maintains a mean level close to the top of the core. The boiling process causes pressure variations, which in turn, cause variations in the core collapsed level and the flow rates of liquid and vapor out of the top of the core. In the WCOBRA/TRAC analysis, the core is nodalized as described in Reference 24. The void fraction in the top cell is shown in Figure 15.6.5.4C-17 for the core hot assembly, and Figure 15.6.5.4C-18 shows the void fraction that exists one cell further down in the hot assembly. The PCT does not rise appreciably above the saturation temperature (Figure 15.6.5.4C.3-26). The flow through the core and out of the reactor coolant system is more than sufficient to provide adequate flushing to preclude concentration of the boric acid solution. Liquid collects above the upper core plate in the upper plenum, where the average collapsed liquid level is about 3.6 feet (Figure 15.6.5.4C-22). There is no significant flow through the cold legs into either the broken or the intact loops, and there is no significant quantity of liquid residing in any of the cold legs.

The pressure in the upper plenum is shown in Figure 15.6.5.4C-25. The upper plenum pressurization, which occurs periodically, is due to the ADS Stage 4 water discharge. The collapsed liquid level in the hot leg of the pressurizer loop varies between 1.0 feet and 2.1 feet, as shown in Figure 15.6.5.4C-19. Injection rates through the DVI lines into the vessel are presented in Figures 15.6.5.4C-27 and -28.

15.6.5.4C.4 Post Accident Core Boron Concentration

An evaluation has been performed of the potential for the boron concentration to build up in the core following a cold leg LOCA. The evaluation methodology, simplified calculations, and their results are discussed in Reference 24. This evaluation considers both short-term operations, before ADS is actuated, and long-term operations, after ADS is actuated. These evaluations and their results are discussed in the follow paragraphs.

Short-Term – Prior to ADS actuation, it is not likely for boron to build up significantly in the core. Normally, water circulation mixes boron in the RCS and prevents buildup in the core. In order for boron to start to build up in the core region, water circulation through the steam generators and PRHR HX has to stop. In addition, significant injection of borated water is needed from the CMTs and the CVS. For this situation to happen, the hot legs need to void sufficiently to allow the steam generator tubes to drain. Once the steam generator tubes void, the cold legs will also void since they are located higher than the hot legs. When the top of the cold legs void, the CMTs will begin to drain. When the CMTs drain to the ADS stage 1 setpoint, ADS is actuated.

Short-Term Results – As shown in subsection 15.6.5.4B.3.4, a 2-inch LOCA requires less than 16 minutes from the time that the hot legs void significantly until ADS is actuated. For larger LOCAs, this time difference is shorter, as seen for the 10-inch cold leg LOCA (subsection 15.6.5.4B.3.6). The core boron concentration will not build up significantly in this short time. If the break is smaller than 2 inches, voiding of the hot legs will occur at a later time. With maximum operation of CVS makeup, it takes more than 3 hours for the core boron concentration to build up significantly. In addition, the volume of the boric acid tank limits the maximum buildup of boron in the core.

Following a small LOCA where ADS is not actuated, the operators are guided to sample the RCS boron concentration and to initiate a post-LOCA cooldown and depressurization. The cooldown and depressurization of the RCS reduces the leak rate and facilitates recovery of the pressurizer level. Recovery of the pressurizer level allows for re-establishment of water flow through the RCS loops, which mixes the boron. The operators are guided to take an RCS boron sample within 3 hours of the accident and several more during the plant cooldown. The purpose of the boron samples is to assess that there is adequate shutdown margin and that the RCS boron concentration has not built up to excessive levels. The maximum calculated core boron concentration 3 hours after a LOCA without ADS actuation is less than 16,000 ppm. Operator action within 3 hours maintains the maximum core boron concentration well below the boron solubility limit for the core inlet temperatures during the cooldown.

Long-Term – Once ADS is actuated, water carryover out the ADS Stage 4 lines limits the potential core boron concentration buildup following a cold leg LOCA. The design of the AP1000 facilitates water discharge from the hot legs as follows:

- PXS recirculation flow capability tends to fill the hot legs and bring the water level up to the ADS Stage 4 inlet.
- ADS Stage 4 lines discharge at an elevation 3 to 4 feet above the containment water level.

With water carried out ADS Stage 4, the core boron concentration increases until the boron added to the core in the safety injection flow equals the boron removed in the water leaving the RCS through the ADS Stage 4 flow. The lower the ADS Stage 4 vent quality, the lower the core boron concentration buildup.

Long-Term Results – Analyses have been performed (Reference 24) to bound the maximum core boron concentration buildup. These analyses demonstrate that highest ADS Stage 4 vent qualities result from the following:

- Highest decay heat levels
- Lowest PXS injection/ADS 4 vent flows, including high line resistances and low containment water levels

The long-term cooling analysis discussed in subsection 15.6.5.4C.2 is consistent with these assumptions. The ADS Stage 4 vent quality resulting from this analysis is less than 40 percent at the beginning of IRWST injection and reaches a maximum of less than 50 percent around the initiation of recirculation. It decreases after this peak, dropping to a value less than 8 percent at 14 days.

With the maximum ADS Stage 4 vent qualities, the maximum core boron concentration peaks at a value of about 7400 ppm at the time of recirculation initiation. After this time, the core boron concentration decreases as the ADS Stage 4 vent quality decreases, reaching 5000 ppm about 9 hours after the accident. The core boron solubility temperature reaches a maximum of 58°F (at 7400 ppm) and quickly drops to 40°F (at 5000 ppm). With these low core boron solubility temperatures, there is no concern with cold PXS injection water causing boron precipitation in the core. With the IRWST located inside containment, its water temperature is normally expected to be above these solubility temperatures. Even considering the minimum IRWST temperature permitted by the Technical Specifications (50°F), the minimum core inlet temperature is greater than the solubility temperature considering heatup of the injection by steam condensation in the downcomer and pickup of sensible heat from the reactor vessel, core barrel, and lower support plate.

The boron concentration water in the containment is initially about 2980 ppm. As the core boron concentration increases, the containment concentration decreases slightly. The minimum boron concentration in containment is greater than 2950 ppm. The solubility temperature of the containment water at its maximum boron concentration is 32°F.

With high decay heat values, the ADS Stage 4 vent flows and velocities are high. These high vent velocities result in flow regimes that are annular for more than 30 days. The annular flow regime moves water up and out the ADS Stage 4 lines. This flow regime is based on the Taitel-Dukler vertical flow regime map. Lower decay heat levels can be postulated later in time or just after a refueling outage. Significantly lower decay heat levels result in lower ADS Stage 4 vent qualities. They also result in ADS Stage 4 vent flows/velocities that are lower. Even with low ADS Stage 4 vent flow velocities, the AP1000 plant will move water out the ADS Stage 4 operating as a manometer. Small amounts of steam generated in the core reduce the density of the steam/water mixture in the core, upper plenum, and ADS Stage 4 line as it bubbles up through the water. As a result, the injection head is sufficient to push the less dense, bubbly steam/water mix out the ADS Stage 4 line.

At the time recirculation begins, the containment level will be about 109.3 feet (for a non-DVI LOCA) and will be about 108.0 feet (for a DVI LOCA). Over a period of weeks after a LOCA, water may slowly leak from the flooded areas in containment to other areas inside containment that did not initially flood. As a result, the minimum containment water could decrease to 103.5 feet. During recirculation operation following a LOCA and ADS actuation, the operators are guided to maintain the containment water level above the 107-foot elevation by adding borated water to the containment. In addition, if the plant continues to operate in the recirculation mode, the operators are guided to increase the level to 109 feet within 30 days of the accident. These actions provide additional margin in water flow through the ADS Stage 4 line. The operators are also guided to sample the hot leg boron concentration prior to initiating recovery actions that might introduce low temperature water to the reactor.

15.6.5.4C.5 Conclusions

Calculations of AP1000 long-term cooling performance have been performed using the WCOBRA/TRAC model developed for AP1000 and described in Reference 24. The DEDVI case was chosen because it reaches sump recirculation at the earliest time (and highest decay heat). A window mode case at the minimum containment water level postulated to occur 2 weeks into long-term cooling was also performed.

The DEDVI small-break LOCA exhibits no core uncovery due to its adequate reactor coolant system mass inventory condition during the long-term cooling phase from initiation into containment recirculation. Adequate flow through the core is provided to maintain a low cladding temperature and to prevent any buildup of boric acid on the fuel rods. The wall-to-wall floodup case using the window mode technique demonstrates that effective core cooling is also provided at the minimum containment water level. The results of these cases demonstrate the capability of the AP1000 passive systems to provide long-term cooling for a limiting LOCA event.

15.6.6 References

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Table 15.6.1-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT CAUSE A DECREASE IN REACTOR COOLANT INVENTORY

Accident	Event	Time (seconds)
Inadvertent opening of a pressurizer safety valve with offsite power available	Pressurizer safety valve opens fully	0.0
	Overtemperature ΔT reactor trip setpoint reached	18.55
	Rods begin to drop	20.55
	Minimum DNBR occurs	21.3
Inadvertent opening of a pressurizer safety valve without offsite power available	Pressurizer safety valve opens fully	0.0
	Overtemperature ΔT reactor trip setpoint reached	18.55
	Turbine trip signal	20.23
	Rods begin to drop	20.55
	Minimum DNBR occurs	21.3
	ac power lost, reactor coolant pumps begin coasting down	23.23
Inadvertent opening of two ADS Stage 1 trains with offsite power available	ADS valves begin to open	0.0
	Overtemperature ΔT reactor trip setpoint reached	18.40
	Rods begin to drop	20.40
	Minimum DNBR occurs	21.30
	ADS valves fully open	25.0
Inadvertent opening of two ADS Stage 1 trains without offsite power available	ADS valves begin to open	0.0
	Low pressurizer pressure reactor trip setpoint reached	18.40
	Turbine trip signal	20.1
	Rods begin to drop	20.40
	Minimum DNBR occurs	21.3
	ac power lost, reactor coolant pumps begin coasting down	23.1
	ADS valves fully open	25.0

Table 15.6.2-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SMALL LINE BREAK OUTSIDE CONTAINMENT

Reactor coolant iodine activity	Initial activity equal to the design basis reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Table 15A-2 in Appendix 15A)[a]
Reactor coolant noble gas activity	280 μCi/g dose equivalent Xe-133
Break flow rate (gpm)	130[b]
Fraction of reactor coolant flashing	0.41
Duration of accident (hr)	0.5
Atmospheric dispersion (χ/Q) factors	See Table 15A-5
Nuclide data	See Table 15A-4

Notes:

a. Use of accident-initiated iodine spike is consistent with the guidance in the Standard Review Plan.

b. At density of 62.4 lb/ft^3.

Table 15.6.3-1

STEAM GENERATOR TUBE RUPTURE SEQUENCE OF EVENTS

Events	Time (seconds)
Double-ended steam generator tube rupture	0
Loss of offsite power	0
Reactor trip	0
Reactor coolant pumps and main feedwater pumps assumed to trip and begin to coastdown	0
One chemical and volume control pump actuated and pressurizer heaters turned on	0
Low-2 pressurizer level signal generated	2,498
Ruptured steam generator power-operated relief valve fails open	2,498
Core makeup tank injection and PRHR operation begins (following maximum delay)	2,515
Ruptured steam generator power-operated relief valve block valve closes on low steamline pressure signal	2,979
Chemical and volume control system isolated on high-2 steam generator narrow range level setpoint	12,541
Break flow terminated	24,100

Table 15.6.3-2

STEAM GENERATOR TUBE RUPTURE MASS RELEASE RESULTS

Total Mass Flow from Initiation of Event to Cooldown to RHR[1] Conditions

	Start of Event to Break Flow Termination (Pounds Mass)	Break Flow Termination to Cut-in of RHR (Pounds Mass)
Faulted steam generator		
– Atmosphere	238,600	93,200
Intact steam generator		
– Atmosphere	183,400	1,234,900
Break flow	385,000	0

Note:
1. RHR = residual heat removal

Table 15.6.3-3

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A STEAM GENERATOR TUBE RUPTURE

Reactor coolant iodine activity	
– Accident initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 335 (see Appendix 15A). Duration of spike is 5.3 hours.
– Preaccident spike	An assumed iodine spike that results in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal	10% of reactor coolant concentrations at maximum equilibrium conditions
Reactor coolant mass (lb)	3.84 E+05
Offsite power	Lost on reactor trip
Condenser	Lost on reactor trip
Time of reactor trip	Beginning of the accident
Duration of steam releases (hr)	13.19
Atmospheric dispersion factors	See Appendix 15A
Nuclide data	See Appendix 15A
Steam generator in ruptured loop	
– Initial secondary coolant mass (lb)	1.66 E+05
– Primary-to-secondary break flow	See Figure 15.6.3-5
– Flashing fraction for break flow	See Figure 15.6.3-10
– Steam released (lb)	See Table 15.6.3-2
– Iodine partition coefficient	1.0 E-02[a]
– Alkali metals partition coefficient	1.0 E-03[a]
Steam generator in intact loop	
– Initial secondary coolant mass (lb)	2.00 E+05
– Primary-to-secondary leak rate (lb/hr)	52.14[b]
– Steam released (lb)	See Table 15.6.3-2
– Iodine partition coefficient	1.0 E-02
– Alkali metals partition coefficient	1.0 E-03

Notes:

a. Iodine partition coefficient does not apply to flashed break flow.

b. Equivalent to 150 gpd at psia cooled liquid at 62.4 lb/ft^3.

Table 15.6.5-1

CORE ACTIVITY RELEASES TO THE CONTAINMENT ATMOSPHERE

Nuclide	Gap Release Released over 0.5 hr. (0.167 - 0.667 hr)[1]	Core Melt In-vessel Release (0.667 - 1.967 hr)[1]
Noble gases	0.05	0.95
Iodines	0.05	0.35
Alkali metals	0.05	0.25
Tellurium group	–	0.05
Strontium and barium	–	0.02
Noble metals group	–	0.0025
Cerium group	–	0.0005
Lanthanide group	–	0.0002

Notes:
1. Releases are stated as fractions of the original core fission product inventory.
2. Dash (–) indicates not applicable.

Table 15.6.5-2 (Sheet 1 of 3)

ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Primary coolant source data	
– Noble gas concentration	280 μCi/g dose equivalent Xe-133
– Iodine concentration	1.0 μCi/g dose equivalent I-131
– Primary coolant mass (lb)	3.72 E+05
Containment purge release data	
– Containment purge flow rate (cfm)	8800
– Time to isolate purge line (seconds)	30
– Time to blow down the primary coolant system (minutes)	10
– Fraction of primary coolant iodine that becomes airborne	0.5
Core source data	
– Core activity at shutdown	See Table 15A-3
– Release of core activity to containment atmosphere (timing and fractions)	See Table 15.6.5-1
– Iodine species distribution (%)	
• Elemental	4.85
• Organic	0.15
• Particulate	95
Containment leakage release data	
– Containment volume (ft^3)	2.06 E+06
– Containment leak rate, 0-24 hr (% per day)	0.10
– Containment leak rate, > 24 hr (% per day)	0.05
– Elemental iodine deposition removal coefficient (hr^{-1})	1.7
– Decontamination factor limit for elemental iodine removal	200
– Removal coefficient for particulates (hr^{-1})	See Appendix 15B
Main control room model	
– Main control room volume (ft^3)	35,700
– Volume of HVAC, including main control room and technical center (ft^3)	105,500
– Normal HVAC operation (prior to switchover to an emergency mode)	
• Air intake flow (cfm)	1925
• Filter efficiency	Not applicable

Table 15.6.5-2 (Sheet 2 of 3)

ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Main control room model (cont.)	
– Atmospheric dispersion factors (sec/m^3)	See Table 15A-6
– Occupancy	
• 0 - 24 hr	1.0
• 24 - 96 hr	0.6
• 96 - 720 hr	0.4
– Breathing rate (m^3/sec)	3.5 E-04
Control room with emergency habitability system credited	
– Main control room activity level at which the emergency habitability system is actuated (Ci/m^3 of dose equivalent I-131)	2.0 E-6
– Time to switch from normal HVAC to emergency habitability system operation after actuation signal generation (sec)	30
– Interval with operation of the emergency habitability system	
• Flow from compressed air bottles of the emergency habitability system (cfm)	60
• Unfiltered inleakage via ingress/egress (cfm)	5.0
• Recirculation flow (cfm)	Not applicable
– Time at which the compressed air supply of the emergency habitability system is depleted (hr)	72
– After depletion of emergency habitability system bottled air supply (>72 hr)	
• Air intake flow (cfm)	1700
• Intake flow filter efficiency (%)	Not applicable
• Recirculation flow (cfm)	Not applicable
– Time at which the compressed air supply is restored and emergency habitability system returns to operation (hr)	168
Control room with credit for continued operation of HVAC	
– Time delay to switch from normal operation to the supplemental air filtration mode (sec)	30
– Filtered air intake flow (cfm)	860
– Filtered air recirculation flow (cfm)	2740
– Filter efficiency (%)	
• Elemental iodine	90
• Organic iodine	90
• Particulates	99

Table 15.6.5-2 (Sheet 3 of 3)

ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Miscellaneous assumptions and parameters	
– Unfiltered air inleakage (cfm)	90
– Offsite power	Not applicable
– Atmospheric dispersion factors (offsite)	See Table 15A-5
– Nuclide dose conversion factors	See Table 15A-4
– Nuclide decay constants	See Table 15A-4
– Offsite breathing rate (m^3/sec)	
0 - 8 hr	3.5 E-04
8 - 24 hr	1.8 E-04
24 - 720 hr	2.3 E-04

Table 15.6.5-3

RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT WITH CORE MELT

	TEDE Dose (rem)
Exclusion zone boundary dose (1.4 - 3.4 hr)[(1)]	24.6
Low population zone boundary dose (0 - 30 days)	23.8
Main control room dose (emergency habitability system in operation)	
– Airborne activity entering the main control room	4.61 rem
– Direct radiation from adjacent structures	0.15 rem
– Sky-shine	0.01 rem
– Total	4.77 rem
Main control room dose (normal HVAC operating in the supplemental filtration mode)	
– Airborne activity entering the main control room	4.38 rem
– Direct radiation from adjacent structures	0.15 rem
– Sky-shine	0.01 rem
– Total	4.54 rem

Note:
1. This is the 2-hour period having the highest dose.

Table 15.6.5-4

MAJOR PLANT PARAMETER ASSUMPTIONS USED IN THE BEST-ESTIMATE LARGE-BREAK LOCA ANALYSIS

	Parameter Value Selected	Other AP1000 Cases Analyzed/Selection Basis
Plant physical configuration		
Steam generator tube plugging level	0% (Bound)	10% uniform
Hot assembly location	Under open hole (bound)	Under guide tube
Pressurizer location	In intact loop (bound)	In broken loop
Power-related parameters		
Initial core power	3400x1.02=3468 MW (bound)	—
Core linear power	5.977 kW/ft (core average)	—
Peak linear heat rate (FQ)	2.6 (bound)	—
Axial power distribution	Power shape 3 (top skewed, bound)	Based on AP600 study
Hot rod assembly power (FΔH)	1.65 (bound)	—
Hot assembly (FΔH)	1.586 (bound)	—
Peripheral assembly power	0.995 (upper bound)	0.3 (lower bound)
Initial fluid conditions		
Reactor coolant system average temperature	573.6°F (bound)	Value 6.5°F higher
Pressurizer pressure	2300 psia (bound)	Based on AP600 study
Pressurizer level (water volume)	1000 ft^3 (nominal)	—
Accumulator temperature	120°F (bound)	Based on AP600 study
Accumulator pressure	651.7 psia (bound)	Based on AP600 study
Reactor coolant system boundary conditions		
Containment pressure response	From WGOTHIC (lower bound)	—
Offsite power availability	Loss at time zero	Available(1)

Note:
1. A reactor coolant pump automatic trip occurs at 8.2 seconds; due to an “S” signal.

Table 15.6.5-5

AP1000 LOCA CHRONOLOGY

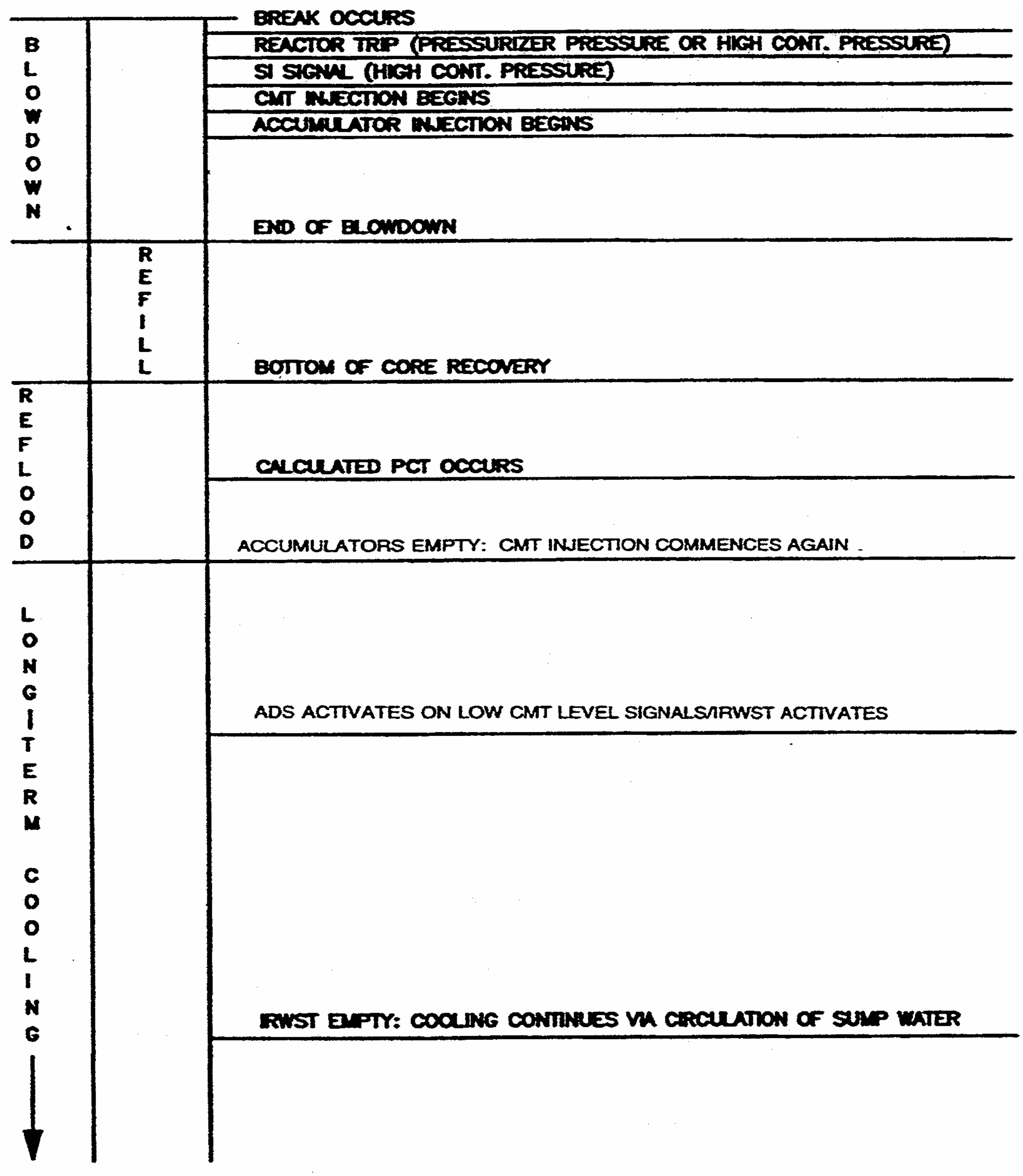

Table 15.6.5-6

REFERENCE TRANSIENT DECLG BREAK SEQUENCE OF EVENTS

Event	Time (seconds)
Break occurs coincident with loss of offsite power	0.0
“S” signal occurs due to containment high-1 pressure	2.2
PRHR, core makeup tank isolation valves begin to open	4.2
Accumulator injection begins	15
End of blowdown	47
Calculated PCT occurs	109.6
Core quench occurs	238

Table 15.6.5-7

DECL SPLIT BREAK RESULTS

Discharge Coefficient	Blowdown PCT (°F)	Reflood PCT (°F)
1.8	1557	1498
1.6	1529	1538
1.4	1482	1468

Table 15.6.5-8

BEST-ESTIMATE LARGE-BREAK LOCA RESULTS

Parameter	Value	Criteria
Calculated 50th percentile PCT (°F) (for time period of maximum 95th percentile)	1840	N/A
Calculated 95th percentile PCT (°F)	2124	2200
Maximum local cladding oxidation (%)	< 12.9	17
Maximum core-wide cladding oxidation (%)	0.73	1
Coolable geometry	Core remains coolable	Core remains coolable
Long-term cooling	Core remains cool in long term	Core remains cool in long term

Table 15.6.5-9

INITIAL CONDITIONS FOR AP1000 SMALL-BREAK LOCA ANALYSIS

Condition	Calculation	Nominal Steady-state
Pressurizer pressure (psia)	2303.1	2300
Vessel inlet temperature (°F)	534.03	534.3
Vessel outlet temperature (°F)	612.83	612.9
Vessel flow rate (lb/sec)	31086	31089
Steam generator pressure (psia)	806.5	788.5

Table 15.6.5-10

AP1000 ADS PARAMETERS

Actuation Signal (percentage of core makeup tank level)		Actuation Time (seconds)	Minimum Valve Flow Area (for each path, in^2)	Number of Paths	Valve Opening Time (seconds)
Stage 1 – Control Low 1	67.5	20 after CMT-Low 1	4.6	2 out of 2	≤ 30
Stage 2 – Control		70 after Stage 1	21	2 out of 2	≤ 80
Stage 3 – Control		120 after Stage 2	21	2 out of 2	≤ 80
Stage 4A	20	120 after Stage 3	67	1 out of 2	≤ 2
Stage 4B		60 after Stage 4A	67	2 out of 2	≤ 2

Table 15.6.5-11

INADVERTENT ADS DEPRESSURIZATION SEQUENCE OF EVENTS

Event	AP1000 Time (seconds)
Inadvertent opening of ADS valves	0.0
Reactor trip signal	37.8
Steam turbine stop valves close	43.8
"S" signal	44.1
Main feed isolation valves begin to close	49.1
Reactor coolant pumps start to coast down	50.1
ADS Stage 2	70.0
ADS Stage 3	190.0
Accumulator injection starts	268
Accumulator empties	693
ADS Stage 4	1746
Core makeup tank empty	2112
IRWST injection starts	2663

Table 15.6.5-12

2-INCH COLD LEG BREAK IN CLBL LINE SEQUENCE OF EVENTS

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	54.7
Steam turbine stop valves close	60.7
“S” signal	61.9
Main feed isolation valves begin to close	63.9
Reactor coolant pumps start to coast down	67.9
ADS Stage 1	1334.1
ADS Stage 2	1404.1
Accumulator injection starts	1405
ADS Stage 3	1524.1
Accumulator empties	1940.2
ADS Stage 4	2418.6
Core makeup tank empty	2895
IRWST injection starts	3280

Table 15.6.5-13

DOUBLE-ENDED INJECTION LINE BREAK SEQUENCE OF EVENTS – 20 psi

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	13.1
Steam turbine stop valves close	19.1
“S” signal	18.6
Main feed isolation valves begin to close	20.6
Reactor coolant pumps start to coast down	24.6
ADS Stage 1	182.5
ADS Stage 2	252.5
Intact accumulator injection starts	254
ADS Stage 3	372.5
ADS Stage 4	492.5
Intact accumulator empties	600.0
Intact loop IRWST injection starts*	1470
Intact loop core makeup tank empties	2123

Note:
*Continuous injection period

Table 15.6.5-13A

DOUBLE-ENDED INJECTION LINE BREAK SEQUENCE OF EVENTS – 14.7 psi

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	13.1
Steam turbine stop valves close	19.1
“S” signal	18.5
Main feed isolation valves begin to close	20.5
Reactor coolant pumps start to coast down	24.5
ADS Stage 1	182.7
Intact accumulator injection starts	251
ADS Stage 2	252.7
ADS Stage 3	372.7
ADS Stage 4	492.7
Intact accumulator empties	598.4
Intact loop core makeup tank empties	2006
Intact loop IRWST injection starts*	2076

Note:
*Continuous injection period

Table 15.6.5-14

10-INCH COLD LEG BREAK IN SEQUENCE OF EVENTS

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	5.2
“S” signal	6.4
Main feed isolation valves begin to close	8.4
Steam turbine stop valves close	11.2
Reactor coolant pumps start to coast down	12.4
Accumulator injection starts	85.
Accumulator 1 empties	418.2
Accumulator 2 empties	425.5
ADS Stage 1	750.0
ADS Stage 2	820.
ADS Stage 3	940.
ADS Stage 4	1491.
Core makeup tank 2 empty	1800.*
IRWST injection starts	~1800
Core makeup tank 1 empty	1900.*

Note:
*The CMTs never truly empty although they cease to discharge at these times.

Table 15.6.5-15

DOUBLE-ENDED INJECTION LINE BREAK SEQUENCE OF EVENTS (ENTRAINMENT SENSITIVITY)

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	13.1
Steam turbine stop valves close	19.1
"S" signal	18.6
Main feed isolation valves begin to close	20.6
Reactor coolant pumps start to coast down	24.6
ADS Stage 1	182.4
ADS Stage 2	252.4
Intact accumulator injection starts	255
ADS Stage 3	372.4
ADS Stage 4	492.4
Intact accumulator empties	608.9
Intact loop IRWST injection starts*	1718
Intact loop core makeup tank empties	2106

Note:
*Continuous injection period

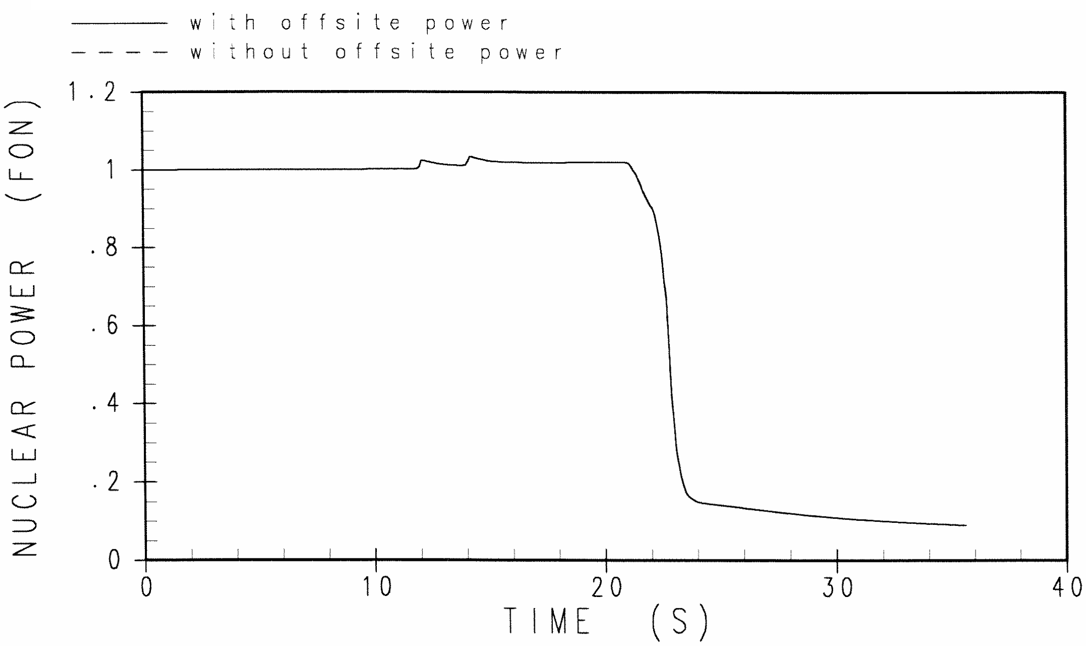

Figure 15.6.1-1

Nuclear Power Transient
Inadvertent Opening of a Pressurizer Safety Valve

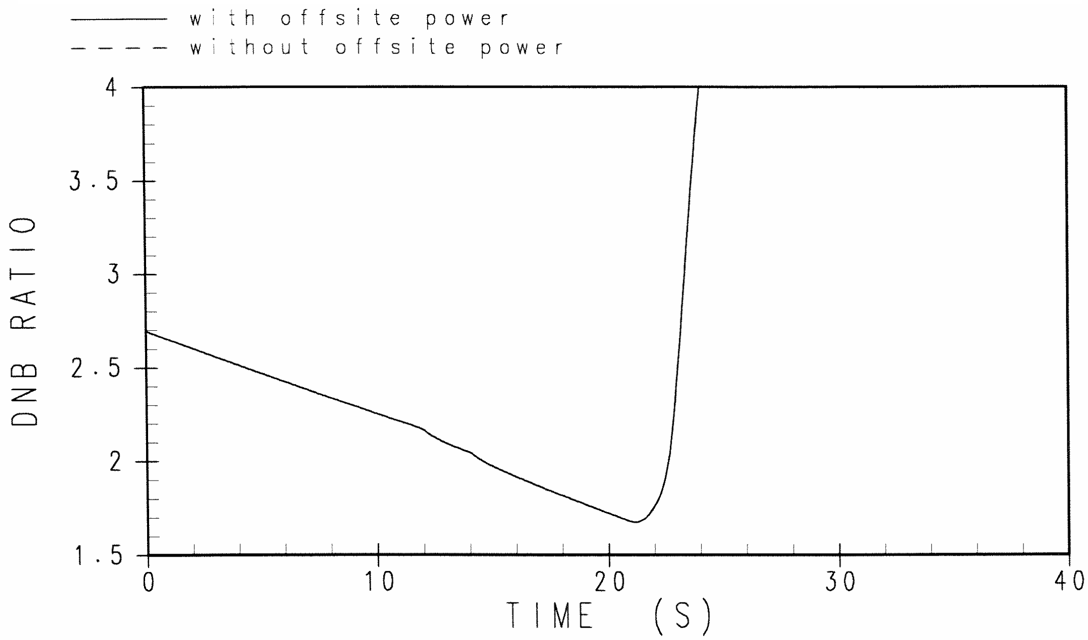

Figure 15.6.1-2

DNBR Transient
Inadvertent Opening of a Pressurizer Safety Valve

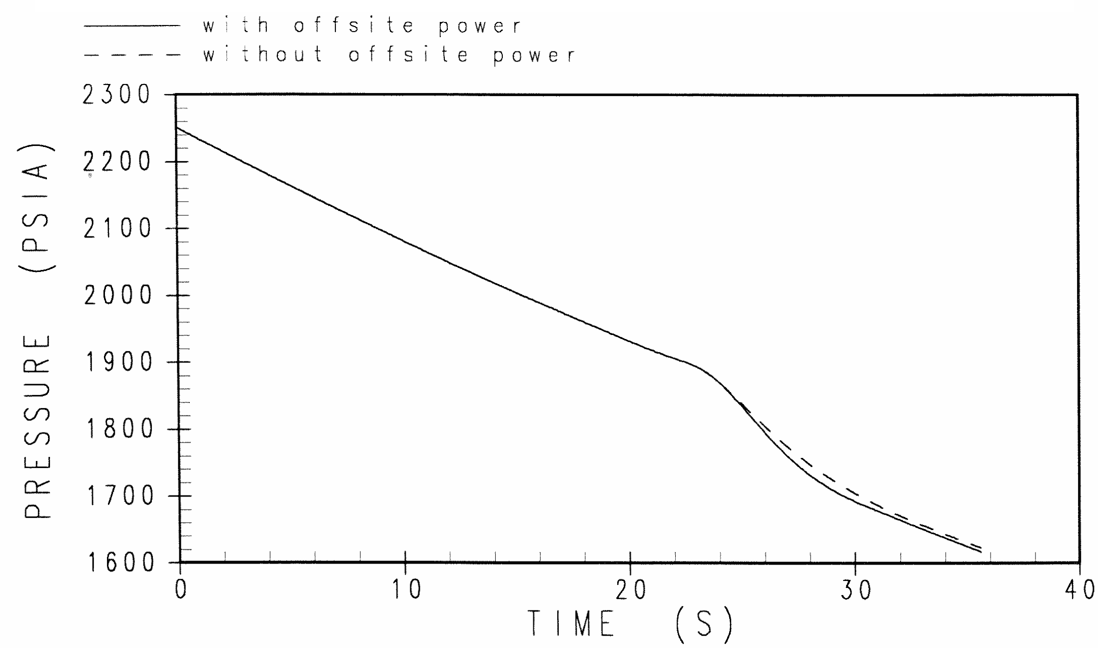

Figure 15.6.1-3

Pressurizer Pressure Transient
Inadvertent Opening of a Pressurizer Safety Valve

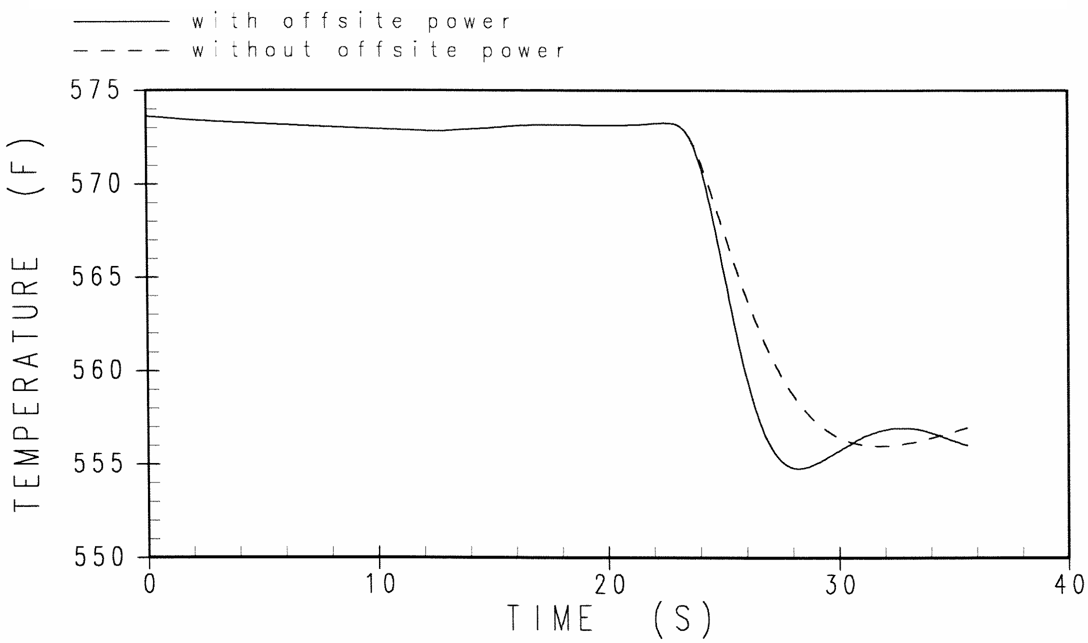

Figure 15.6.1-4

Vessel Average Temperature
Inadvertent Opening of a Pressurizer Safety Valve

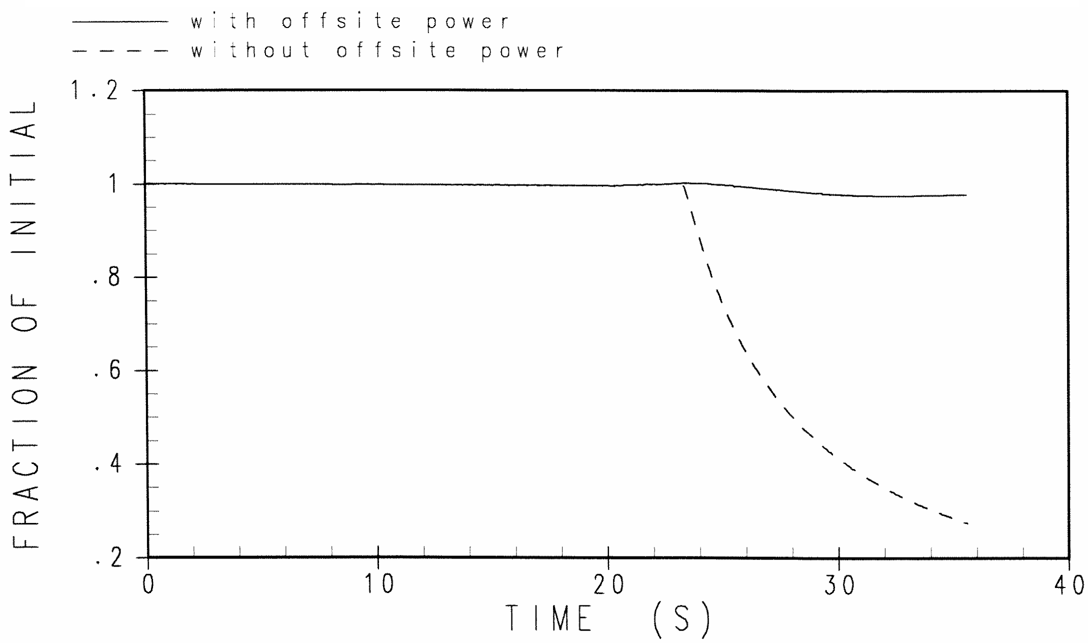

Figure 15.6.1-5

Core Mass Flow Rate
Inadvertent Opening of a Pressurizer Safety Valve

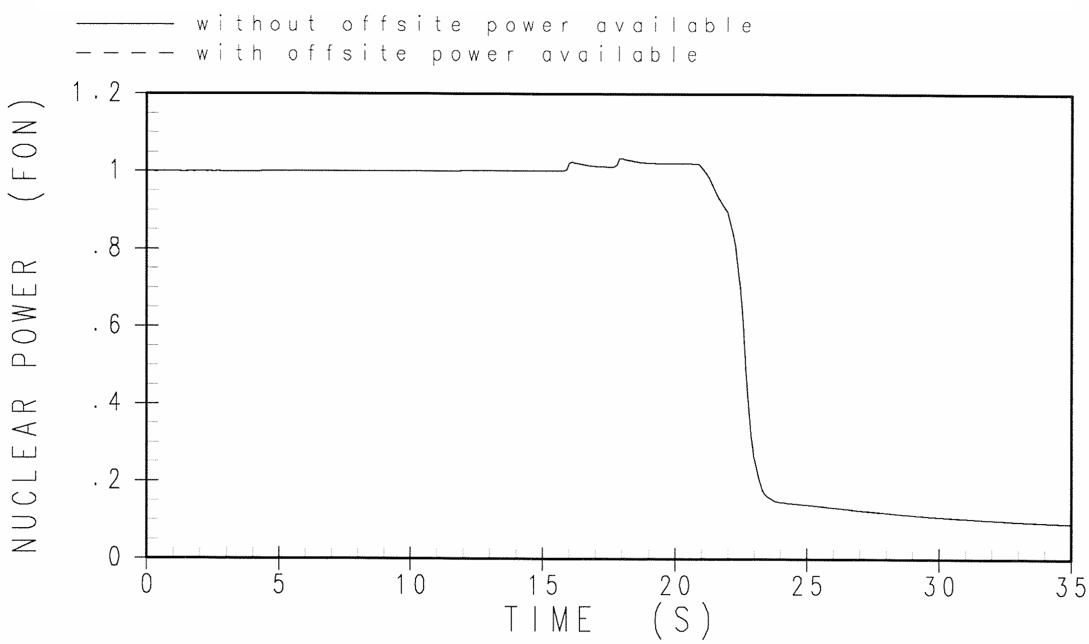

Figure 15.6.1-6

Nuclear Power Transient
Inadvertent Opening of Two ADS Stage 1 Trains

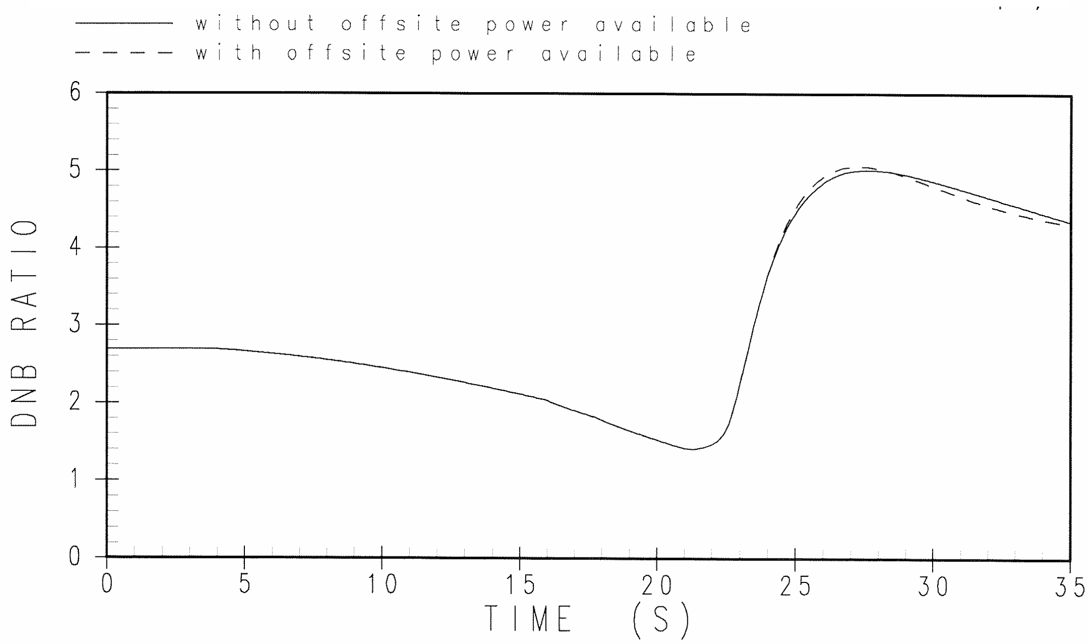

Figure 15.6.1-7

DNBR Transient
Inadvertent Opening of Two ADS Stage 1 Trains

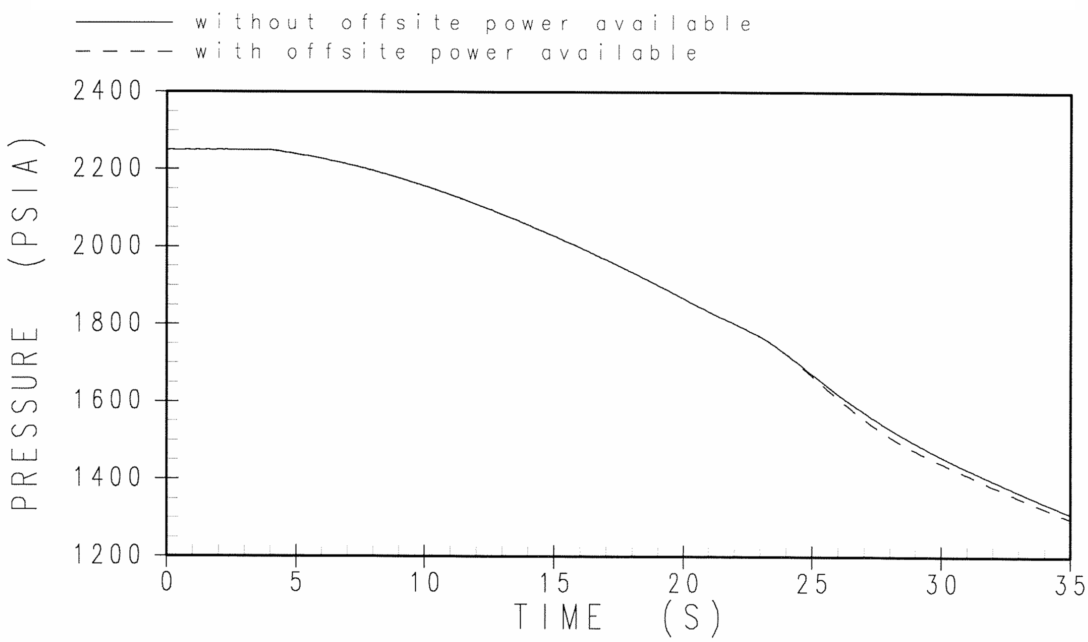

Figure 15.6.1-8

Nuclear Power Transient
Inadvertent Opening of Two ADS Stage 1 Trains

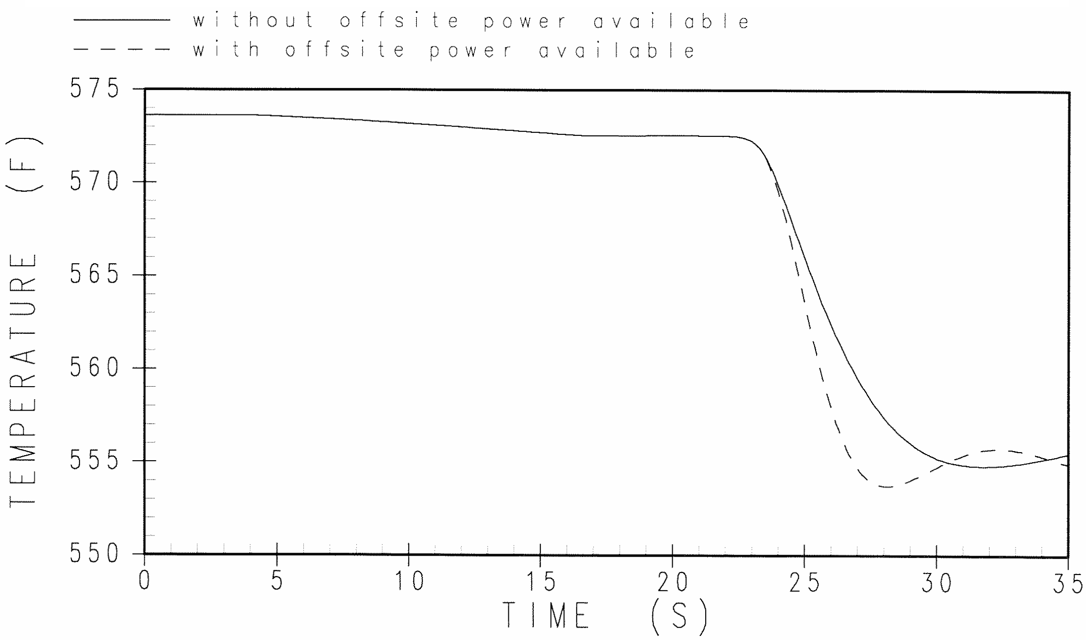

Figure 15.6.1-9

Nuclear Power Transient
Inadvertent Opening of Two ADS Stage 1 Trains

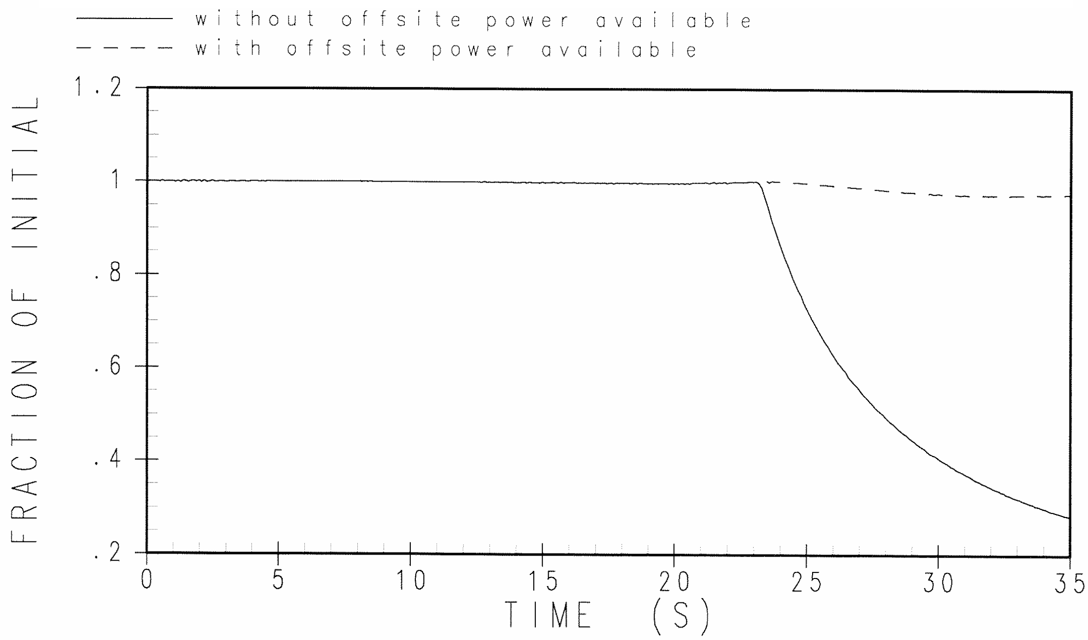

Figure 15.6.1-10

Core Mass Flow Rate
Inadvertent Opening of Two ADS Stage 1 Trains

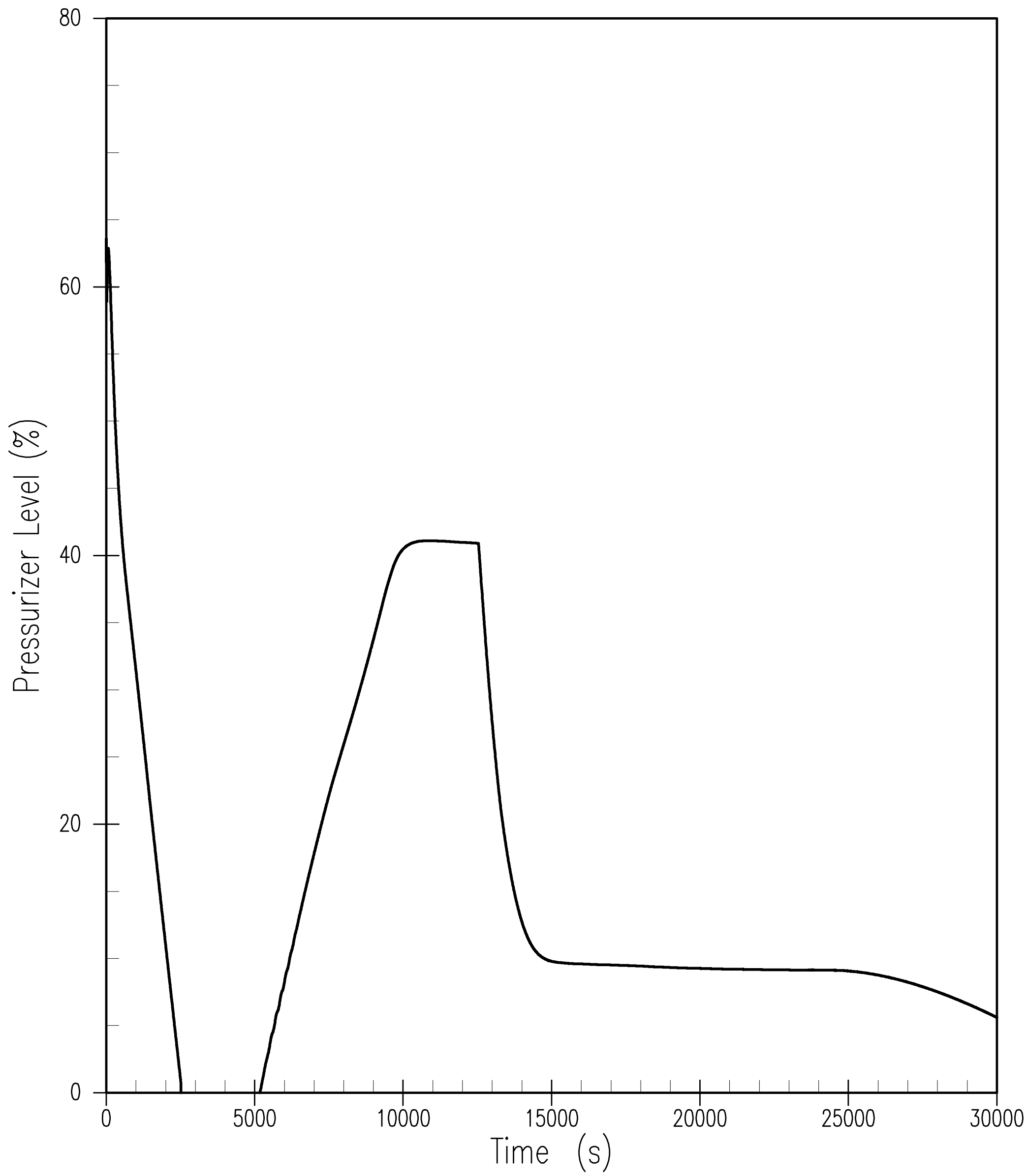

Figure 15.6.3-1

Pressurizer Level for SGTR

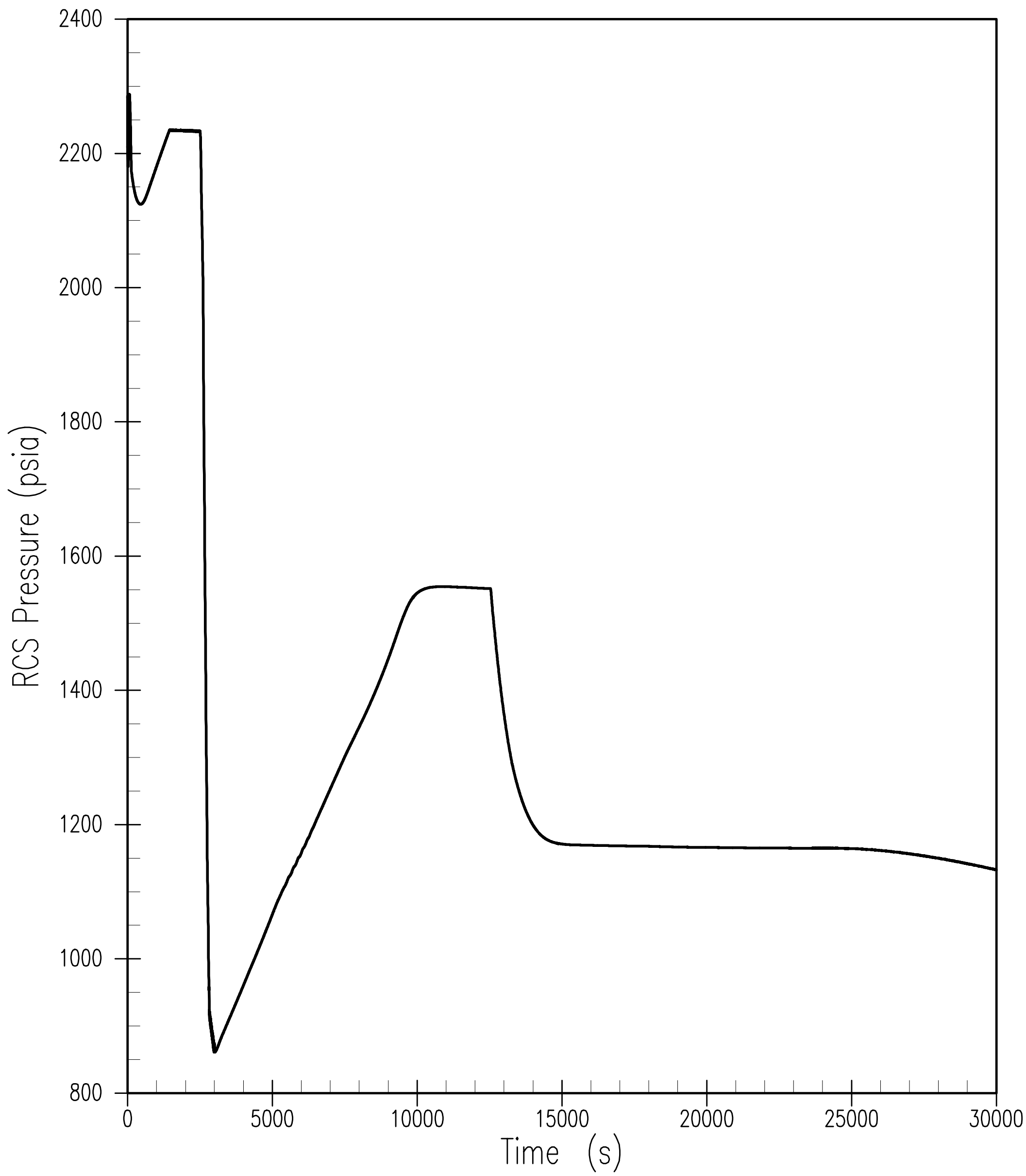

Figure 15.6.3-2

Reactor Coolant System Pressure for SGTR

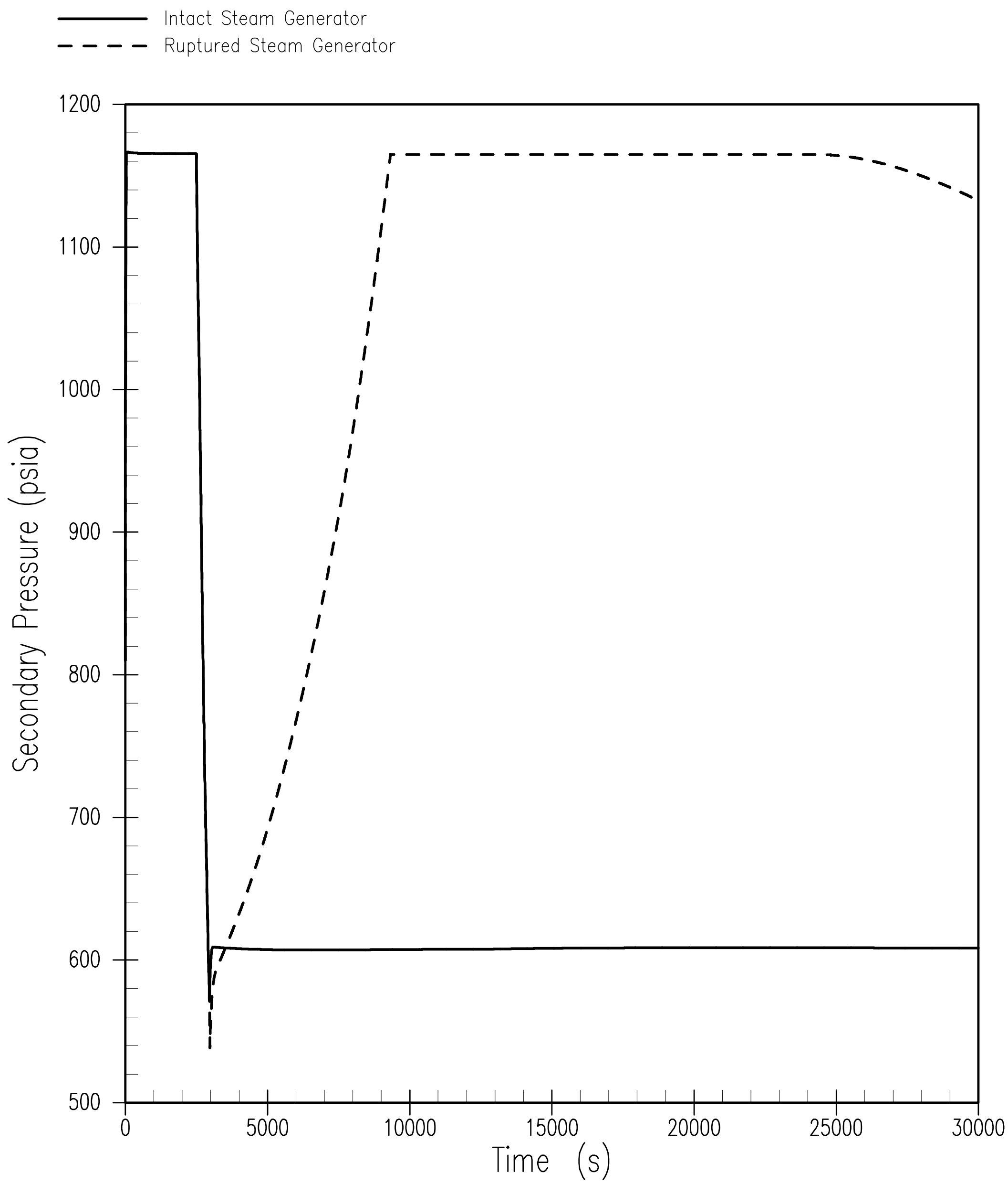

Figure 15.6.3-3

Secondary Pressure for SGTR

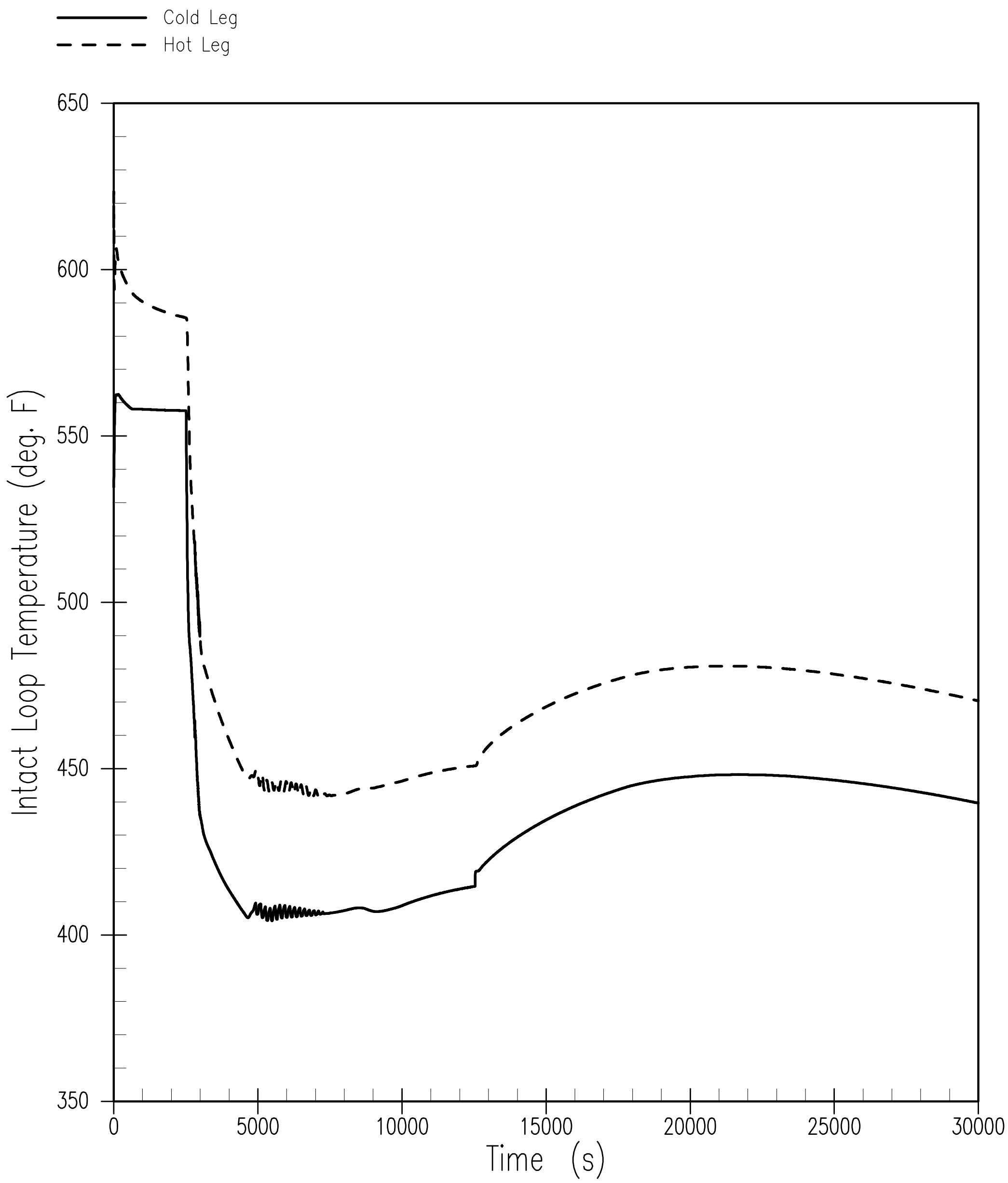

Figure 15.6.3-4

Intact Loop Hot and Cold Leg
Reactor Coolant System Temperature for SGTR

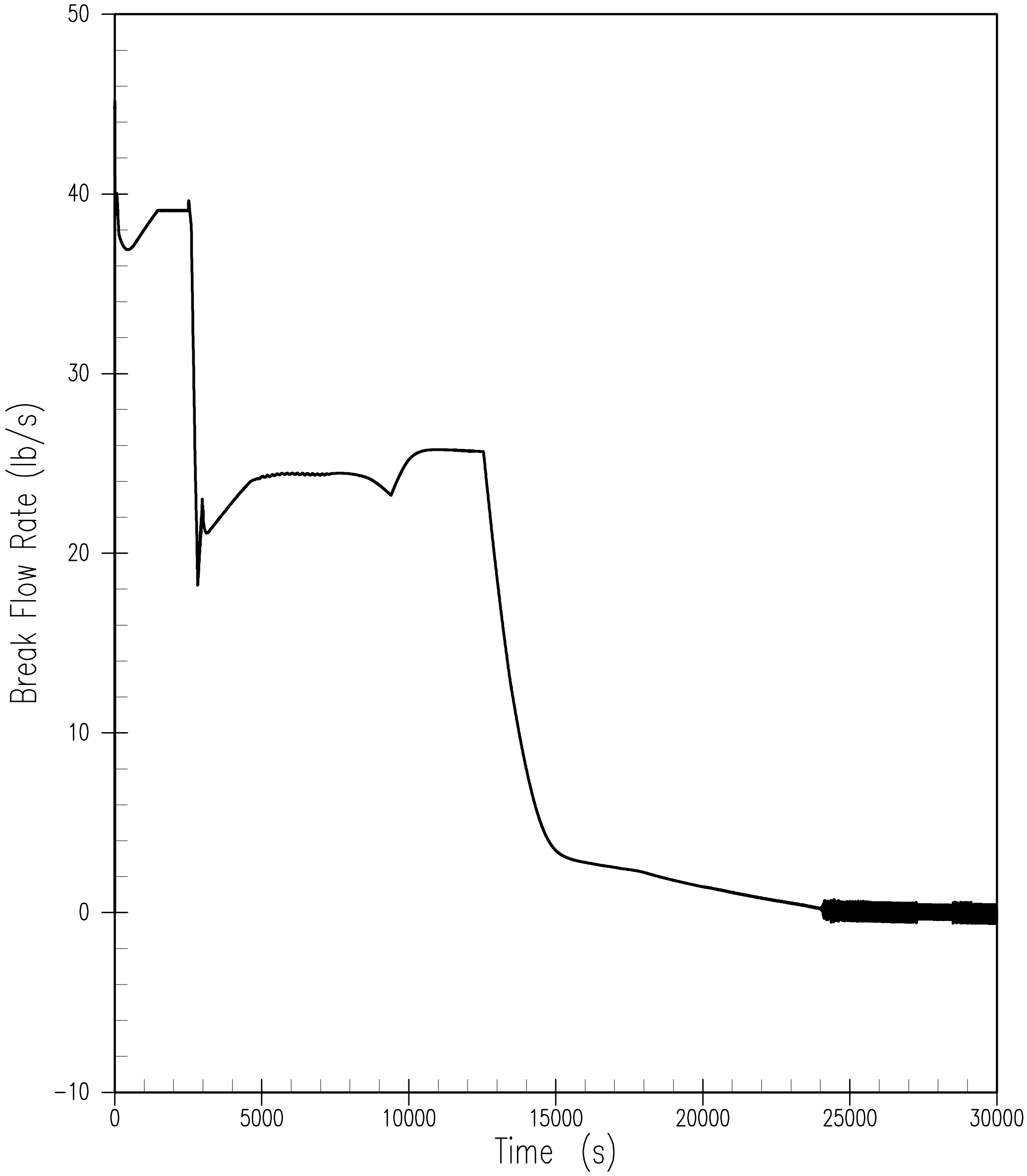

Figure 15.6.3-5

Primary-to-Secondary Break Flow Rate for SGTR

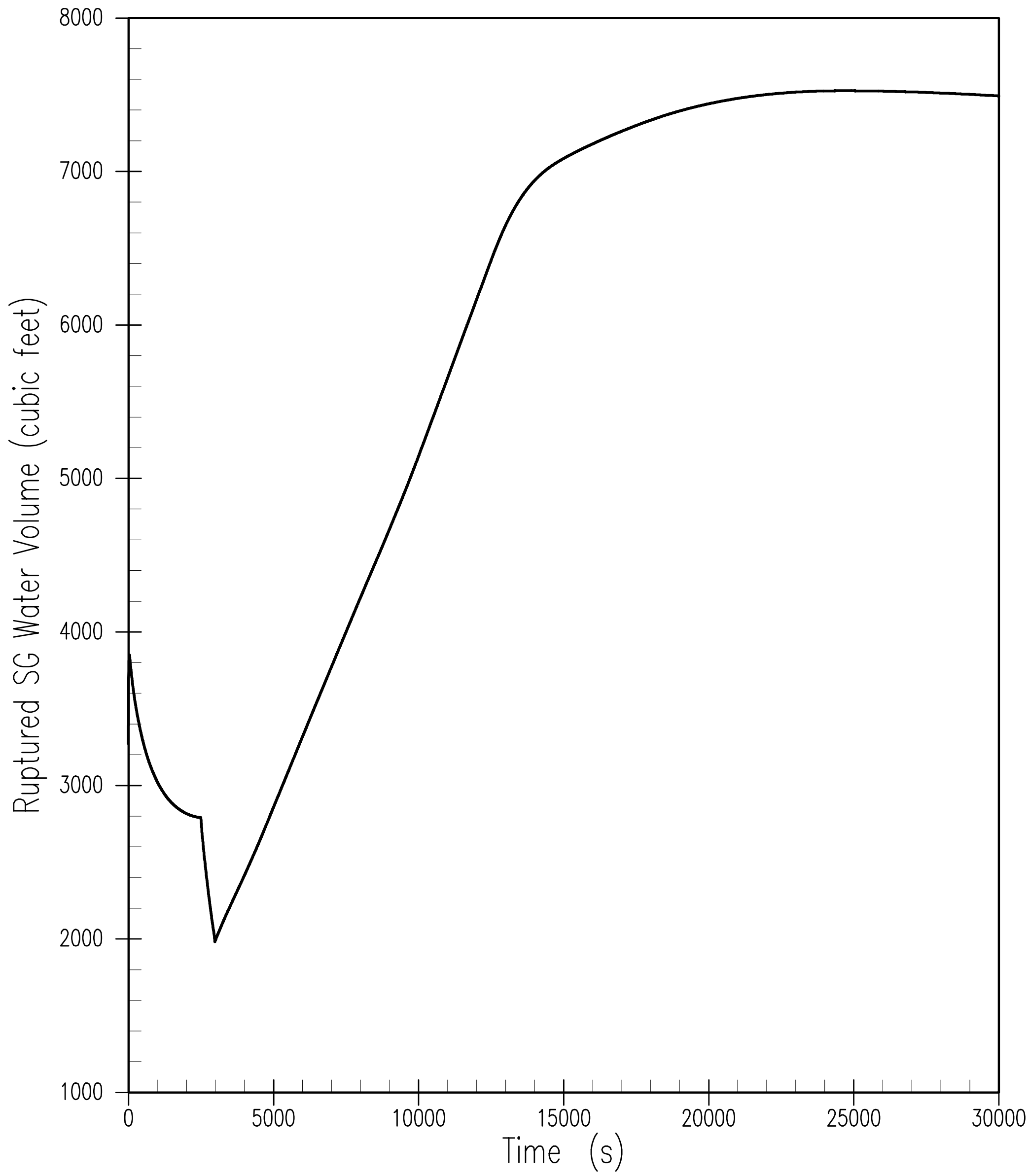

Figure 15.6.3-6

Faulted Steam Generator Water Volume for SGTR

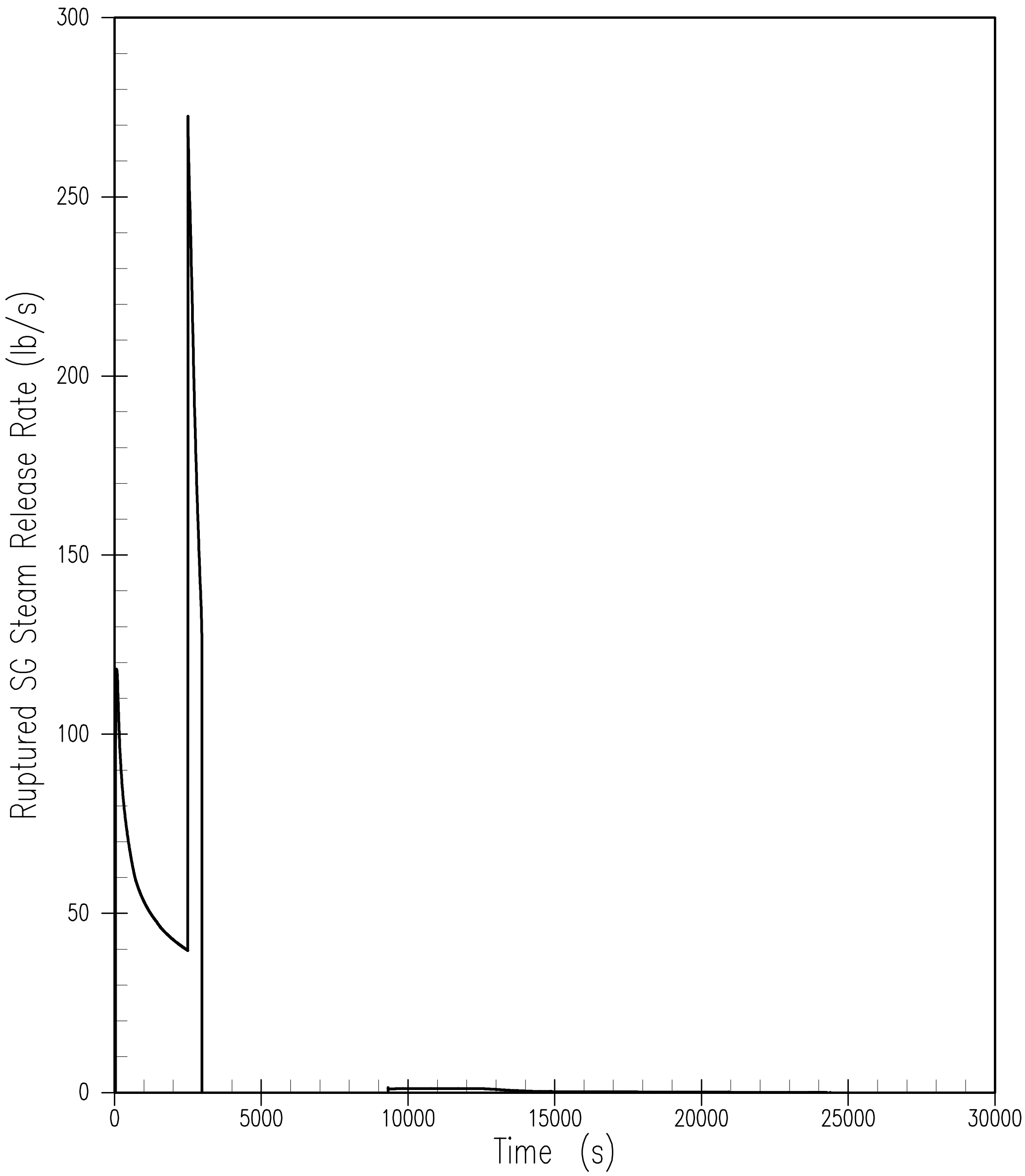

Figure 15.6.3-7

Faulted Steam Generator Mass Release Rate to the Atmosphere for SGTR

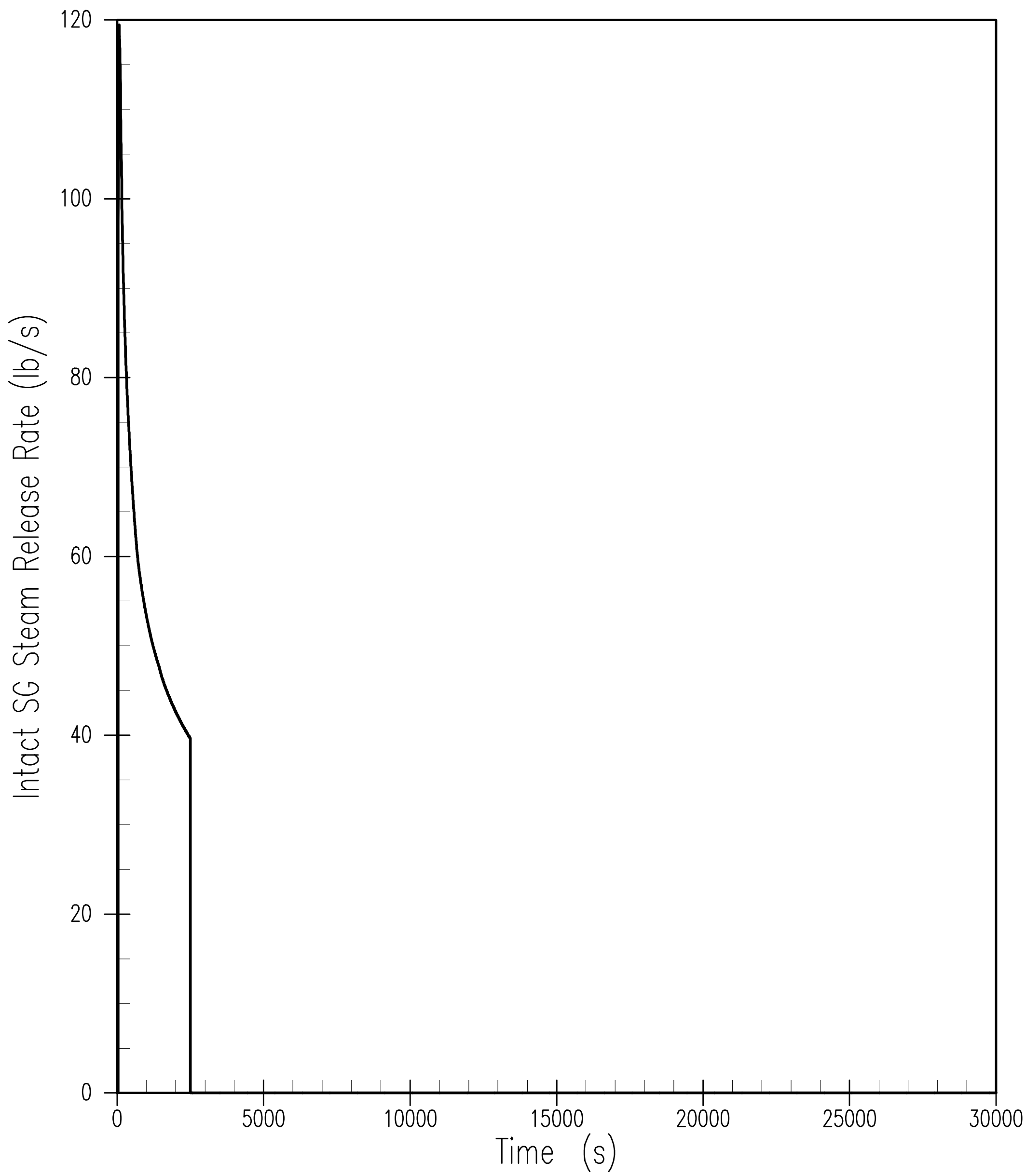

Figure 15.6.3-8

Intact Steam Generator Mass Release Rate to the Atmosphere for SGTR

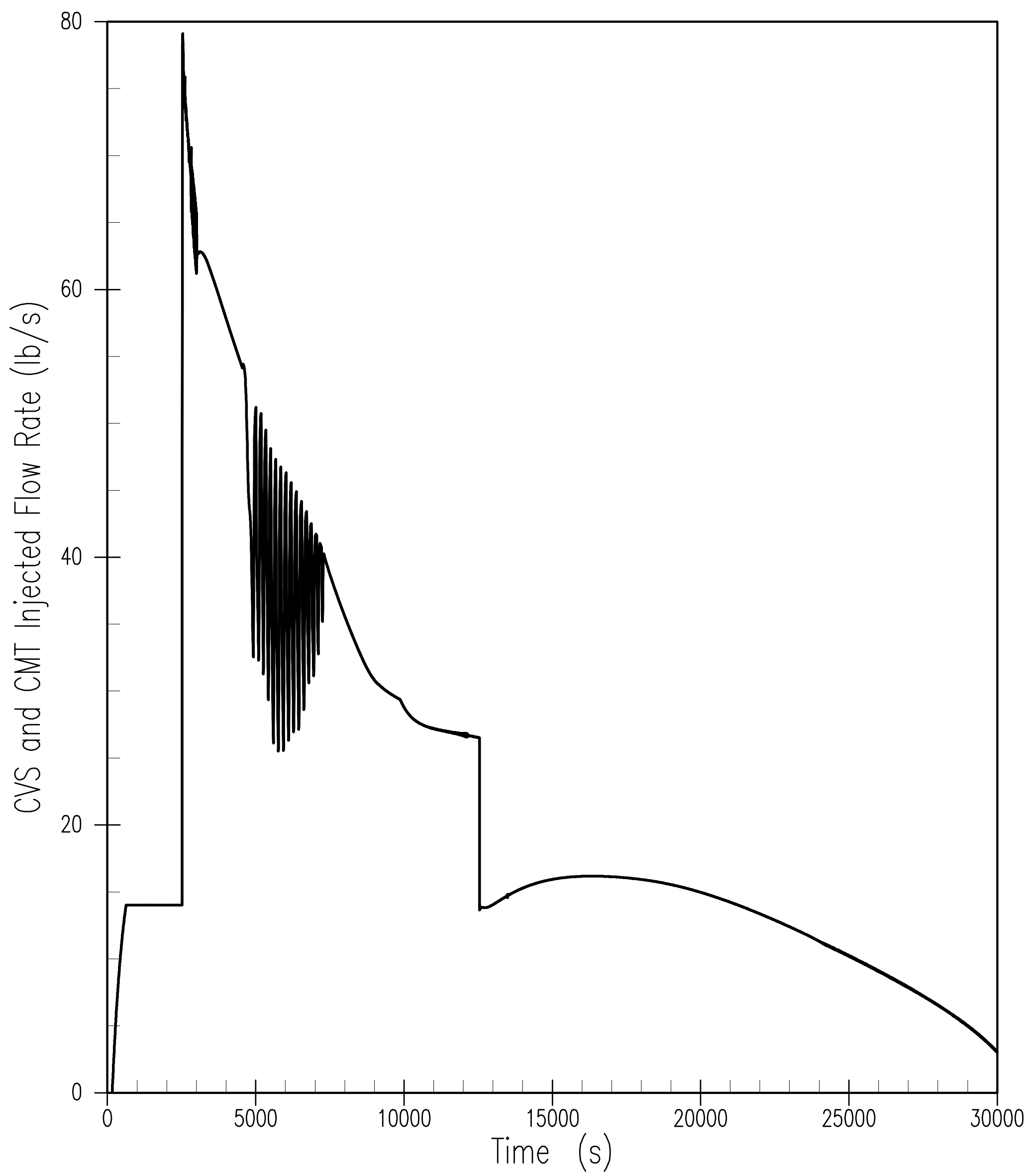

Figure 15.6.3-9

Faulted Loop Chemical and Volume Control System and Core Makeup Tank Injection Flow for SGTR

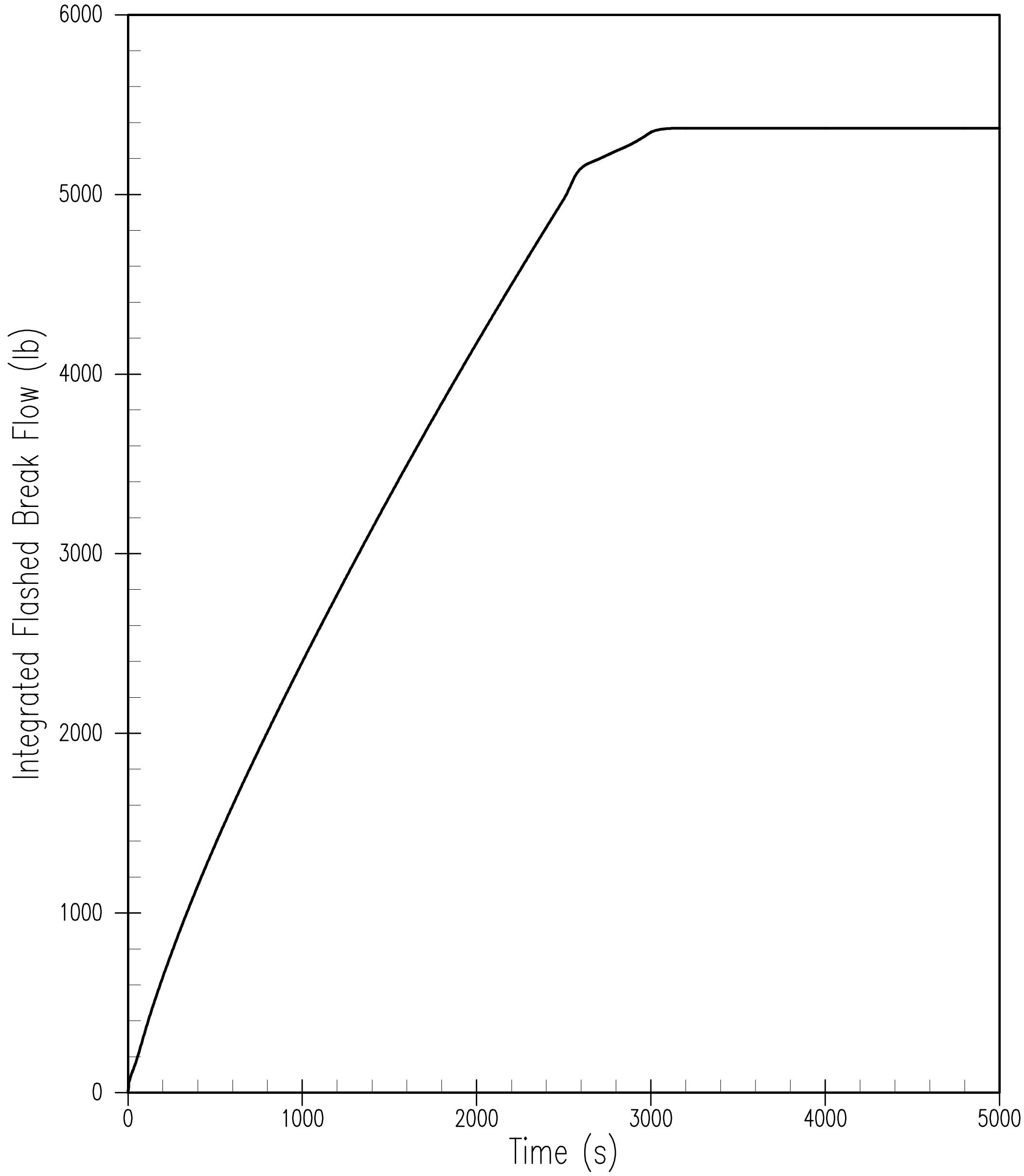

Figure 15.6.3-10

Integrated Flashed Break Flow for SGTR

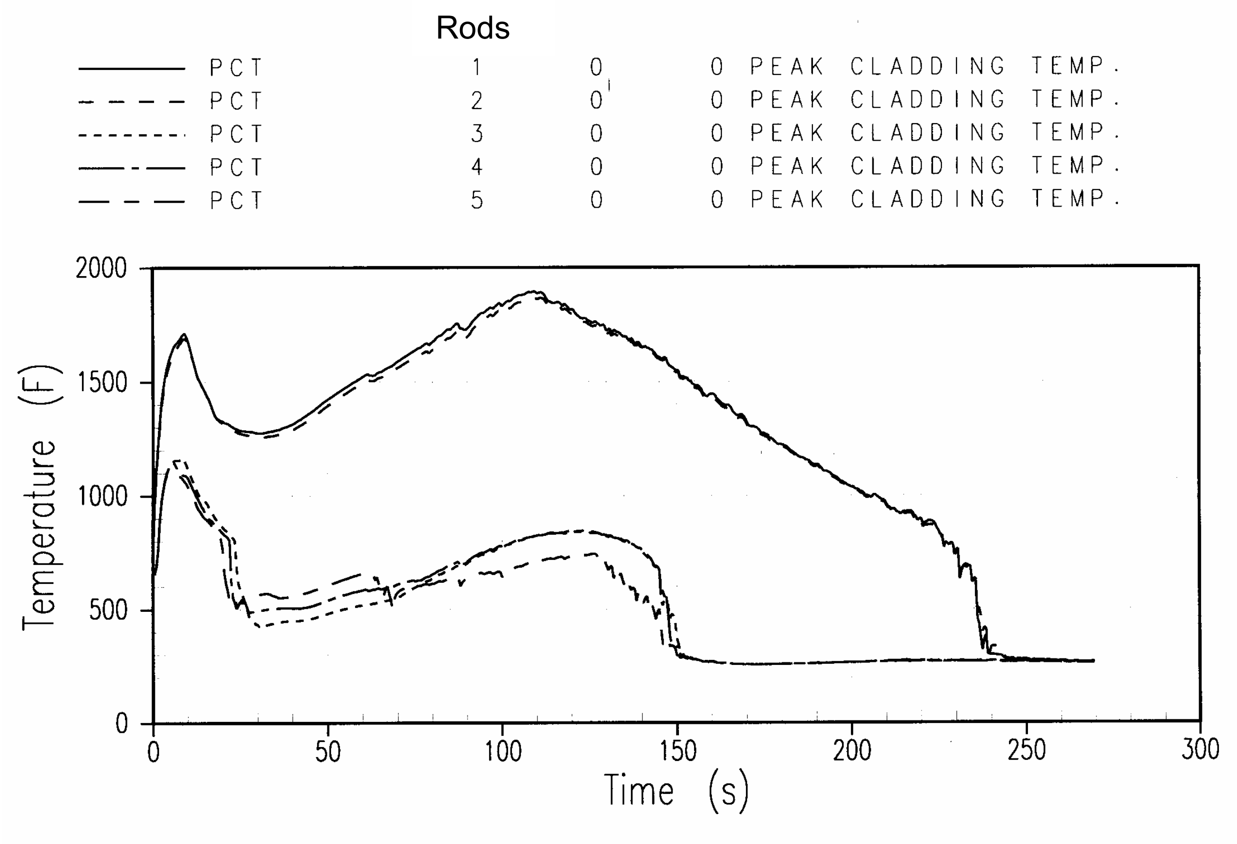

Figure 15.6.5.4A-1

PCT Among All Elevations for Each Fuel Rod

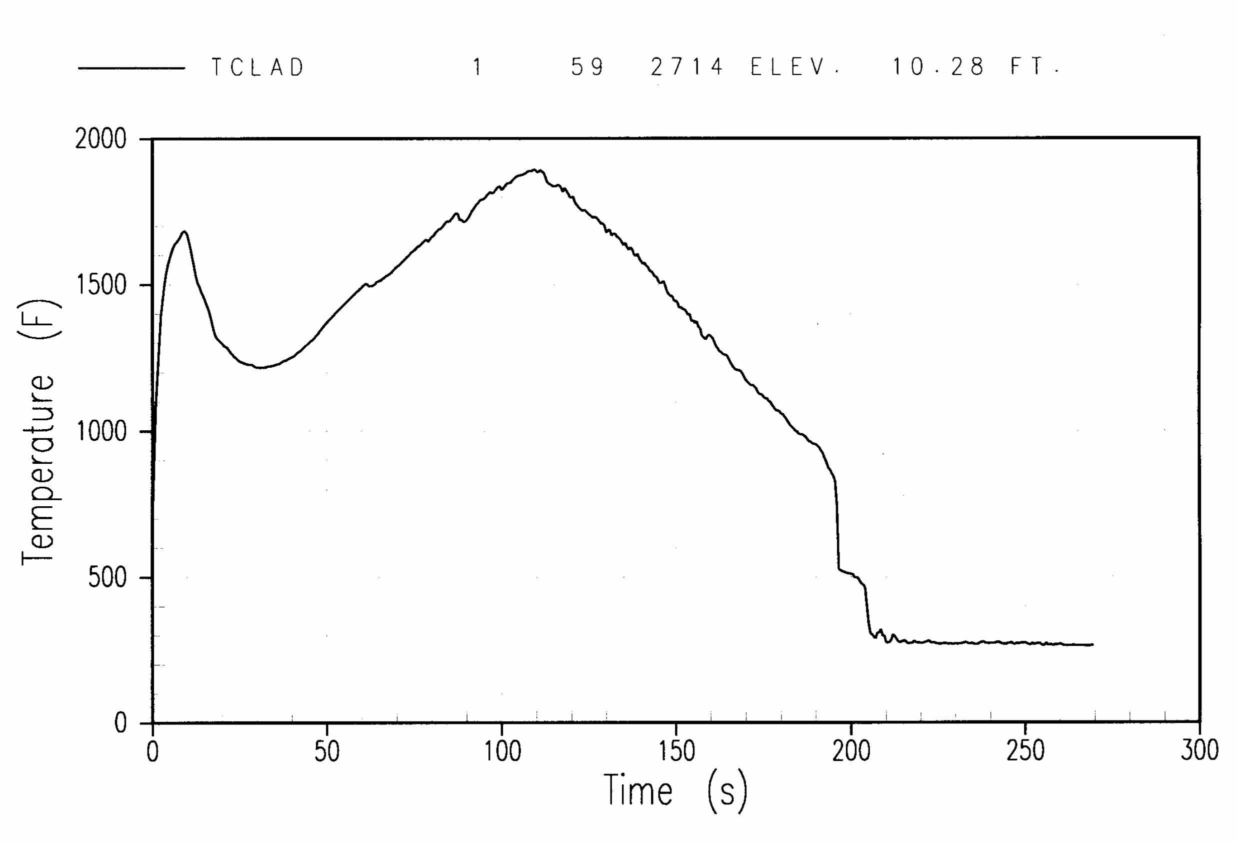

Figure 15.6.5.4A-2

Hot Rod Cladding Temperature Transient, PCT Elevation

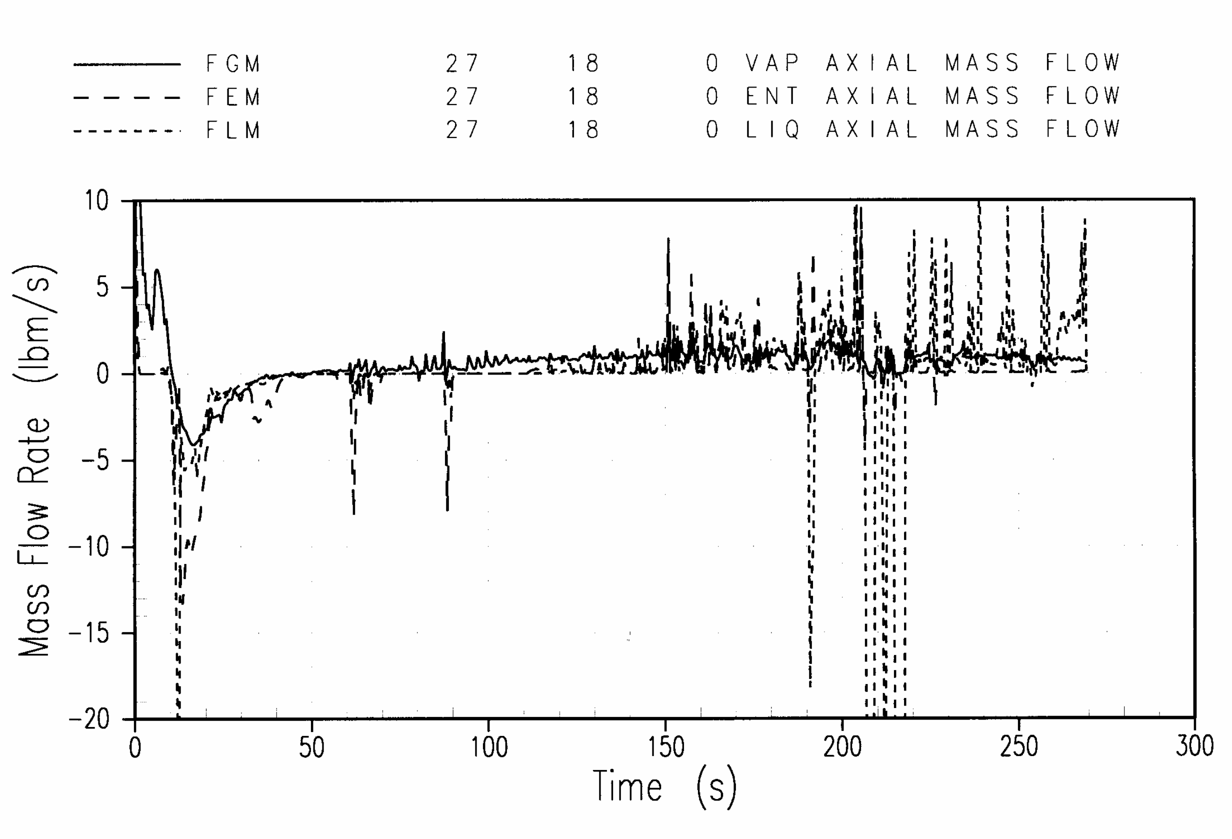

Figure 15.6.5.4A-3

Hot Assembly Exit Vapor,
Entrained Drop, Liquid Flow Rates

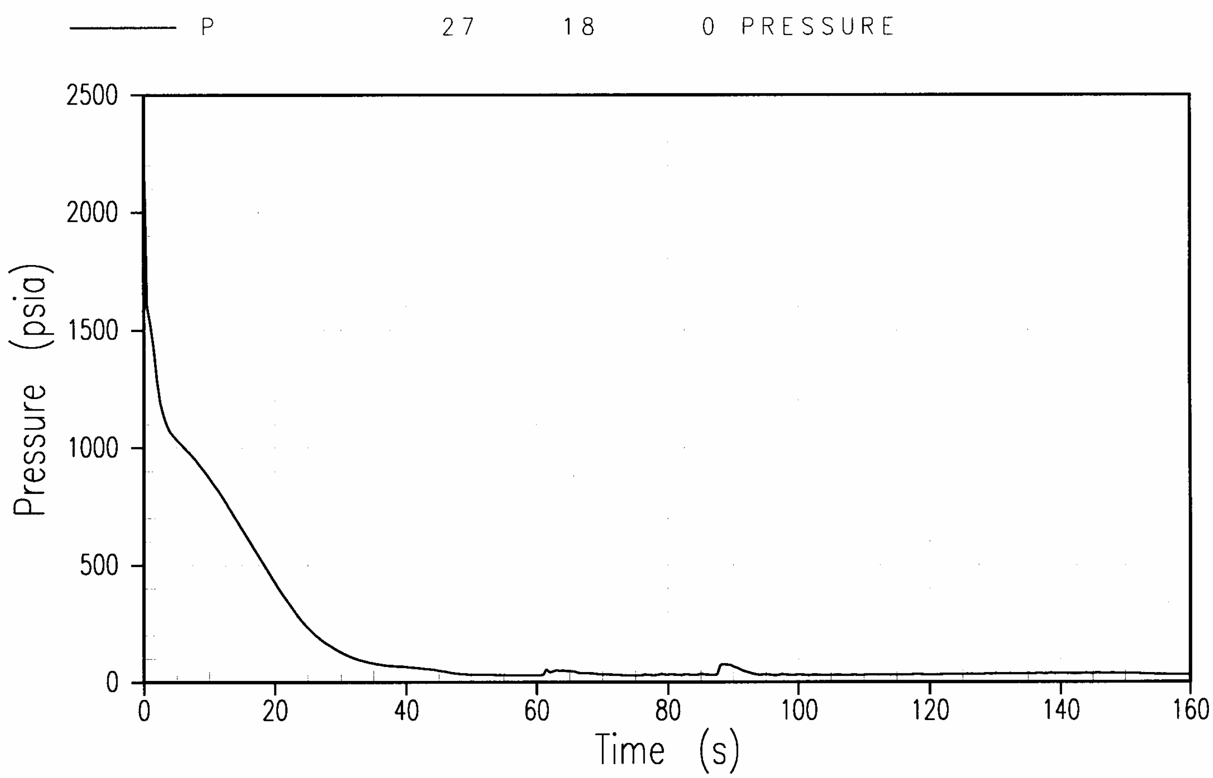

Figure 15.6.5.4A-4

Core Pressure

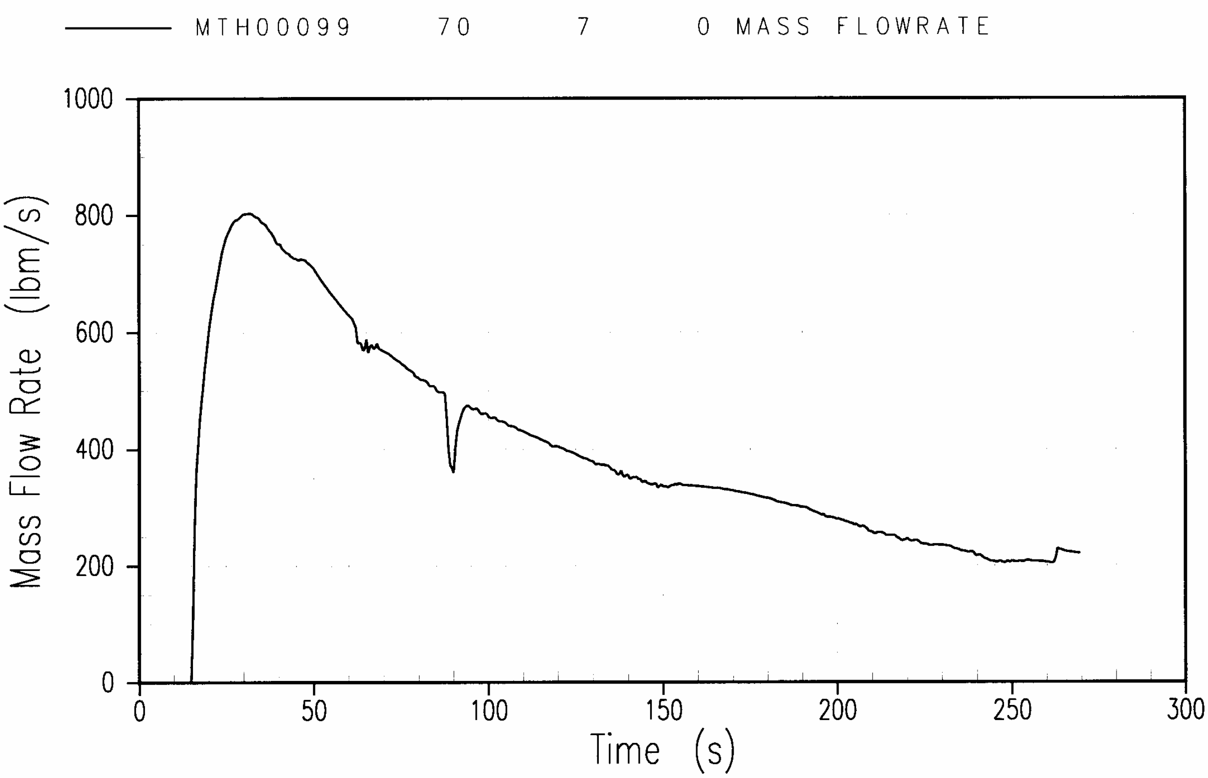

Figure 15.6.5.4A-5

Accumulator Flow Rate

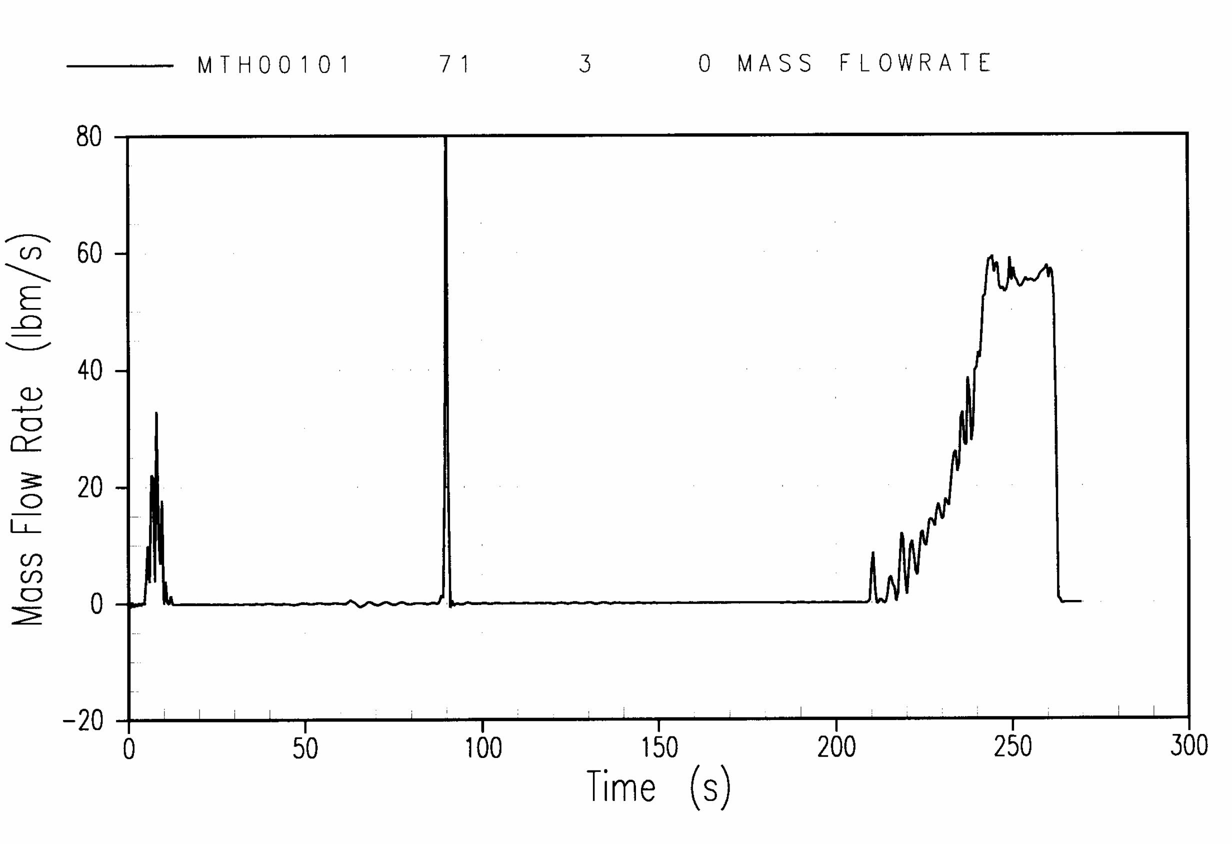

Figure 15.6.5.4A-6

Intact Loop Core Makeup Tank Flow Rate

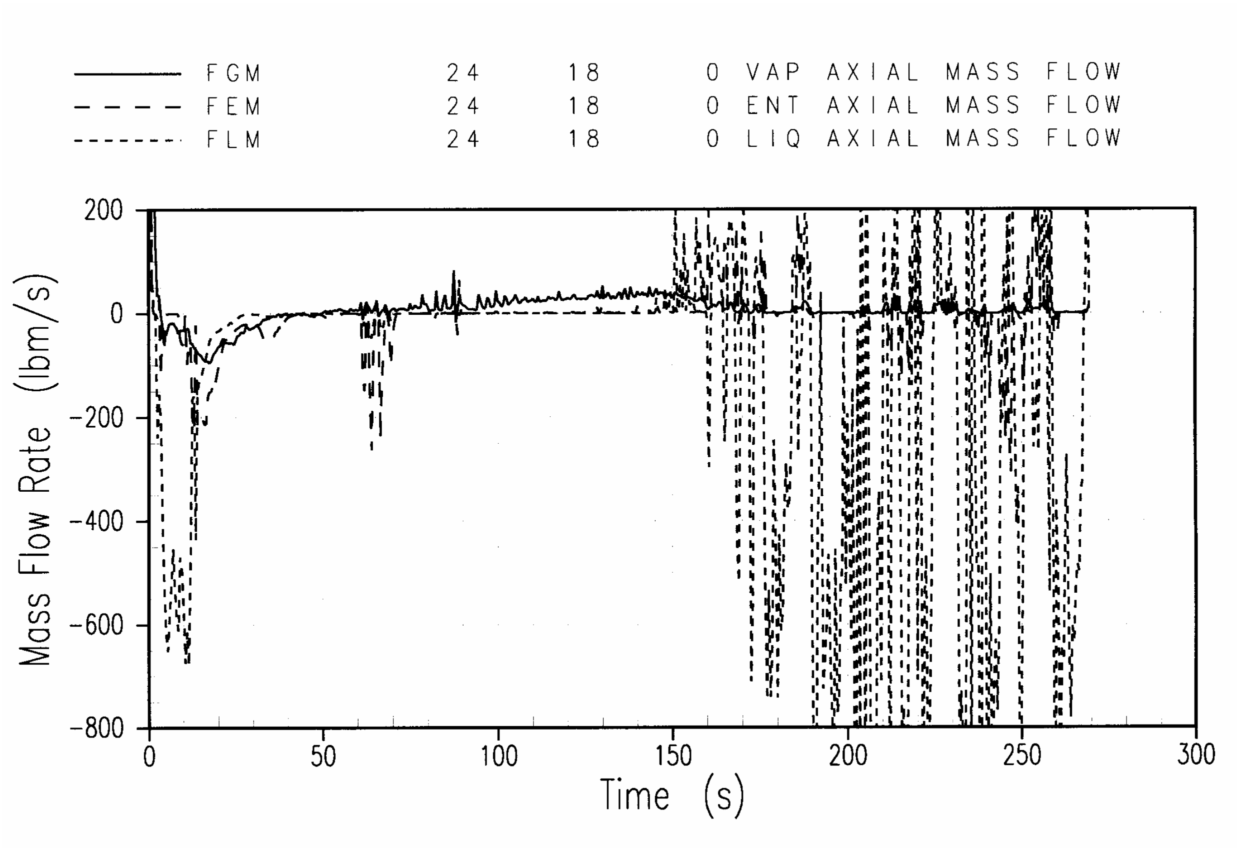

Figure 15.6.5.4A-7

Peripheral Assemblies Exit Vapor, Entrained Drop, Liquid Flow Rates

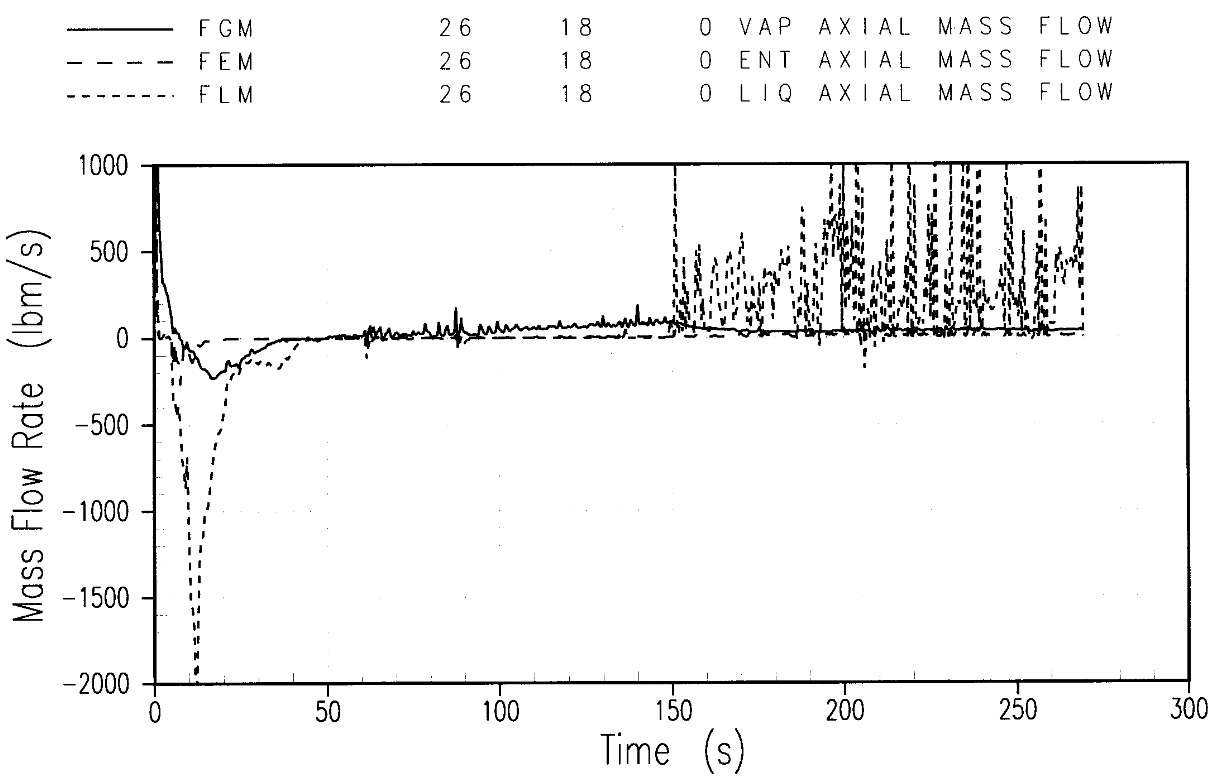

Figure 15.6.5.4A-8

Guide Tube Assemblies Exit Vapor, Entrained Drop, Liquid Flow Rates

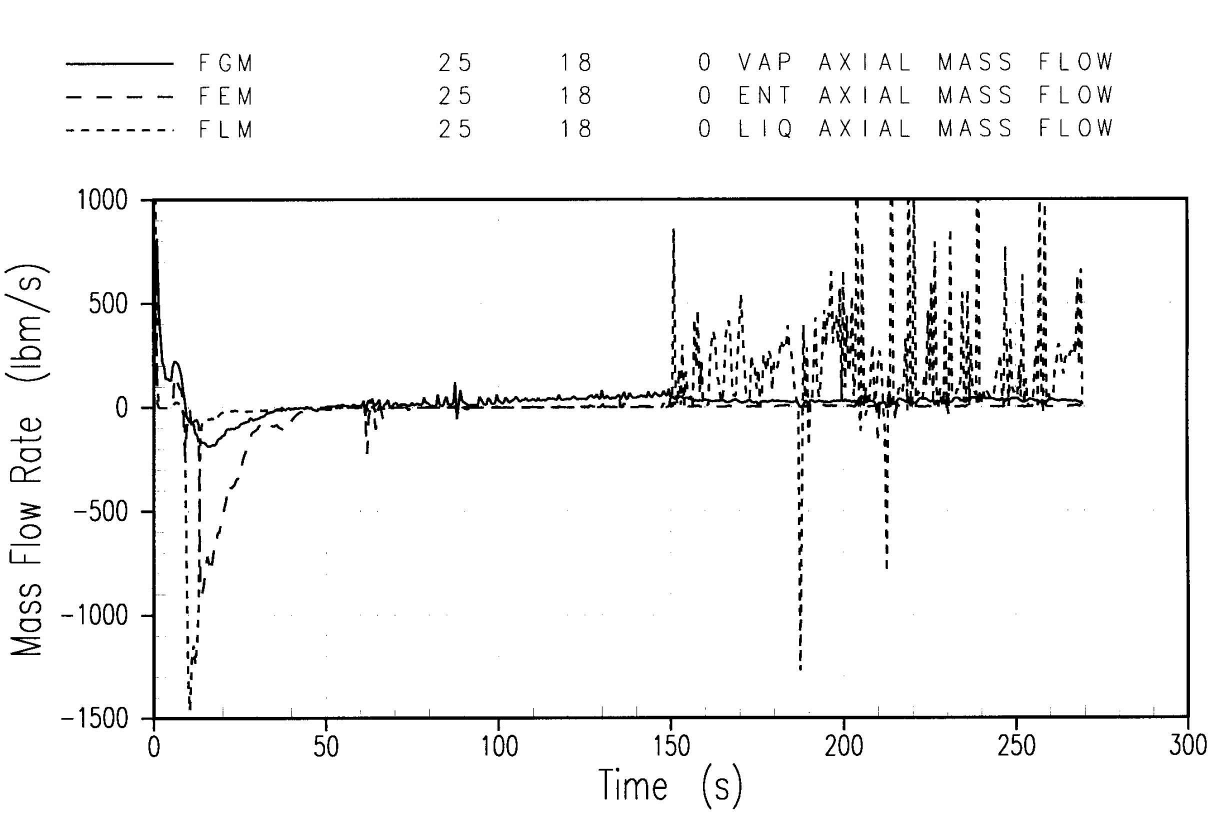

Figure 15.6.5.4A-9

Open Hole Assemblies Exit Vapor, Entrained Drop, Liquid Flow Rates

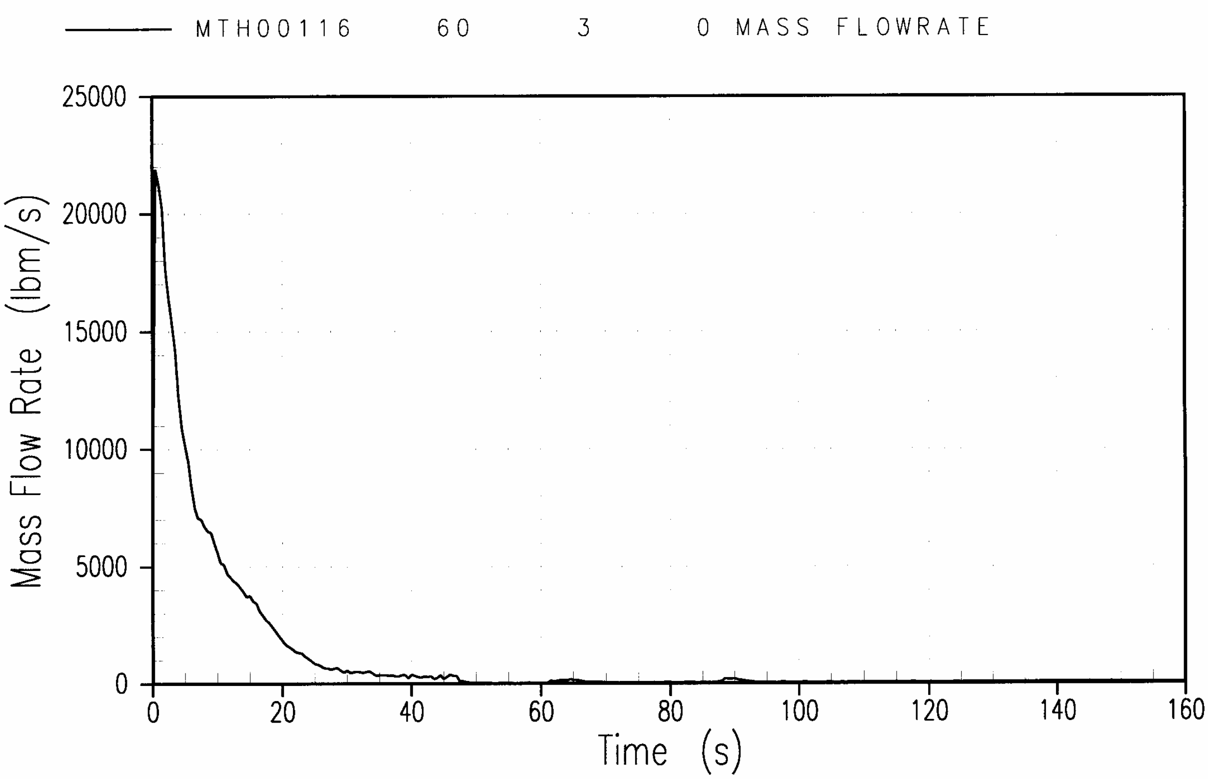

Figure 15.6.5.4A-10

Steam Generator Side DECLG Break Flow Rate

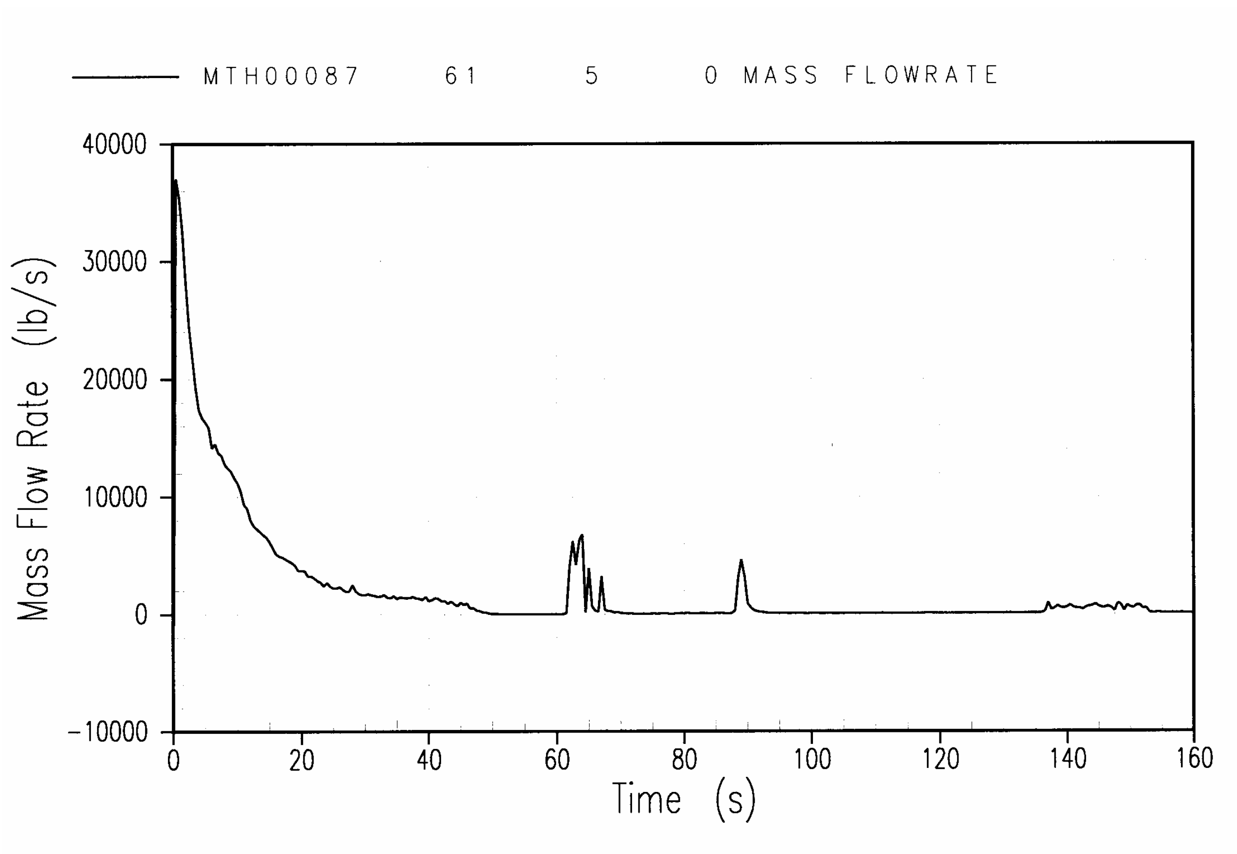

Figure 15.6.5.4A-11

Vessel Side DECLG Break Flow Rate

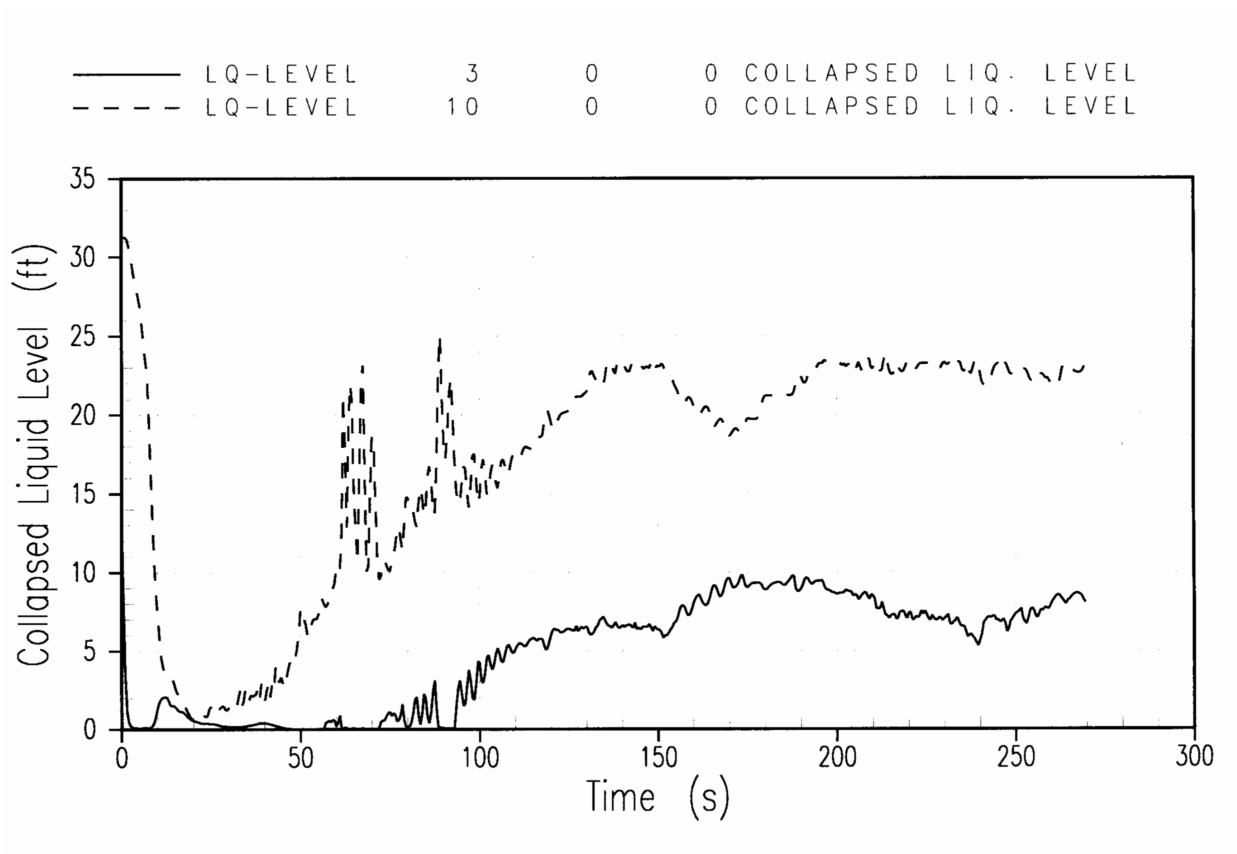

Figure 15.6.5.4A-12

Core and Downcomer Collapsed Liquid Levels

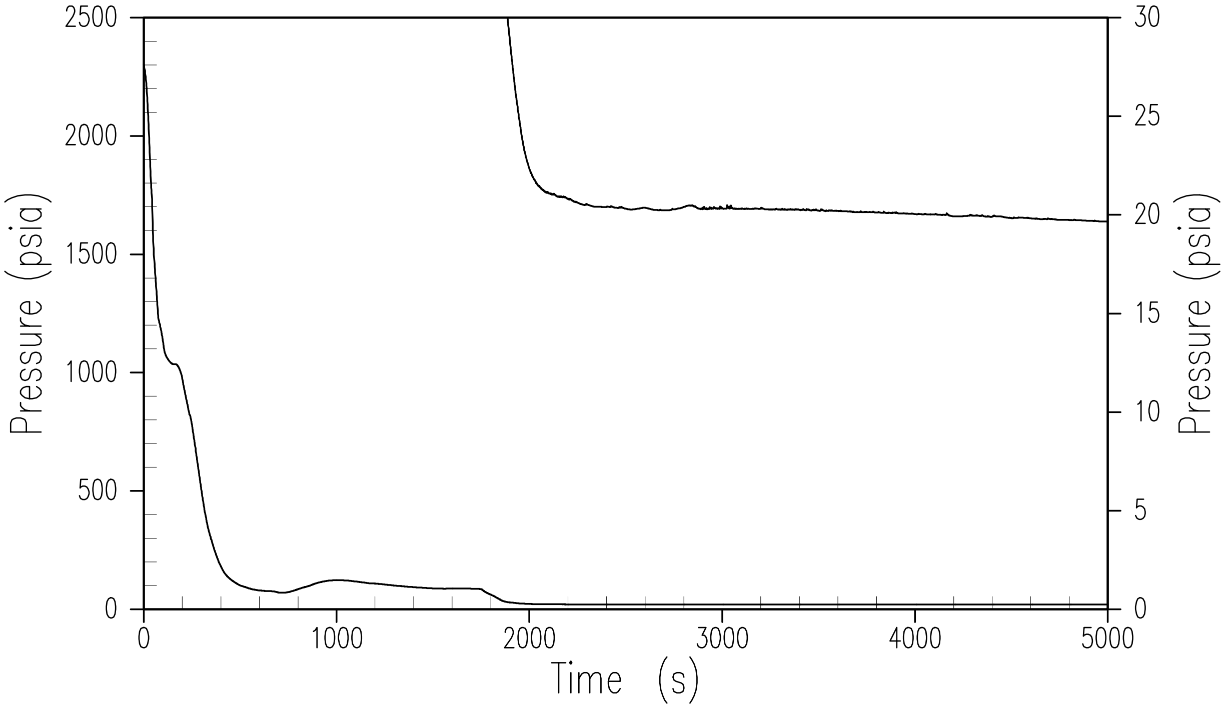

Figure 15.6.5.4B-1

Inadvertent ADS – RCS Pressure

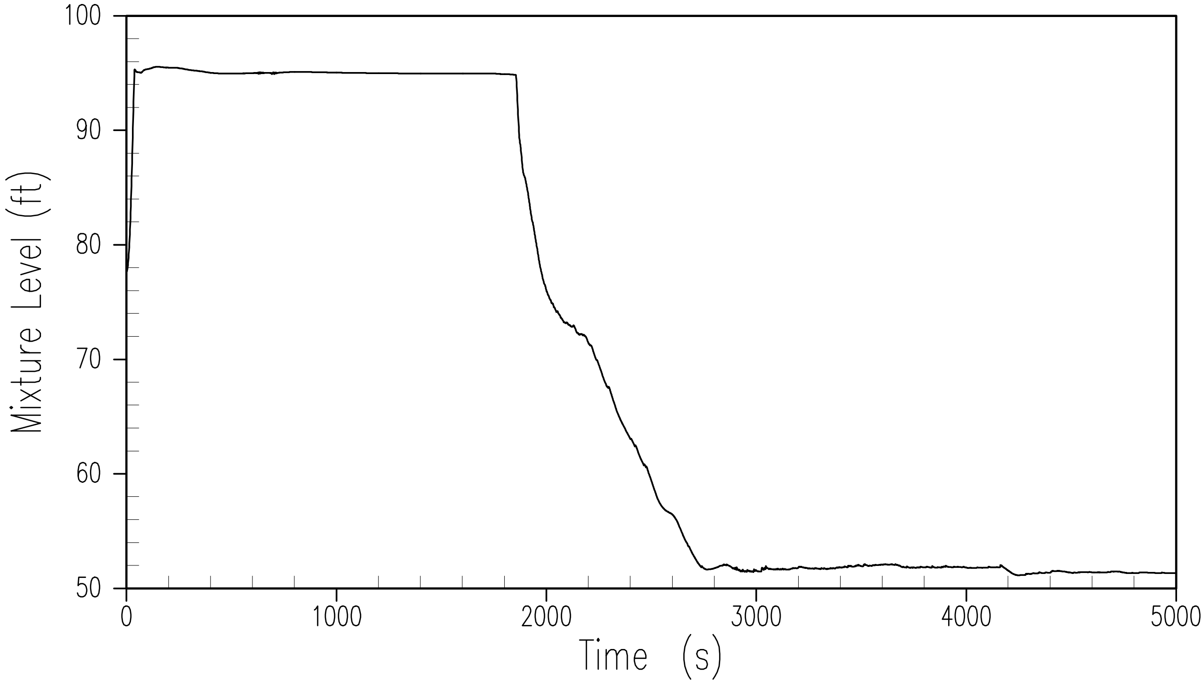

Figure 15.6.5.4B-2

Inadvertent ADS – Pressurizer Mixture Level

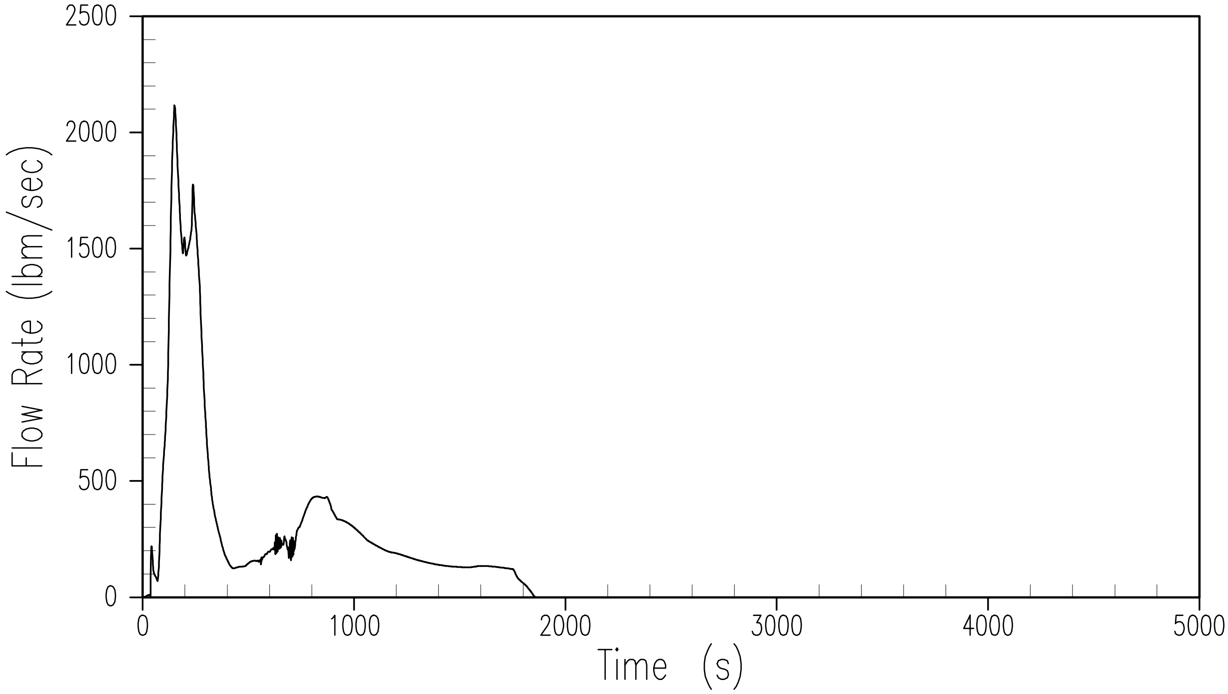

Figure 15.6.5.4B-3

Inadvertent ADS – ADS 1-3 Liquid Discharge

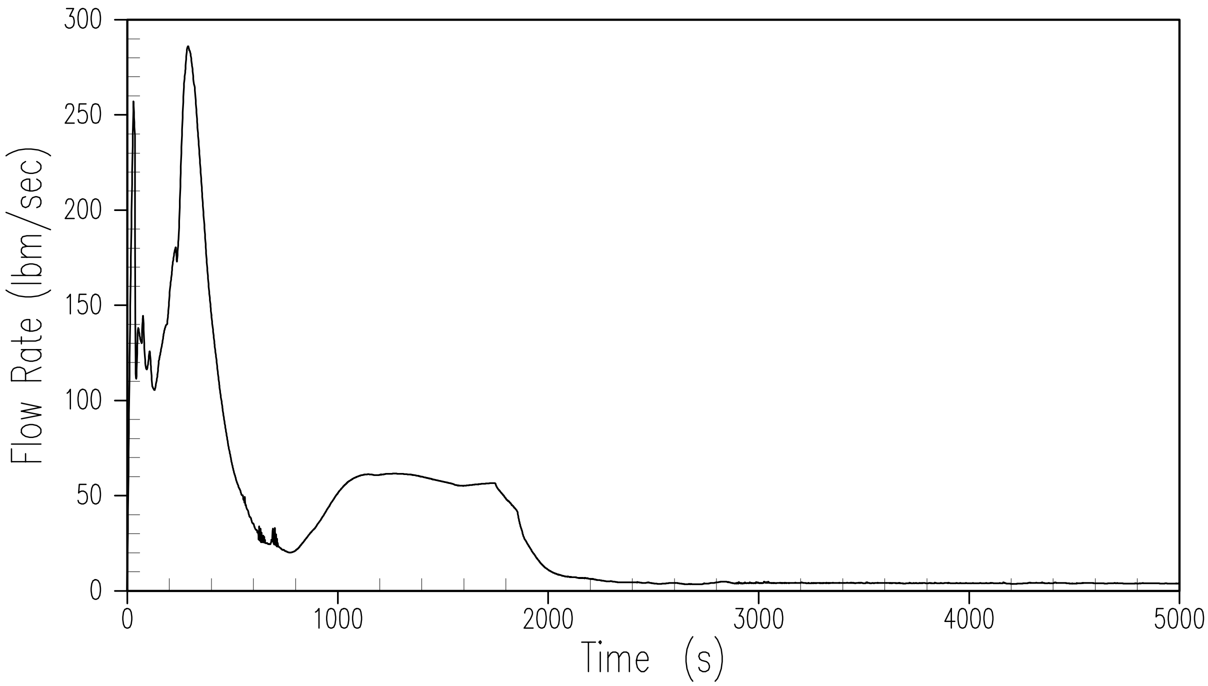

Figure 15.6.5.4B-4

Inadvertent ADS – ADS 1-3 Vapor Discharge

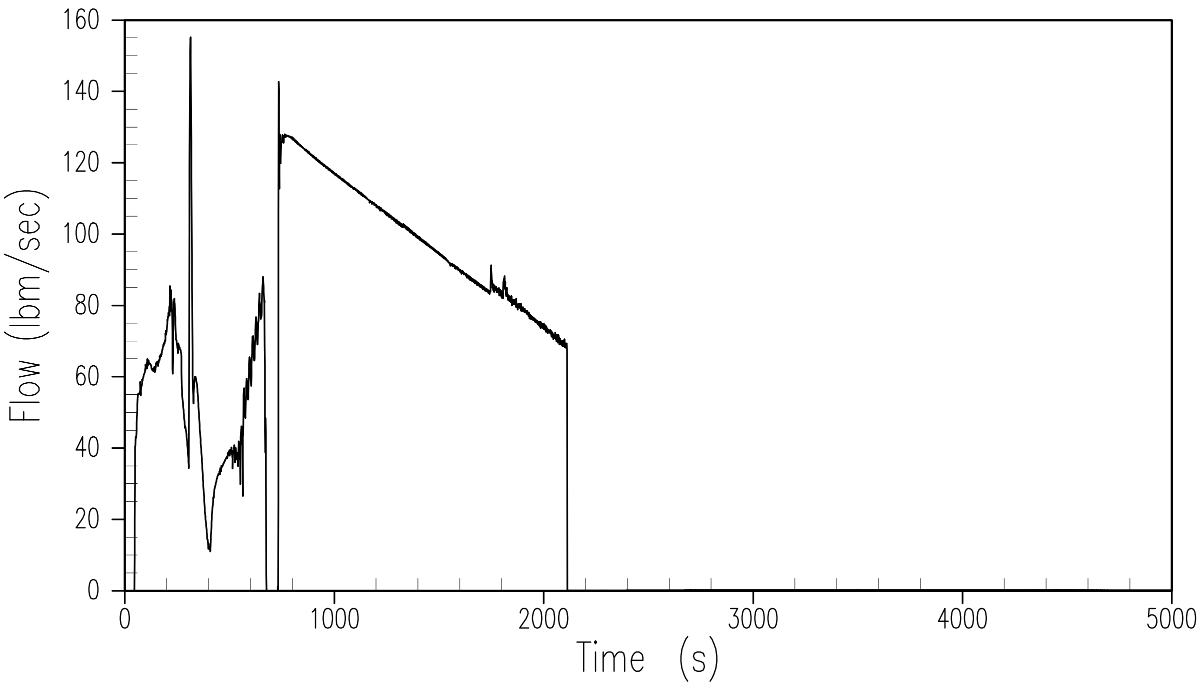

Figure 15.6.5.4B-5

Inadvertent ADS – CMT-1 Injection Rate

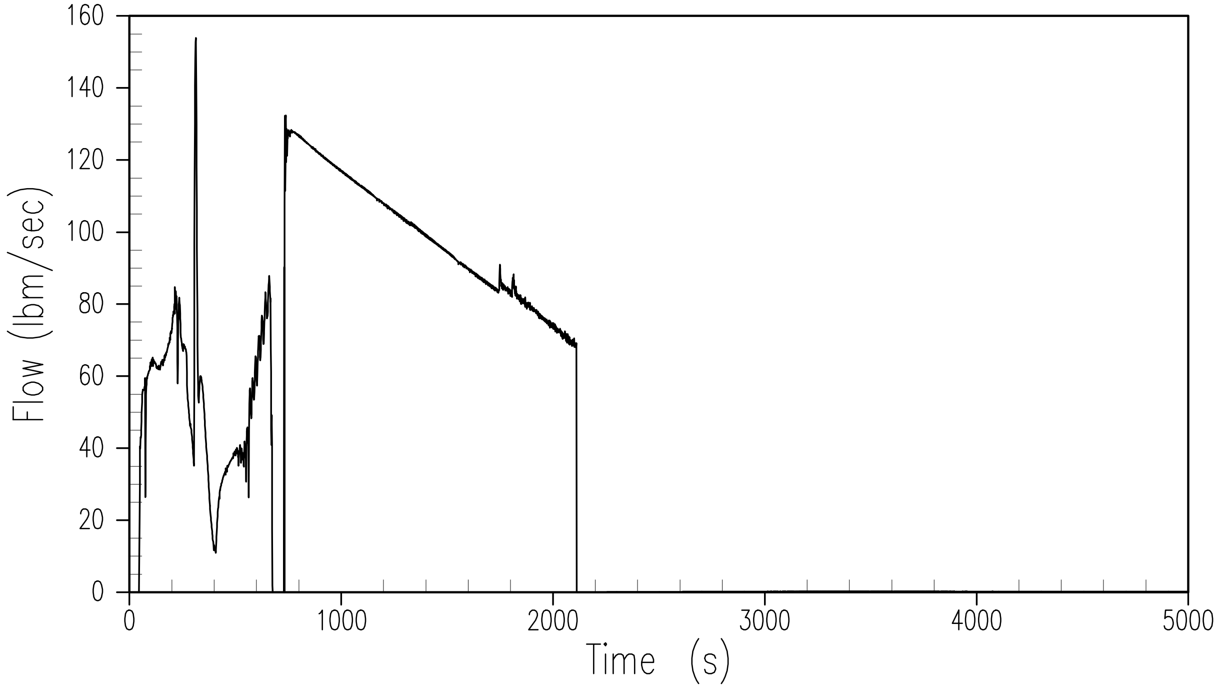

Figure 15.6.5.4B-6

Inadvertent ADS – CMT-2 Injection Rate

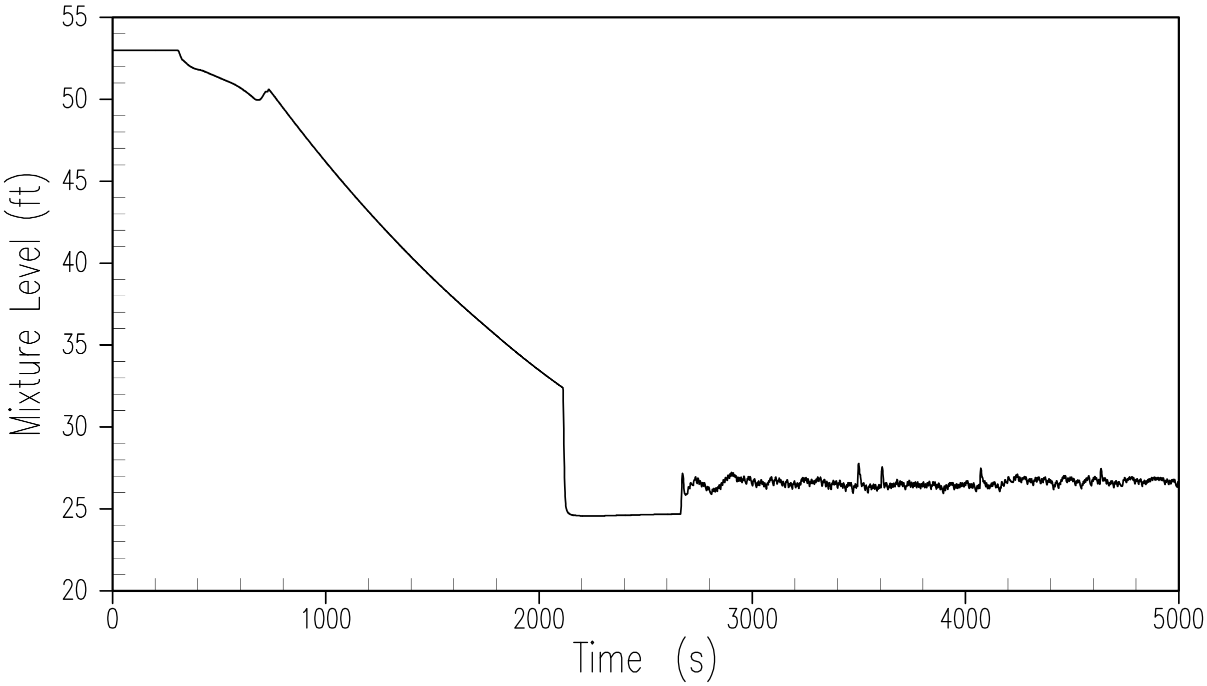

Figure 15.6.5.4B-7

Inadvertent ADS – CMT-1 Mixture Level

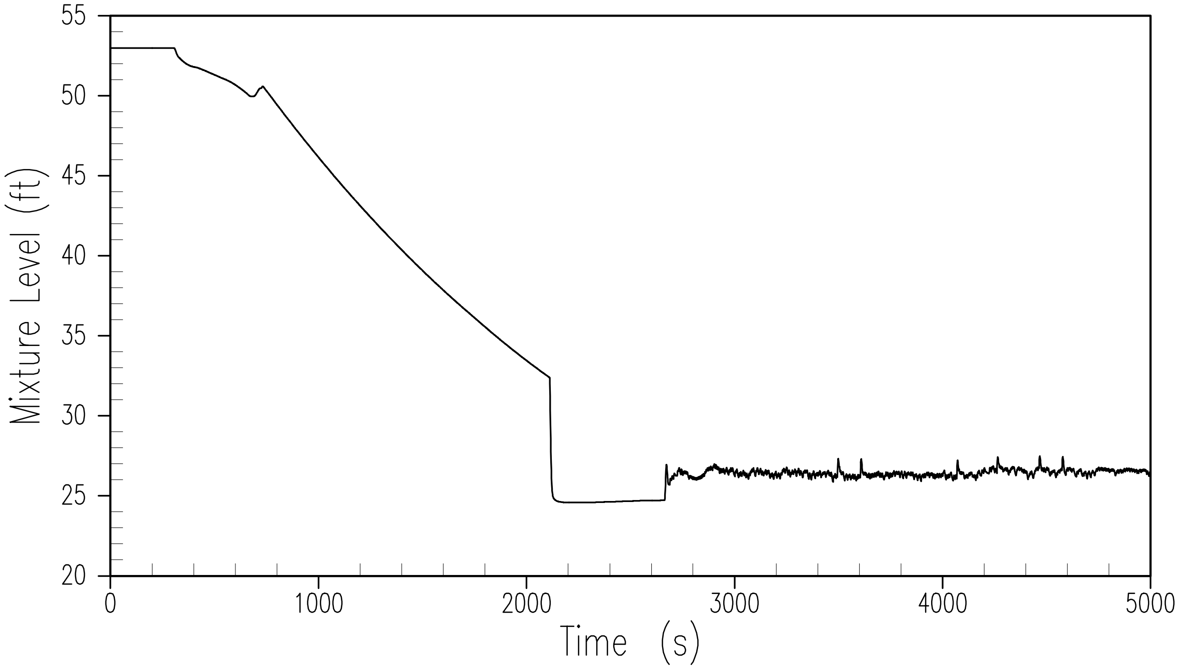

Figure 15.6.5.4B-8

Inadvertent ADS – CMT-2 Mixture Level

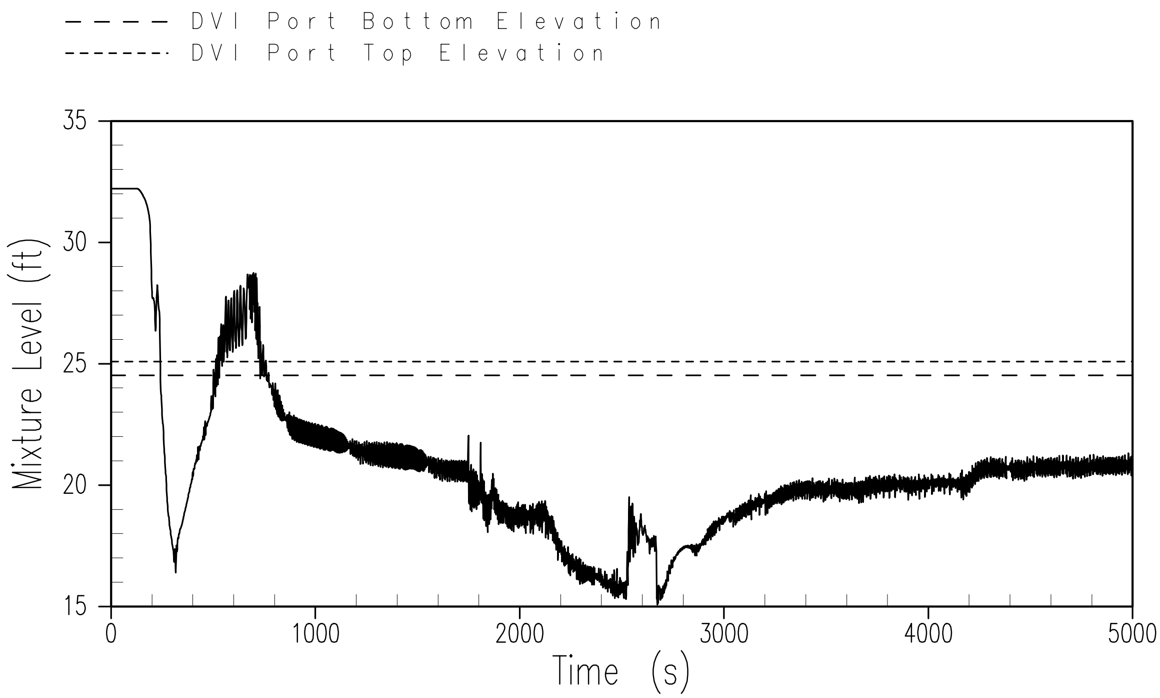

Figure 15.6.5.4B-9

Inadvertent ADS – Downcomer Mixture Level

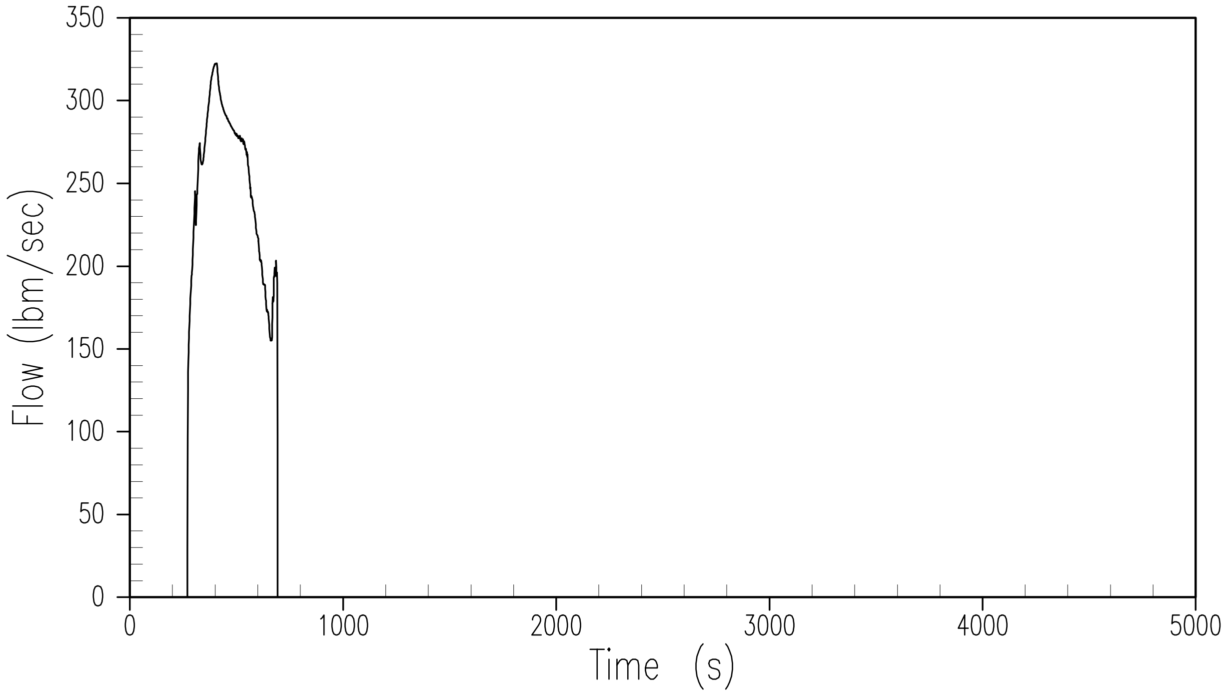

Figure 15.6.5.4B-10

Inadvertent ADS – Accumulator-1 Injection Rate

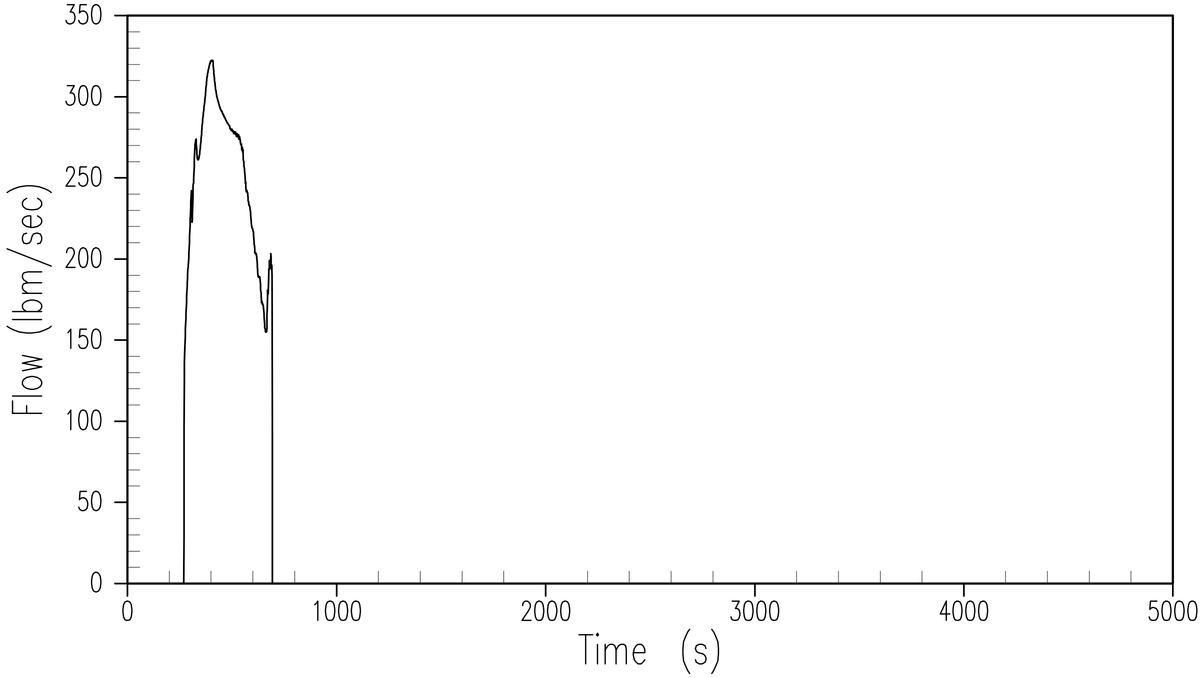

Figure 15.6.5.4B-11

Inadvertent ADS – Accumulator-2 Injection Rate

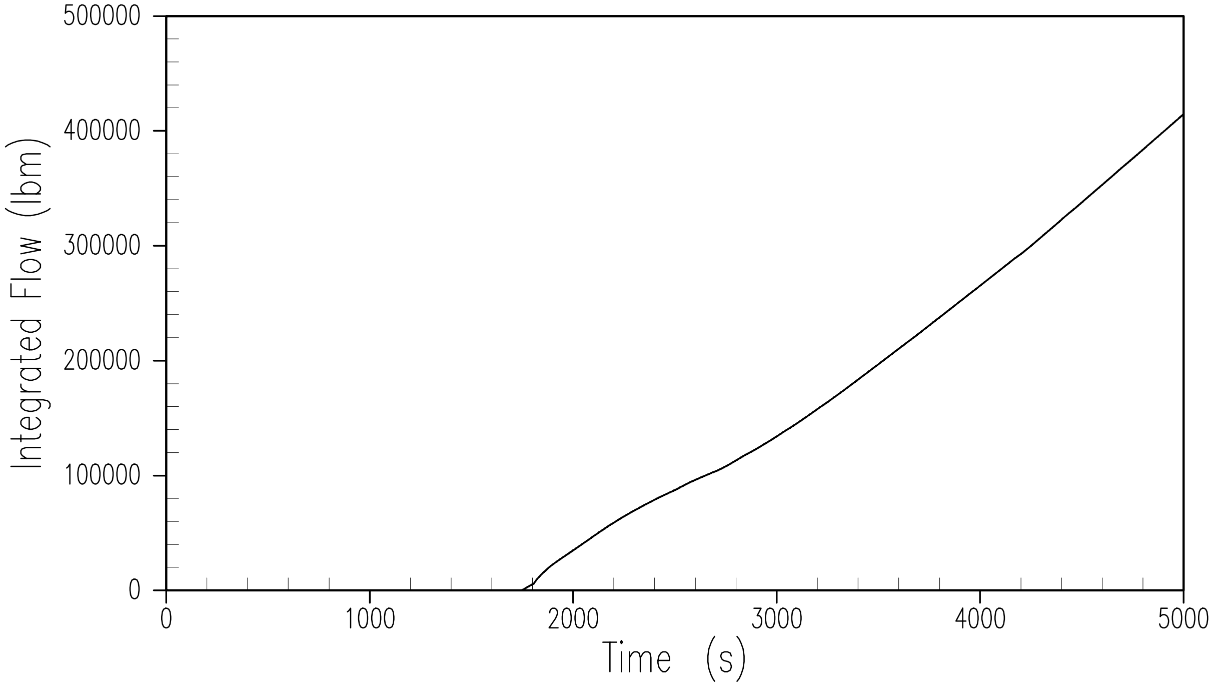

Figure 15.6.5.4B-12

Inadvertent ADS – ADS-4 Integrated Discharge

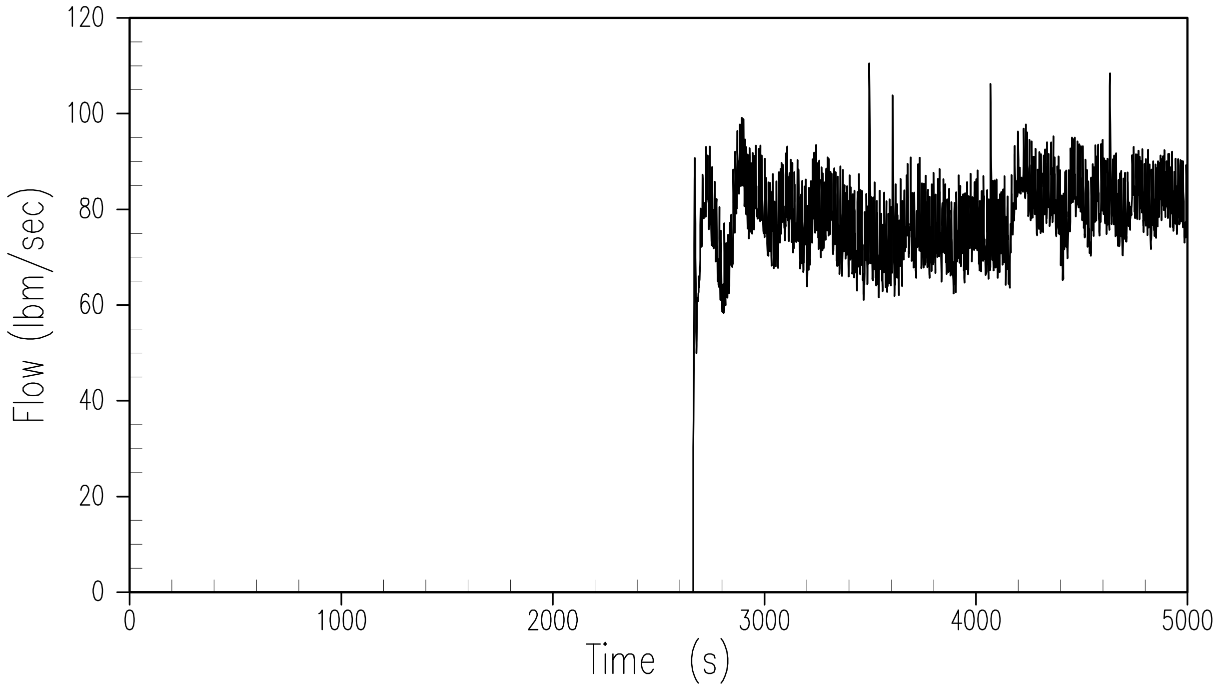

Figure 15.6.5.4B-13

Inadvertent ADS – IRWST-1 Injection Rate

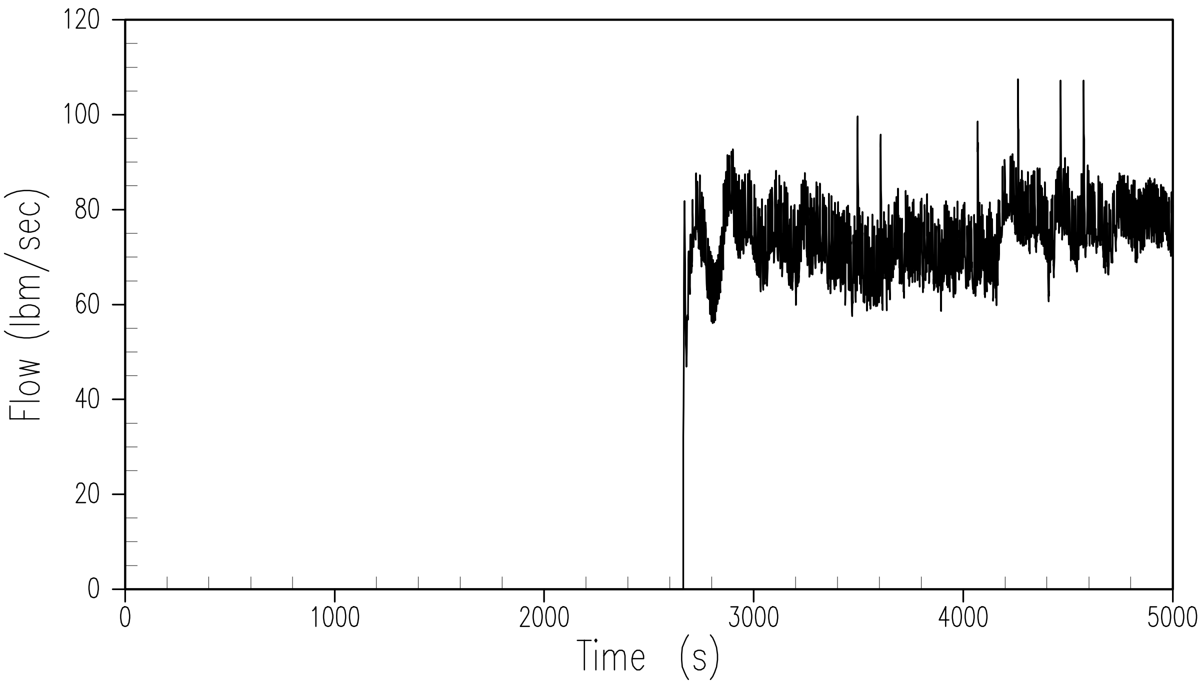

Figure 15.6.5.4B-14

Inadvertent ADS – IRWST-2 Injection Rate

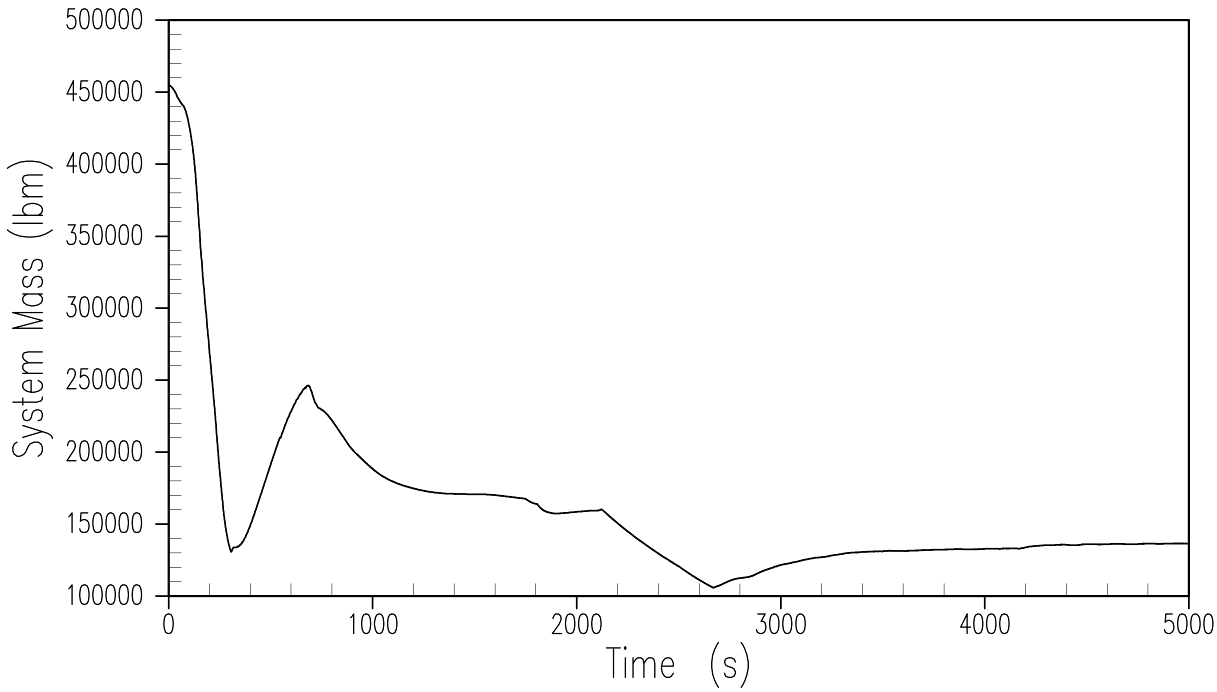

Figure 15.6.5.4B-15

Inadvertent ADS – RCS System Inventory

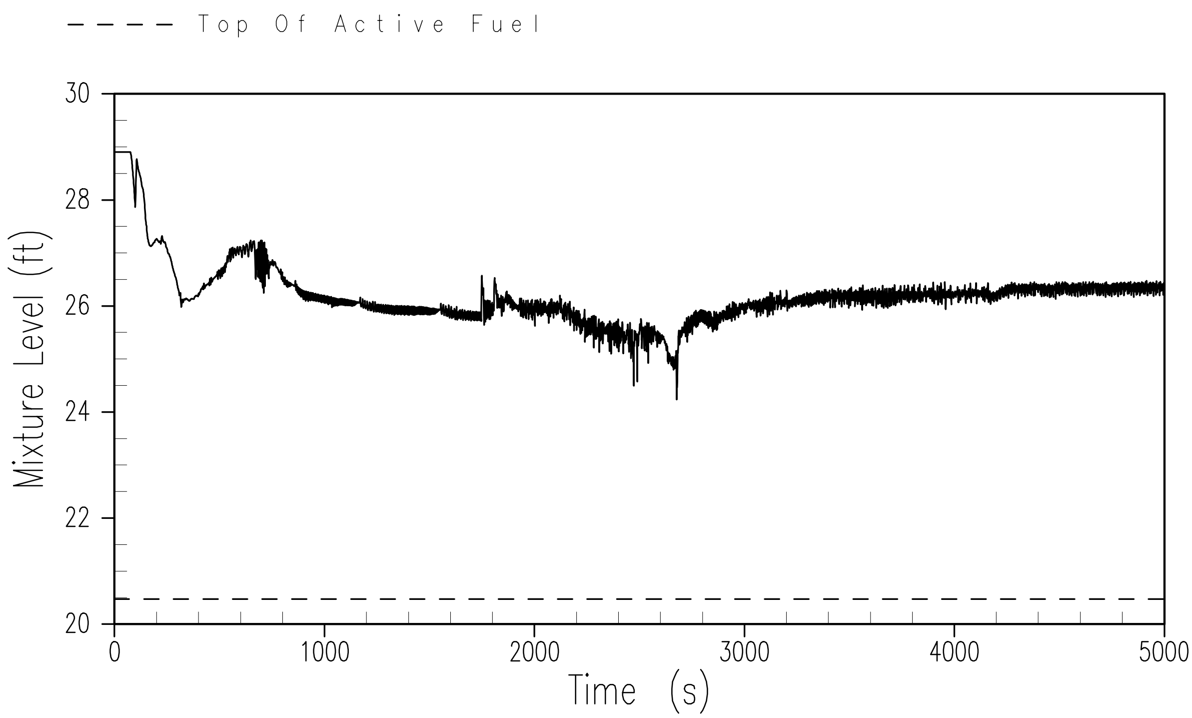

Figure 15.6.5.4B-16

Inadvertent ADS – Core/Upper Plenum Mixture Level

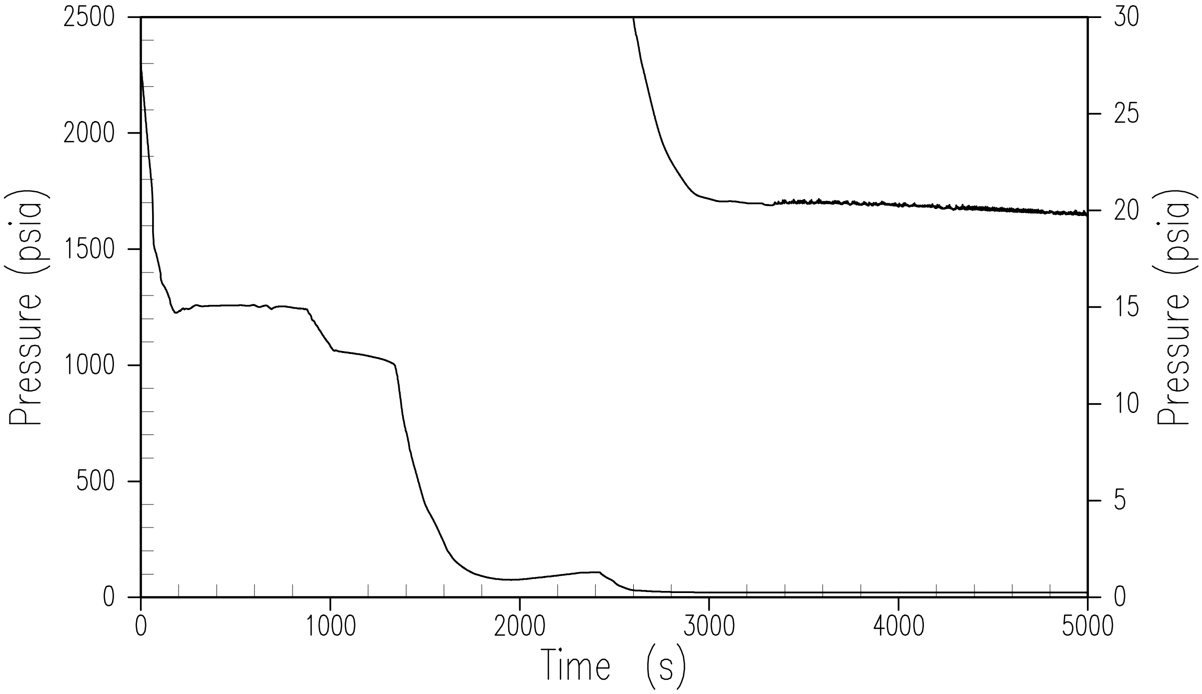

Figure 15.6.5.4B-17

2-Inch Cold Leg Break – RCS Pressure

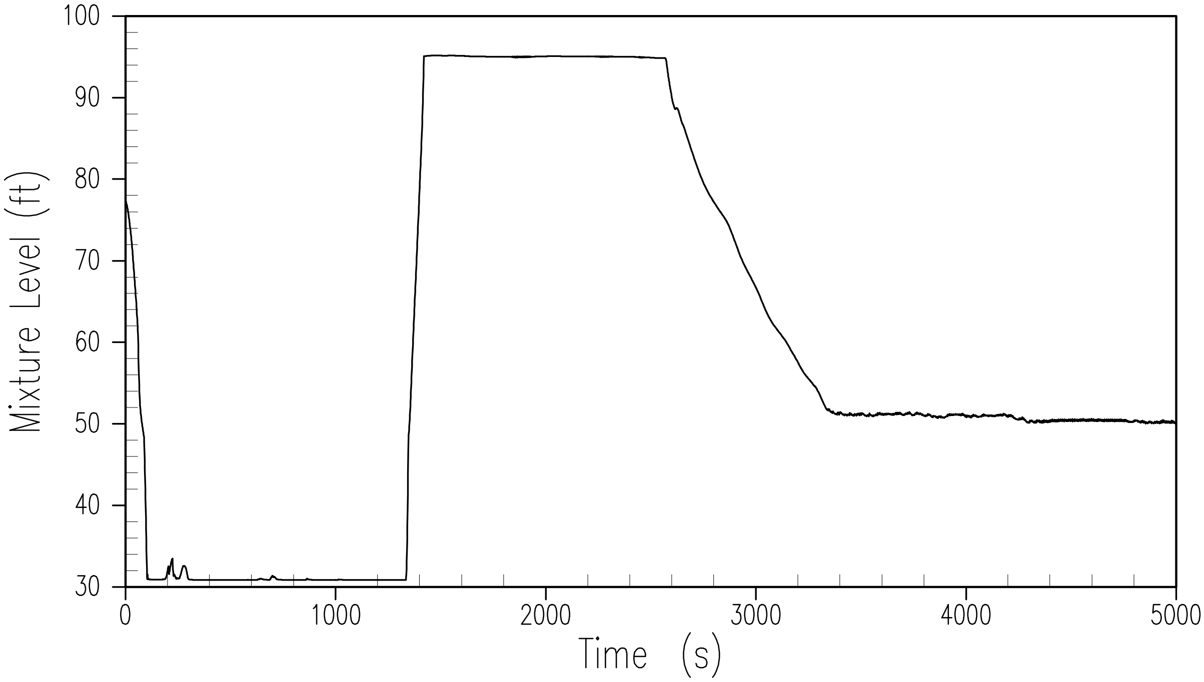

Figure 15.6.5.4B-18

2-Inch Cold Leg Break – Pressurizer Mixture Level

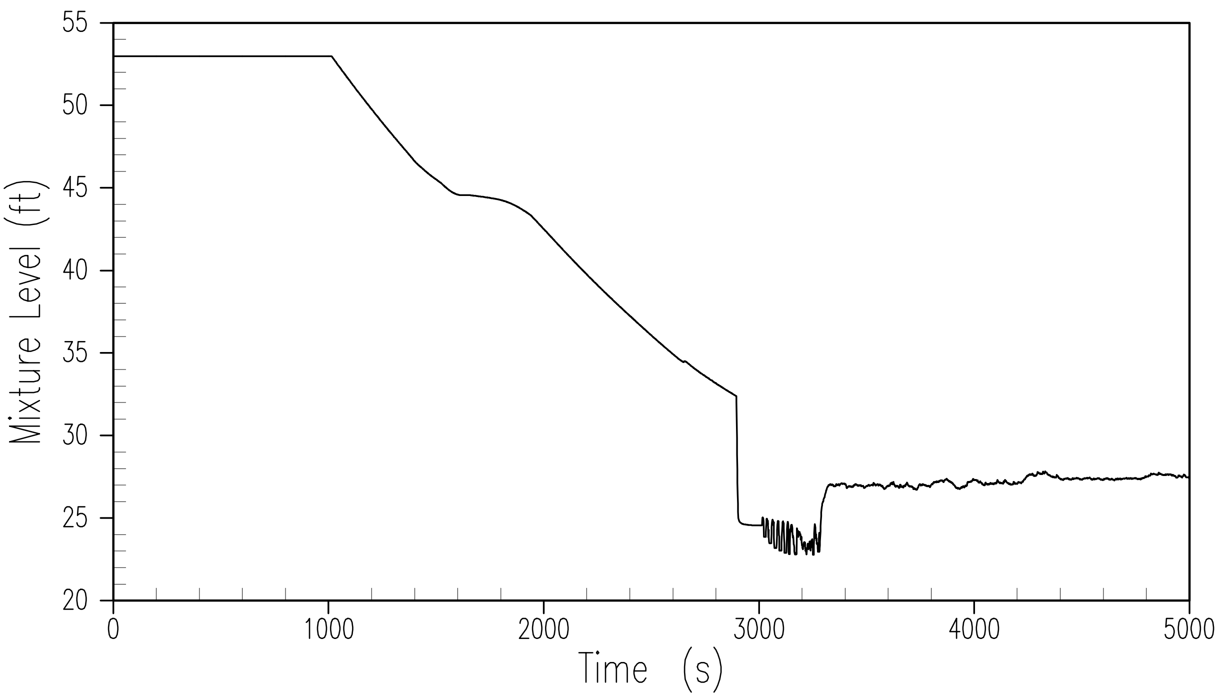

Figure 15.6.5.4B-19

2-Inch Cold Leg Break – CMT-1 Mixture Level

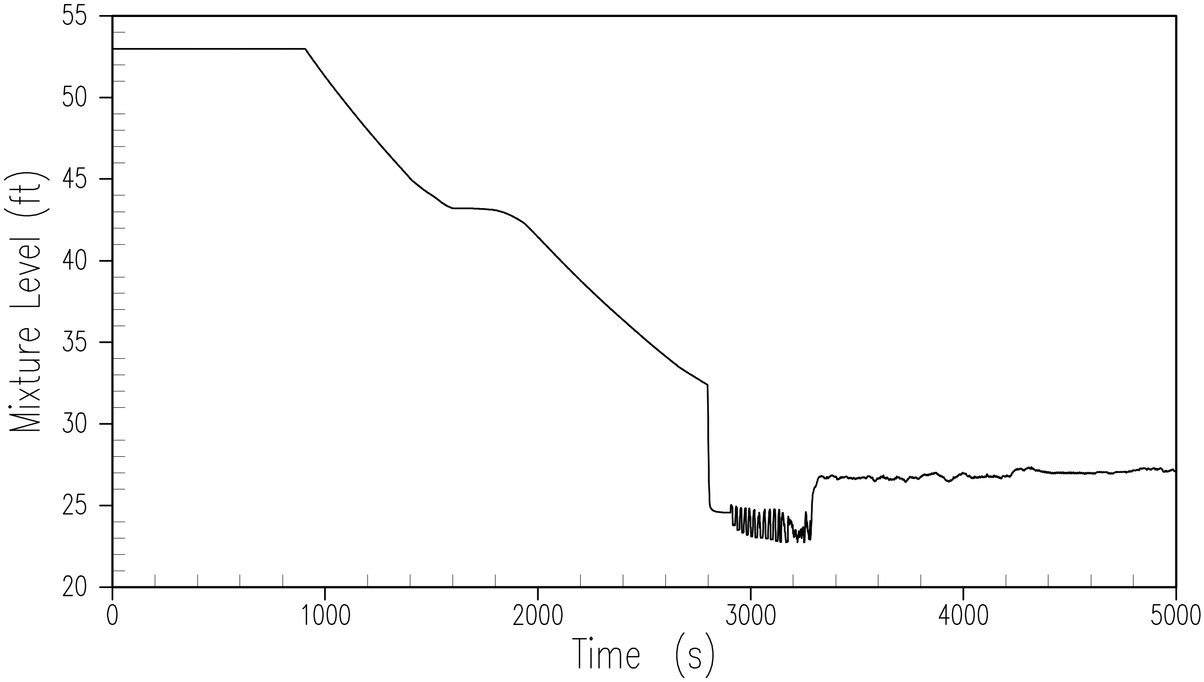

Figure 15.6.5.4B-20

2-Inch Cold Leg Break – CMT-2 Mixture Level

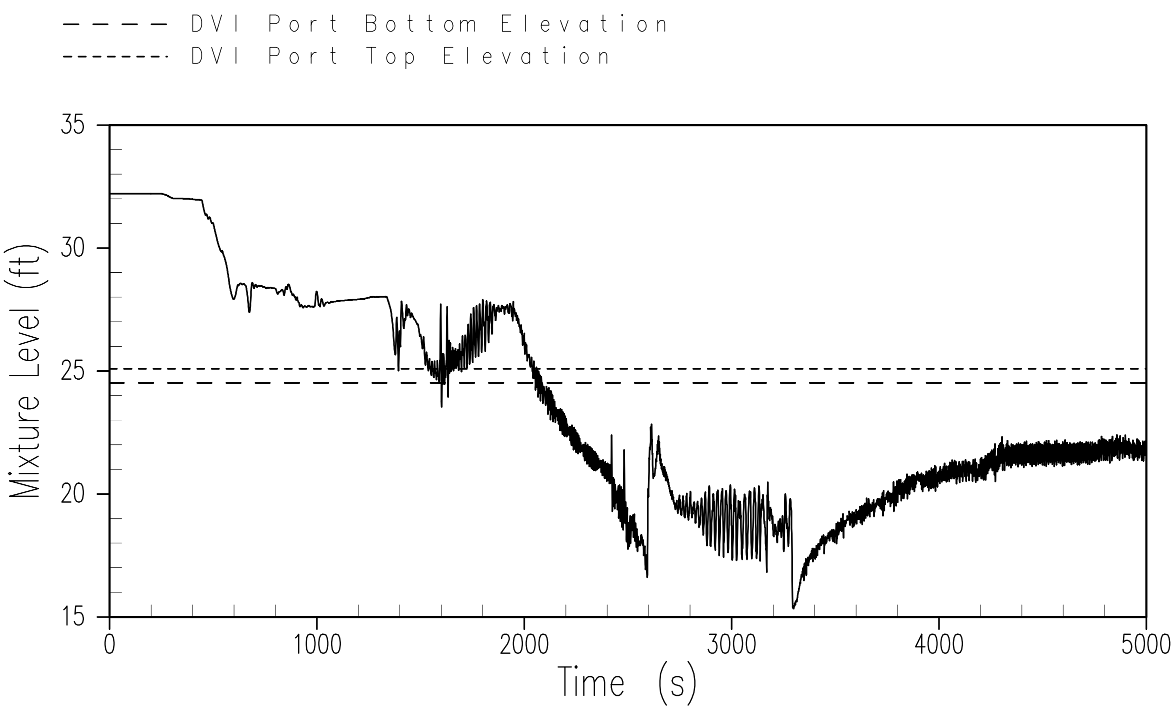

Figure 15.6.5.4B-21

2-Inch Cold Leg Break – Downcomer Mixture Level

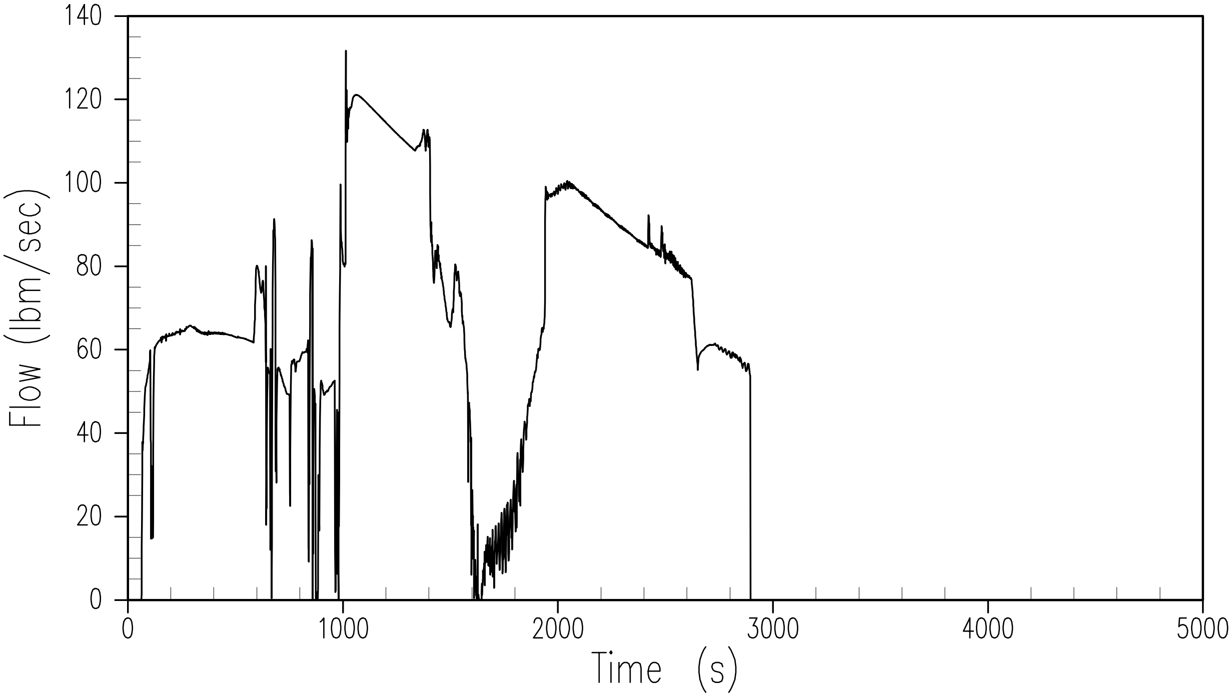

Figure 15.6.5.4B-22

2-Inch Cold Leg Break – CMT-1 Injection Rate

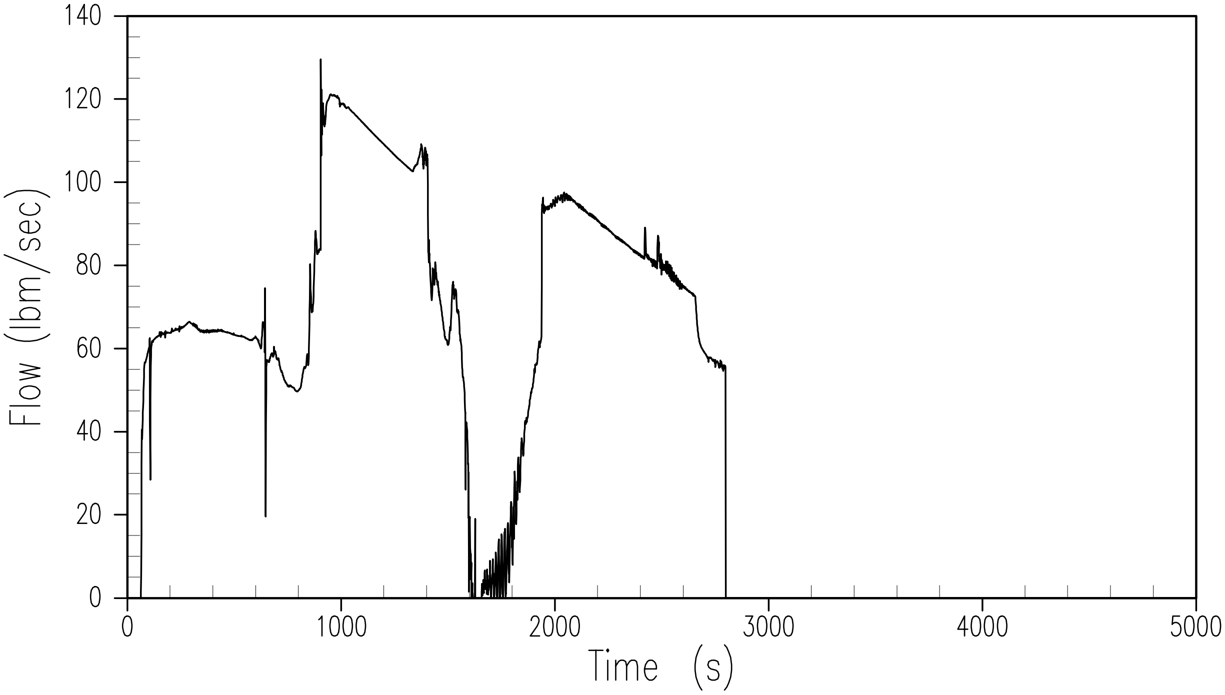

Figure 15.6.5.4B-23

2-Inch Cold Leg Break – CMT-2 Injection Rate

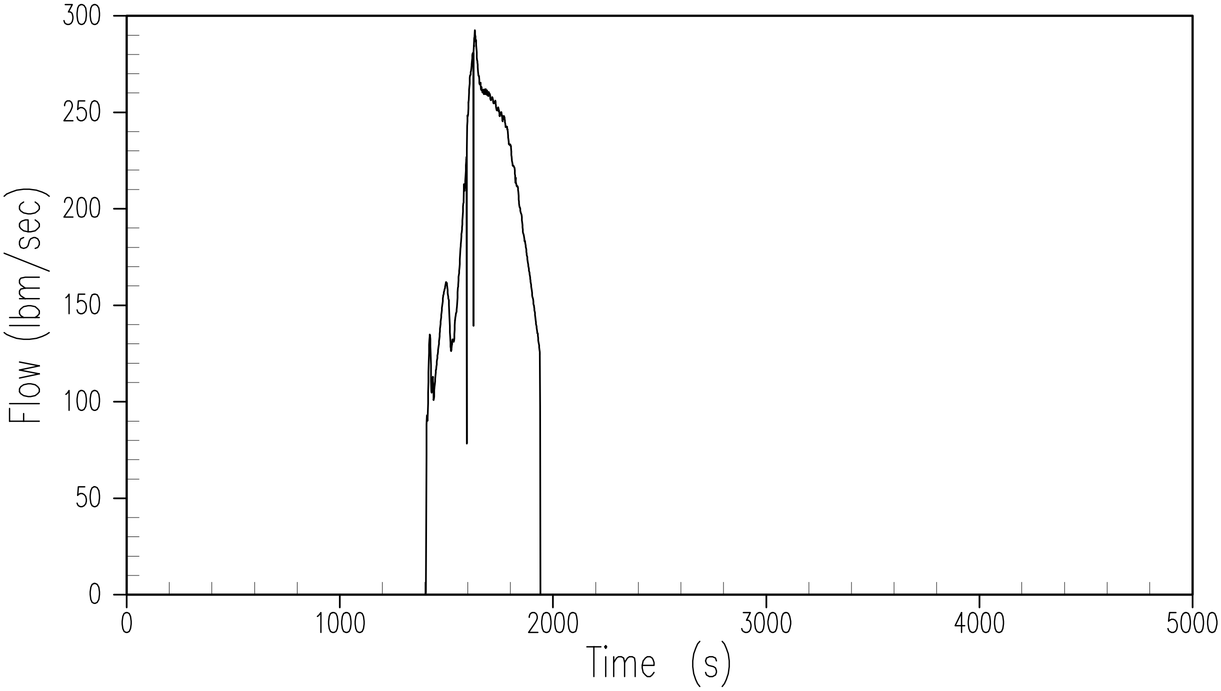

Figure 15.6.5.4B-24

2-Inch Cold Leg Break – Accumulator-1 Injection Rate

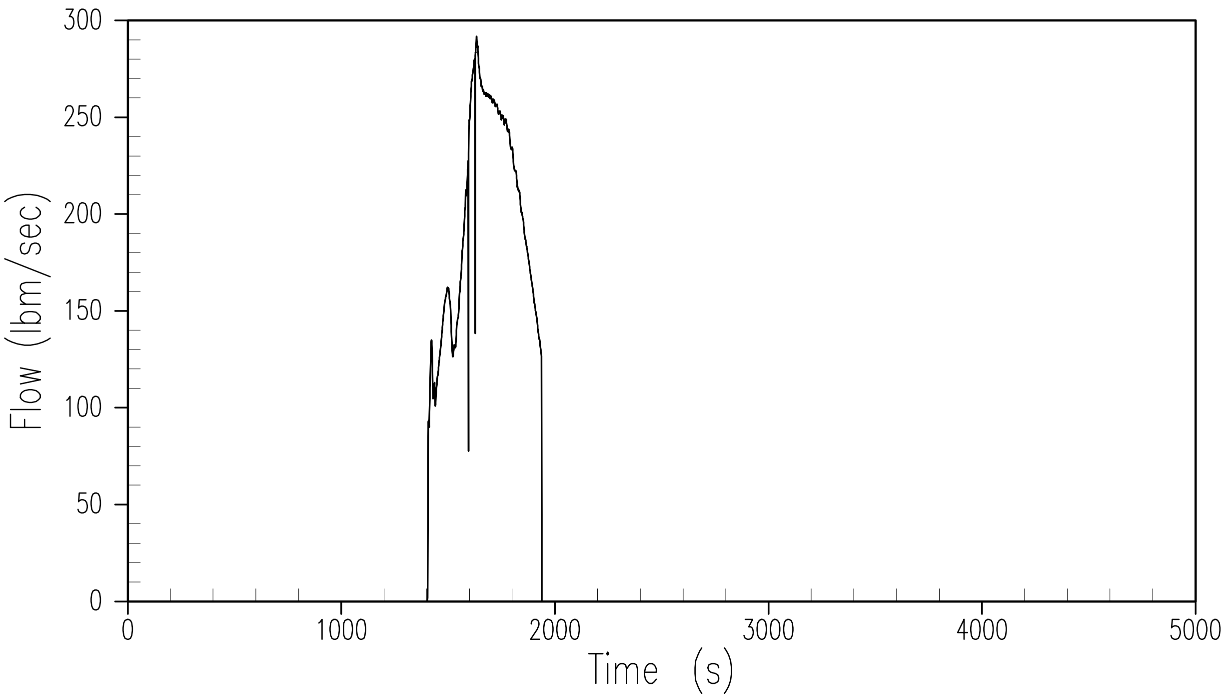

Figure 15.6.5.4B-25

2-Inch Cold Leg Break – Accumulator-2 Injection Rate

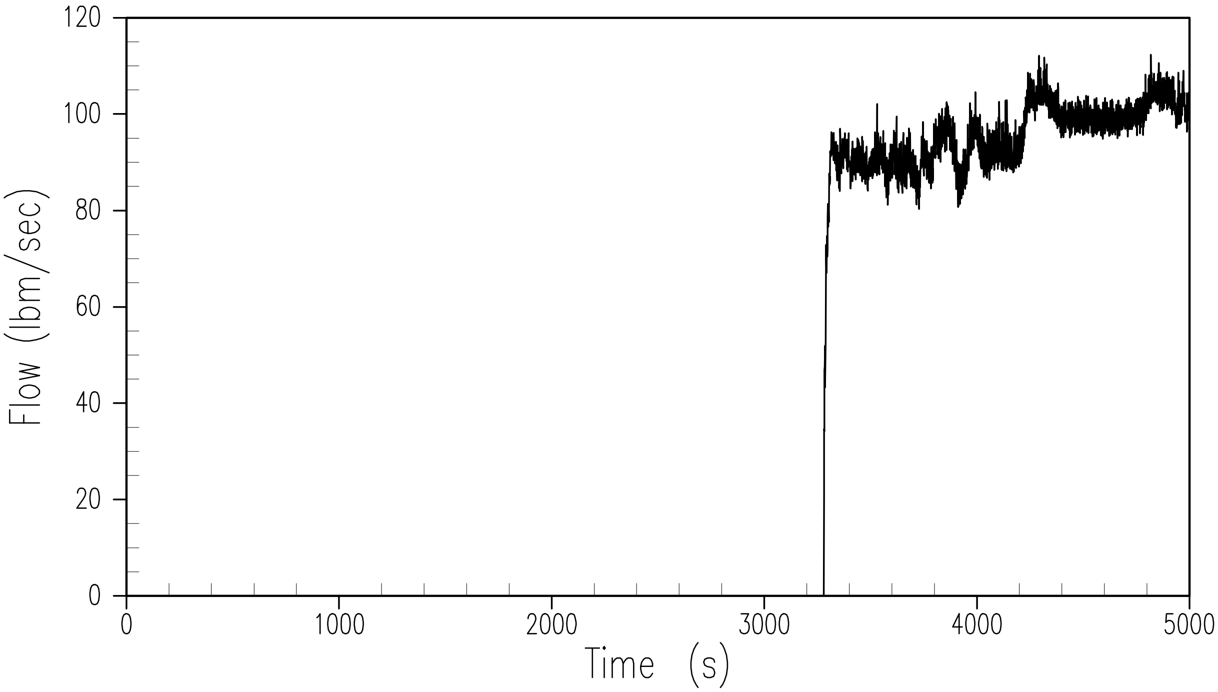

Figure 15.6.5.4B-26

2-Inch Cold Leg Break – IRWST-1 Injection Rate

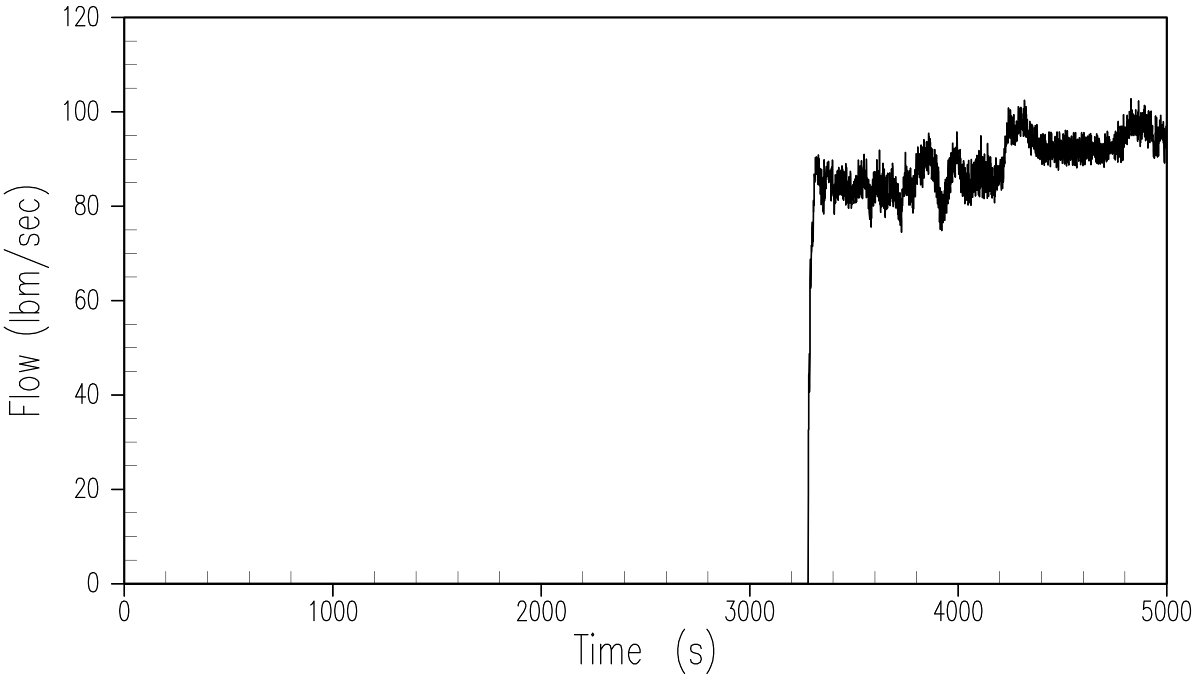

Figure 15.6.5.4B-27

2-Inch Cold Leg Break – IRWST-2 Injection Rate

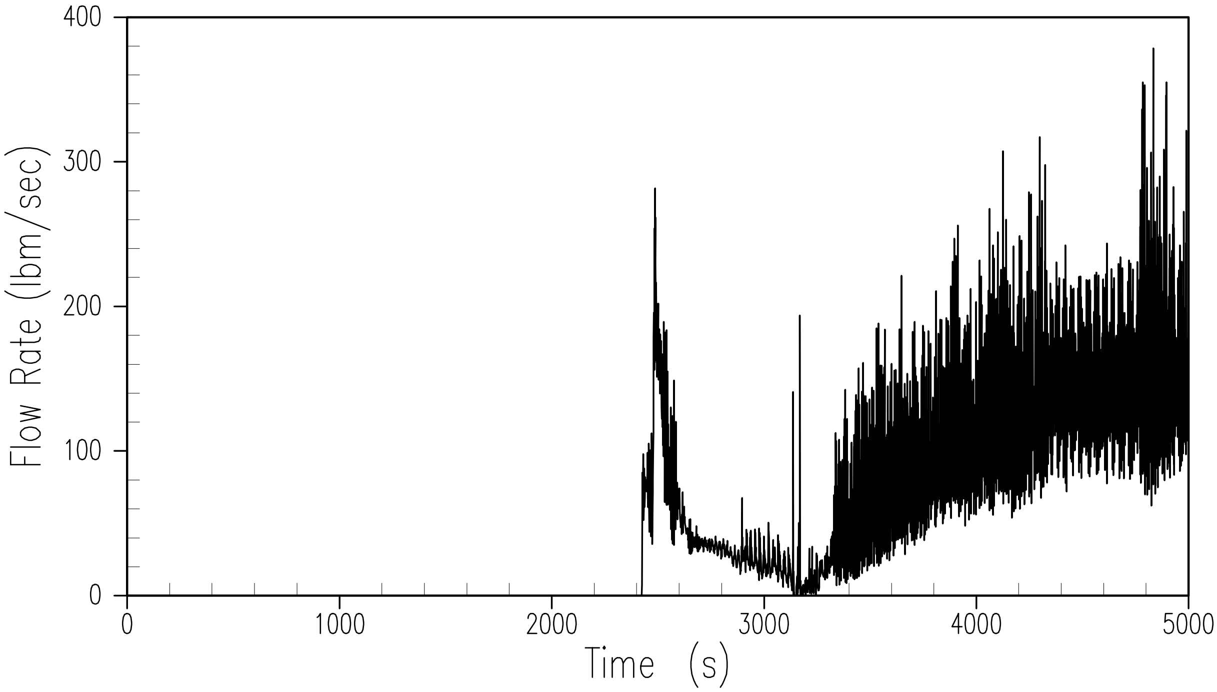

Figure 15.6.5.4B-28

2-Inch Cold Leg Break – ADS-4 Liquid Discharge

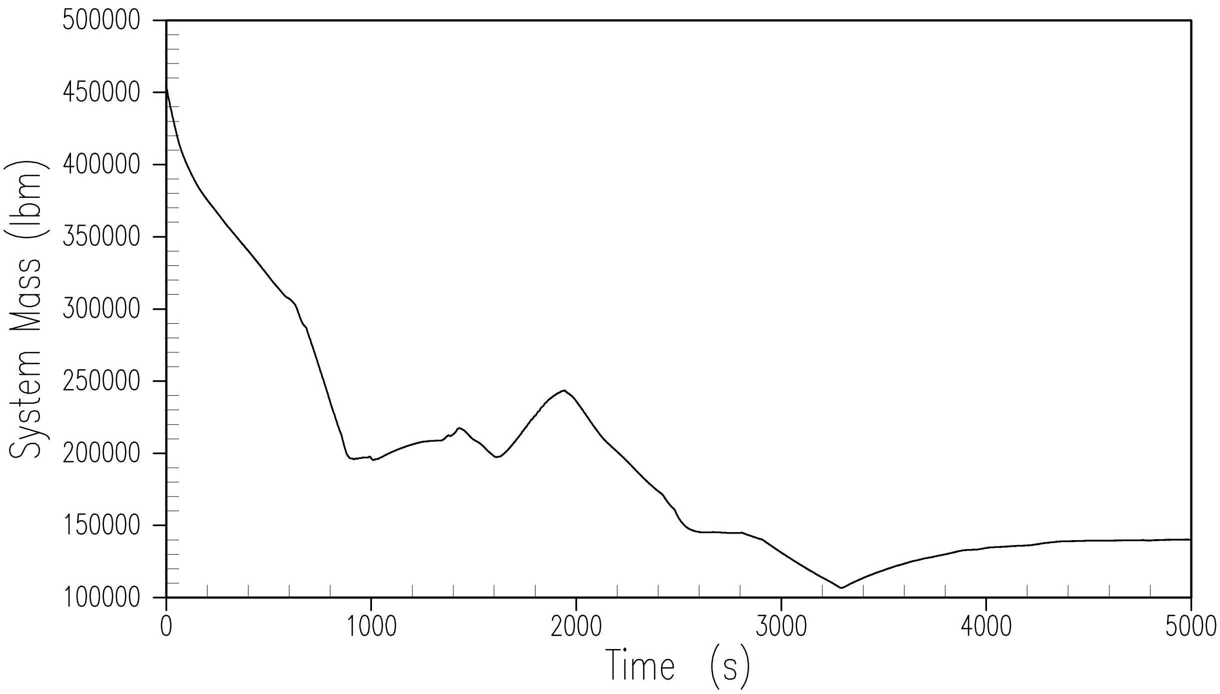

Figure 15.6.5.4B-29

2-Inch Cold Leg Break – RCS System Inventory

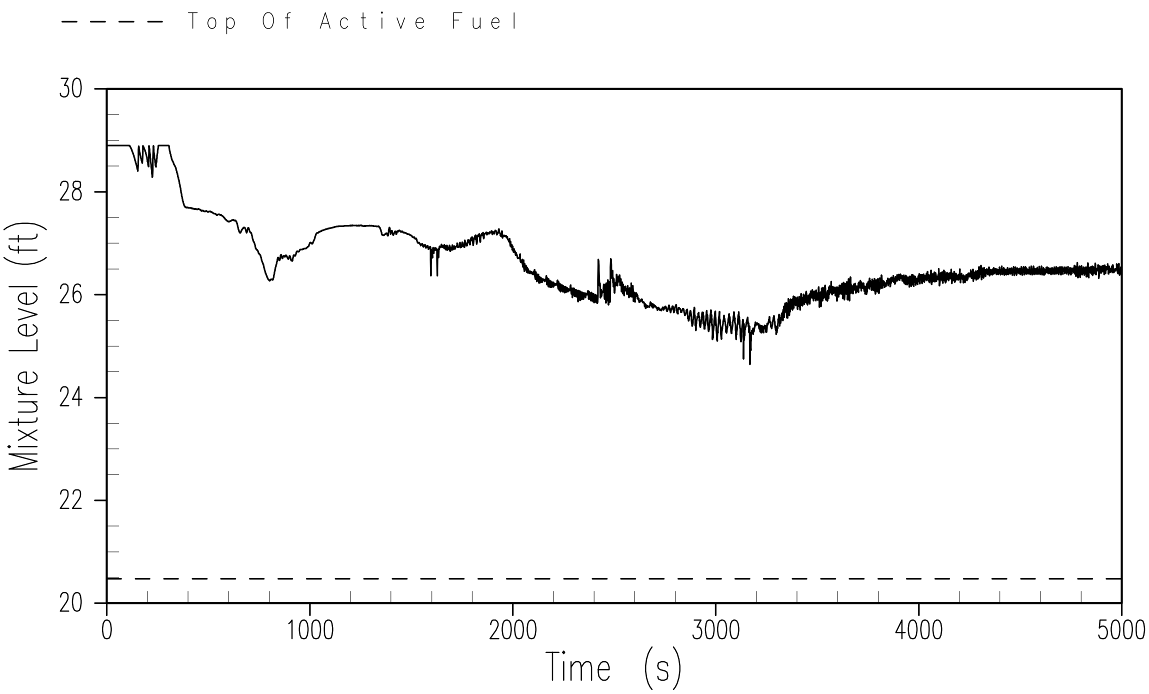

Figure 15.6.5.4B-30

2-Inch Cold Leg Break – Core/Upper Plenum Mixture Level

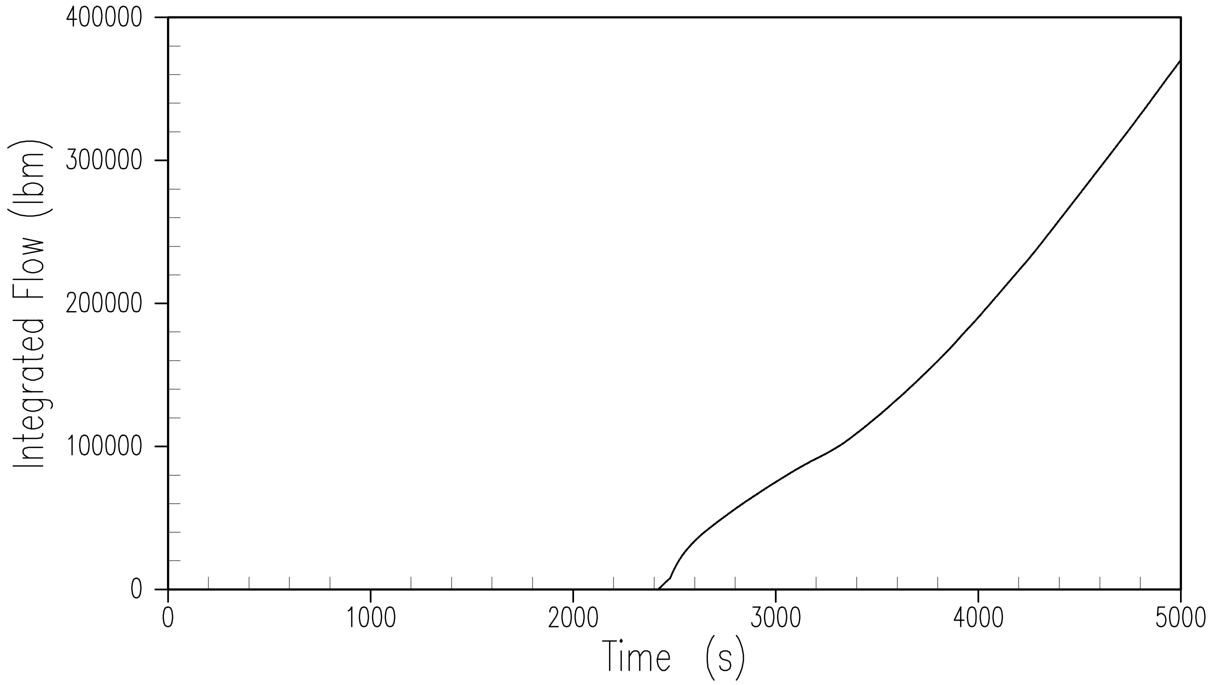

Figure 15.6.5.4B-31

2-Inch Cold Leg Break – ADS-4 Integrated Discharge

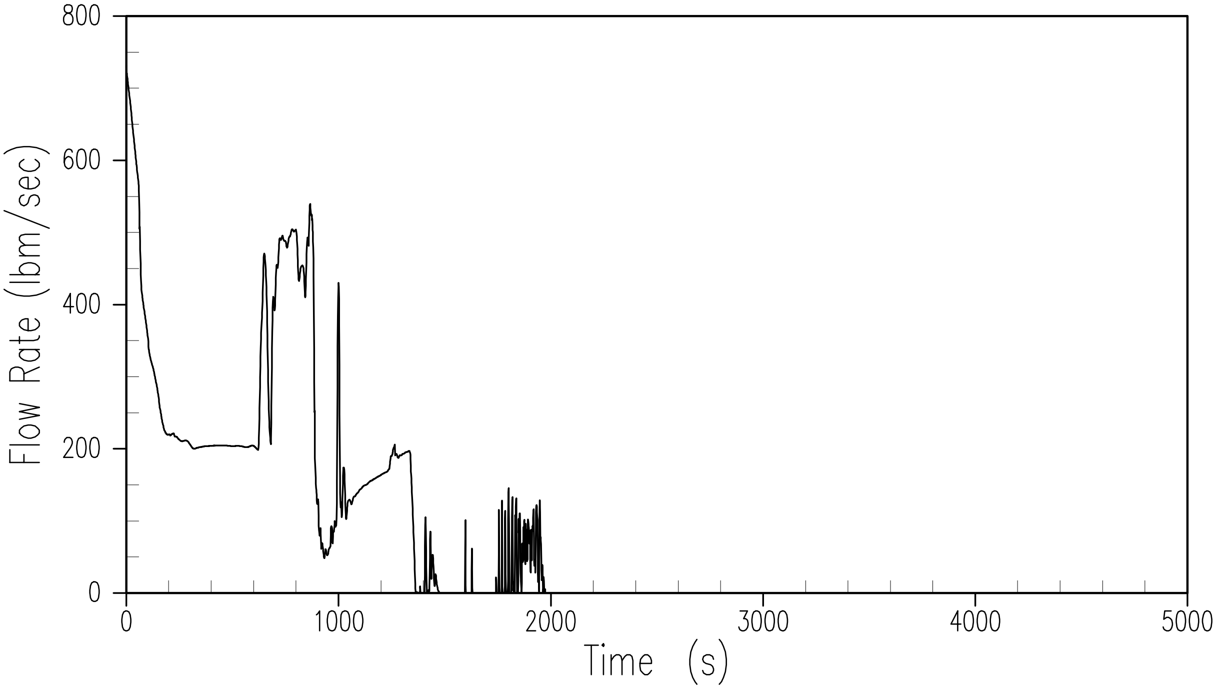

Figure 15.6.5.4B-32

2-Inch Cold Leg Break – Liquid Break Discharge

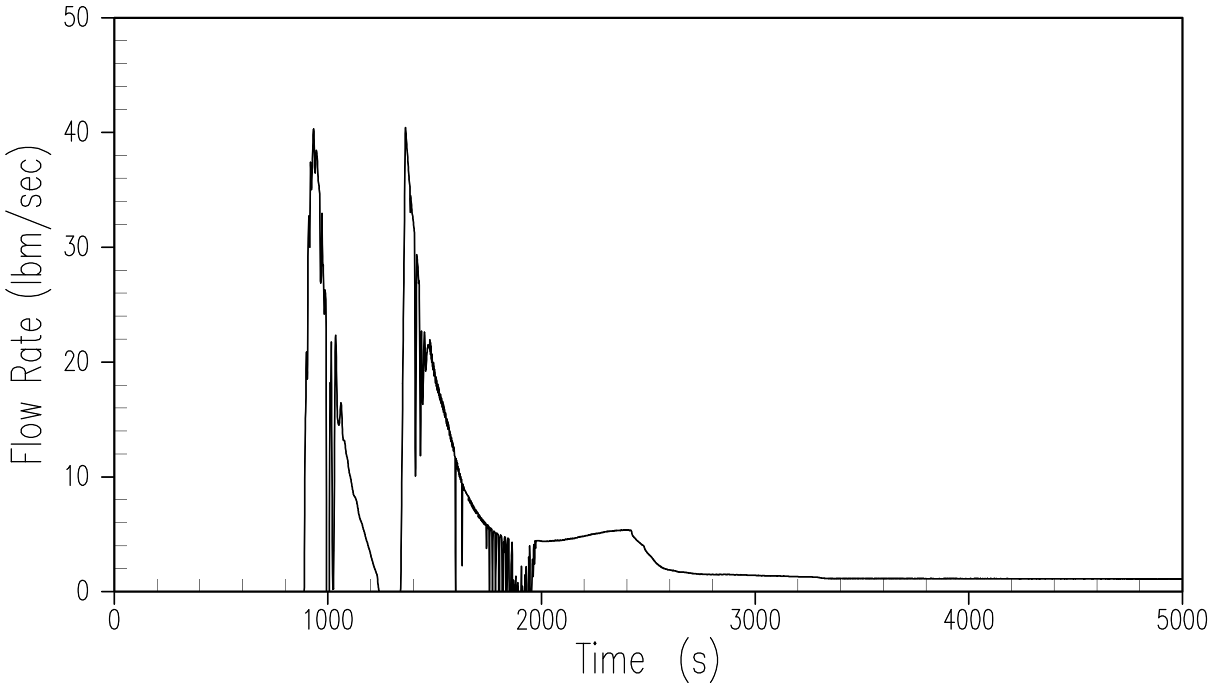

Figure 15.6.5.4B-33

2-Inch Cold Leg Break – Vapor Break Discharge

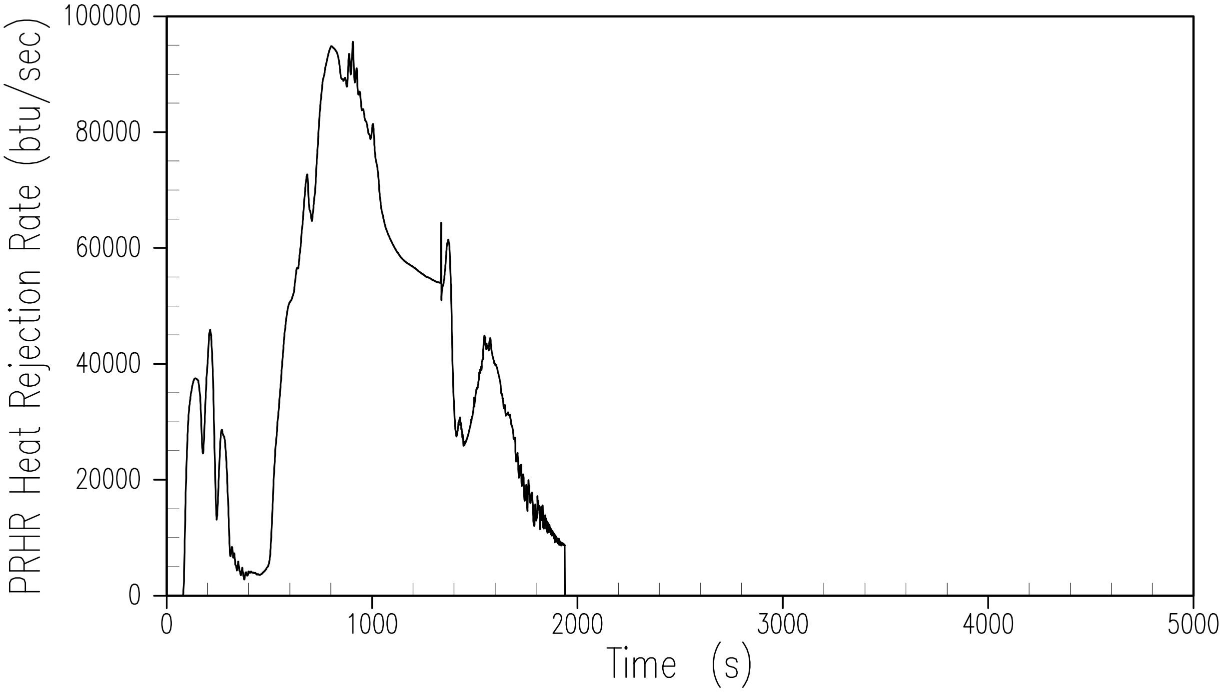

Figure 15.6.5.4B-34

2-Inch Cold Leg Break – PRHR Heat Removal Rate

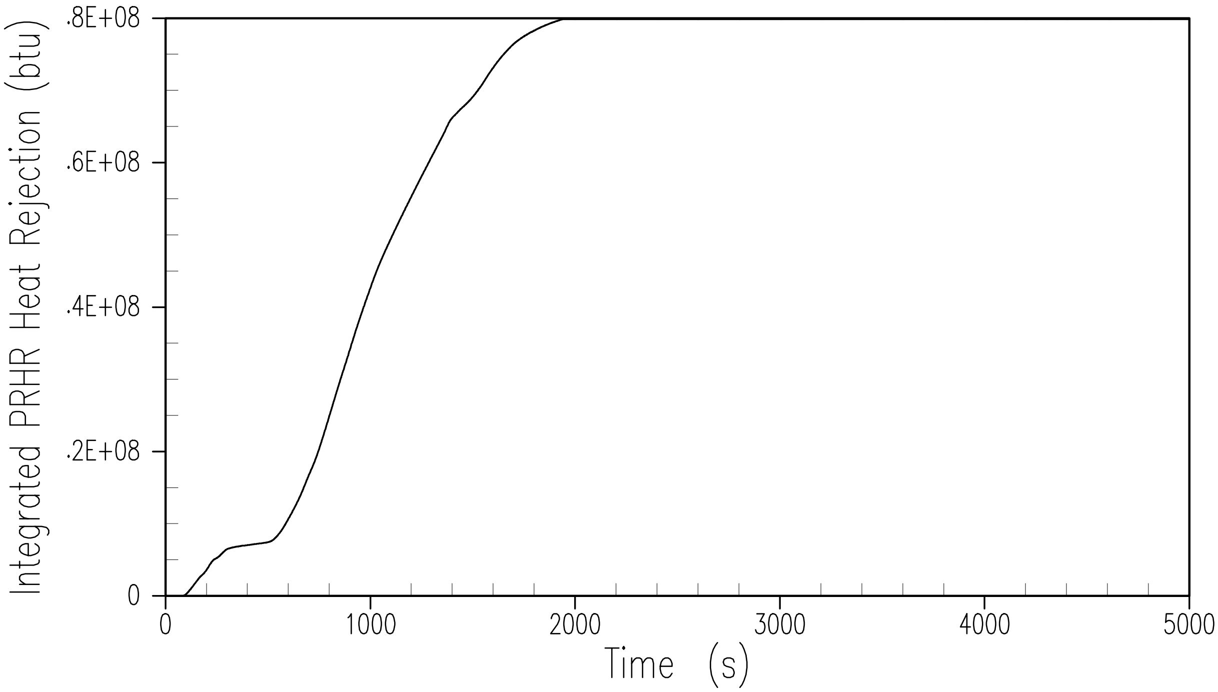

Figure 15.6.5.4B-35

2-Inch Cold Leg Break – Integrated PRHR Heat Removal

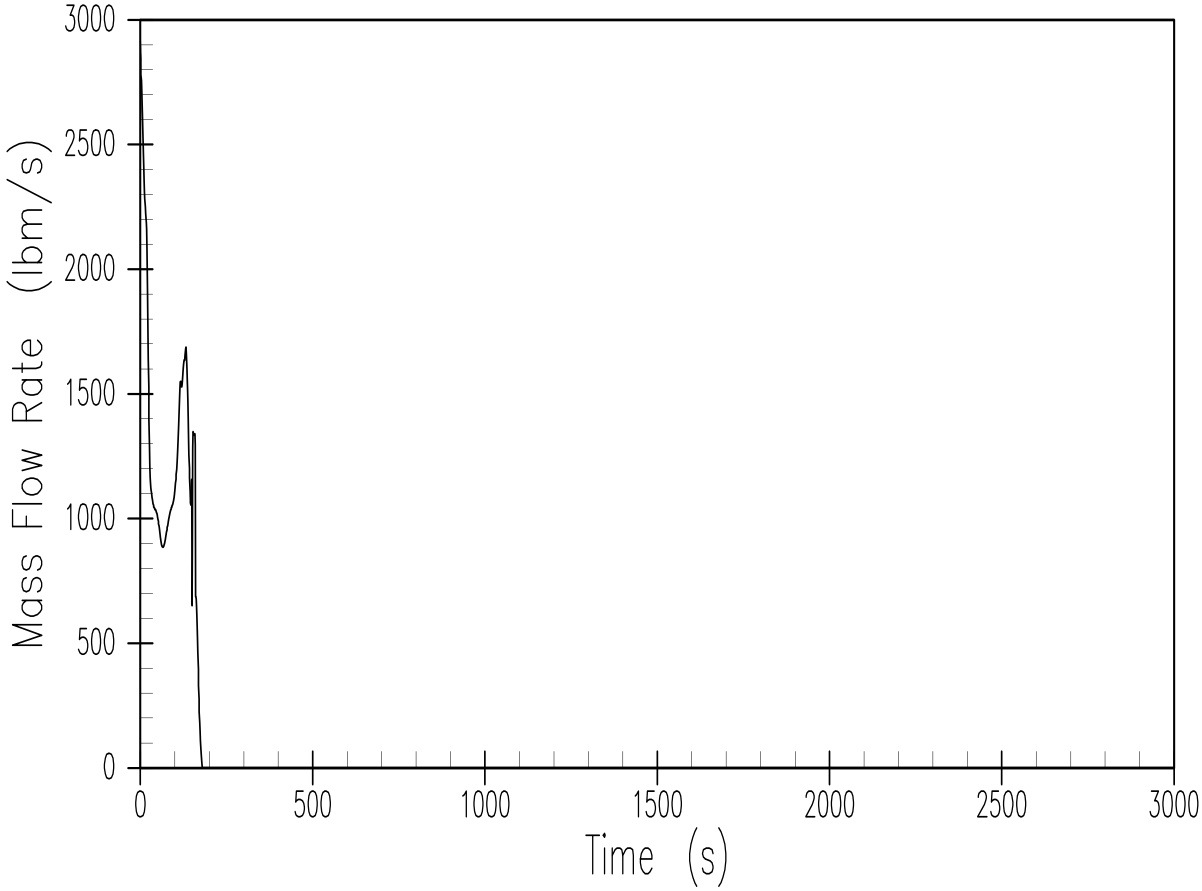

Figure 15.6.5.4B-36

DEDVI – Vessel Side Liquid Break Discharge – 20 psi

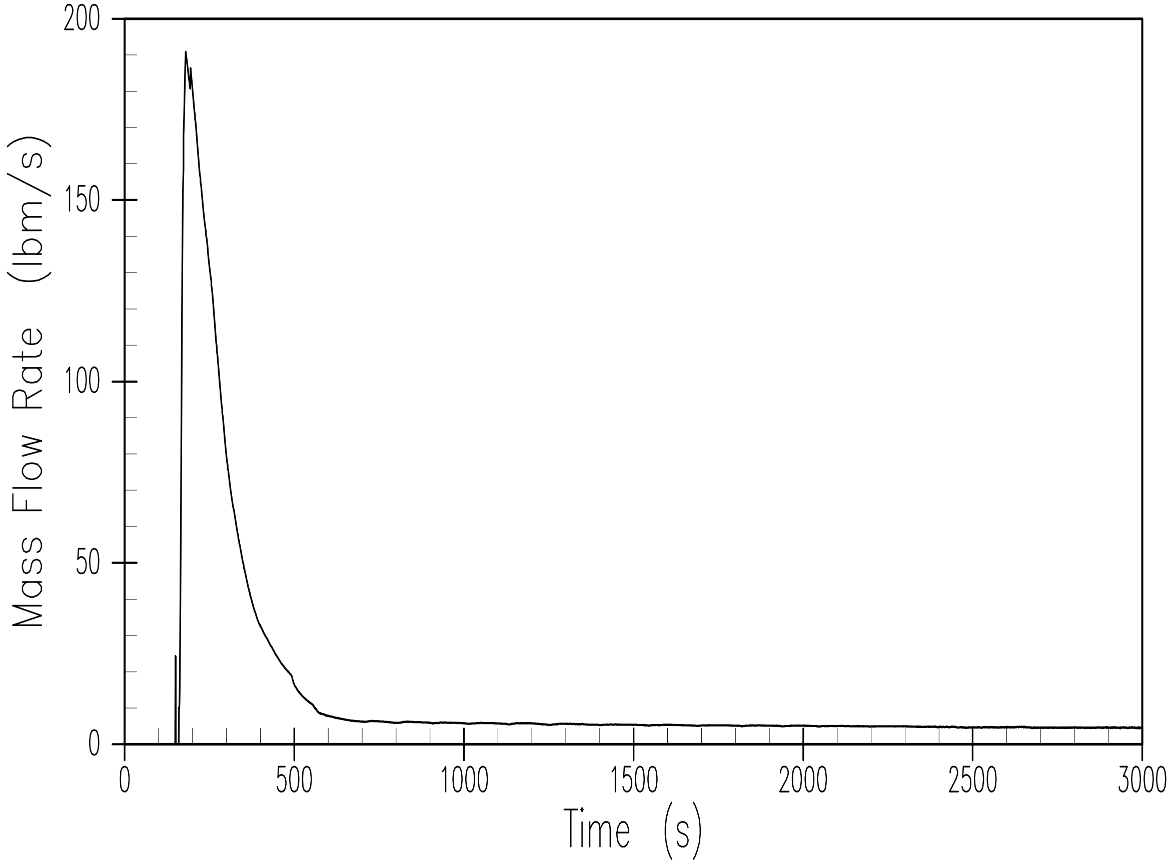

Figure 15.6.5.4B-37

DEDVI – Vessel Side Vapor Break Discharge – 20 psi

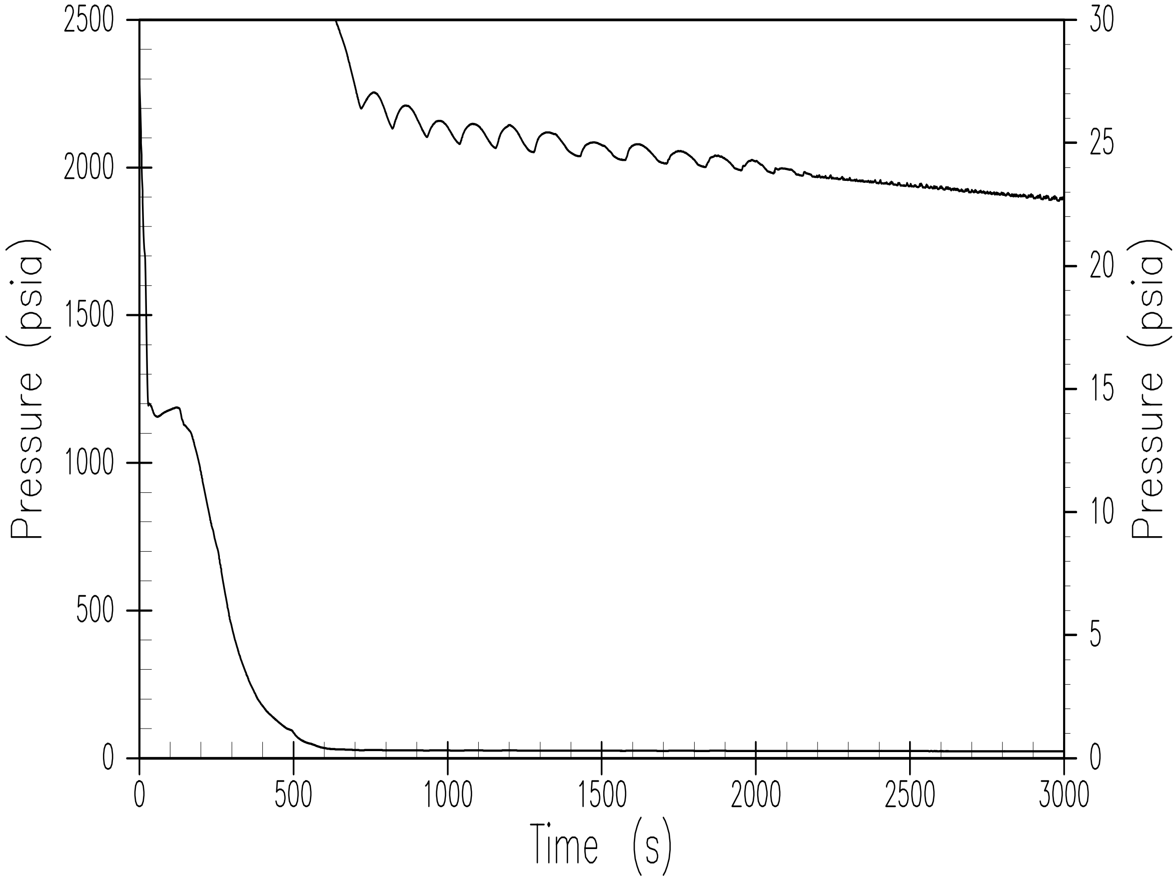

Figure 15.6.5.4B-38

DEDVI – RCS Pressure – 20 psi

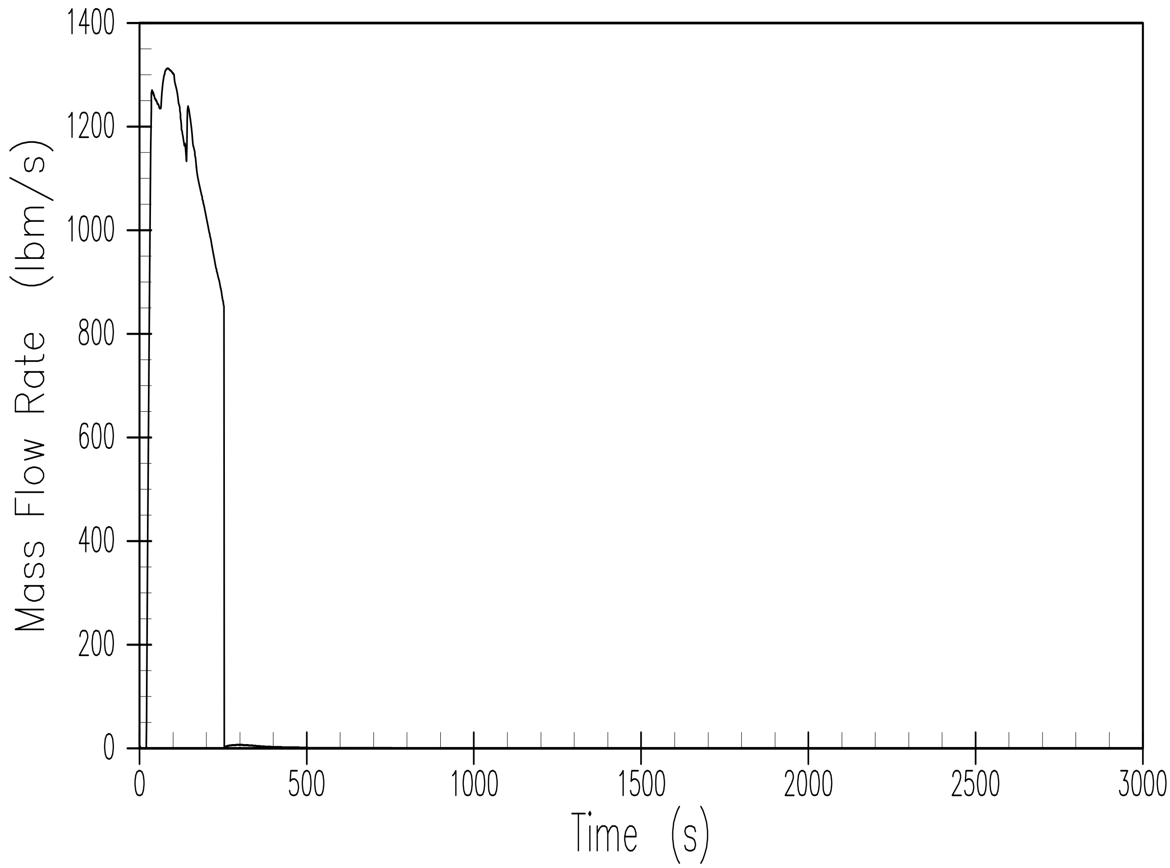

Figure 15.6.5.4B-39

DEDVI – Broken CMT Injection Rate – 20 psi

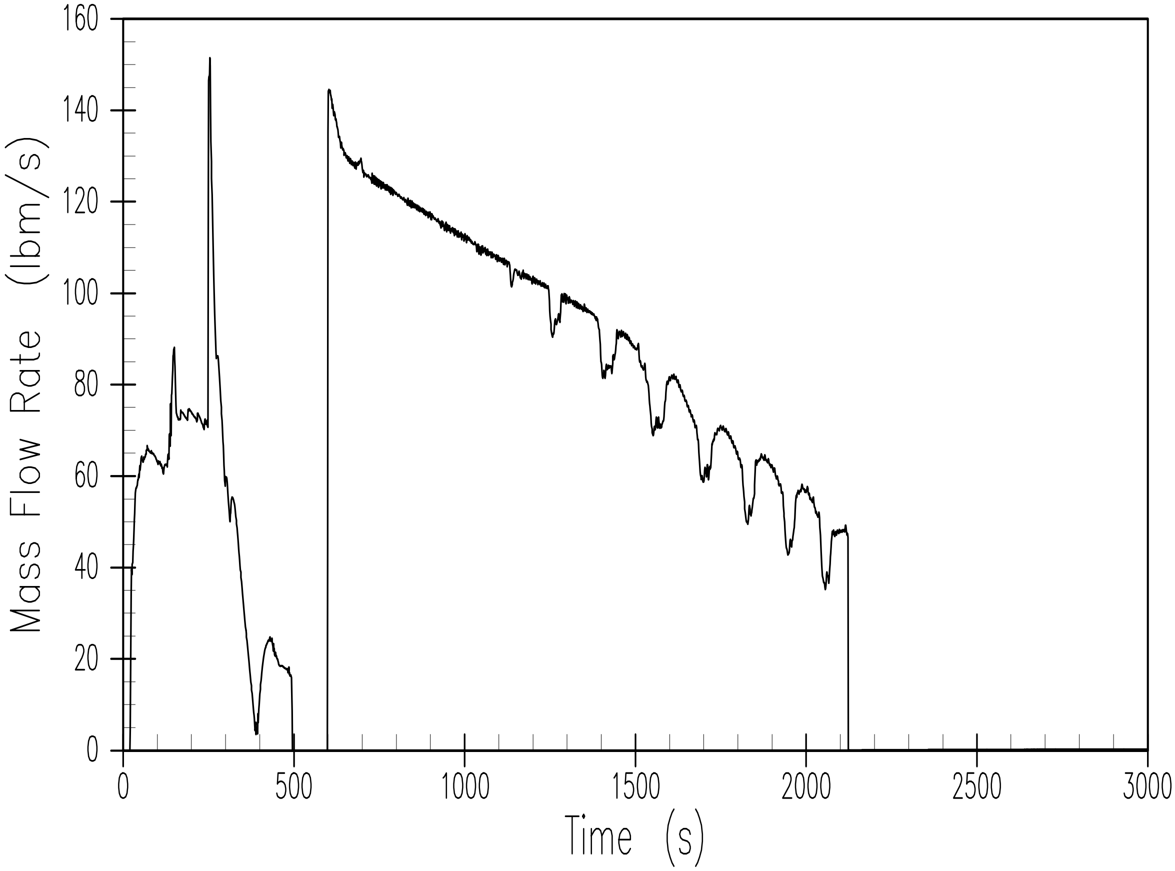

Figure 15.6.5.4B-40

DEDVI – Intact CMT Injection Rate – 20 psi

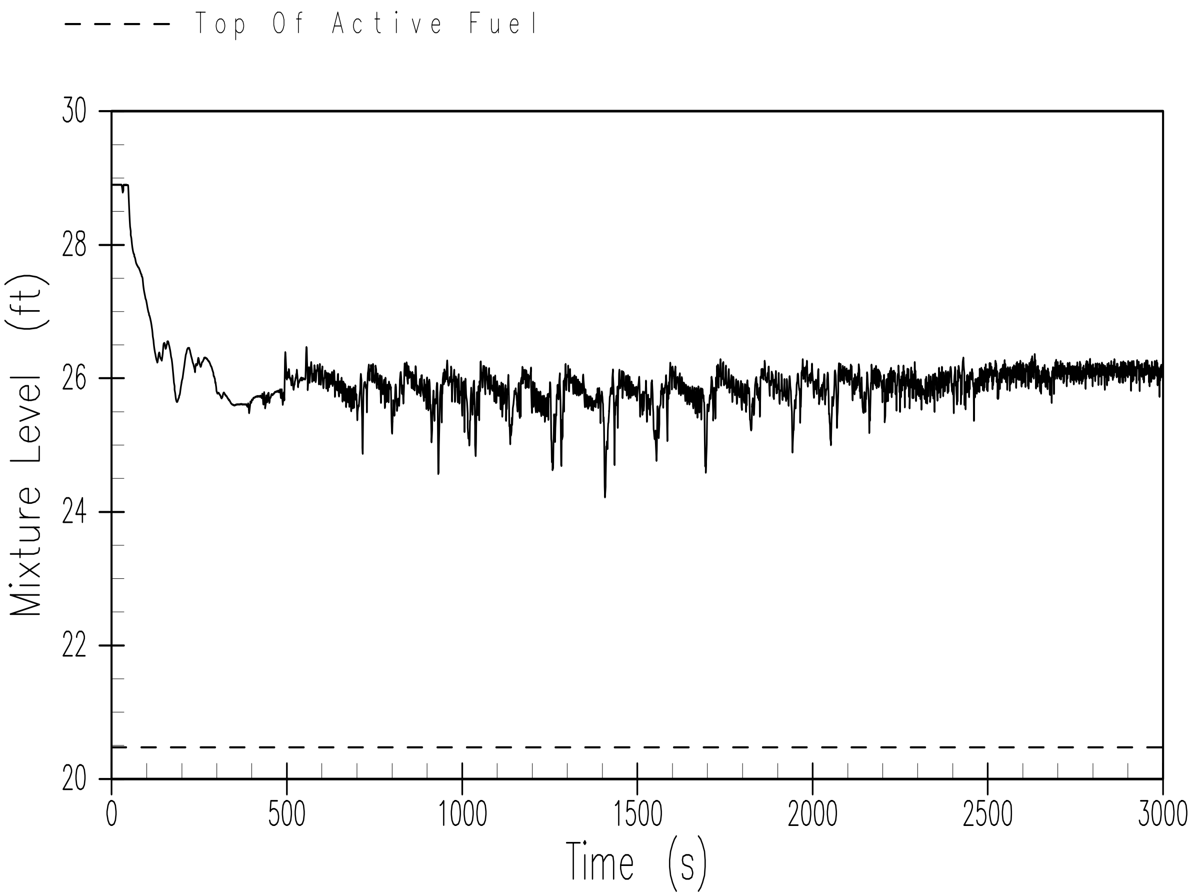

Figure 15.6.5.4B-41

DEDVI – Core/Upper Plenum Mixture Level – 20 psi

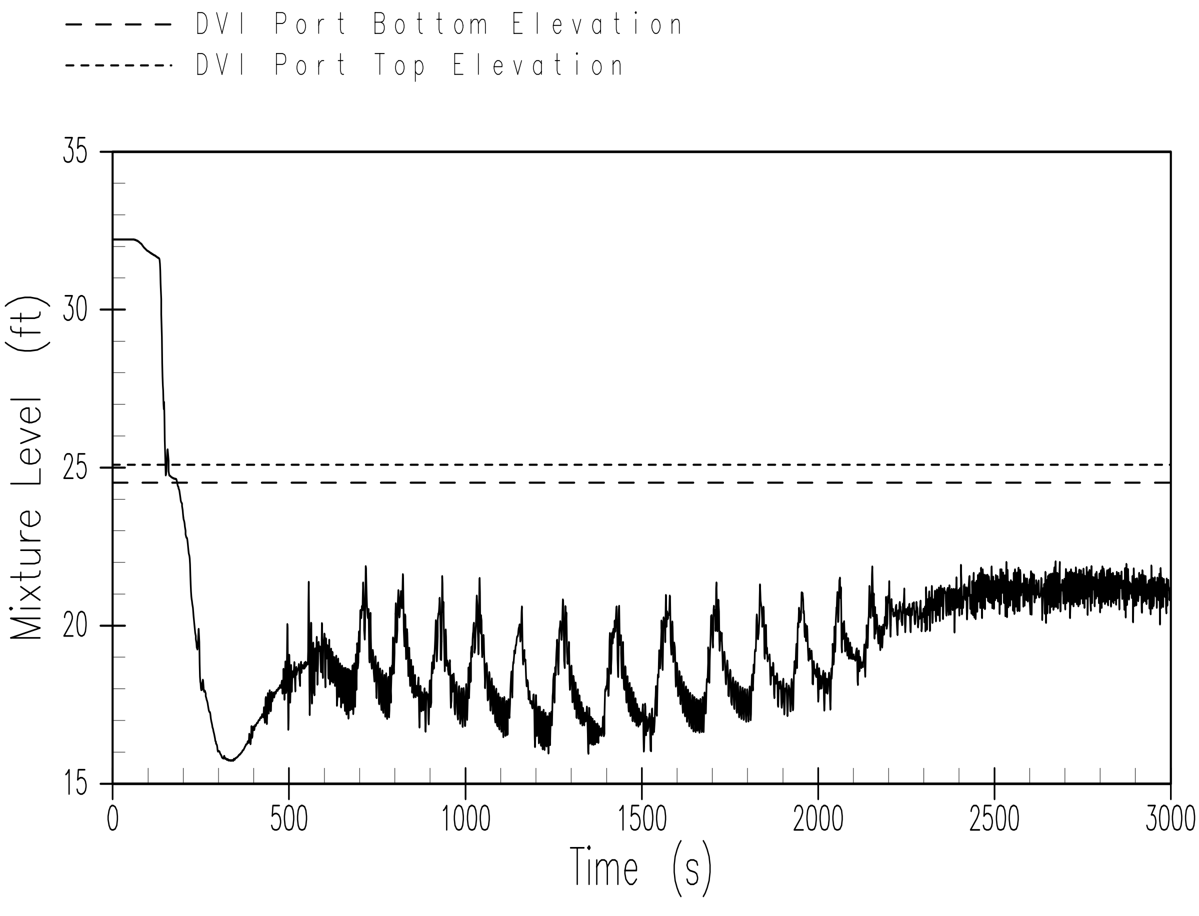

Figure 15.6.5.4B-42

DEDVI – Downcomer Mixture Level – 20 psi

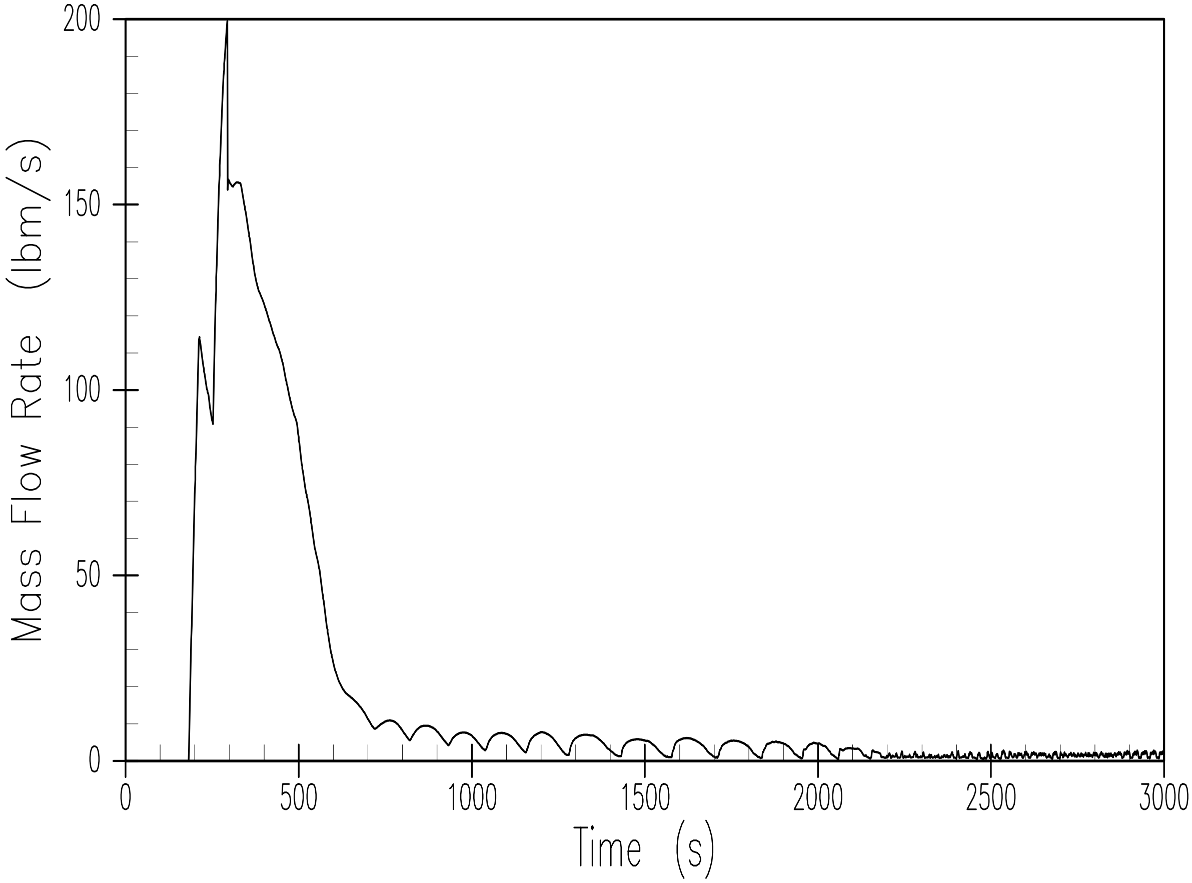

Figure 15.6.5.4B-43

DEDVI – ADS 1-3 Vapor Discharge – 20 psi

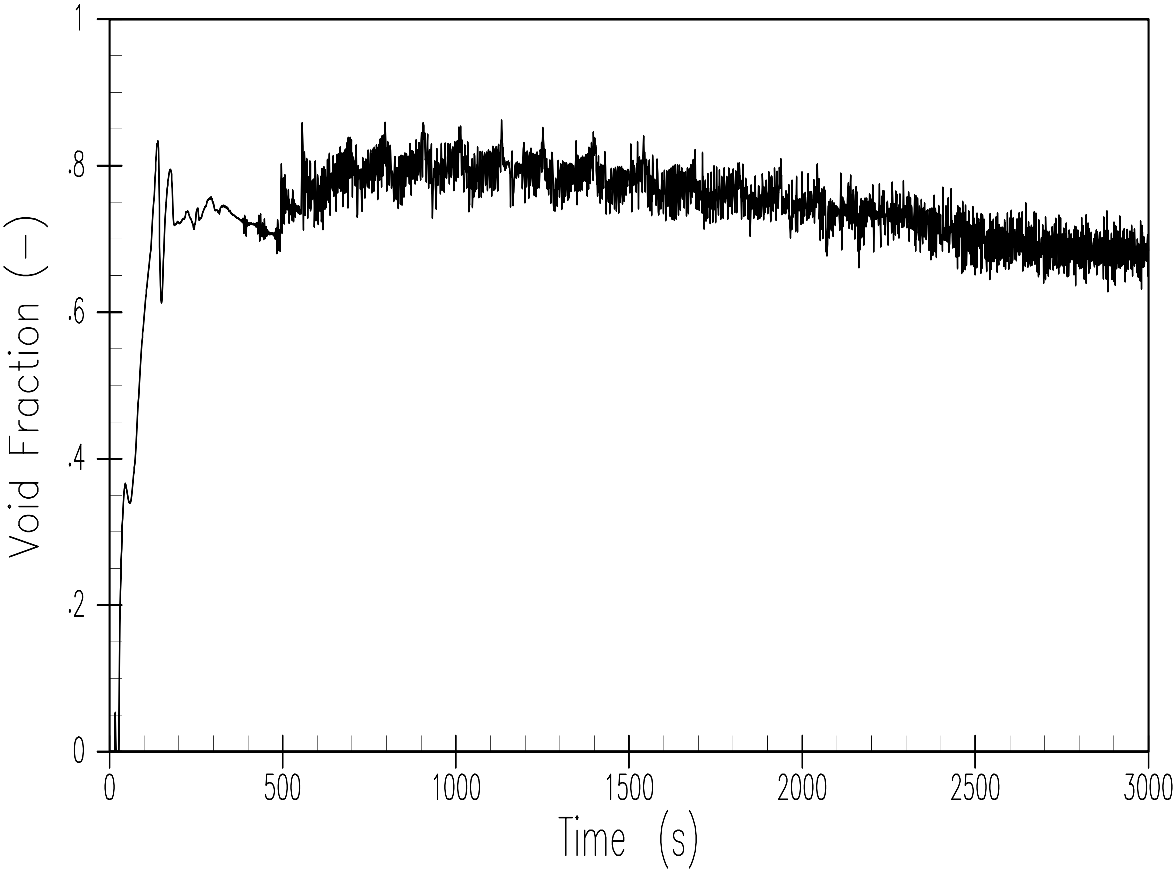

Figure 15.6.5.4B-44

DEDVI – Core Exit Void Fraction – 20 psi

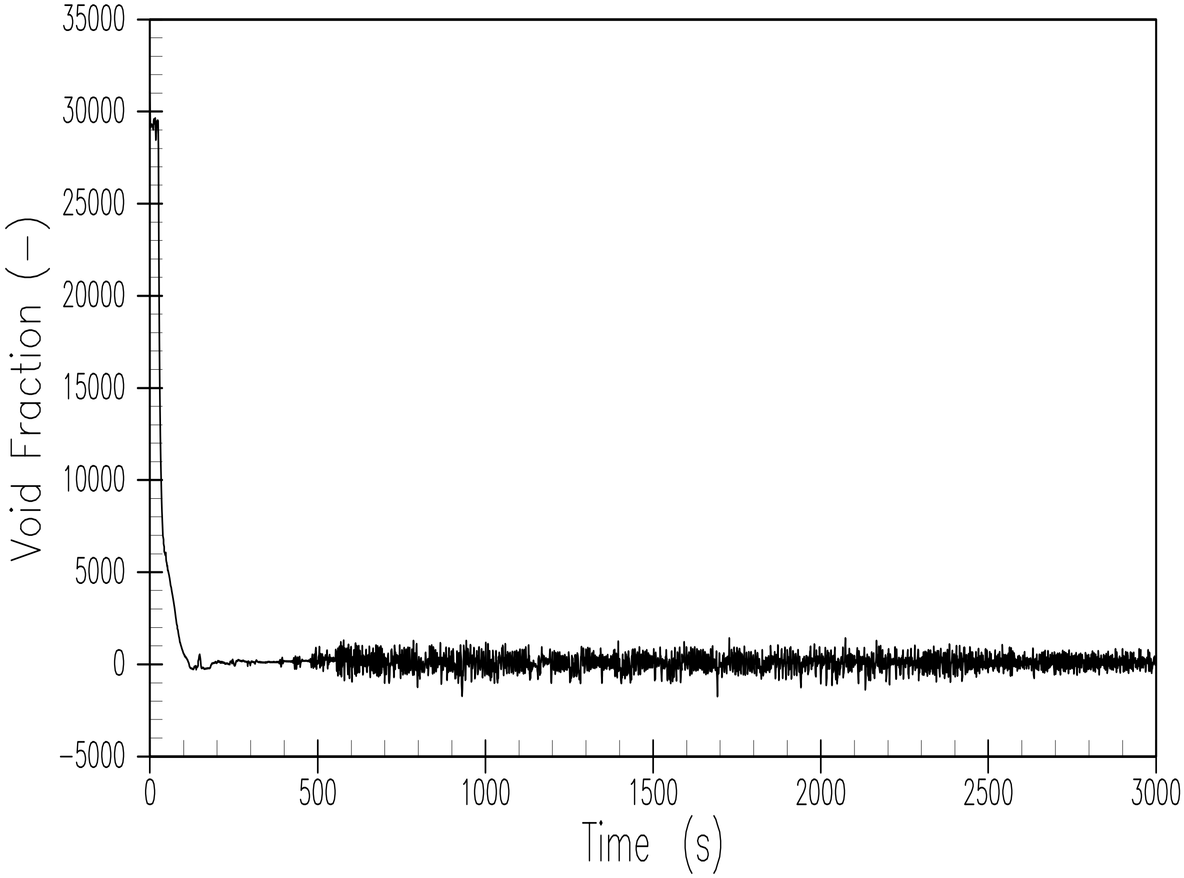

Figure 15.6.5.4B-45

DEDVI – Core Exit Liquid Flow Rate – 20 psi

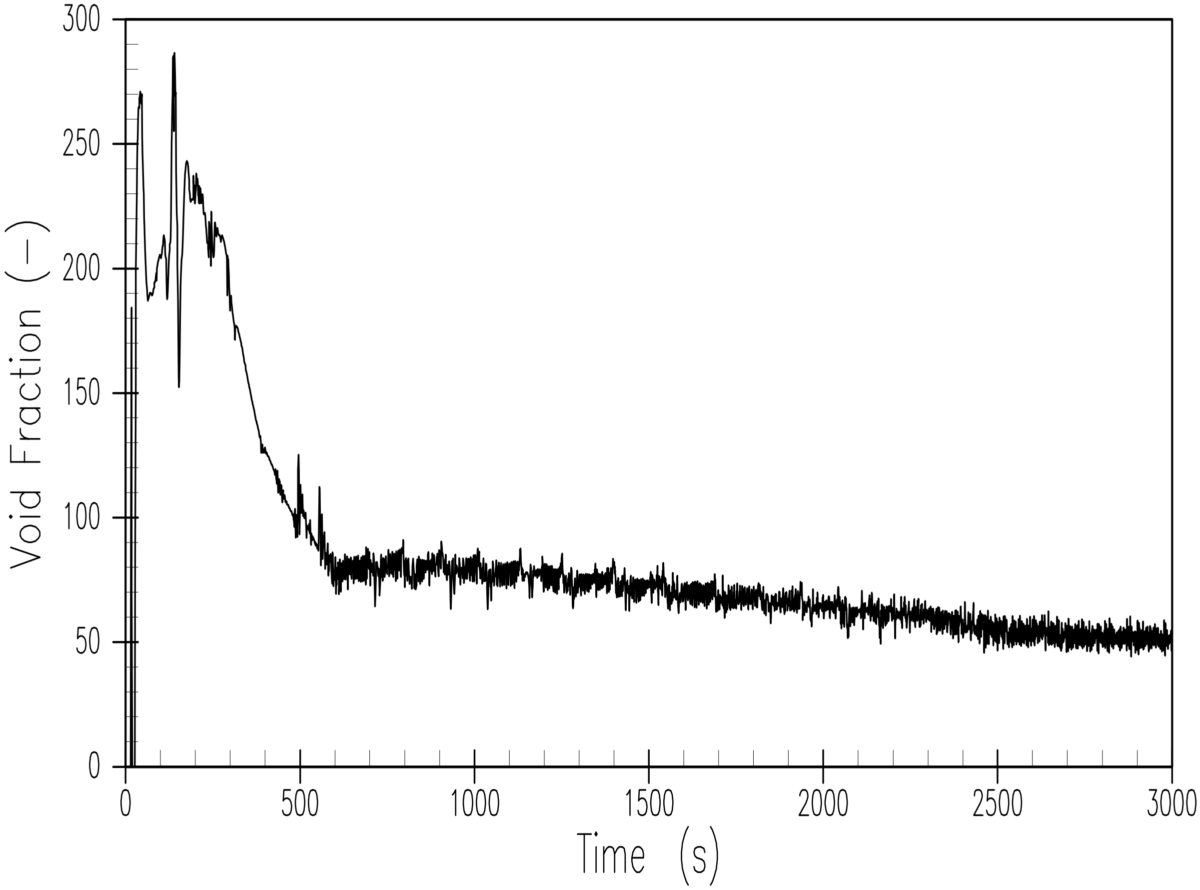

Figure 15.6.5.4B-46

DEDVI – Core Exit Vapor Flow Rate – 20 psi

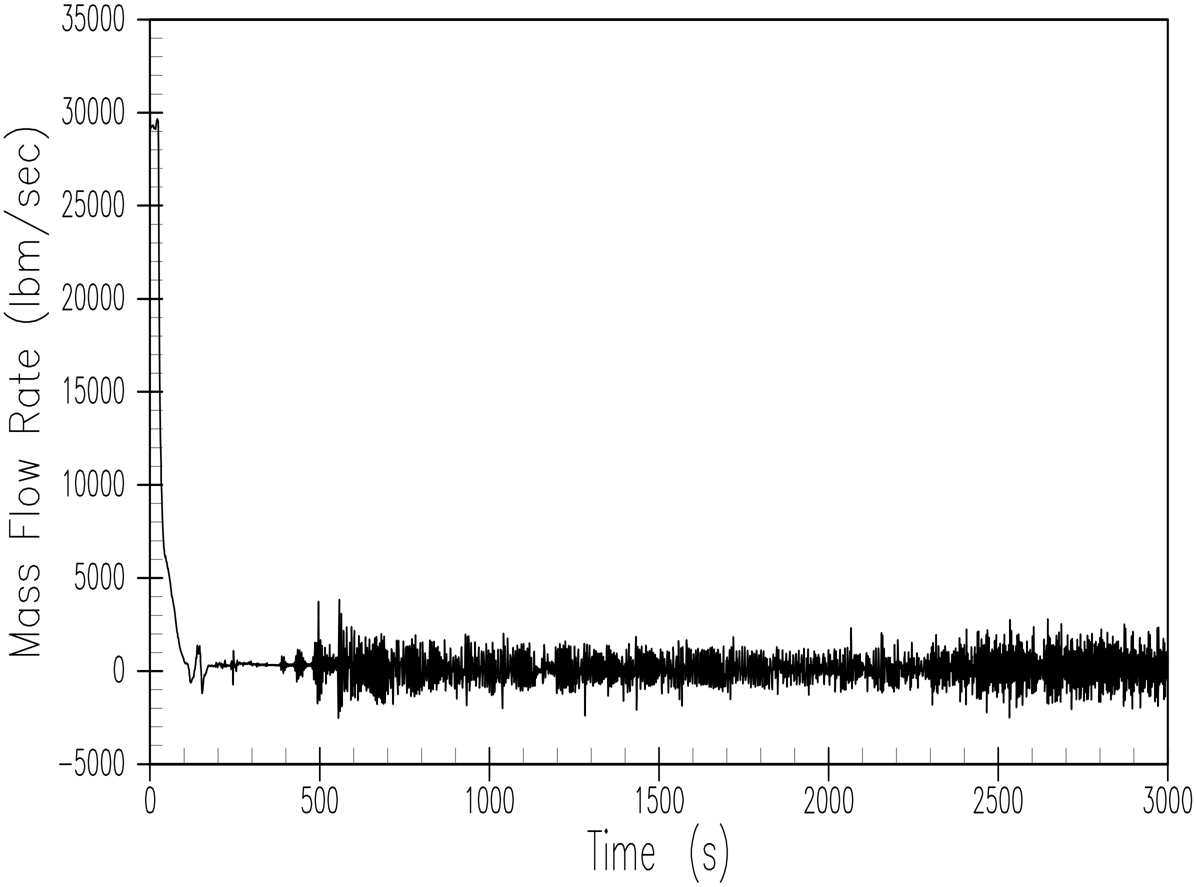

Figure 15.6.5.4B-47

DEDVI – Lower Plenum to Core Flow Rate – 20 psi

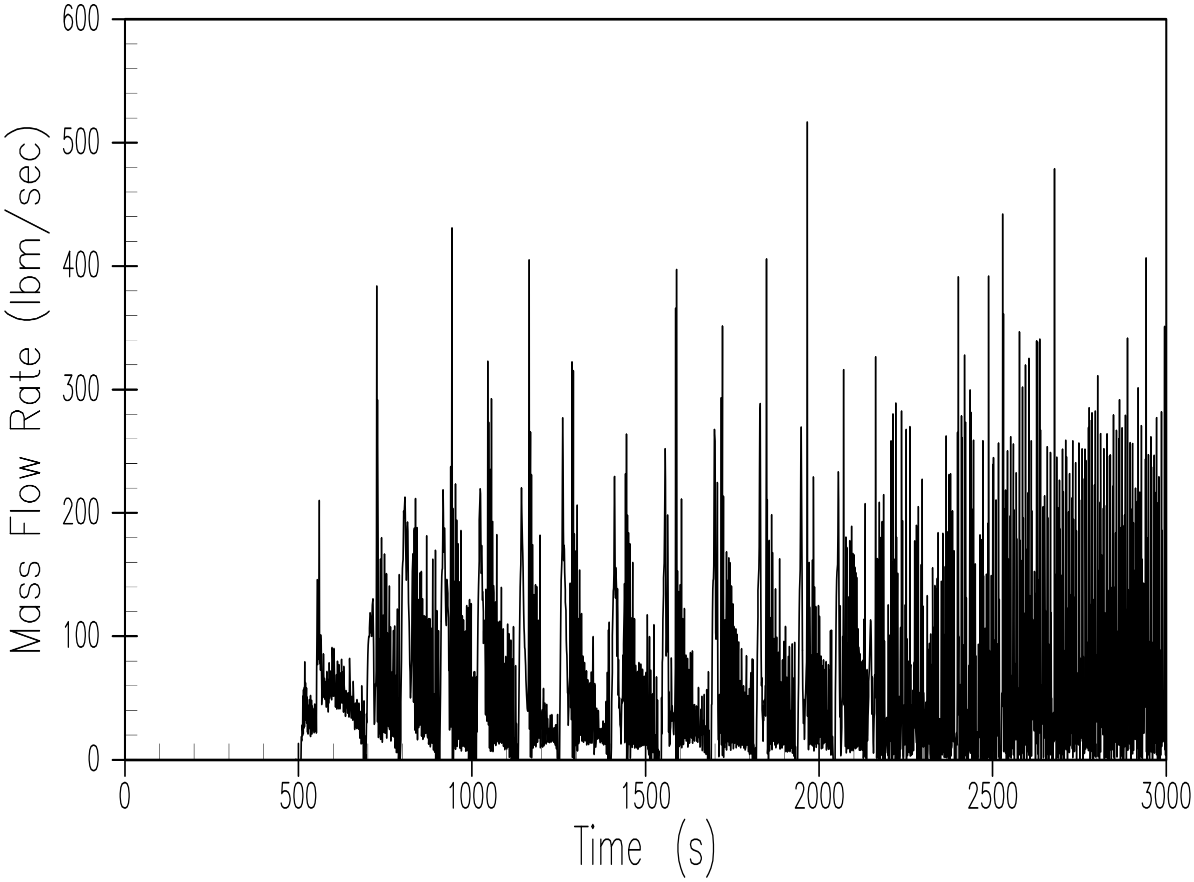

Figure 15.6.5.4B-48

DEDVI – ADS-4 Liquid Discharge – 20 psi

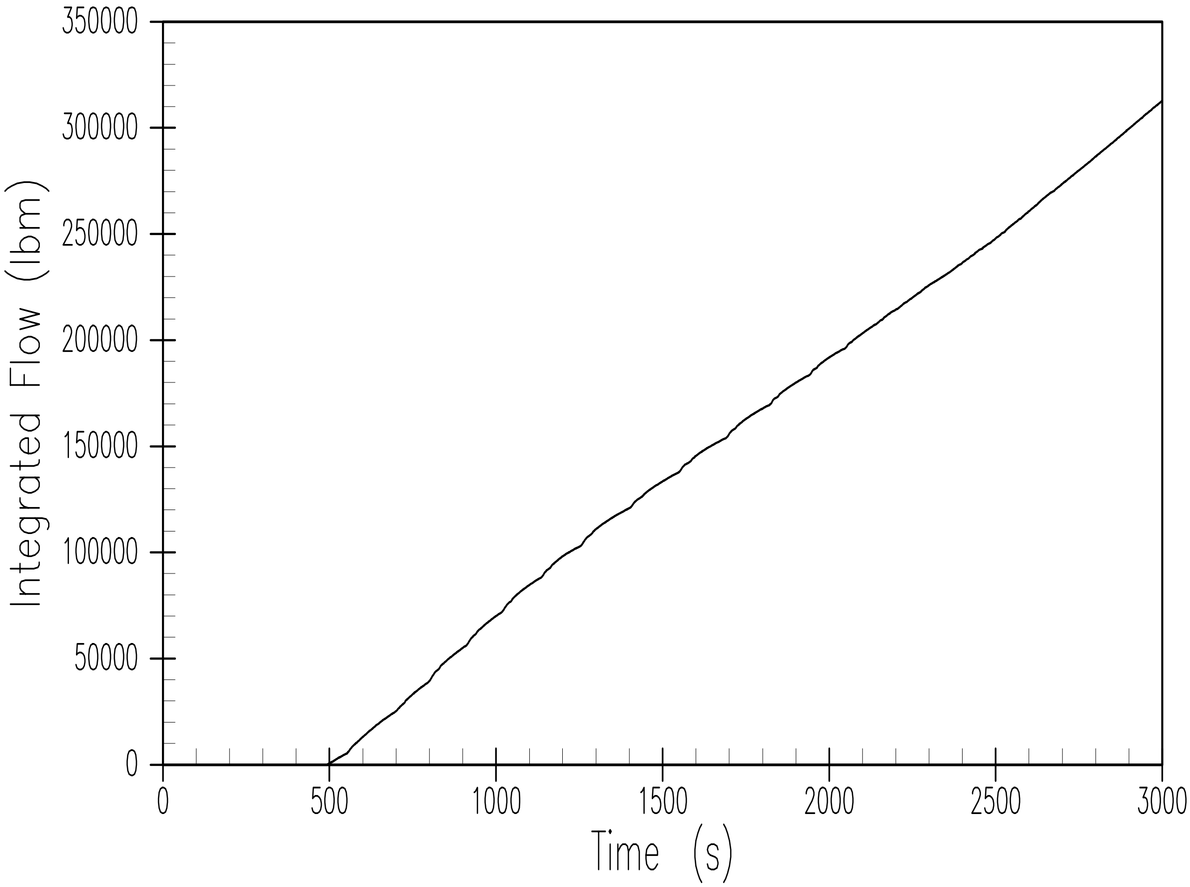

Figure 15.6.5.4B-49

DEDVI – ADS-4 Integrated Discharge – 20 psi

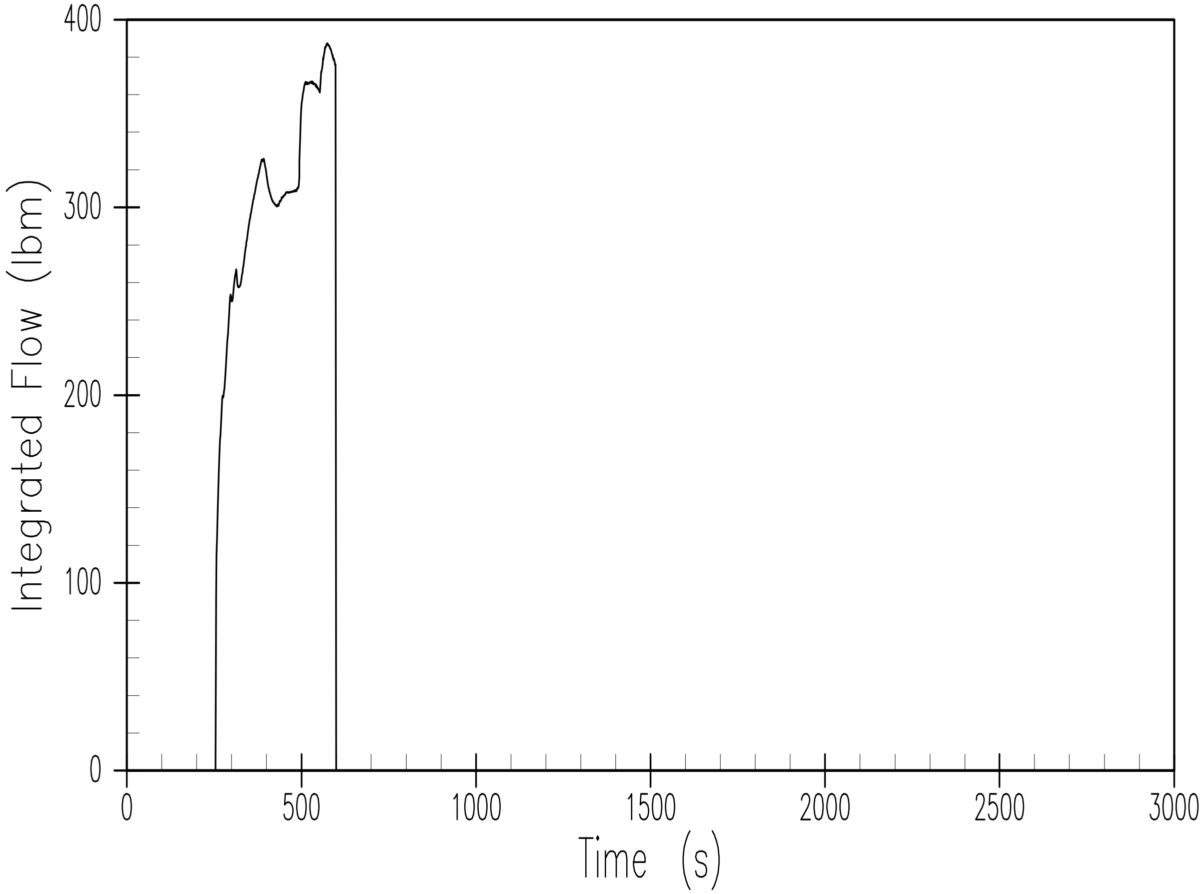

Figure 15.6.5.4B-50

DEDVI – Intact Accumulator Flow Rate – 20 psi

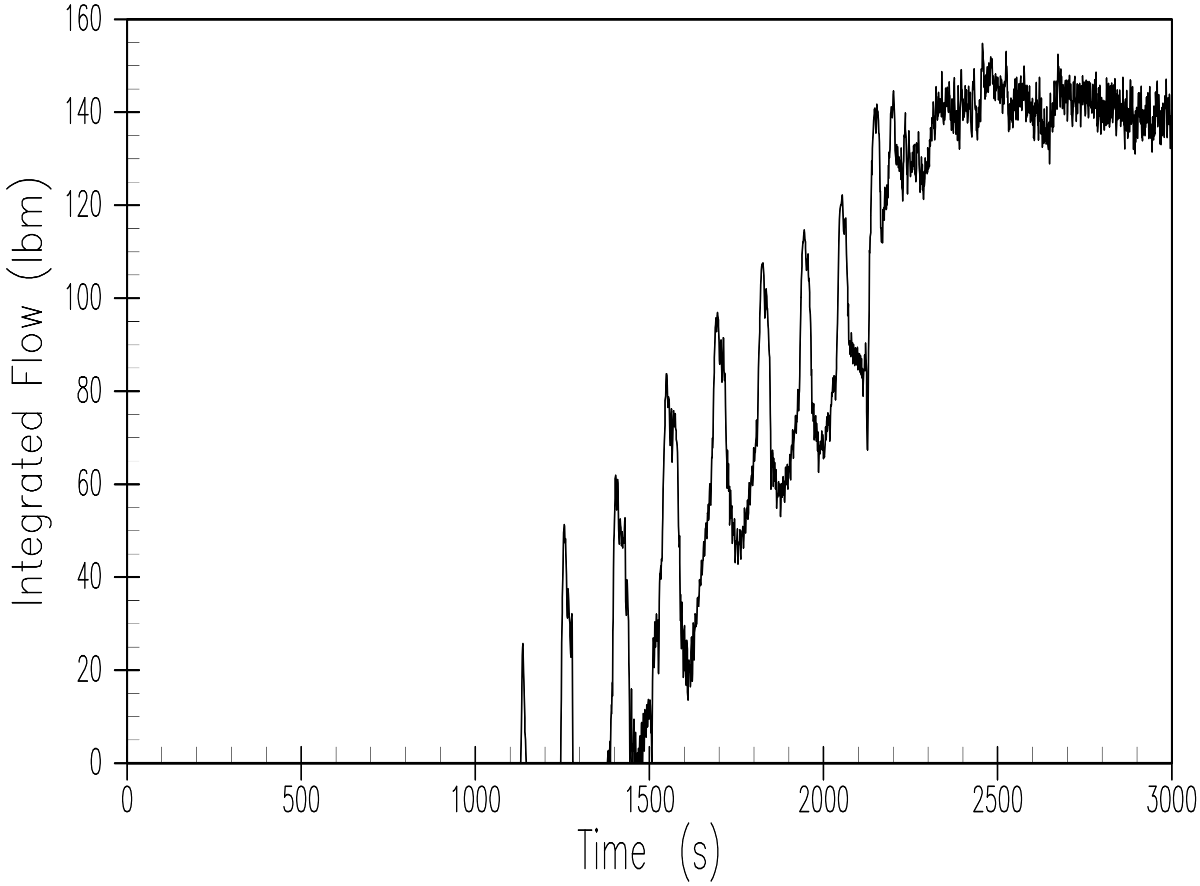

Figure 15.6.5.4B-51

DEDVI – Intact IRWST Injection Rate – 20 psi

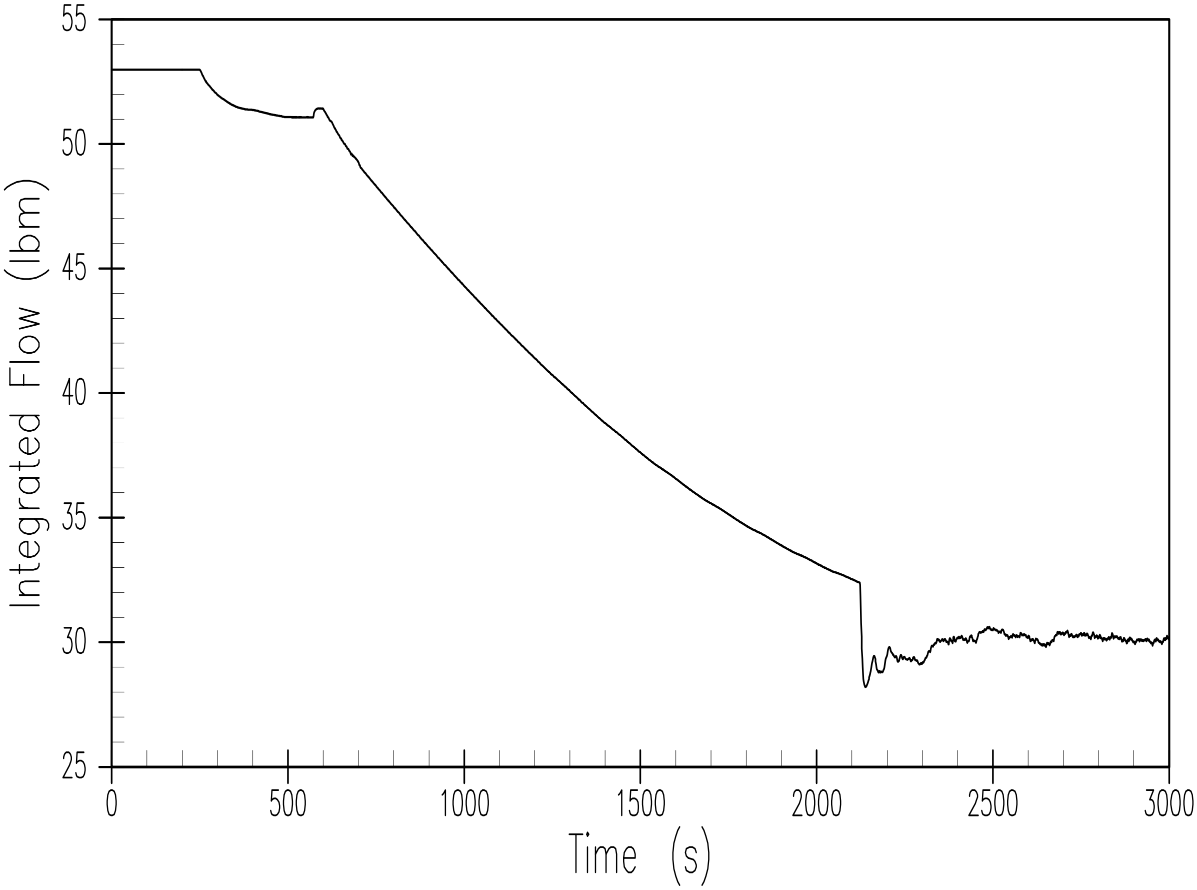

Figure 15.6.5.4B-52

DEDVI – Intact CMT Mixture Level – 20 psi

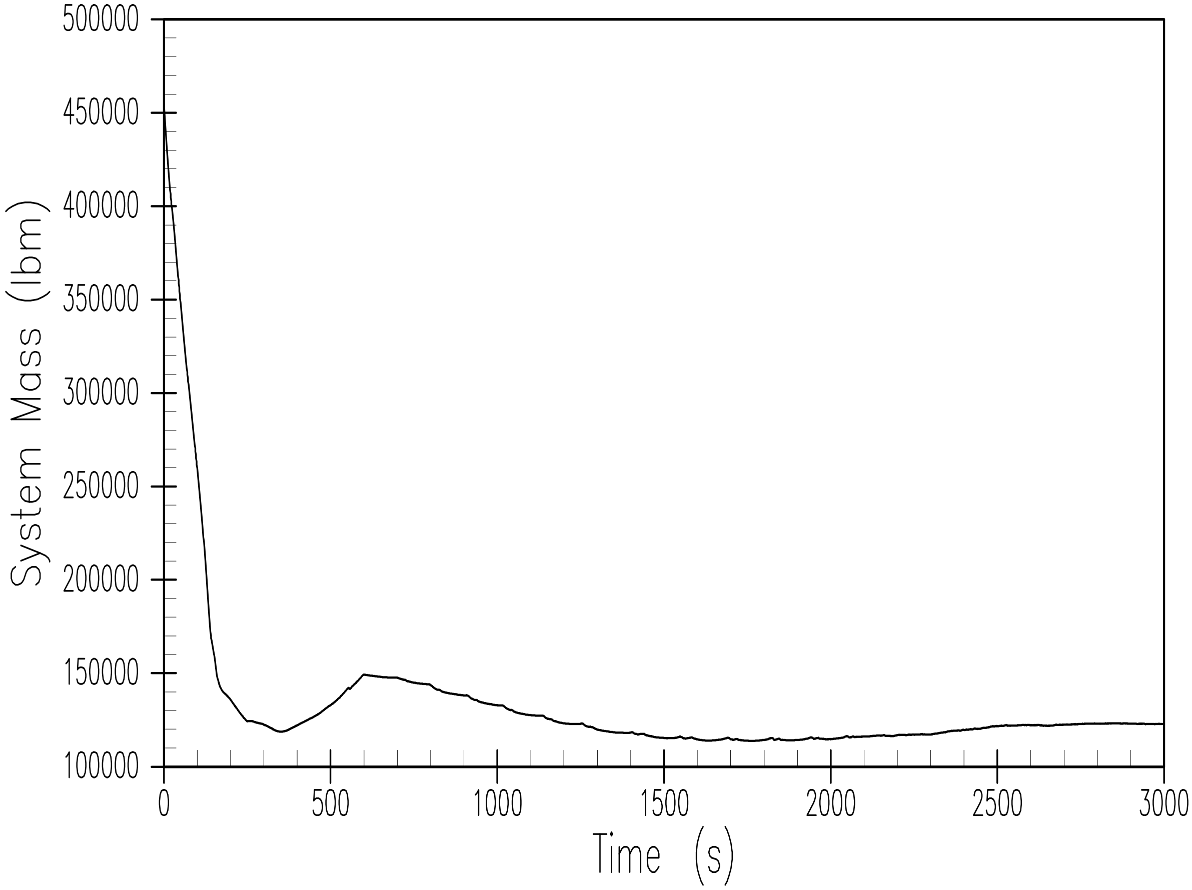

Figure 15.6.5.4B-53

DEDVI – RCS System Inventory – 20 psi

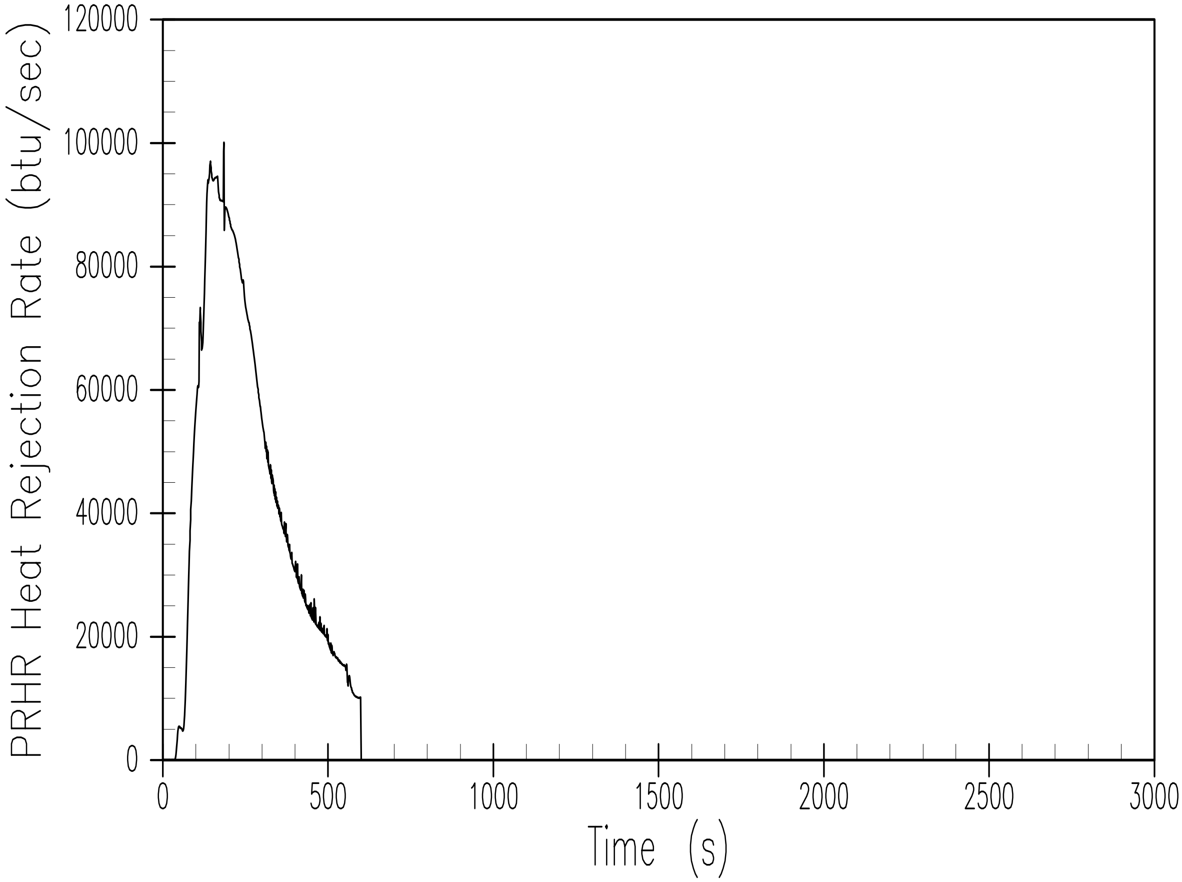

Figure 15.6.5.4B-54

DEDVI – PRHR Heat Removal Rate – 20 psi

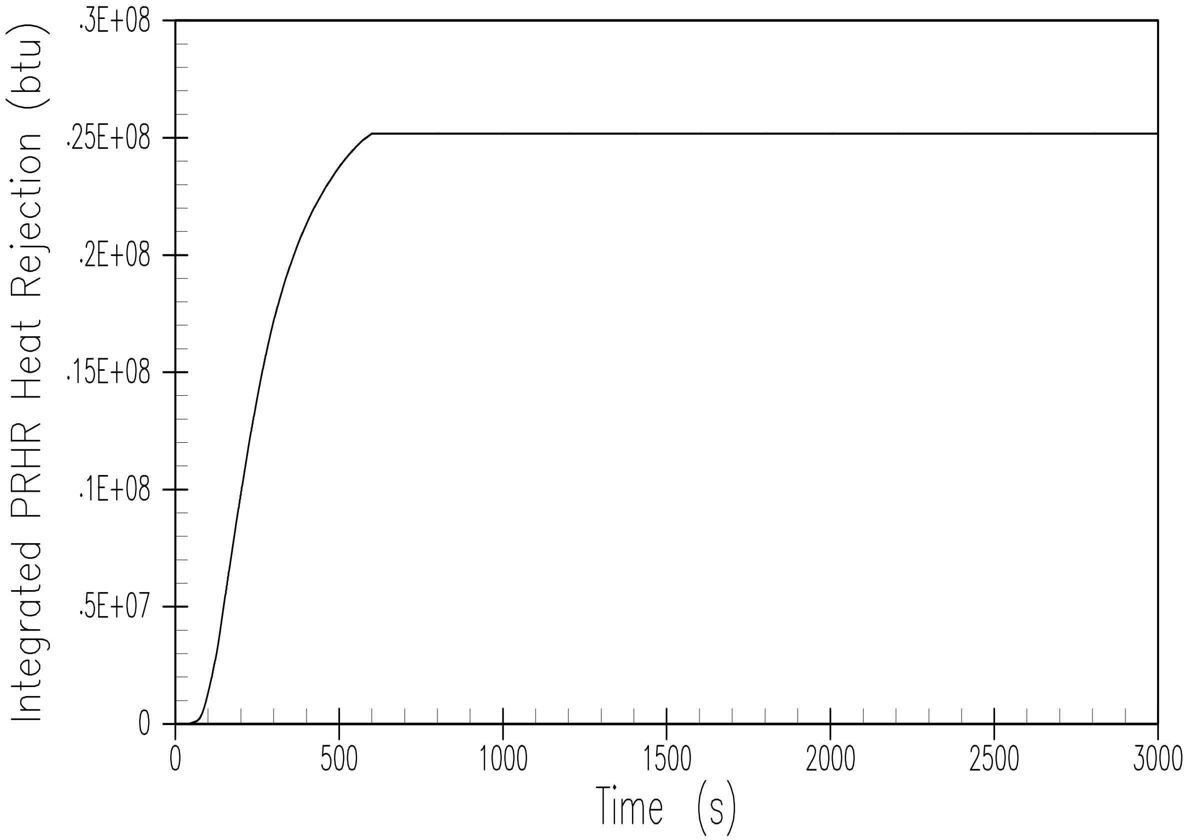

Figure 15.6.5.4B-55

DEDVI – Integrated PRHR Heat Removal – 20 psi

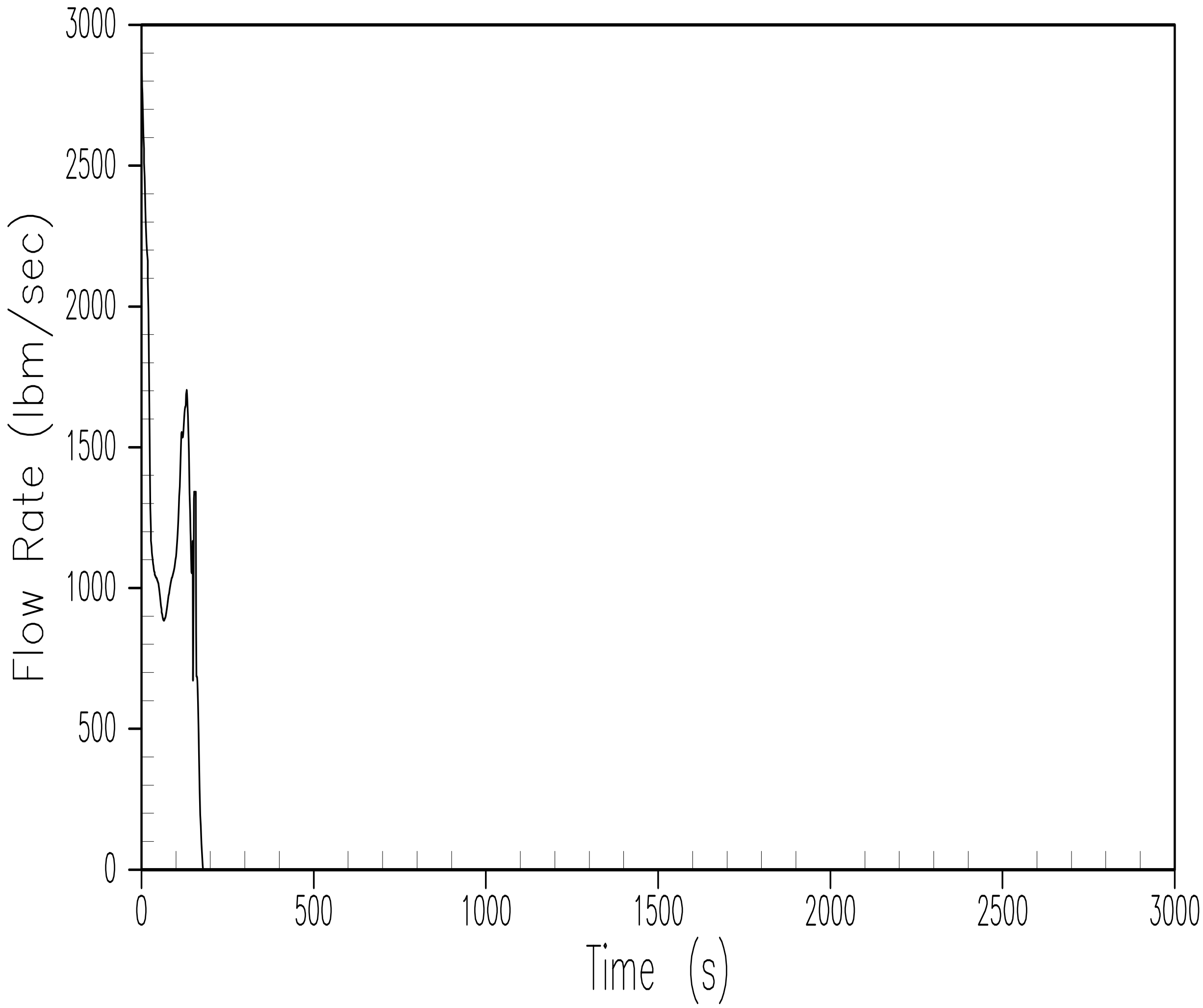

Figure 15.6.5.4B-36A

DEDVI – Vessel Side Liquid Break Discharge – 14.7 psi

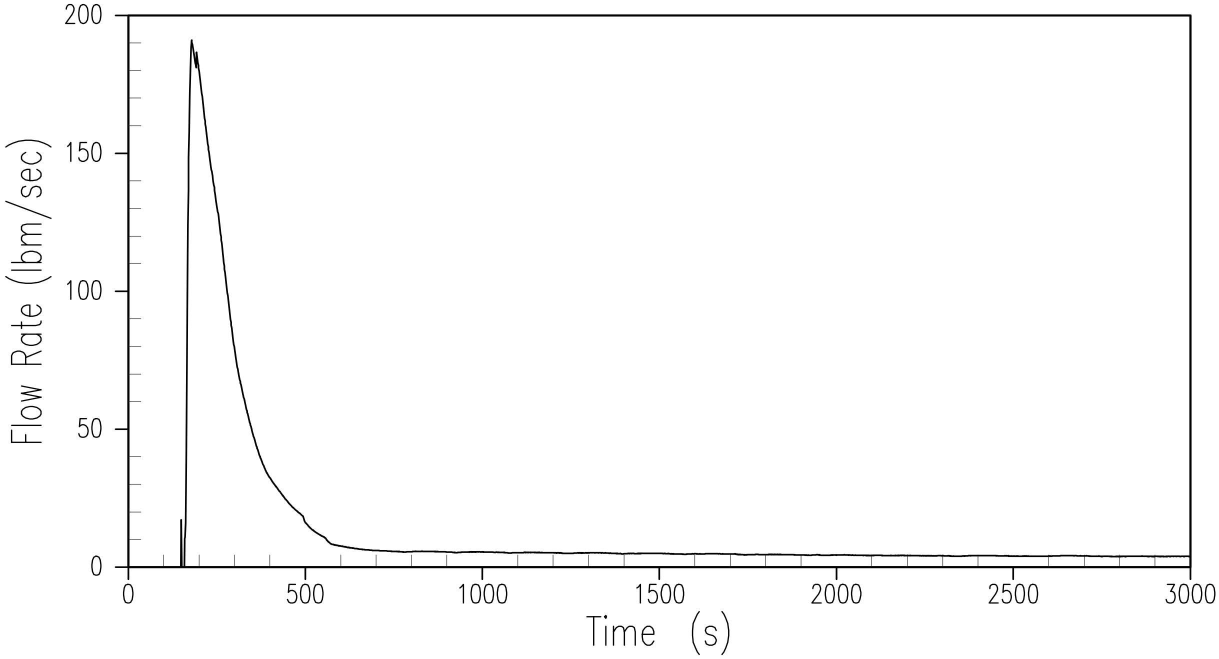

Figure 15.6.5.4B-37A

DEDVI – Vessel Side Vapor Break Discharge – 14.7 psi

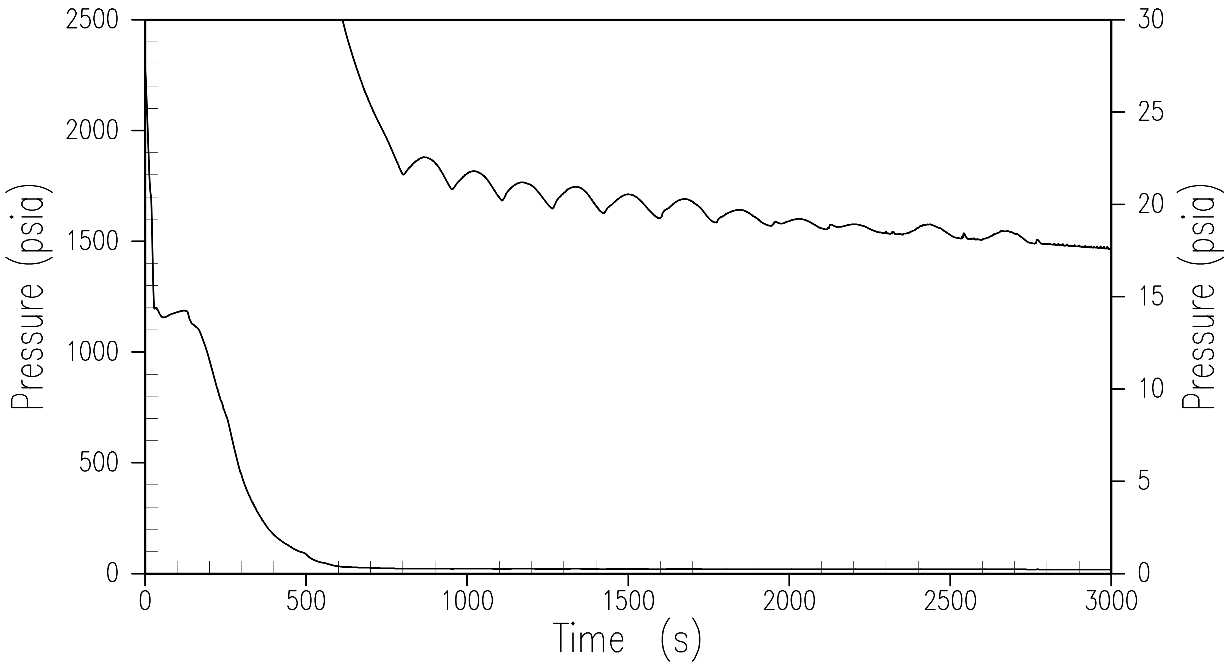

Figure 15.6.5.4B-38A

DEDVI – RCS Pressure – 14.7 psi

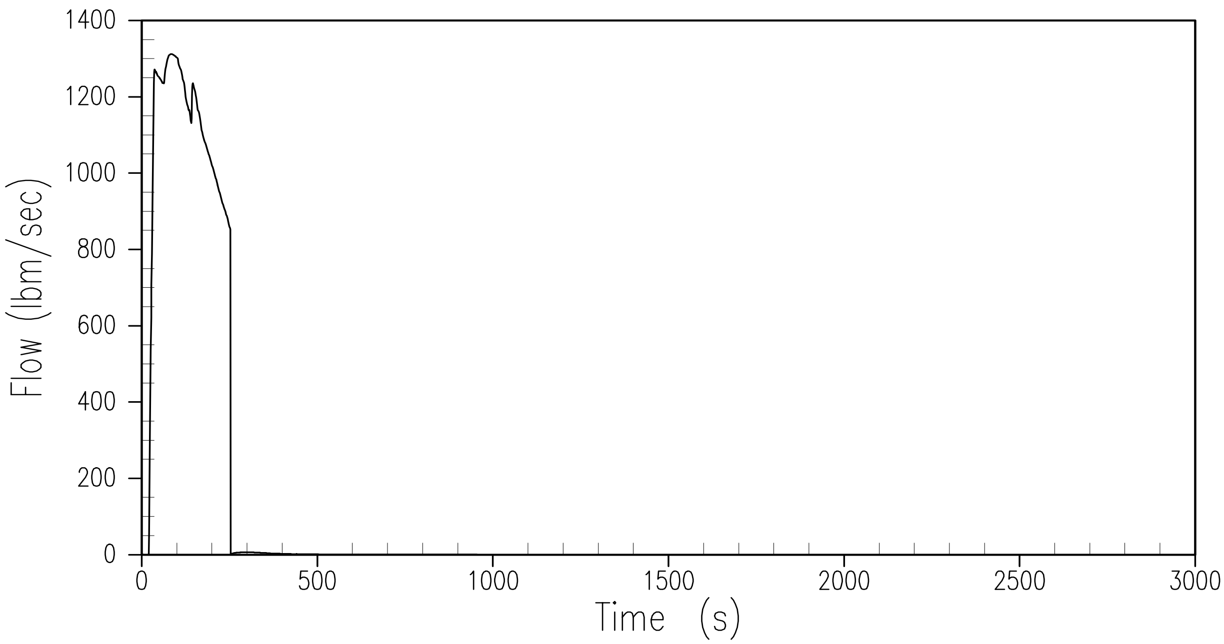

Figure 15.6.5.4B-39A

DEDVI – Broken CMT Injection Rate – 14.7 psi

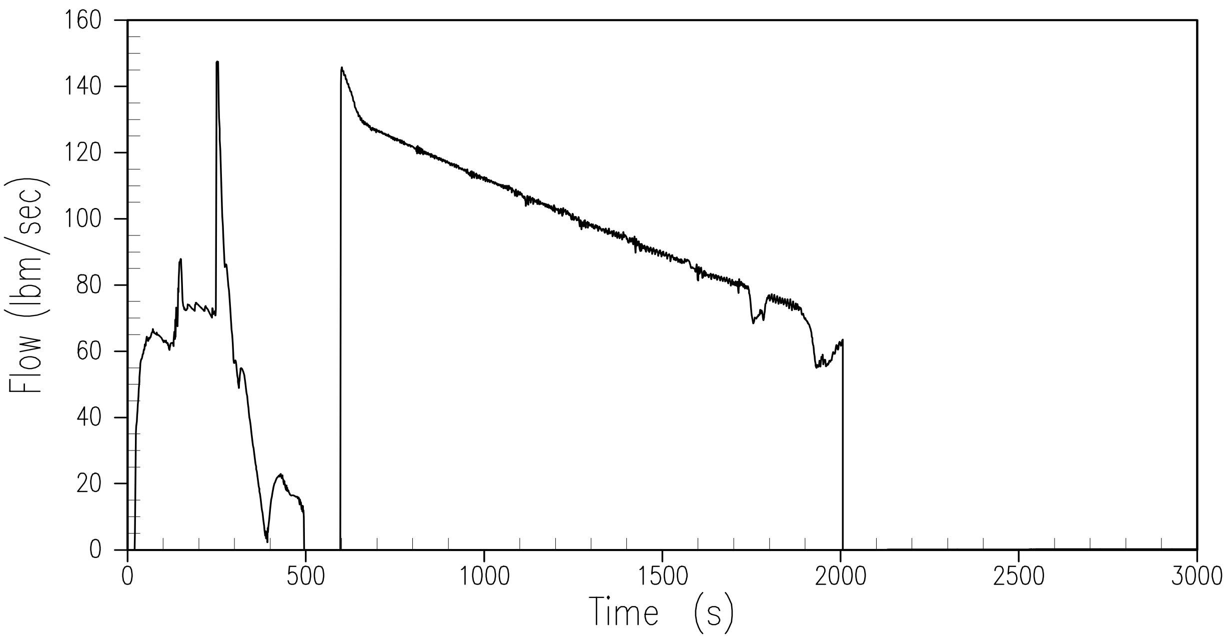

Figure 15.6.5.4B-40A

DEDVI – Intact CMT Injection Rate – 14.7 psi

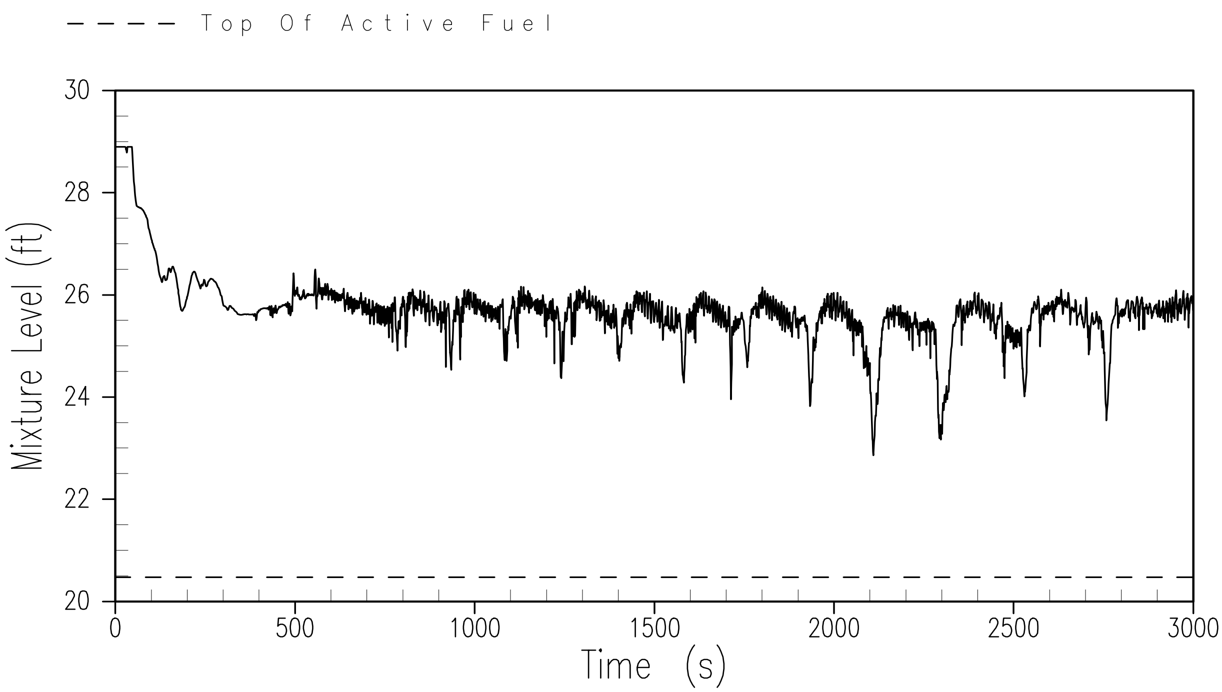

Figure 15.6.5.4B-41A

DEDVI – Core/Upper Plenum Mixture Level – 14.7 psi

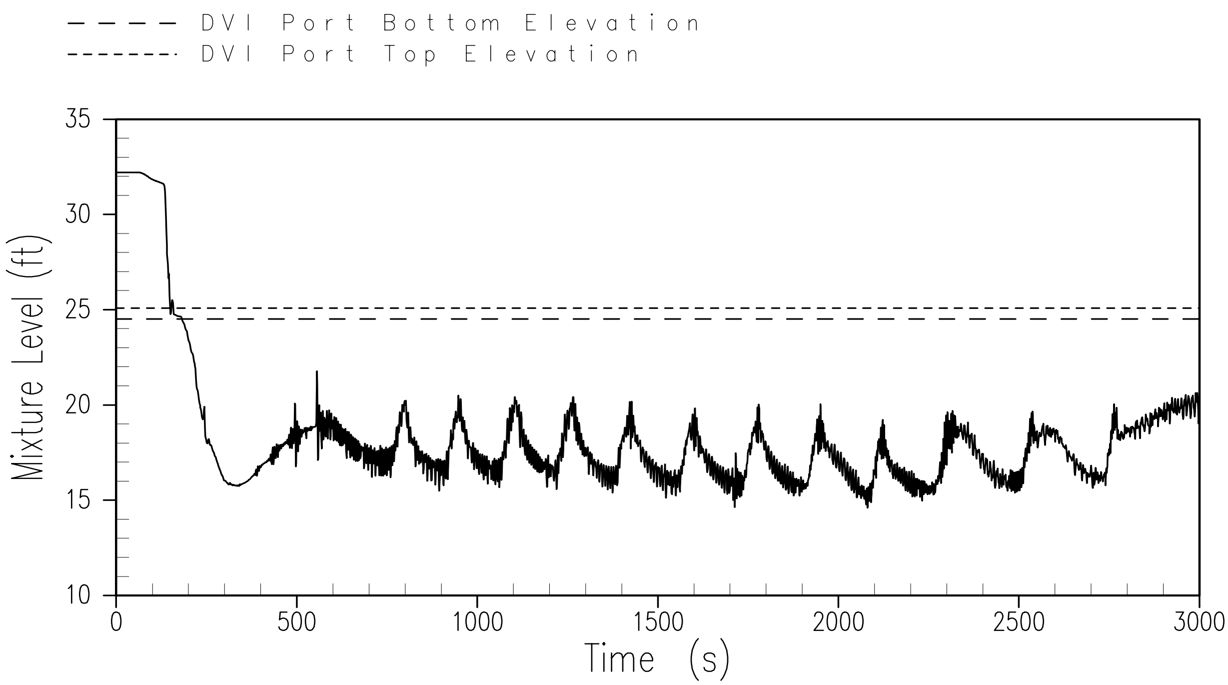

Figure 15.6.5.4B-42A

DEDVI – Downcomer Mixture Level – 14.7 psi

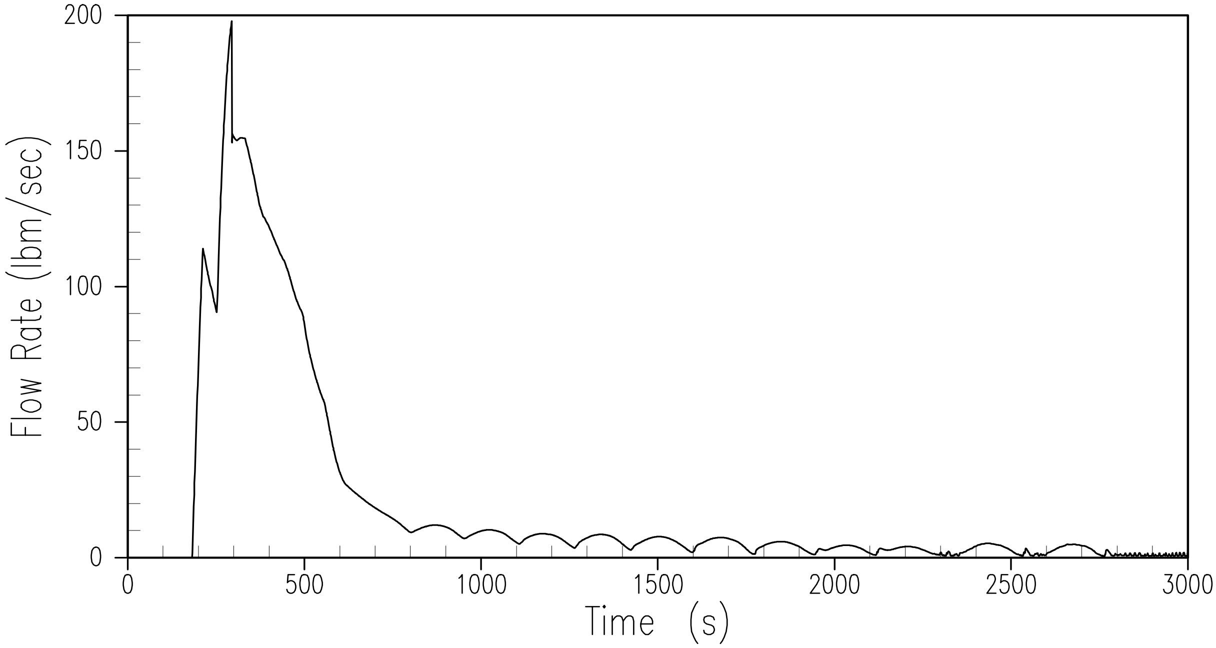

Figure 15.6.5.4B-43A

DEDVI – ADS 1-3 Vapor Discharge – 14.7 psi

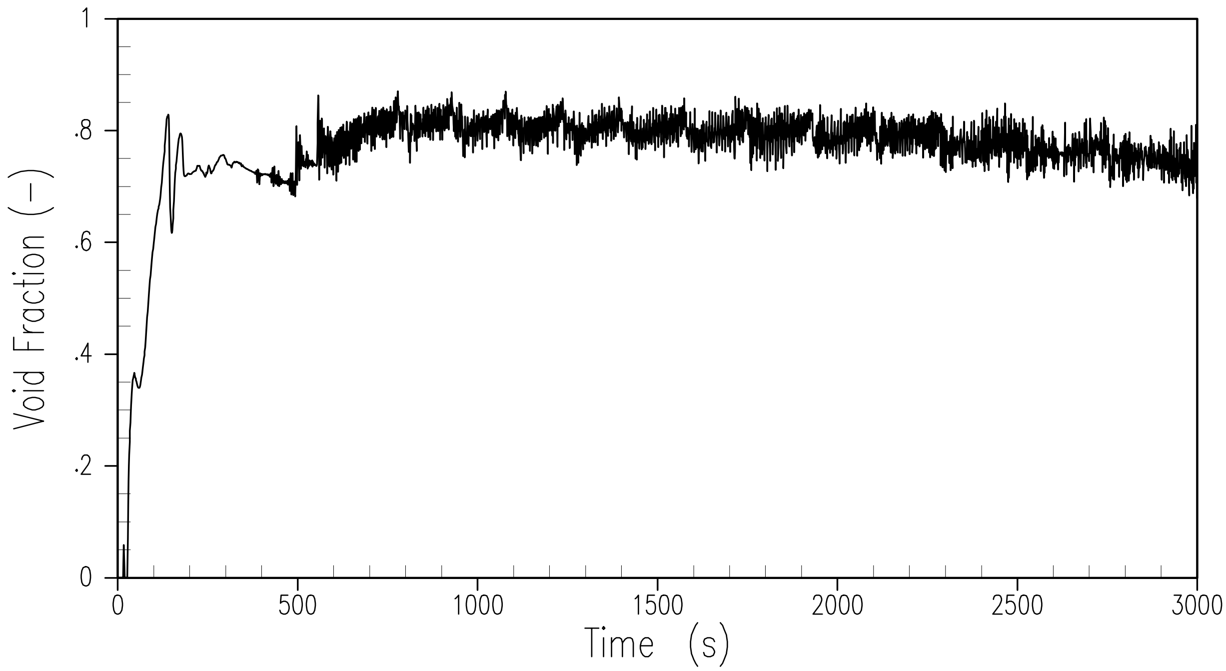

Figure 15.6.5.4B-44A

DEDVI – Core Exit Void Fraction – 14.7 psi

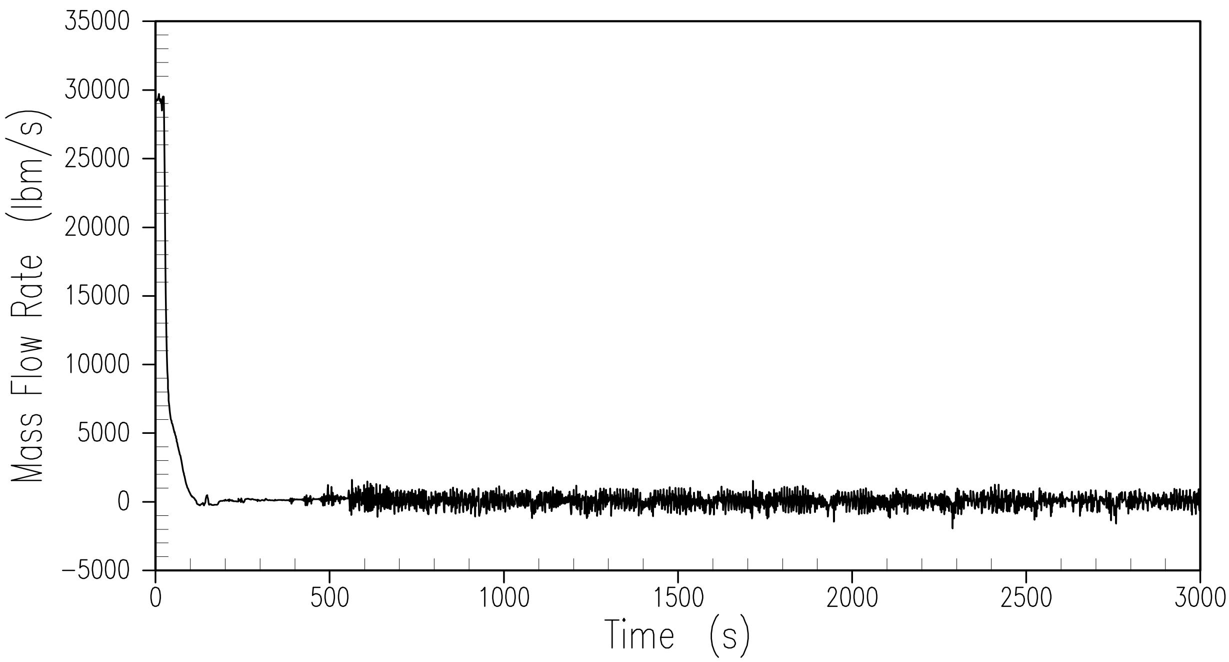

Figure 15.6.5.4B-45A

DEDVI – Core Exit Liquid Flow Rate – 14.7 psi

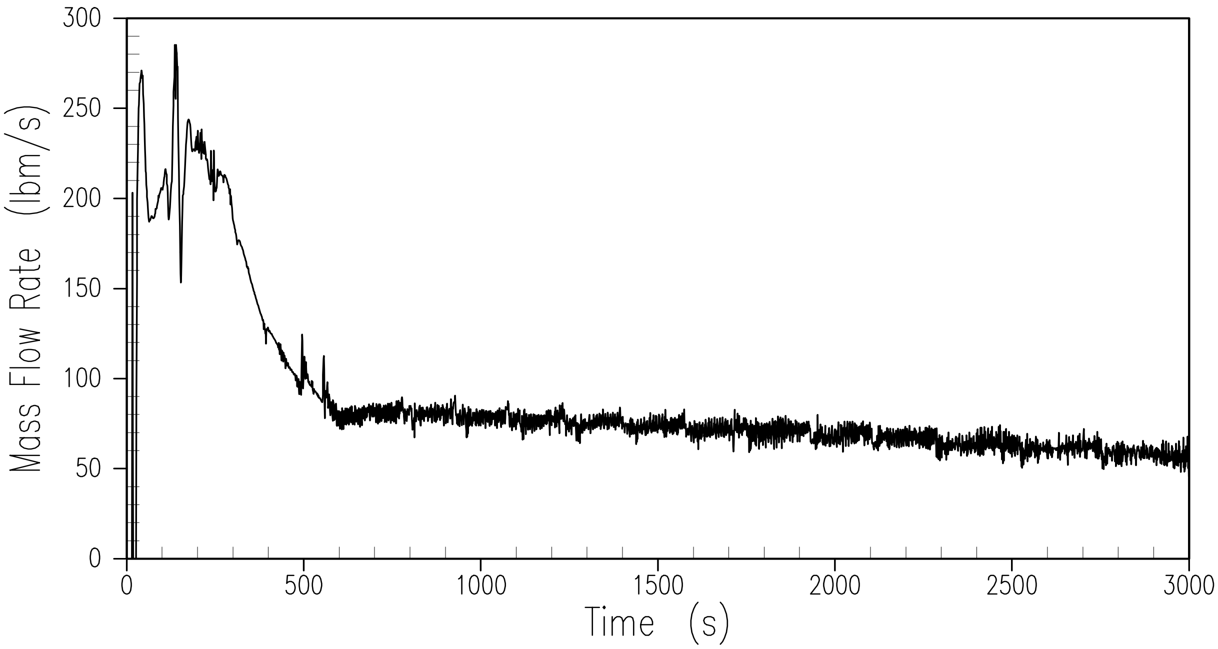

Figure 15.6.5.4B-46A

DEDVI – Core Exit Vapor Flow Rate – 14.7 psi

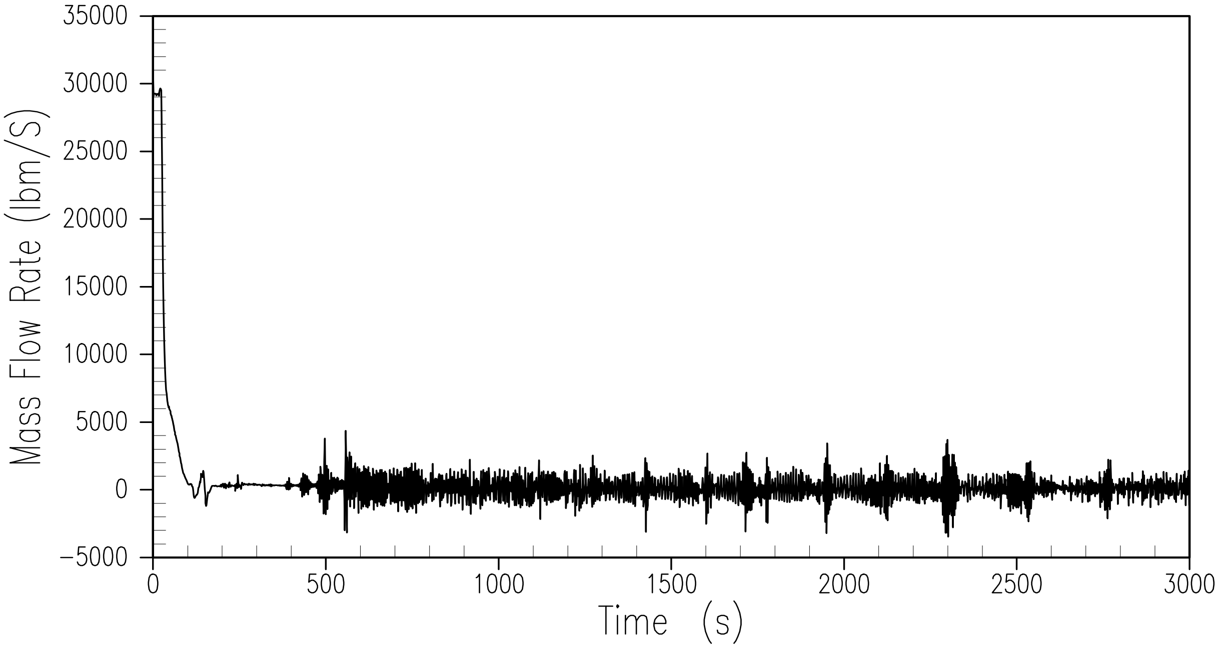

Figure 15.6.5.4B-47A

DEDVI – Lower Plenum to Core Flow Rate – 14.7 psi

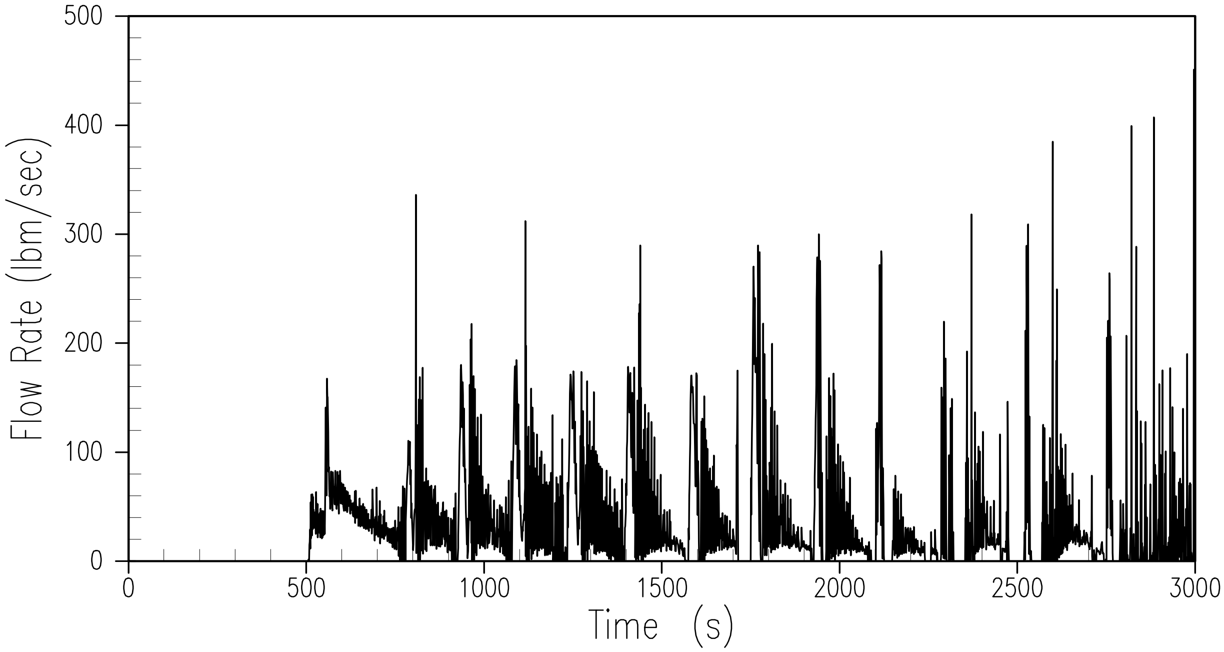

Figure 15.6.5.4B-48A

DEDVI – ADS-4 Liquid Discharge – 14.7 psi

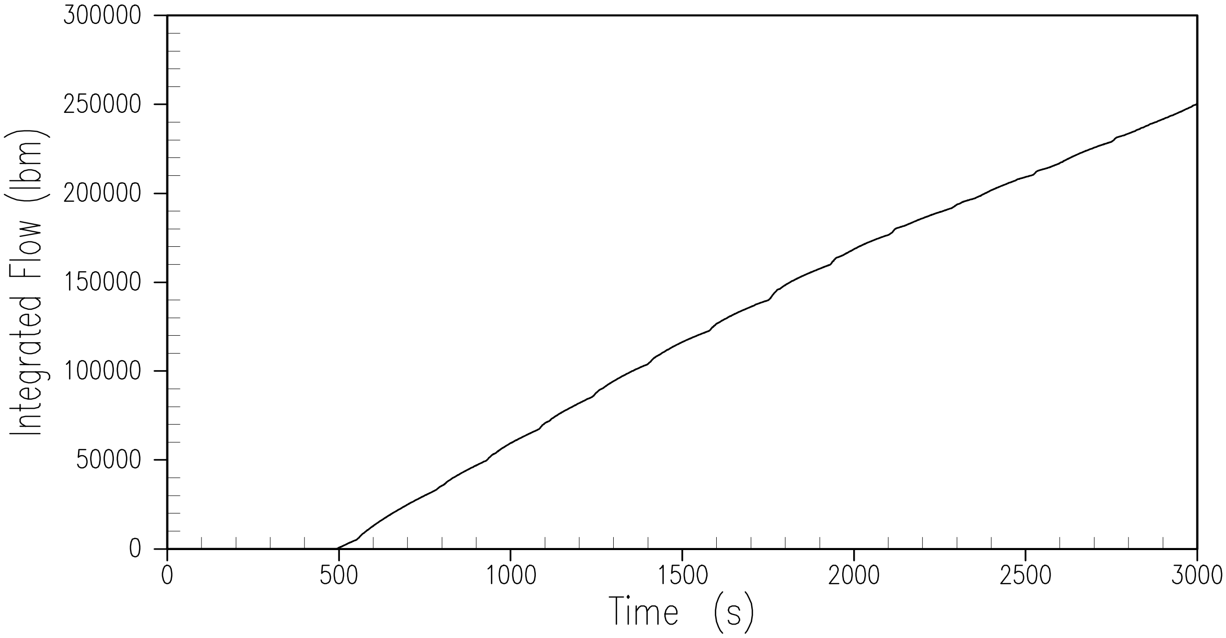

Figure 15.6.5.4B-49A

DEDVI – ADS-4 Integrated Discharge – 14.7 psi

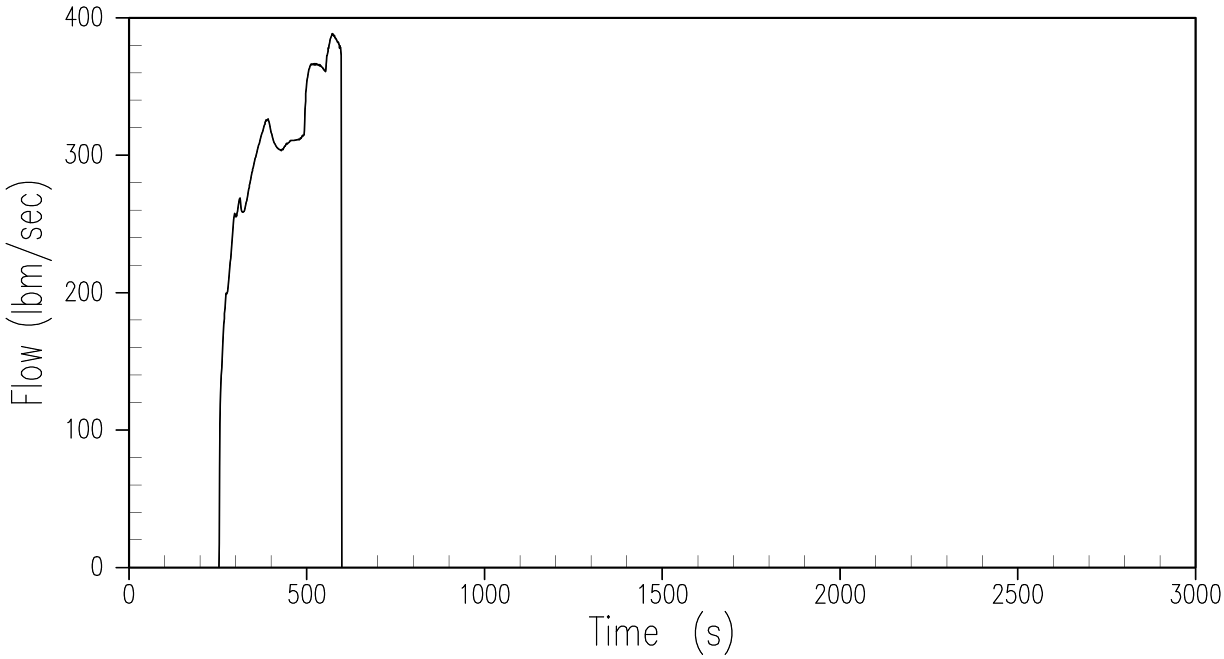

Figure 15.6.5.4B-50A

DEDVI – Intact Accumulator Flow Rate – 14.7 psi

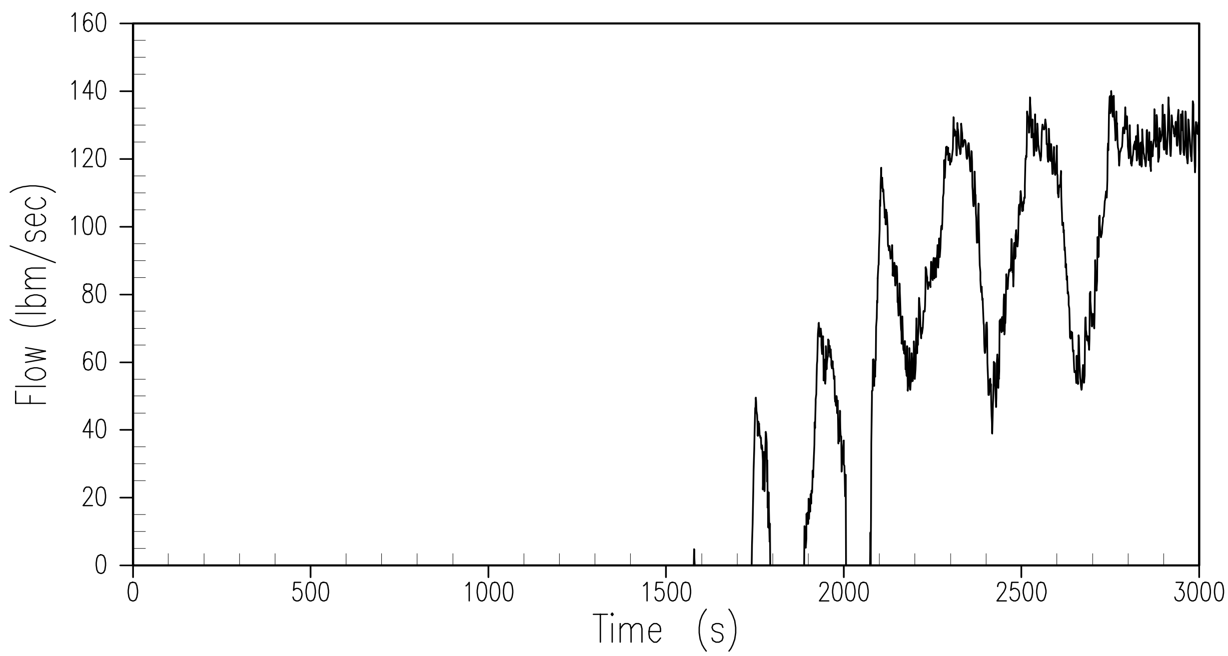

Figure 15.6.5.4B-51A

DEDVI – Intact IRWST Injection Rate – 14.7 psi

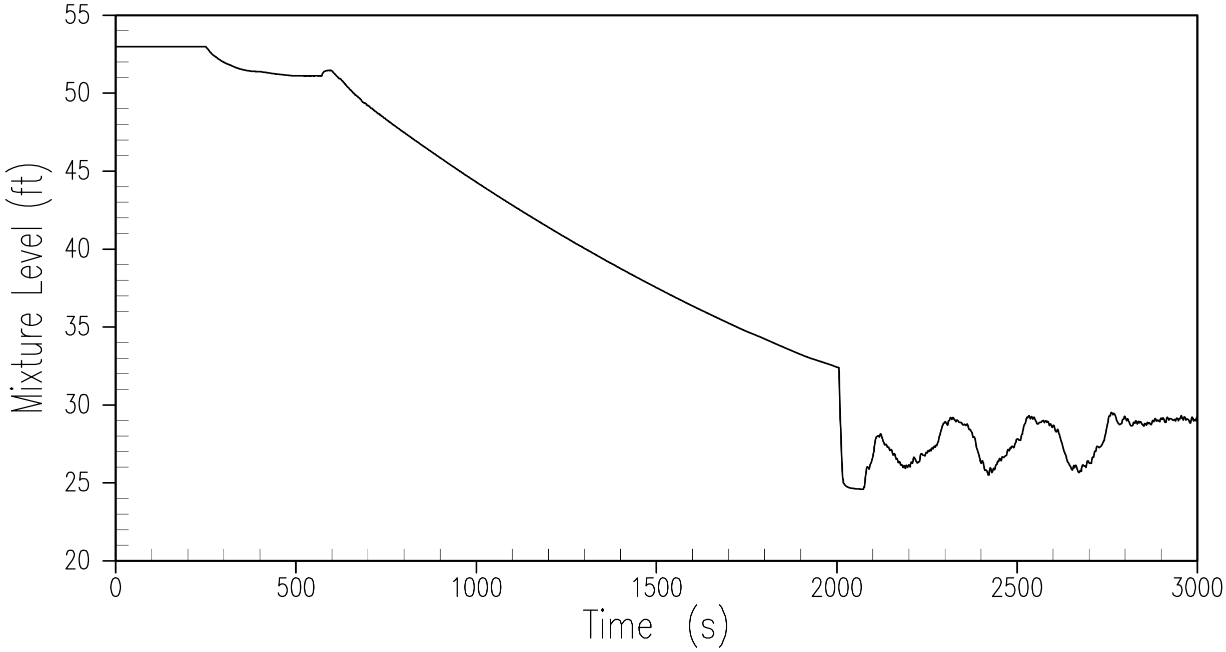

Figure 15.6.5.4B-52A

DEDVI – Intact CMT Mixture Level – 14.7 psi

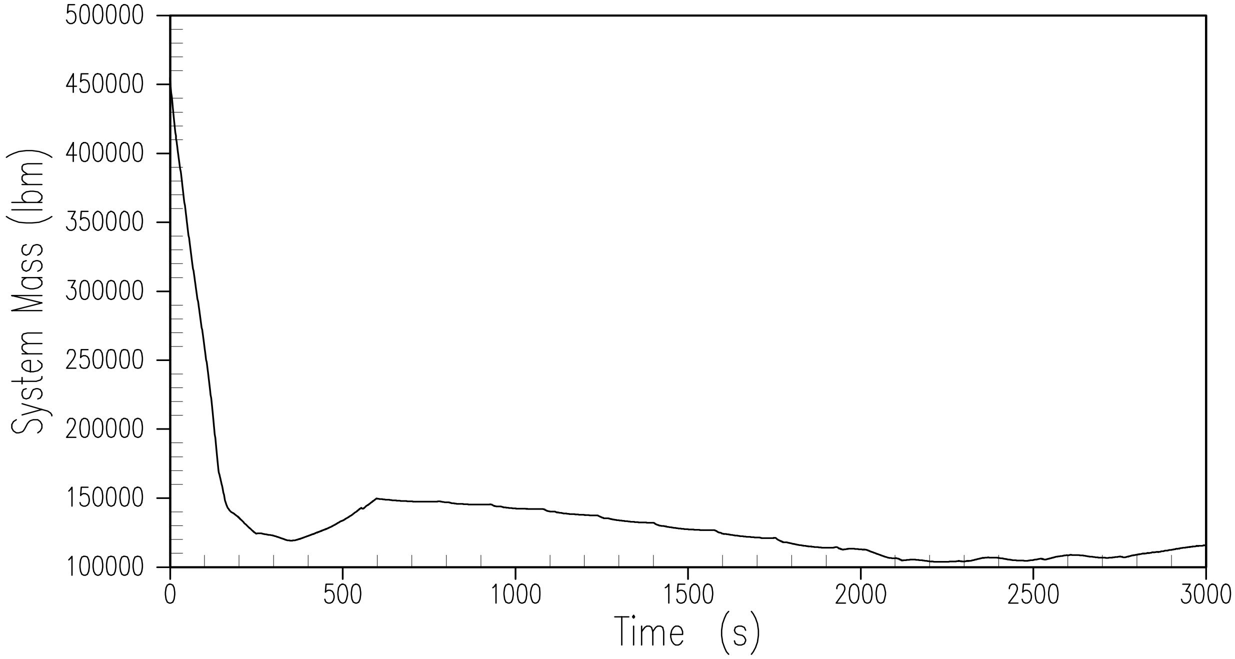

Figure 15.6.5.4B-53A

DEDVI – RCS System Inventory – 14.7 psi

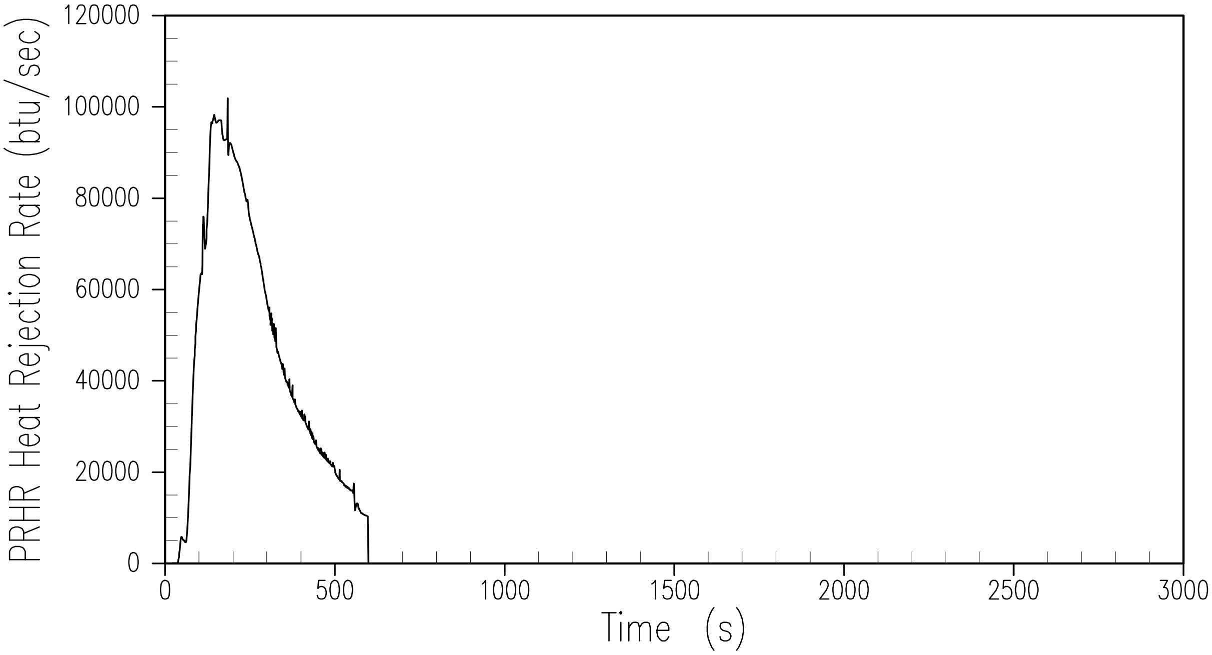

Figure 15.6.5.4B-54A

DEDVI – PRHR Heat Removal Rate – 14.7 psi

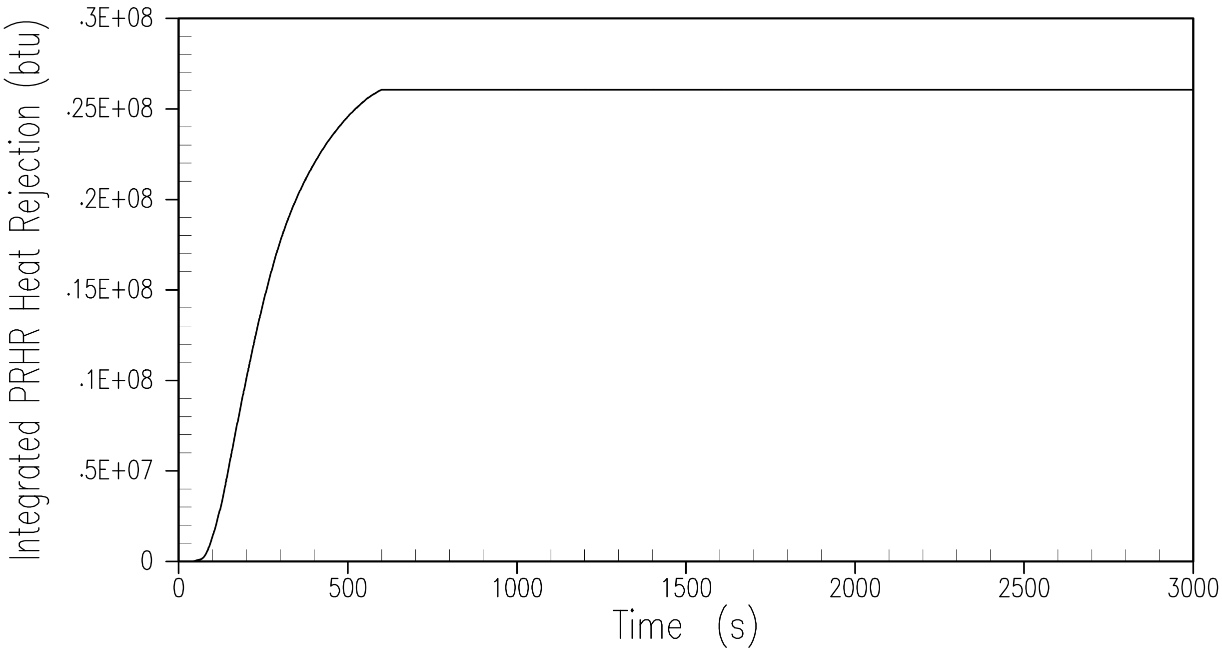

Figure 15.6.5.4B-55A

DEDVI – Integrated PRHR Heat Removal – 14.7 psi

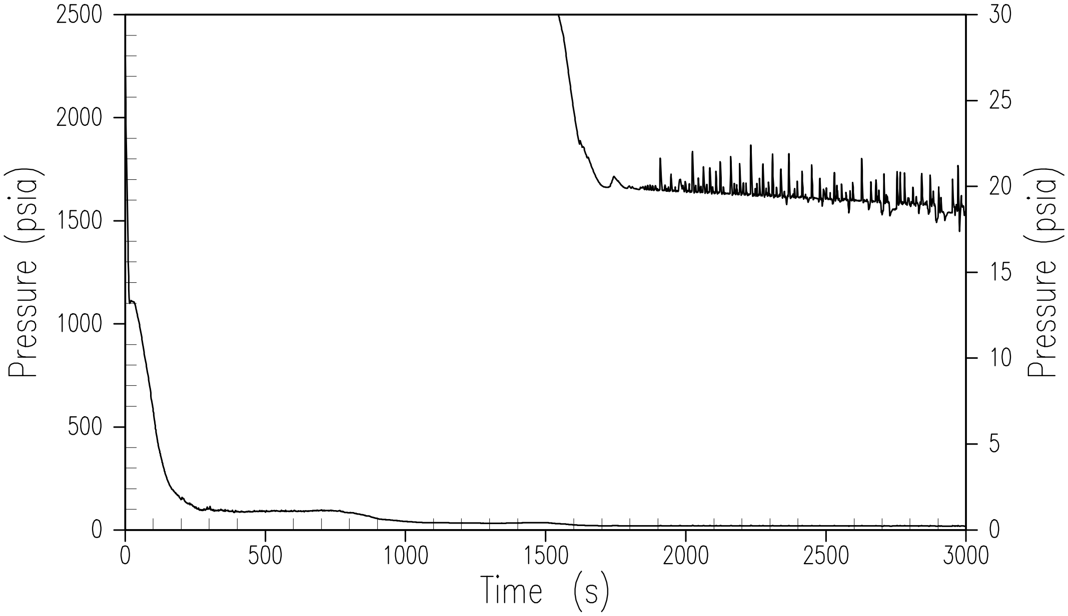

Figure 15.6.5.4B-56

10-Inch Cold Leg Break – RCS Pressure

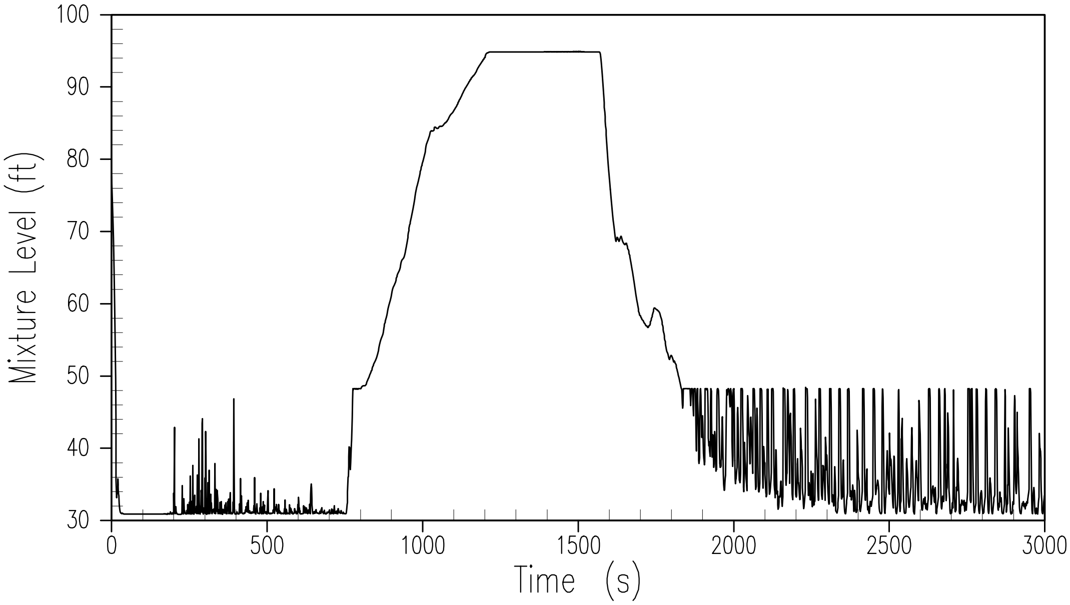

Figure 15.6.5.4B-57

10-Inch Cold Leg Break – Pressurizer Mixture Level

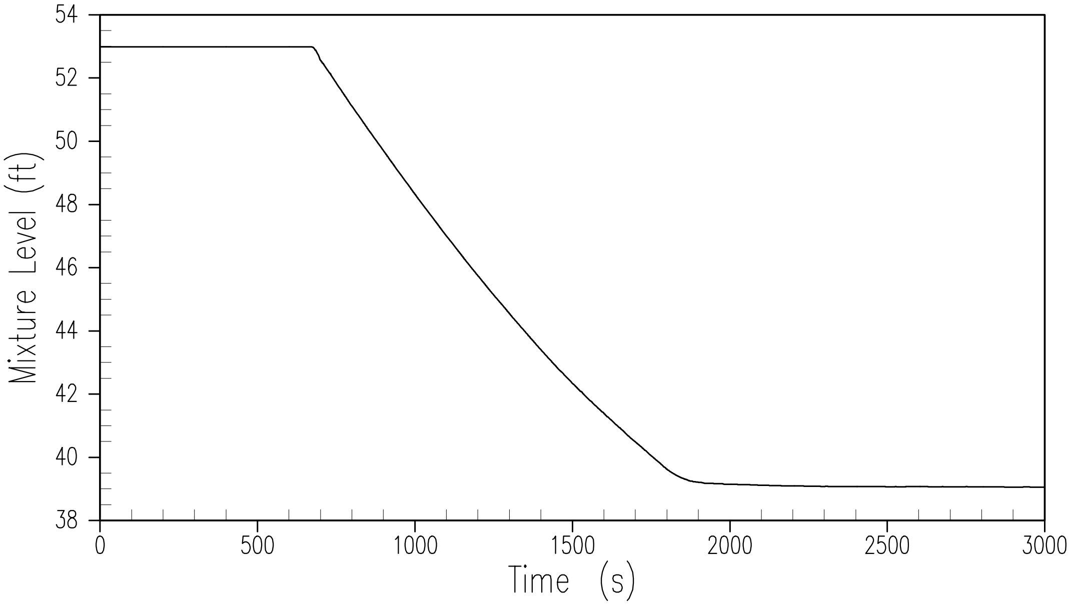

Figure 15.6.5.4B-58

10-Inch Cold Leg Break – CMT-1 Mixture Level

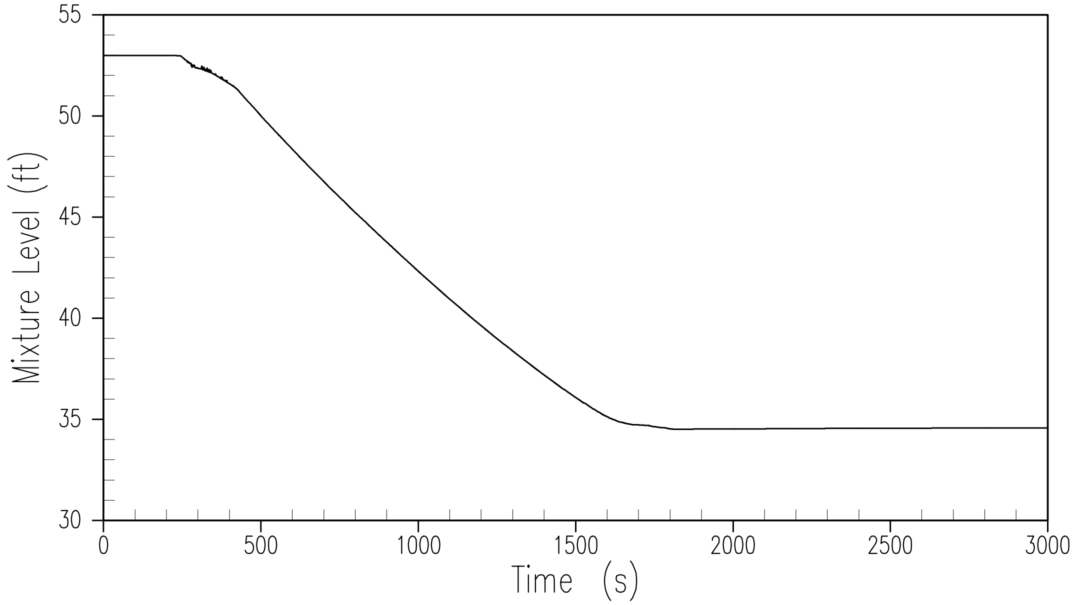

Figure 15.6.5.4B-59

10-Inch Cold Leg Break – CMT-2 Mixture Level

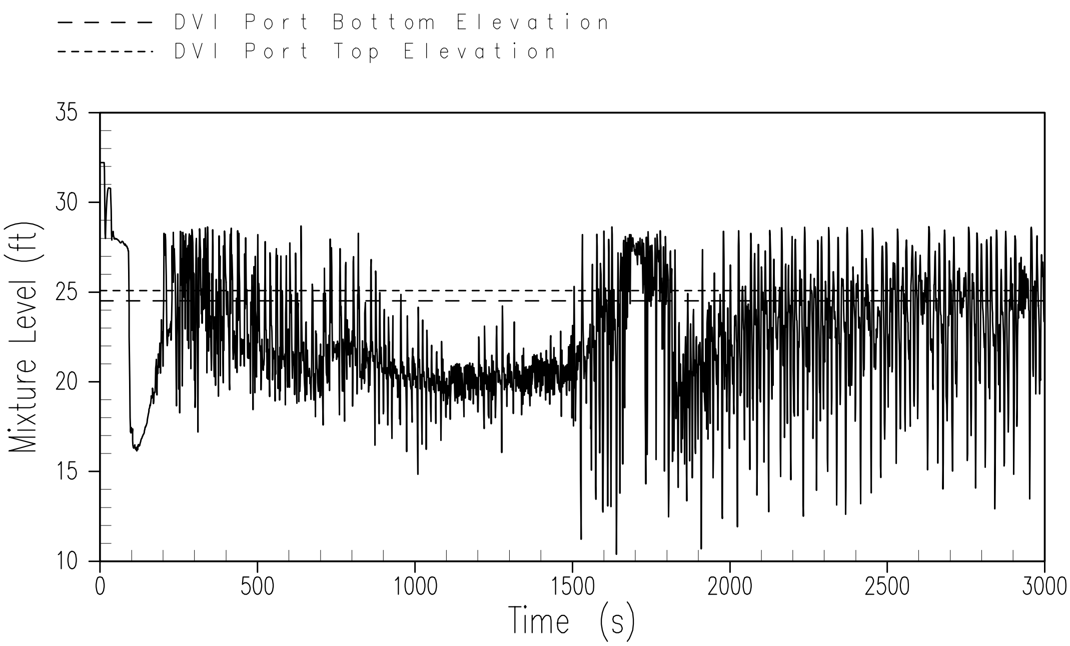

Figure 15.6.5.4B-60

10-Inch Cold Leg Break – Downcomer Mixture Level

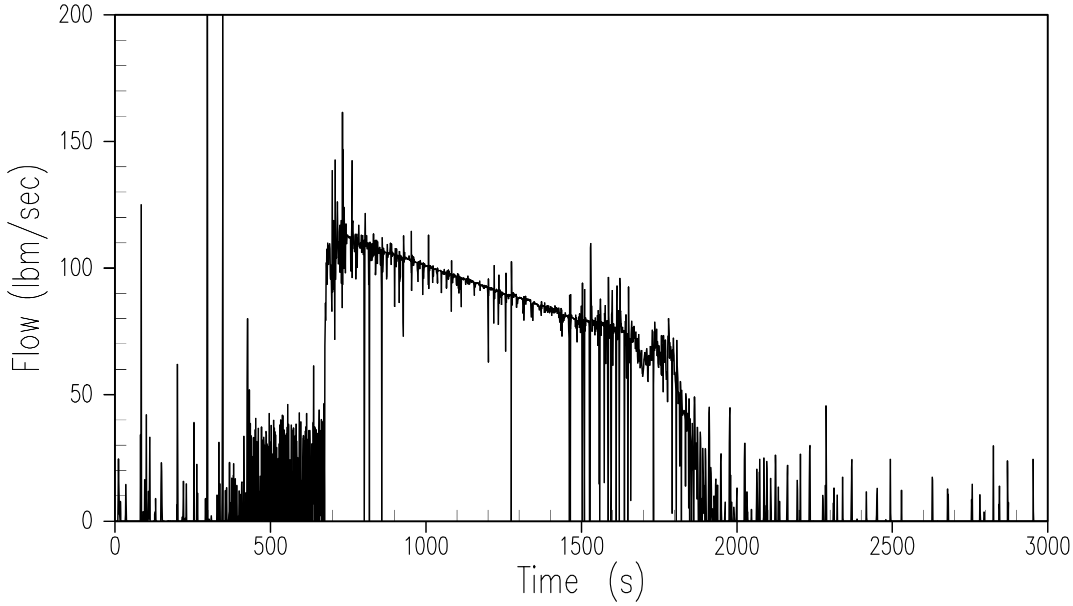

Figure 15.6.5.4B-61

10-Inch Cold Leg Break – CMT-1 Injection Rate

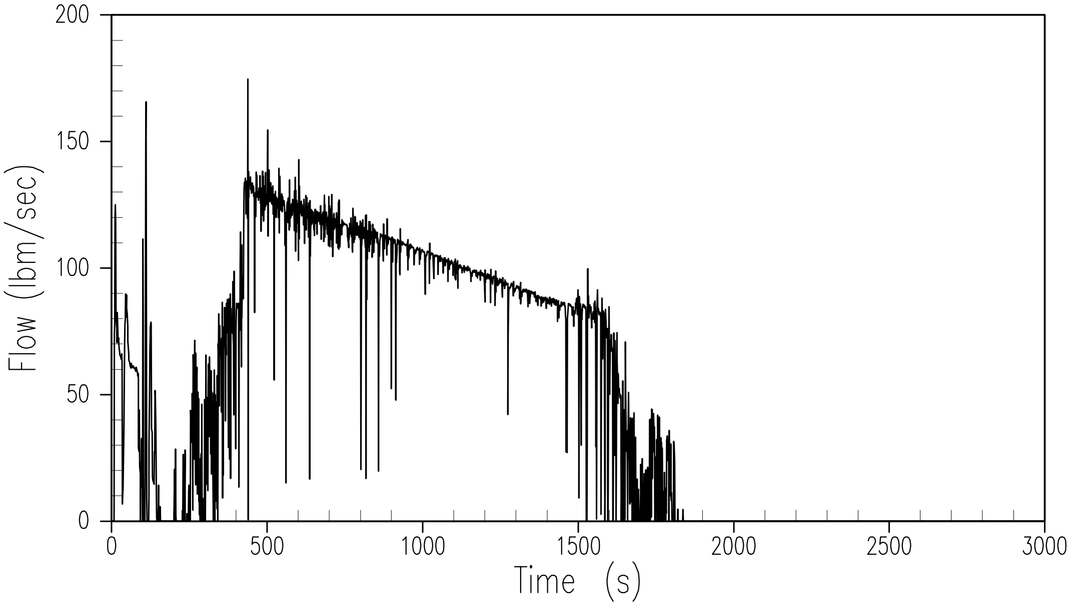

Figure 15.6.5.4B-62

10-Inch Cold Leg Break – CMT-2 Injection Rate

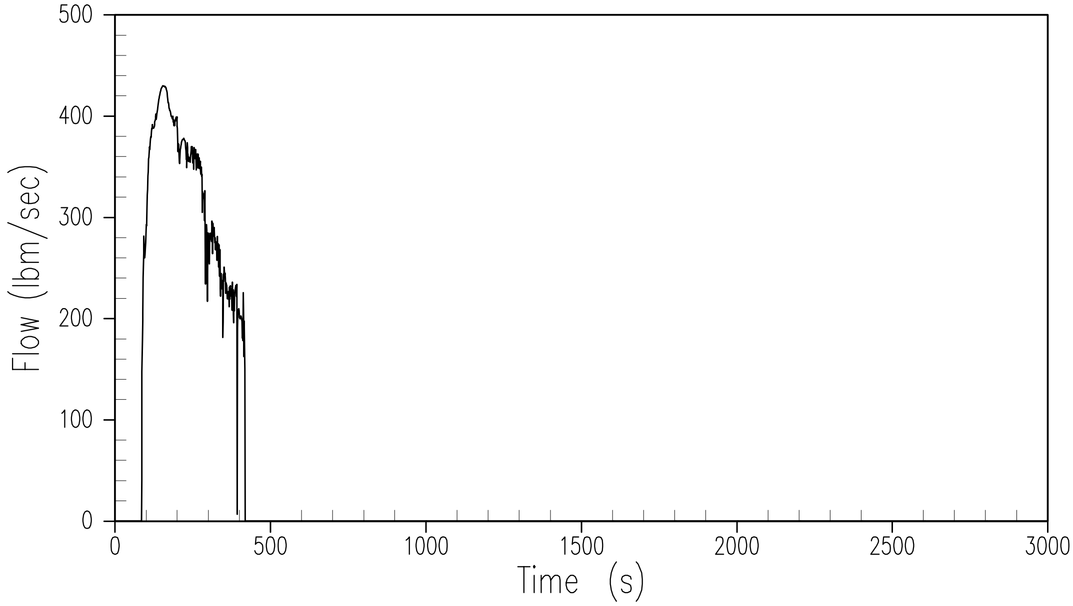

Figure 15.6.5.4B-63

10-Inch Cold Leg Break – Accumulator-1 Injection Rate

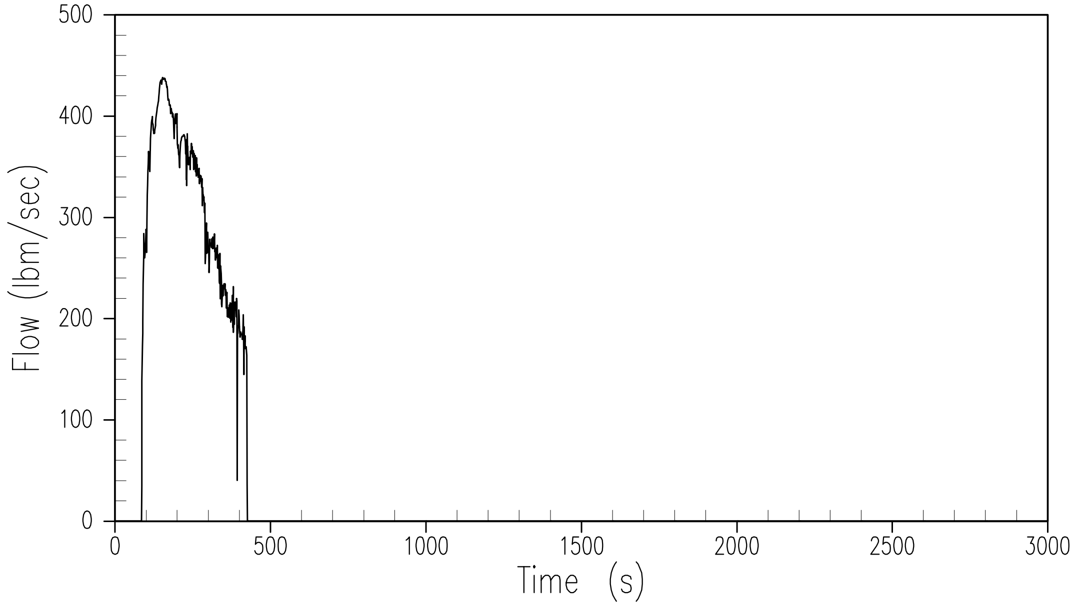

Figure 15.6.5.4B-64

10-Inch Cold Leg Break – Accumulator-2 Injection Rate

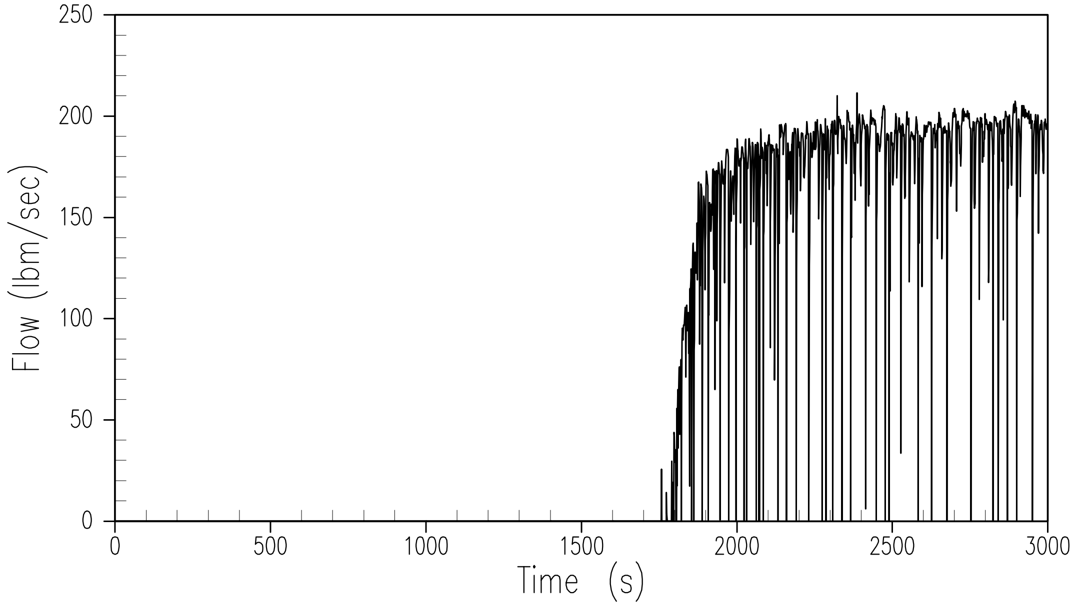

Figure 15.6.5.4B-65

10-Inch Cold Leg Break – IRWST-1 Injection Rate

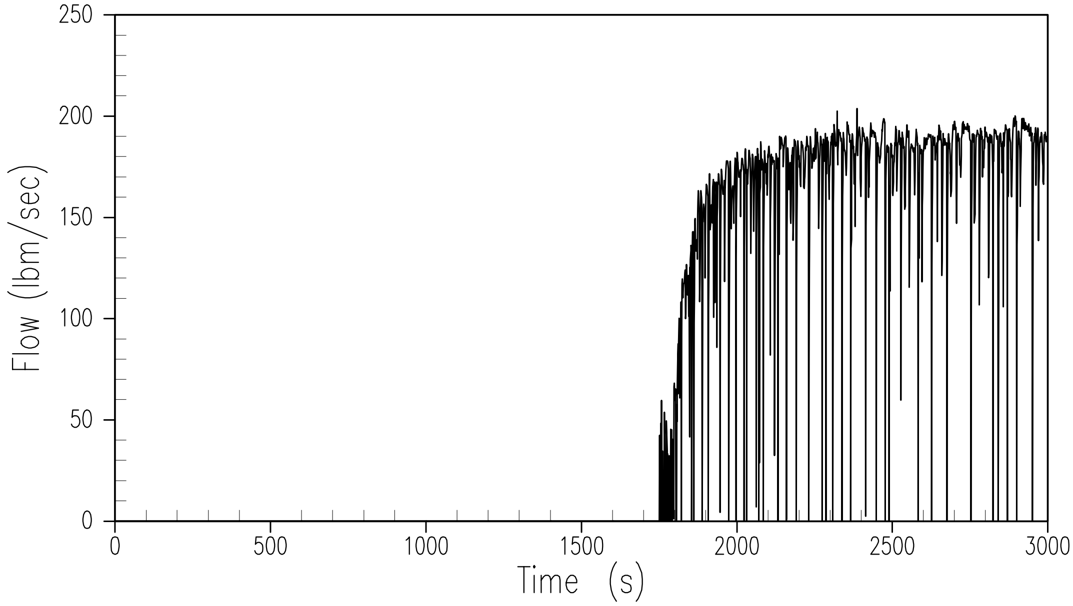

Figure 15.6.5.4B-66

10-Inch Cold Leg Break – IRWST-2 Injection Rate

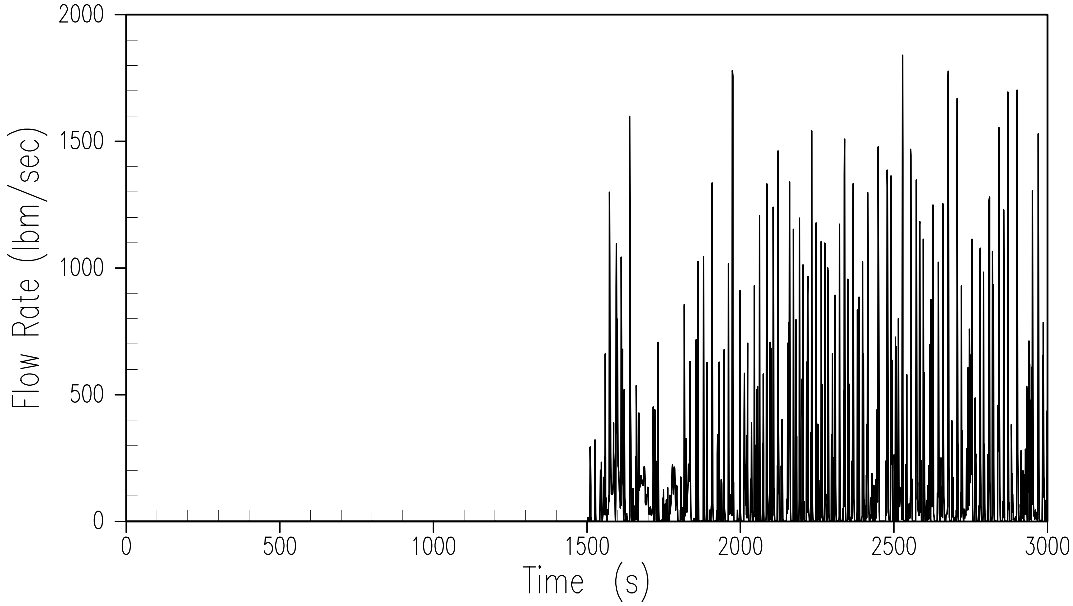

Figure 15.6.5.4B-67

10-Inch Cold Leg Break – ADS-4 Liquid Discharge

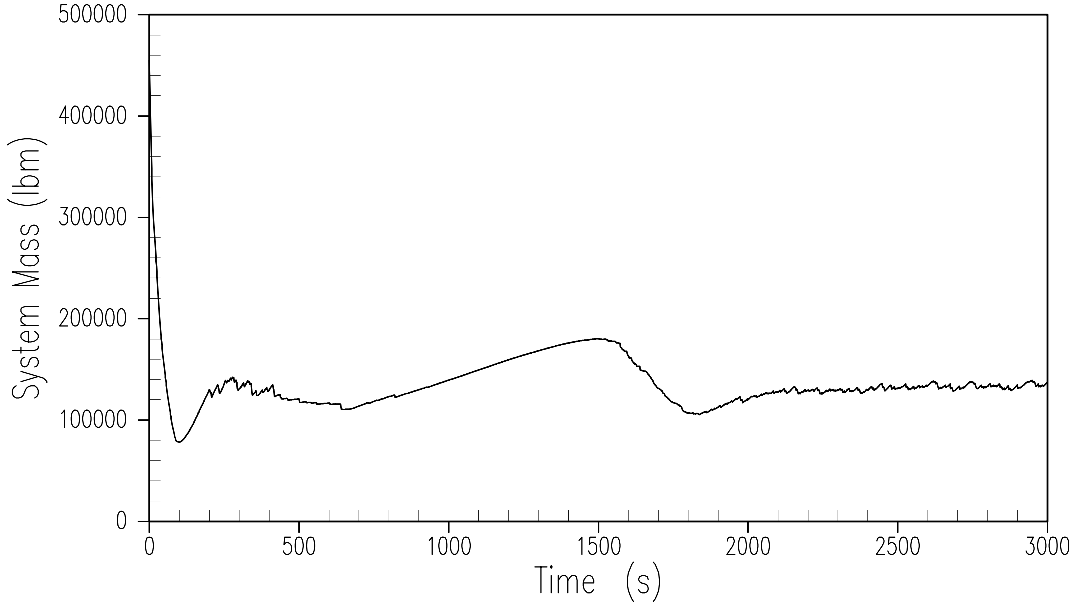

Figure 15.6.5.4B-68

10-Inch Cold Leg Break – RCS System Inventory

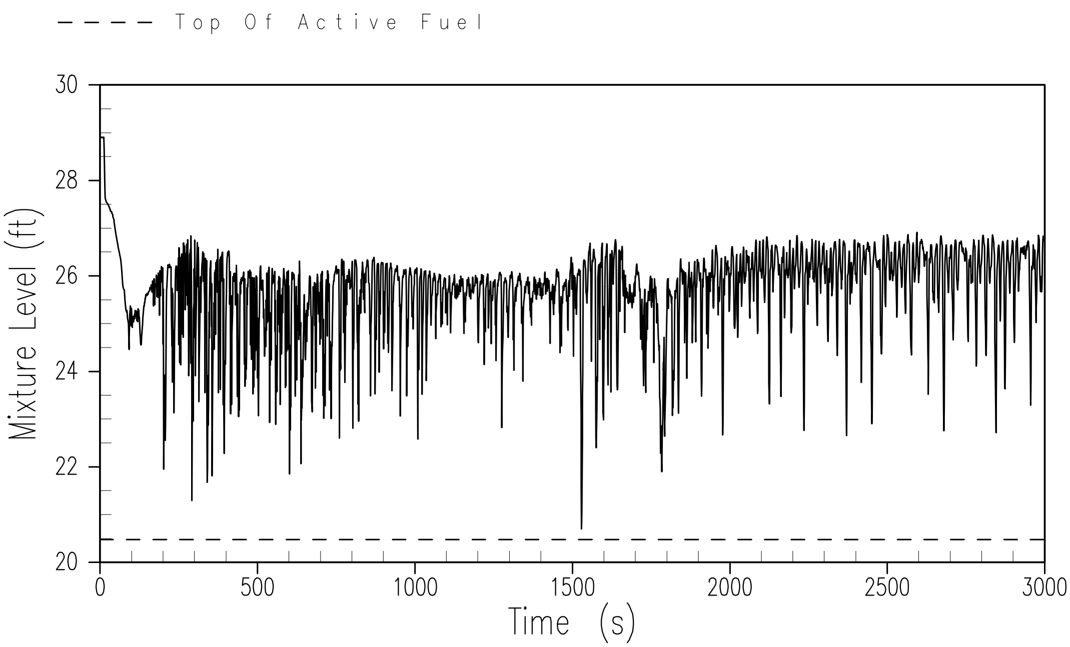

Figure 15.6.5.4B-69

10-Inch Cold Leg Break – Core/Upper Plenum Mixture Level

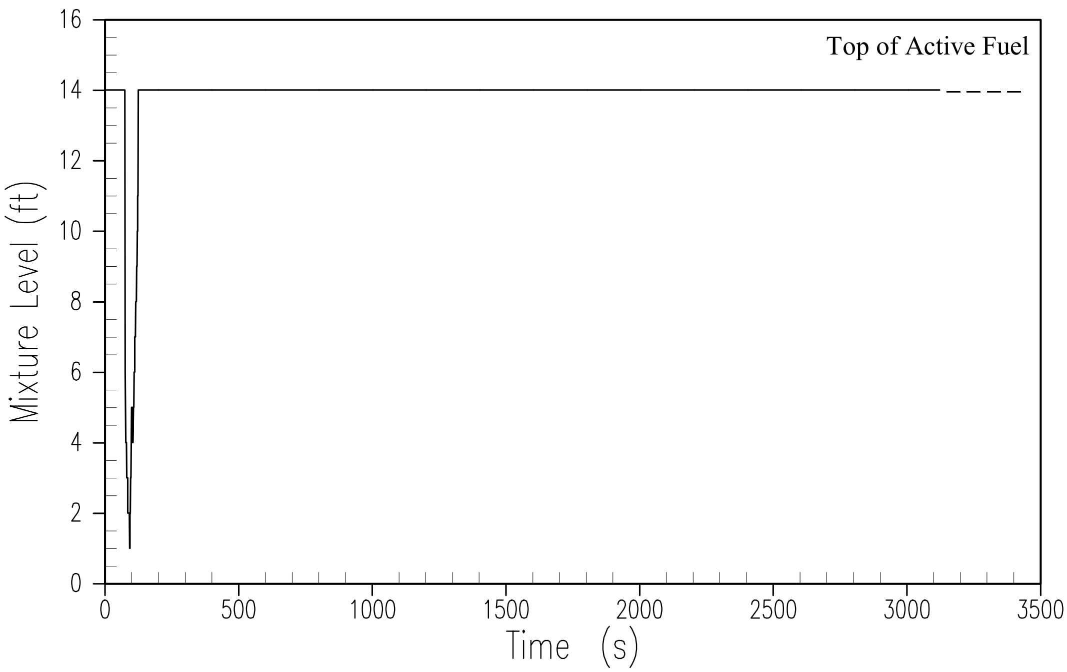

Figure 15.6.5.4B-70

10-Inch Cold Leg Break – Composite Core Mixture Level

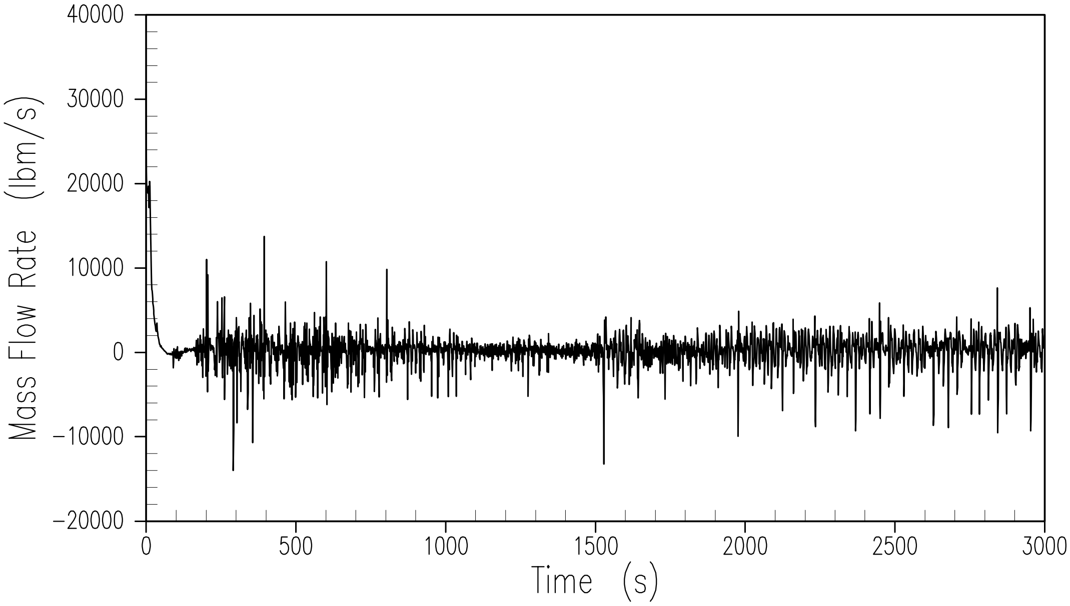

Figure 15.6.5.4B-71

10-Inch Cold Leg Break – Core Exit Liquid Flow

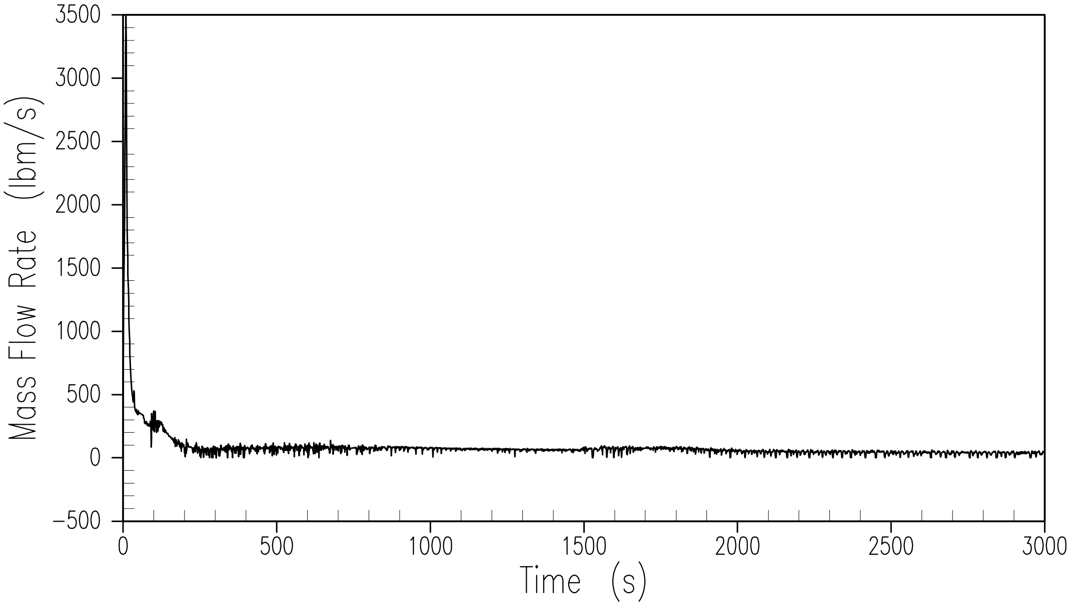

Figure 15.6.5.4B-72

10-Inch Cold Leg Break – Core Exit Vapor Flow

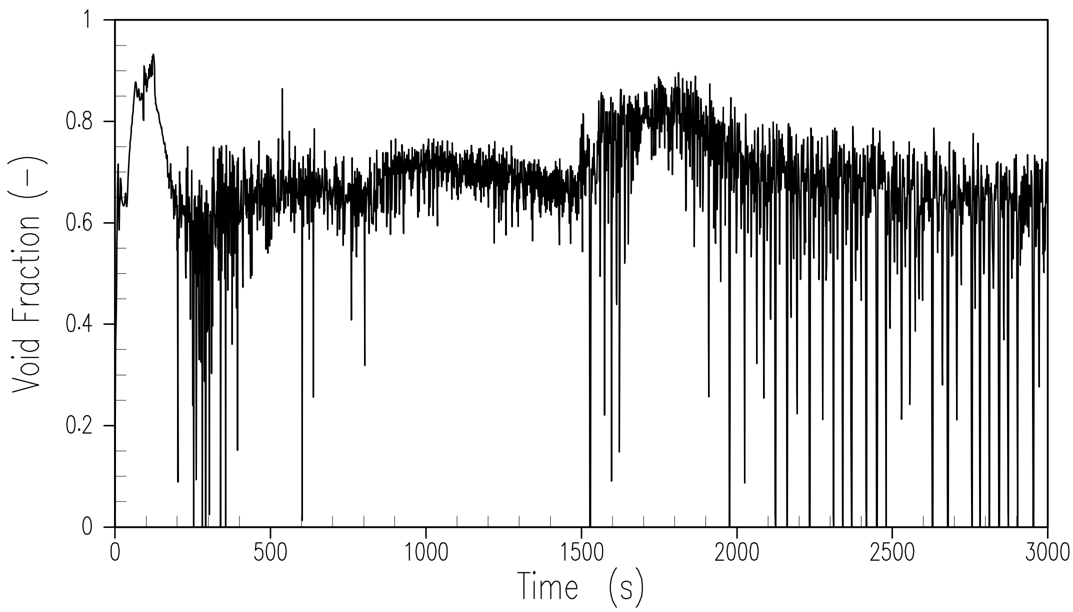

Figure 15.6.5.4B-73

10-Inch Cold Leg Break – Core Exit Void Fraction

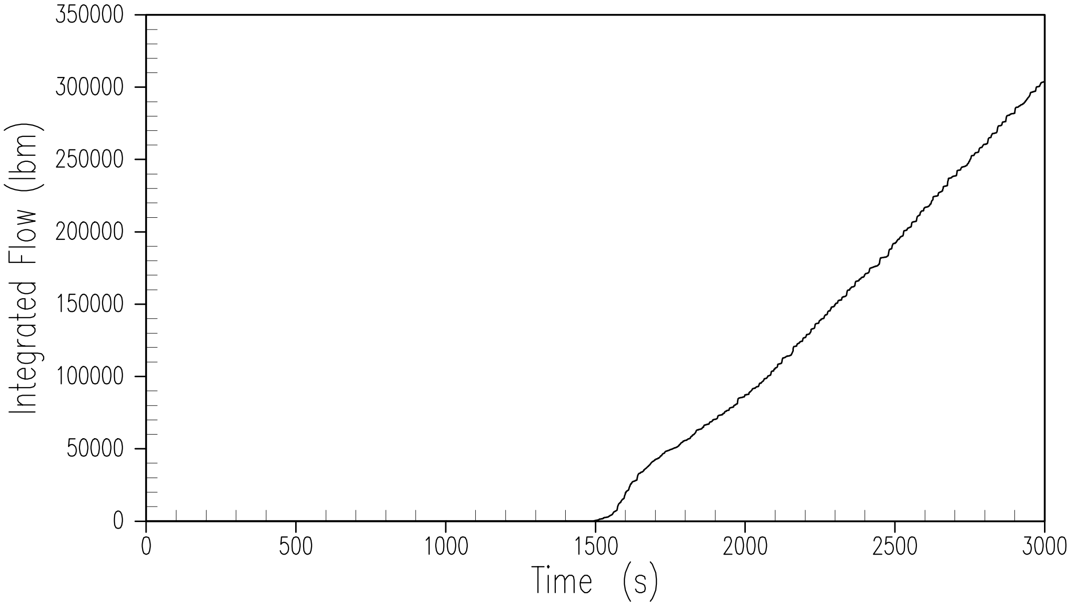

Figure 15.6.5.4B-74

10-Inch Cold Leg Break – ADS-4 Integrated Discharge

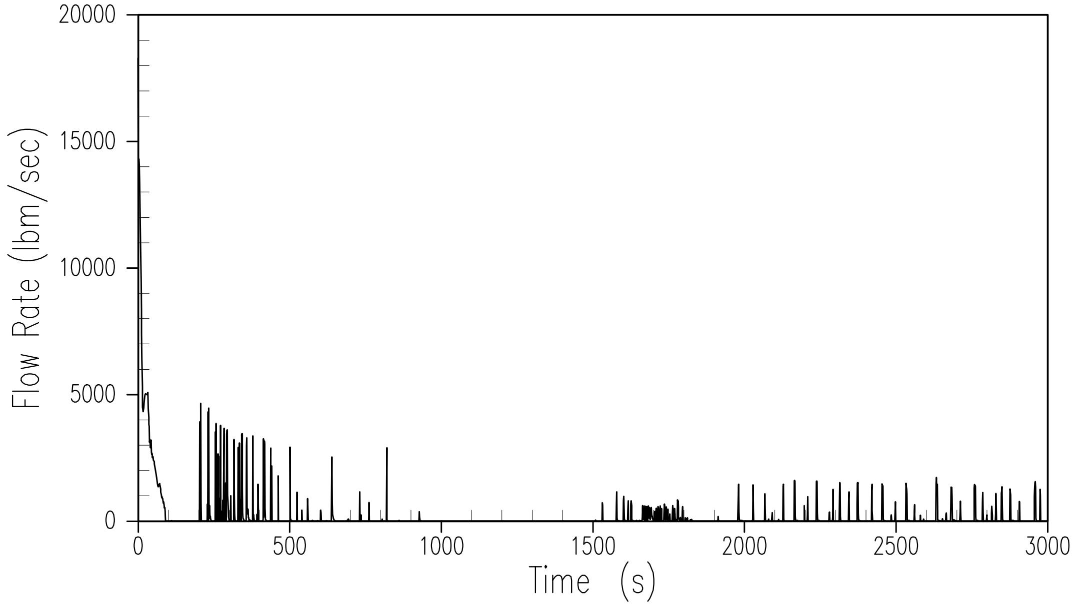

Figure 15.6.5.4B-75

10-Inch Cold Leg Break – Liquid Break Discharge

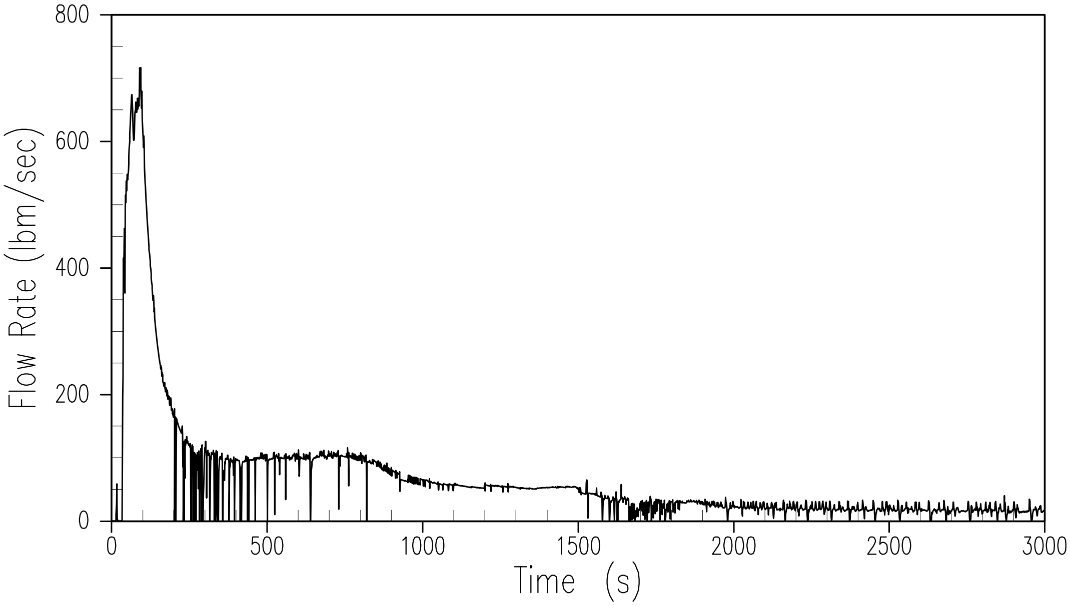

Figure 15.6.5.4B-76

10-Inch Cold Leg Break – Vapor Break Discharge

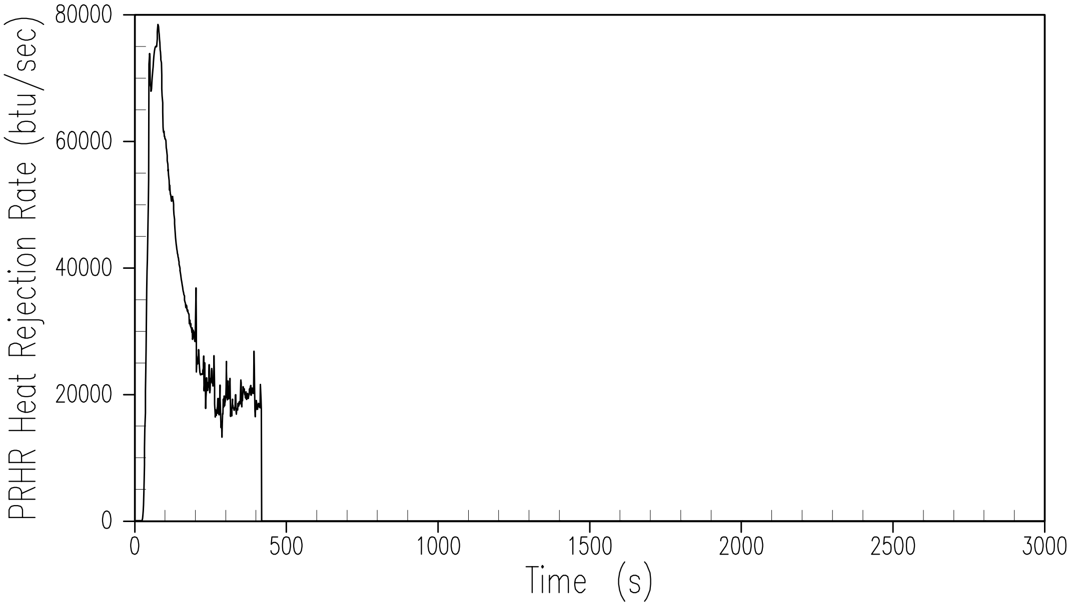

Figure 15.6.5.4B-77

10-Inch Cold Leg Break – PRHR Heat Removal Rate

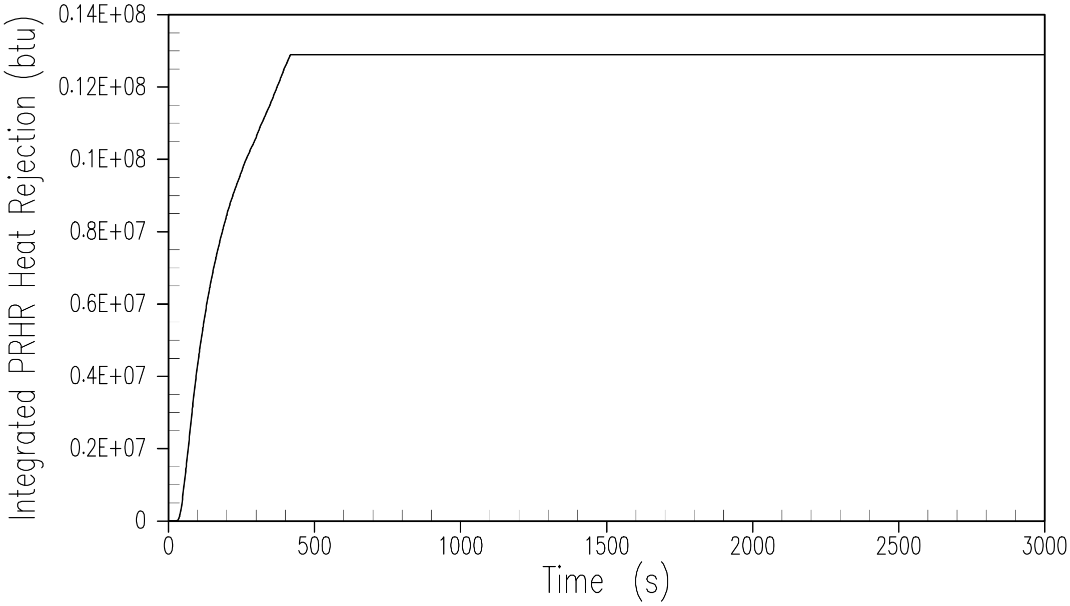

Figure 15.6.5.4B-78

10-Inch Cold Leg Break – Integrated PRHR Heat Removal

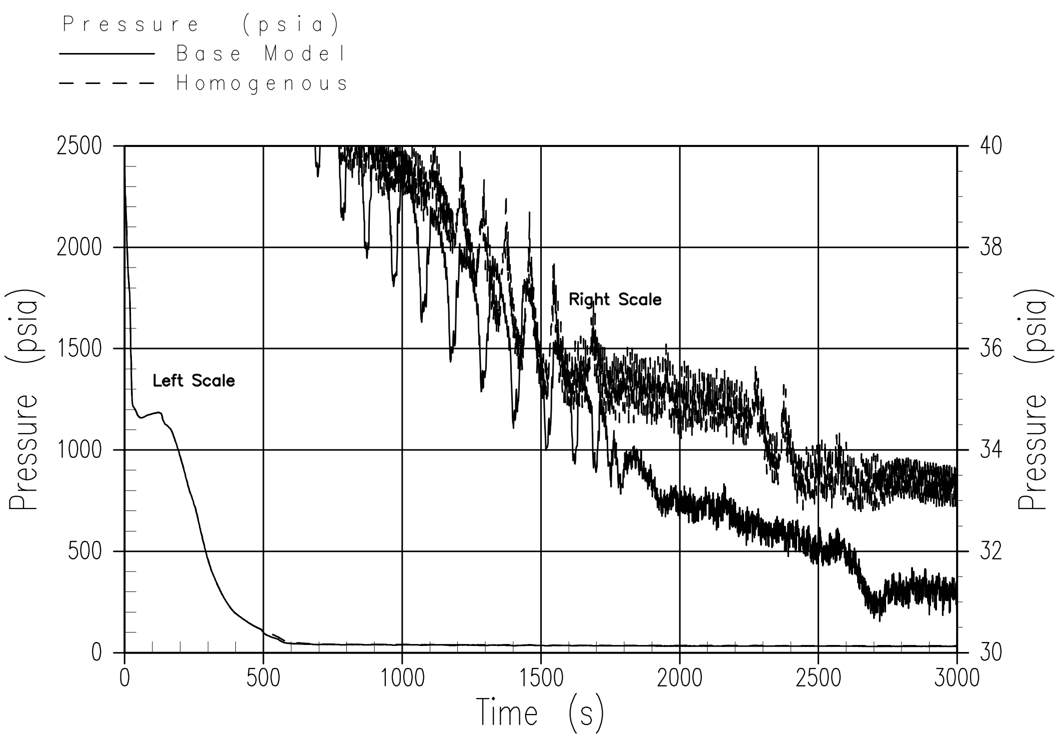

Figure 15.6.5.4B-79

DEDVI – Downcomer Pressure Comparison

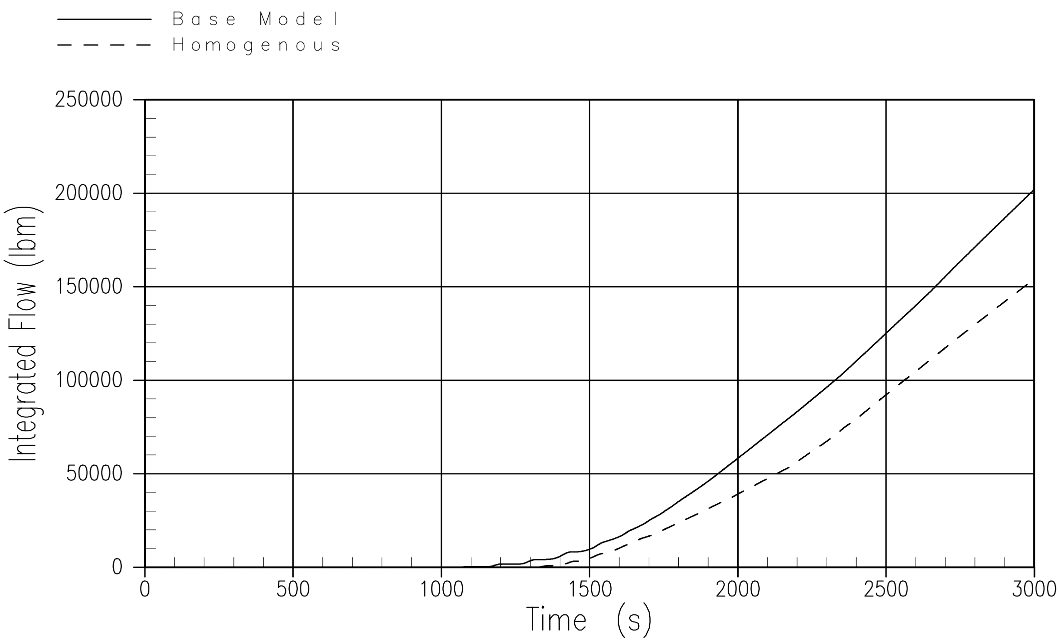

Figure 15.6.5.4B-80

DEDVI – Intact IRWST Injection Flow

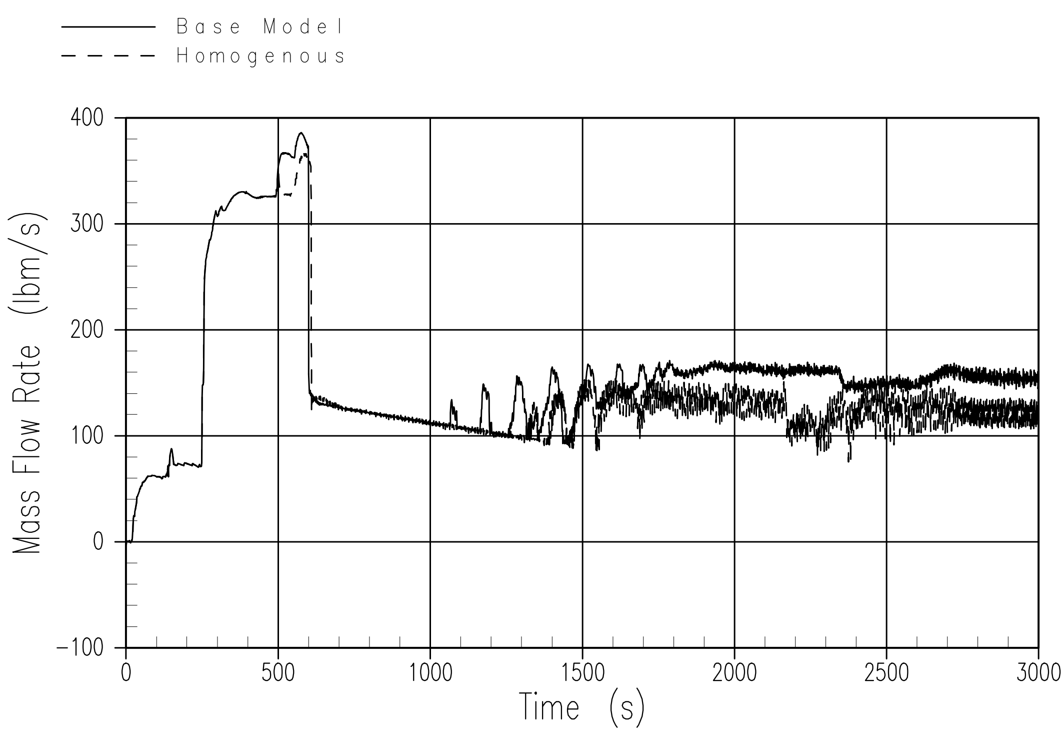

Figure 15.6.5.4B-81

DEDVI – Intact DVI Line Injection Flow

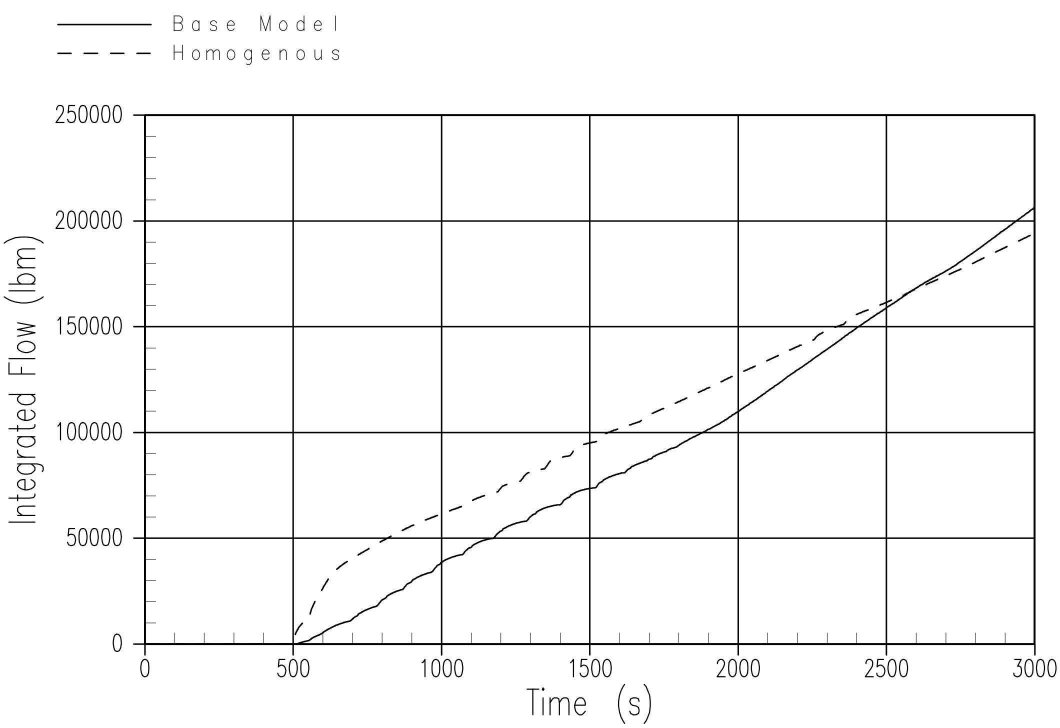

Figure 15.6.5.4B-82

DEDVI – ADS-4 Integrated Liquid Discharge Comparison

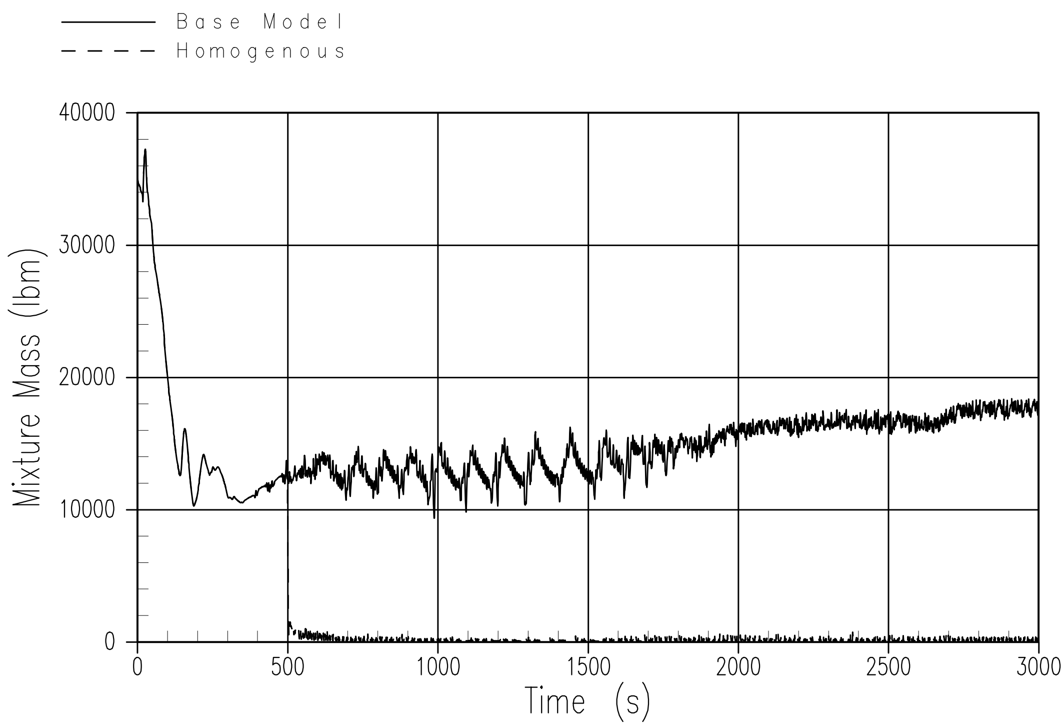

Figure 15.6.5.4B-83

DEDVI – Upper Plenum Mixture Mass Comparison

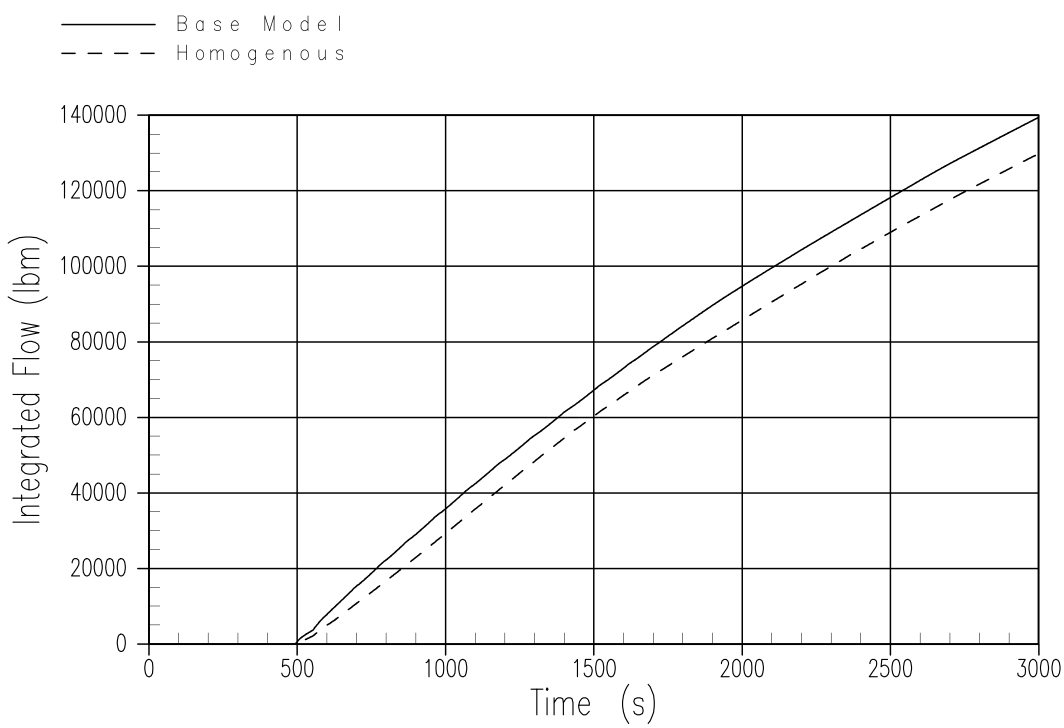

Figure 15.6.5.4B-84

DEDVI – ADS-4 Integrated Vapor Discharge Comparison

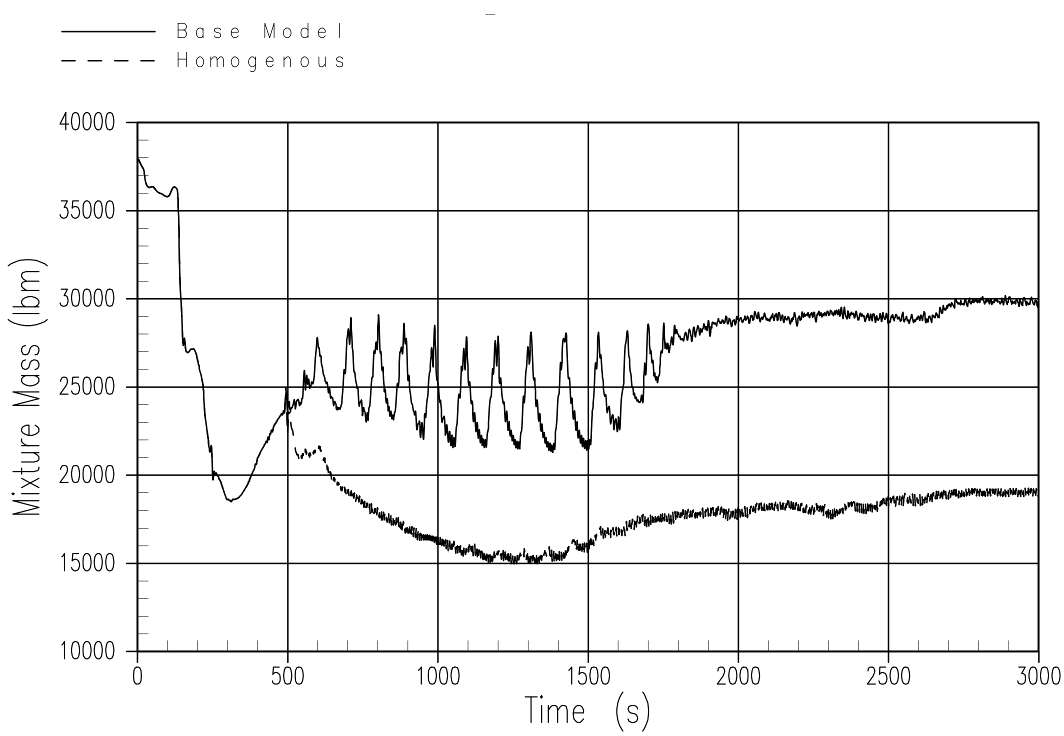

Figure 15.6.5.4B-85

DEDVI – Downcomer Region Mass Comparison

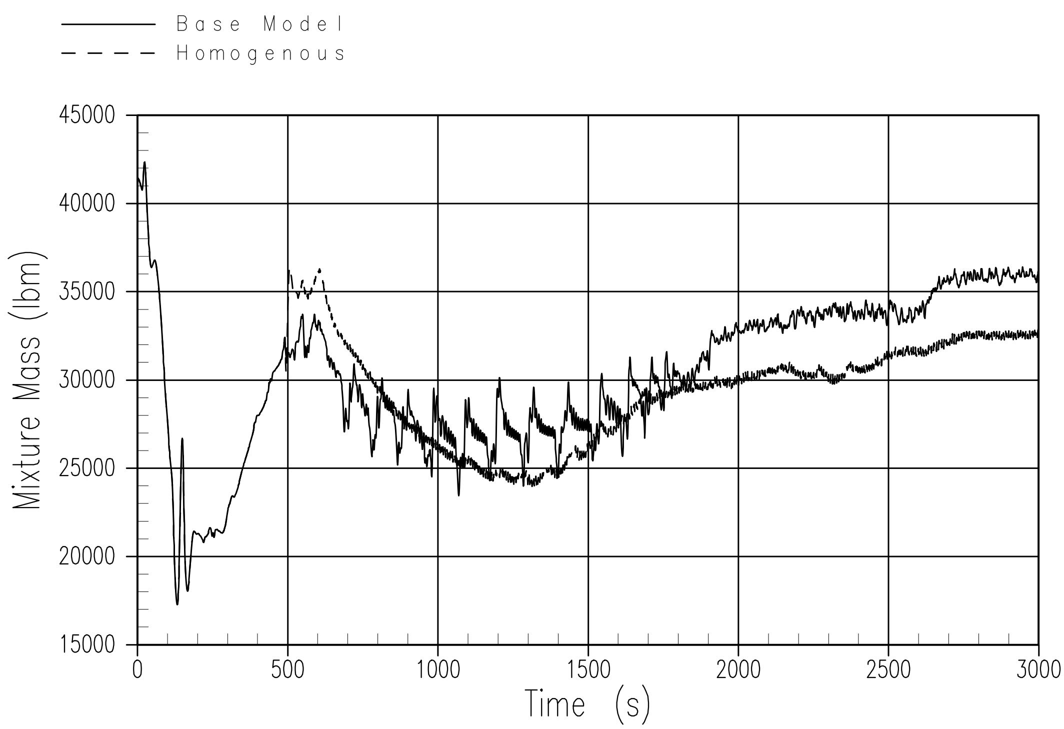

Figure 15.6.5.4B-86

DEDVI – Core Region Mass Comparison

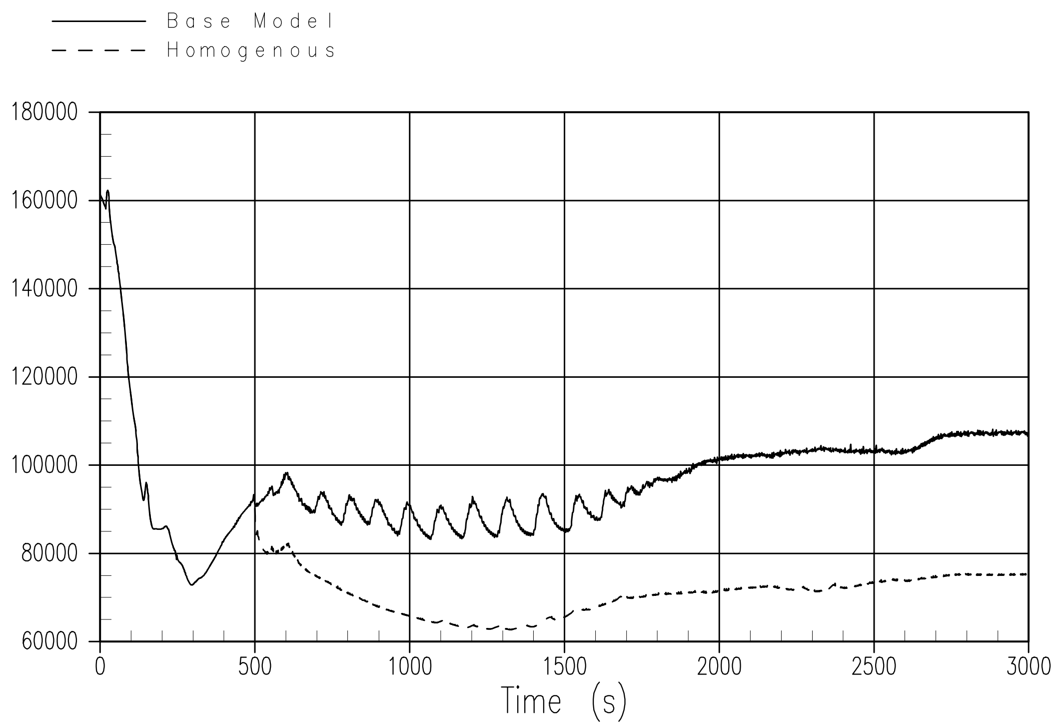

Figure 15.6.5.4B-87

DEDVI – Vessel Mixture Mass Comparison

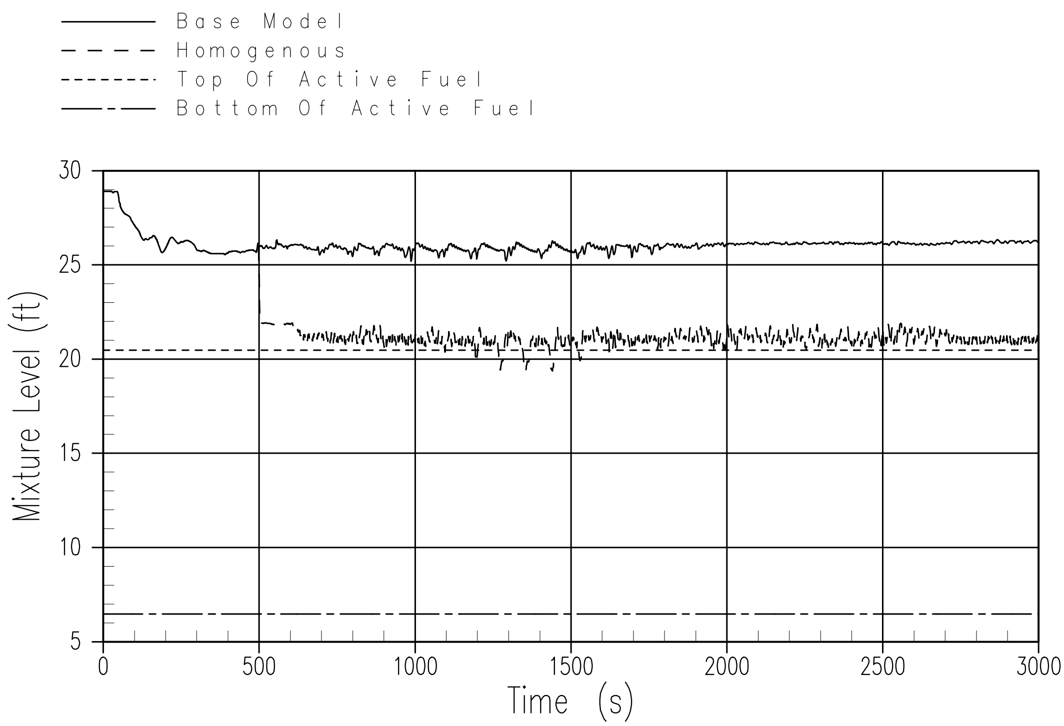

Figure 15.6.5.4B-88

DEDVI – Core/Upper Plenum Mixture Level Comparison

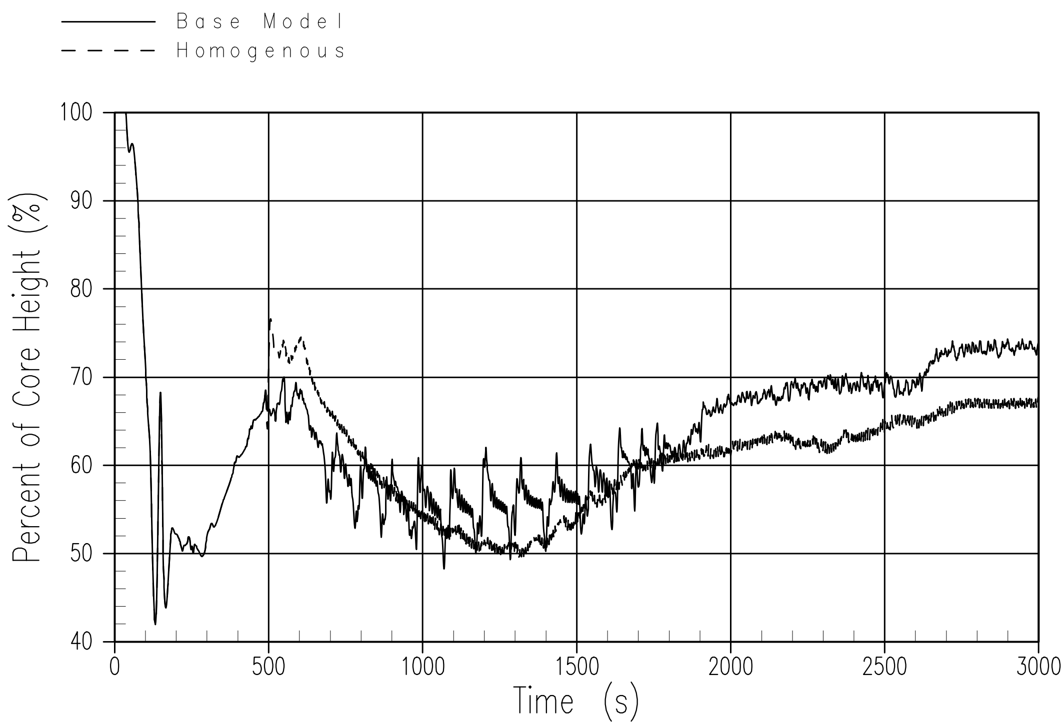

Figure 15.6.5.4B-89

DEDVI – Core Collapsed Liquid Level Comparison

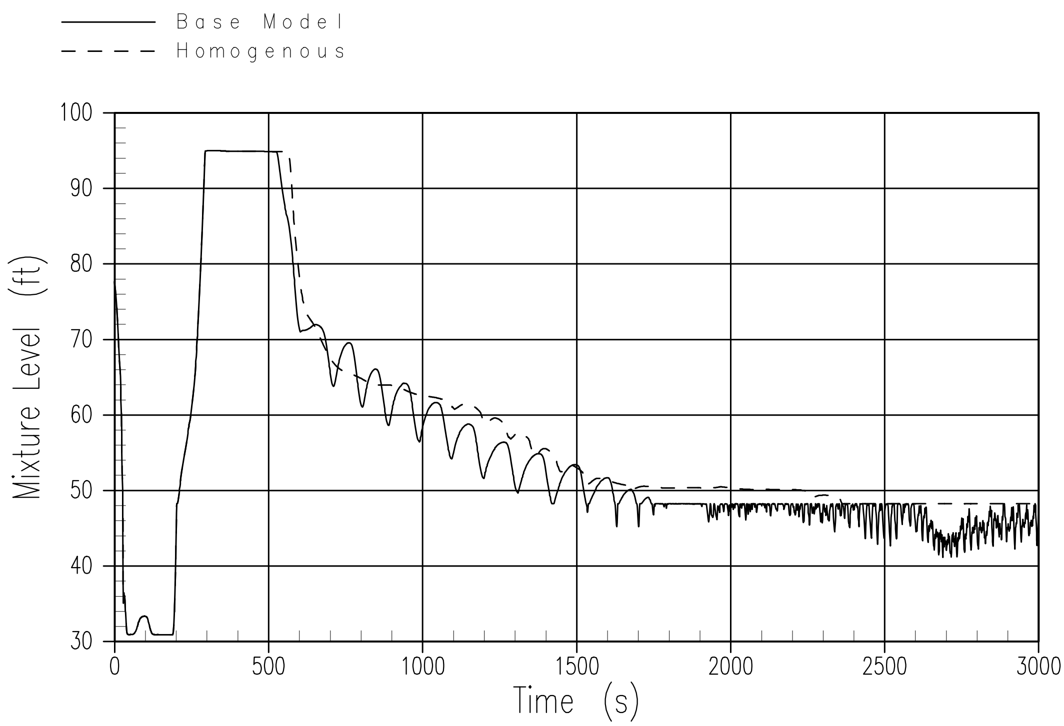

Figure 15.6.5.4B-90

DEDVI – Pressurizer Mixture Level Comparison

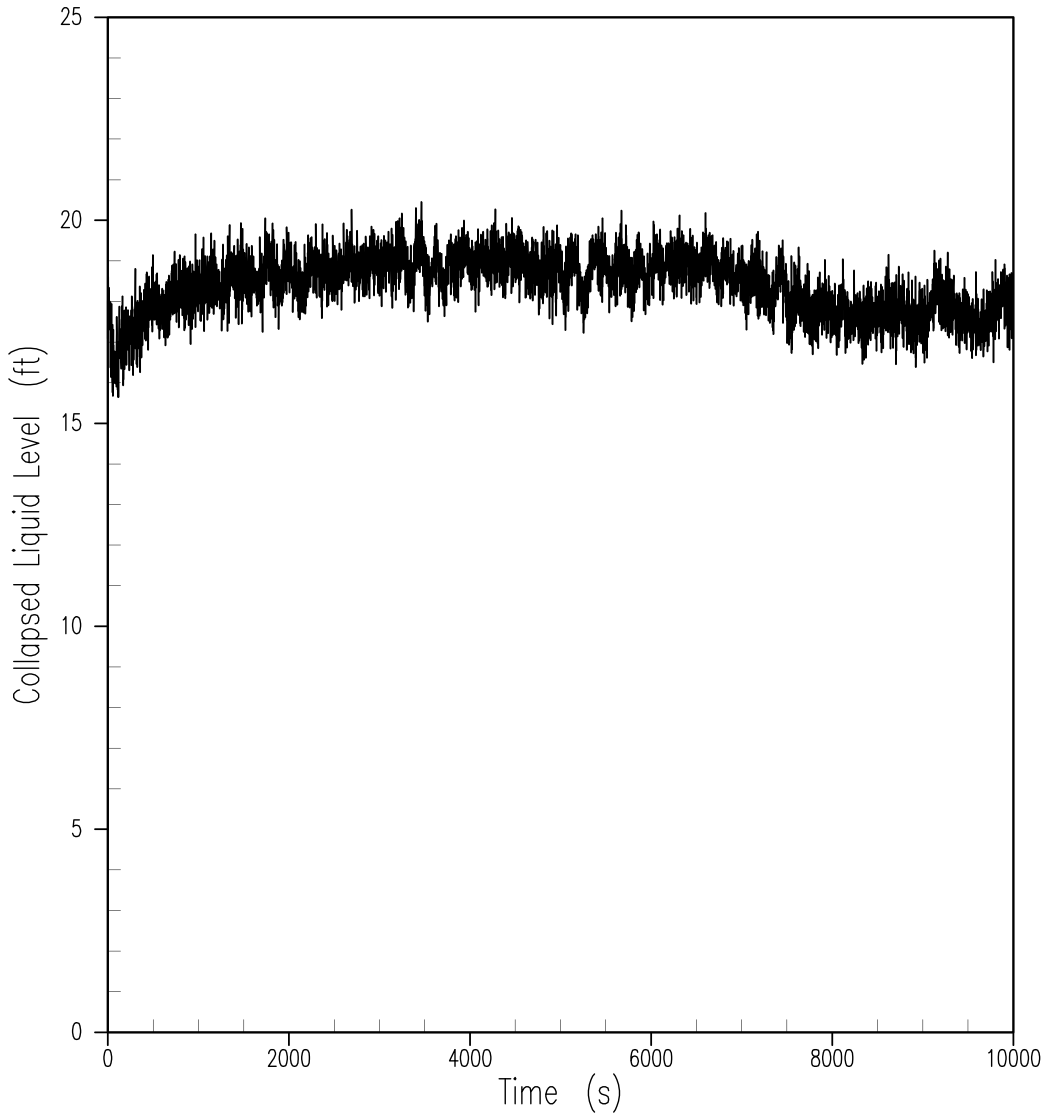

Figure 15.6.5.4C-1

Collapsed Level of Liquid in the Downcomer (DEDVI Case)

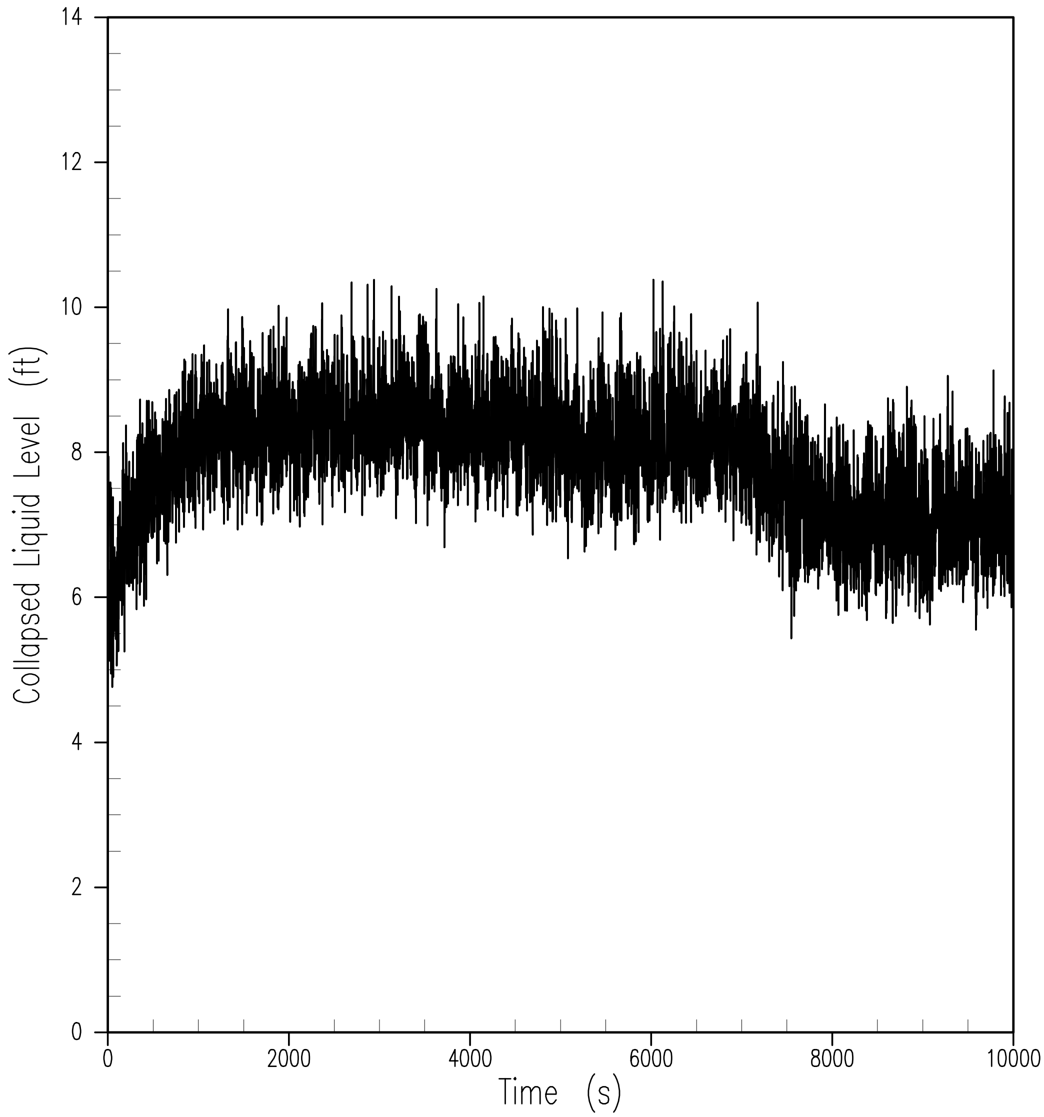

Figure 15.6.5.4C-2

Collapsed Level of Liquid over the Heated Length of the Fuel (DEDVI Case)

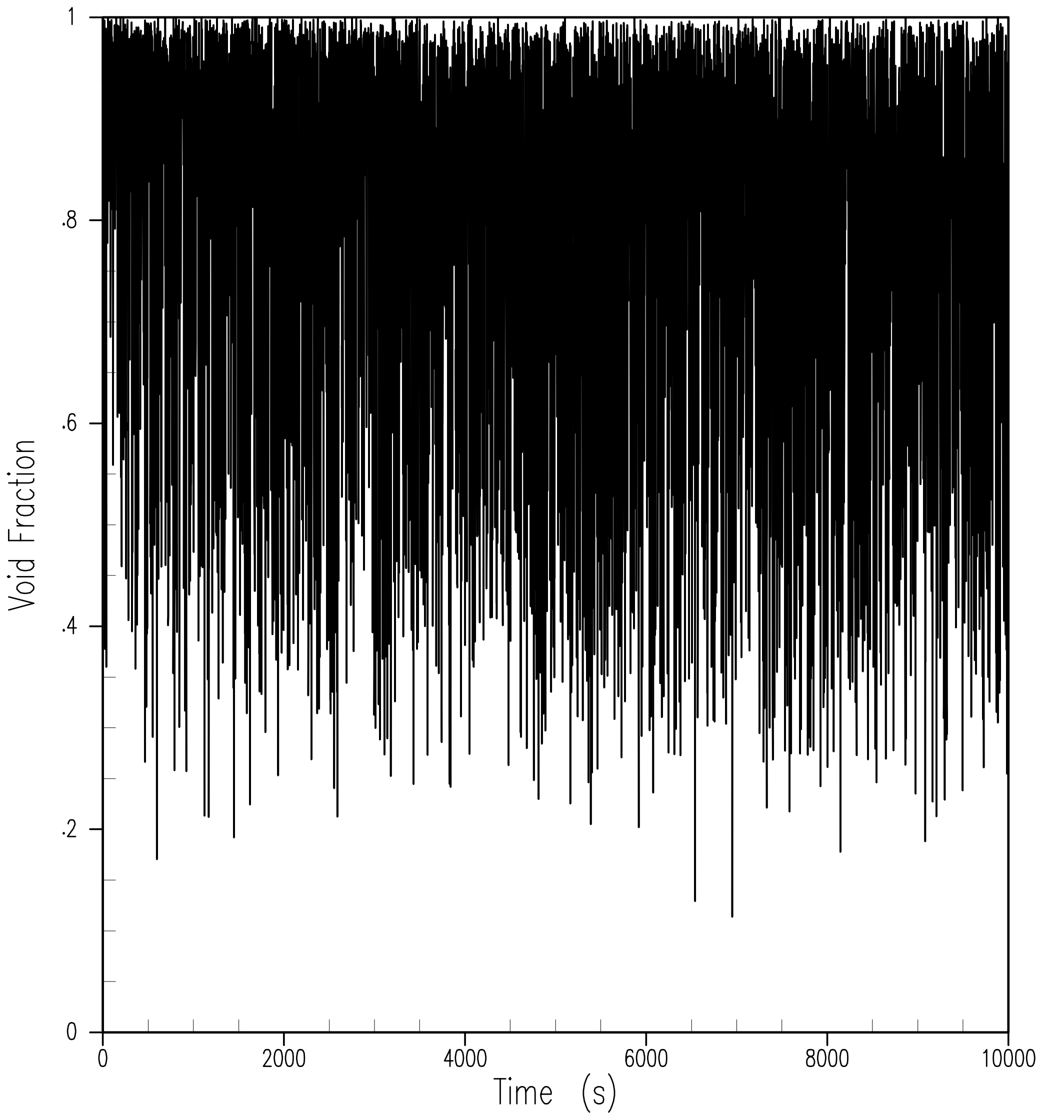

Figure 15.6.5.4C-3

Void Fraction in Core Hot Assembly Top Cell (DEDVI Case)

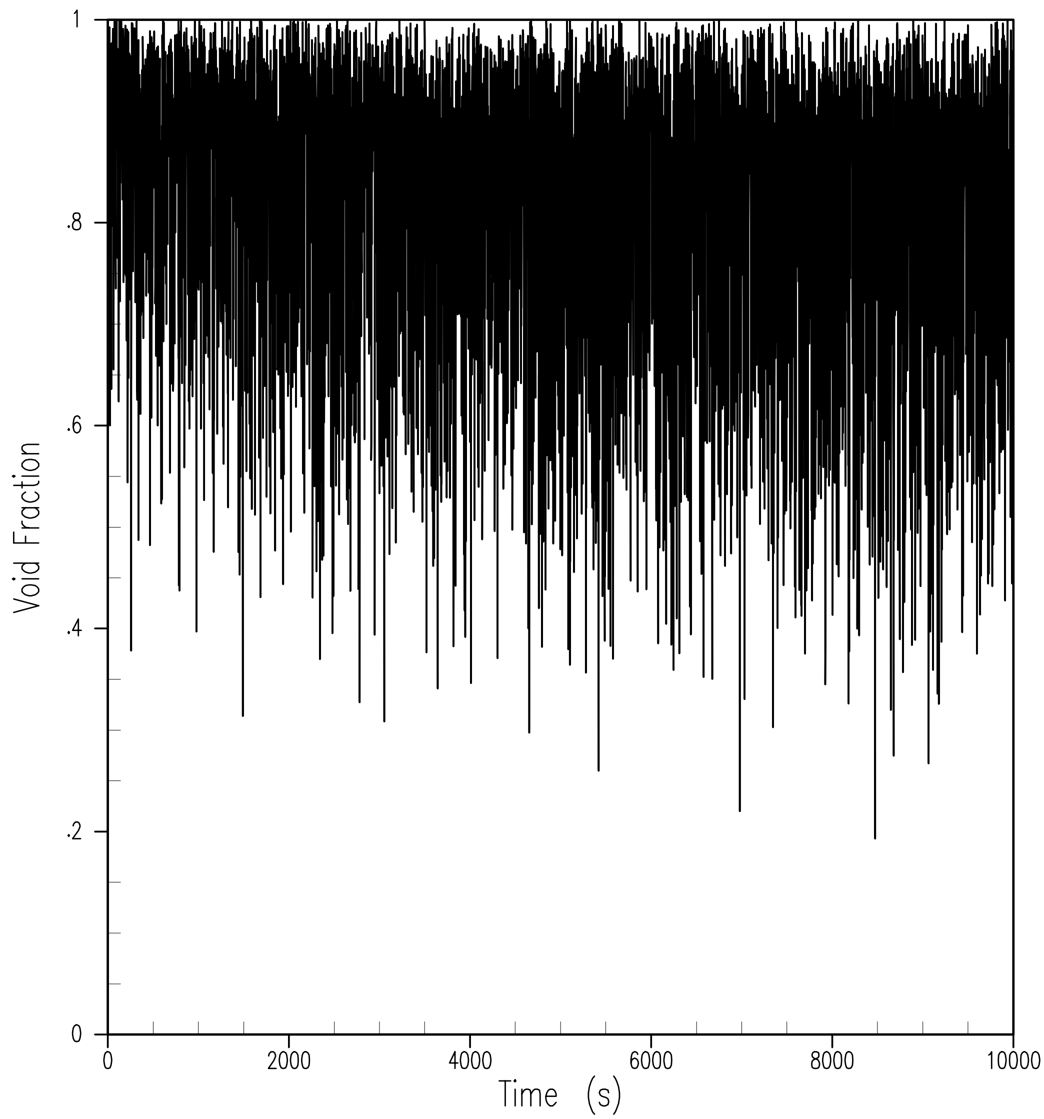

Figure 15.6.5.4C-4

Void Fraction in Core Hot Assembly Second from Top Cell (DEDVI Case)

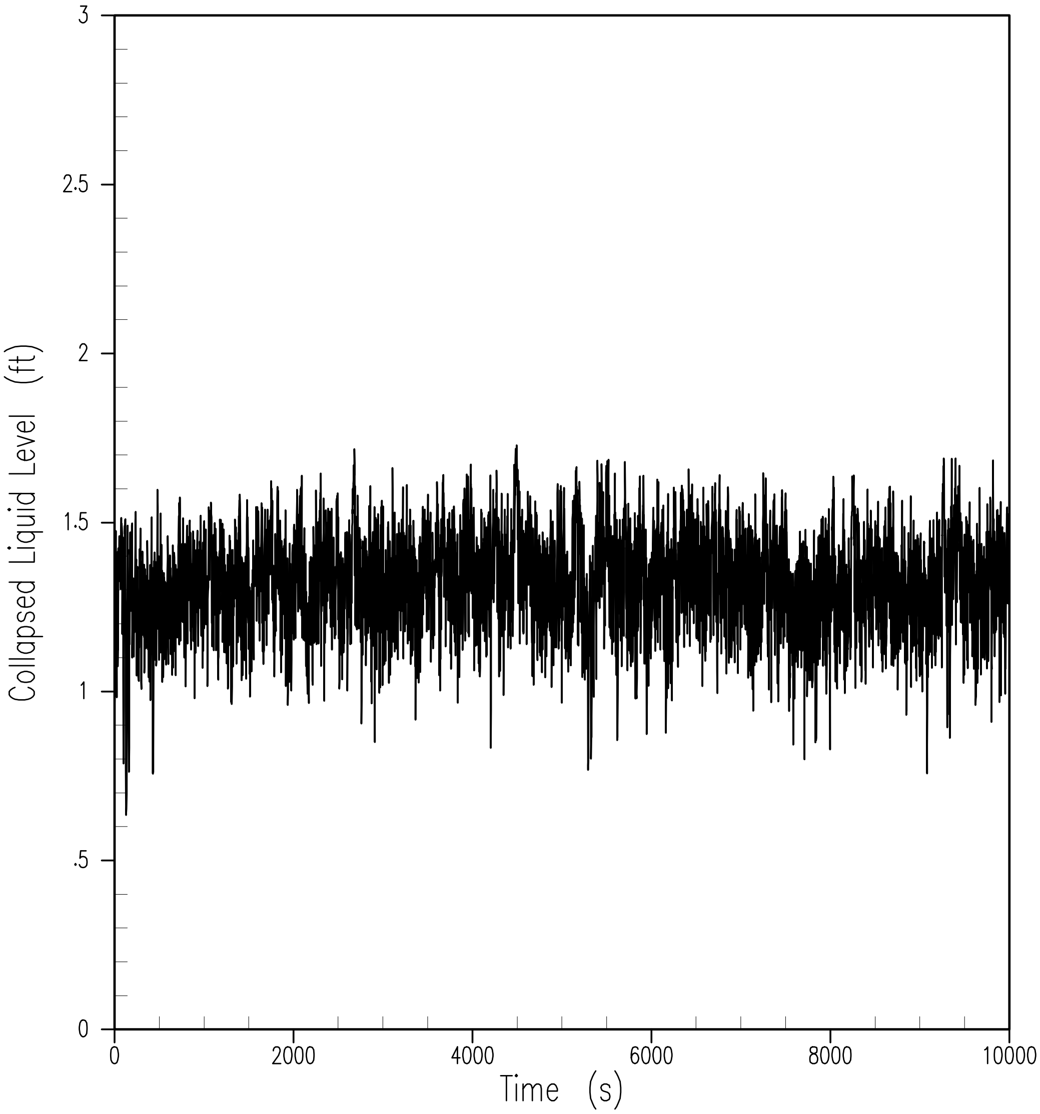

Figure 15.6.5.4C-5

Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (DEDVI Case)

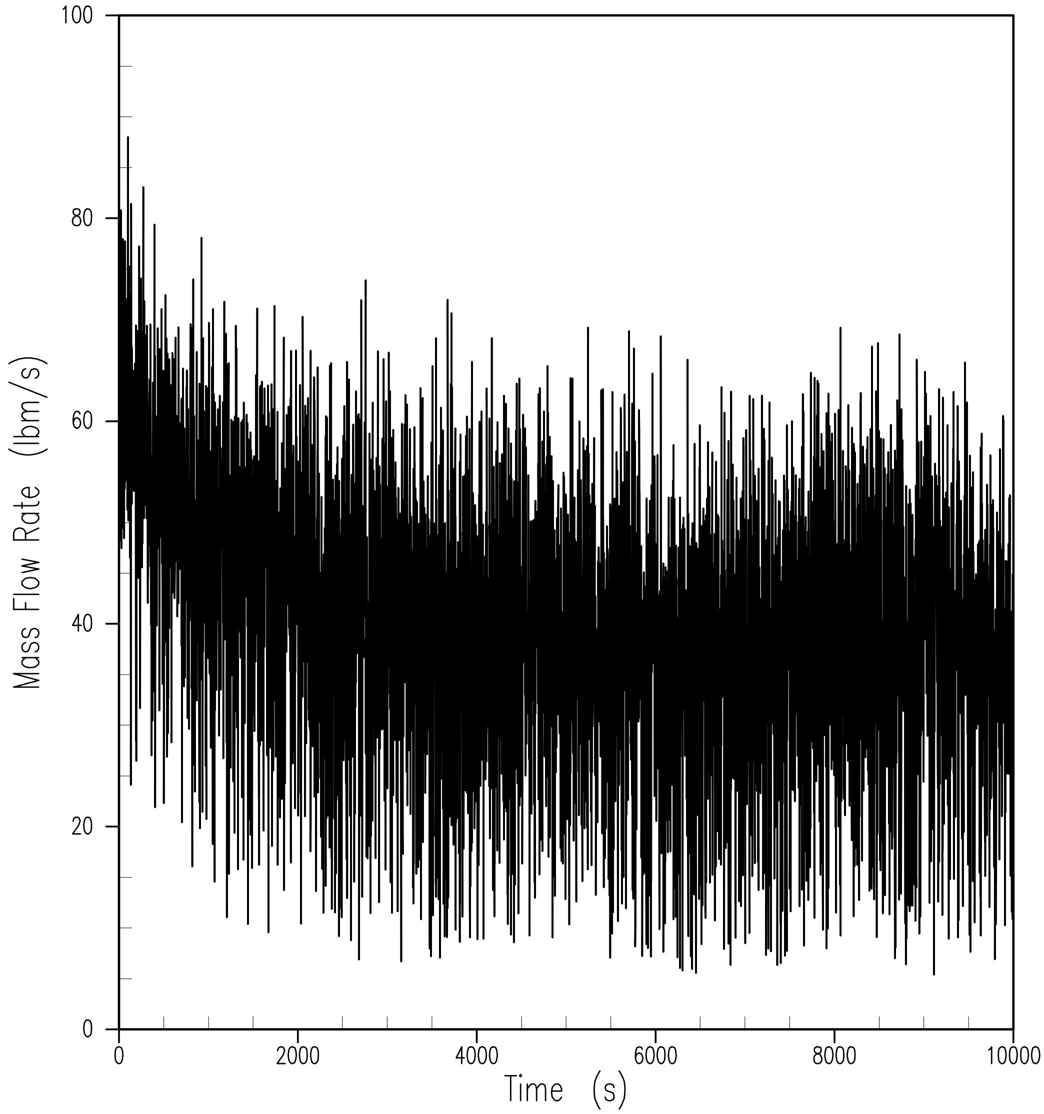

Figure 15.6.5.4C-6

Vapor Rate out of the Core (DEDVI Case)

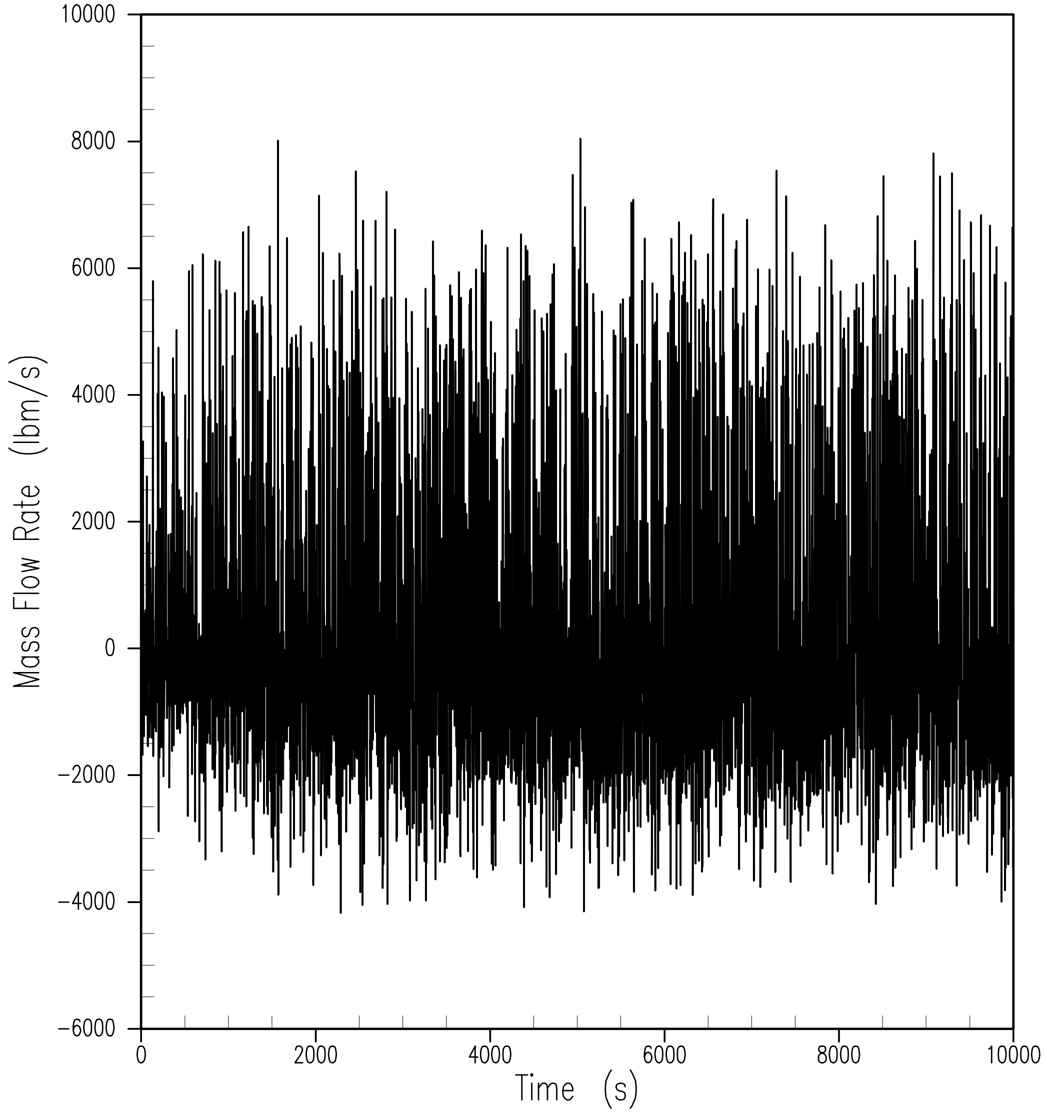

Figure 15.6.5.4C-7

Liquid Flow Rate out of the Core (DEDVI Case)

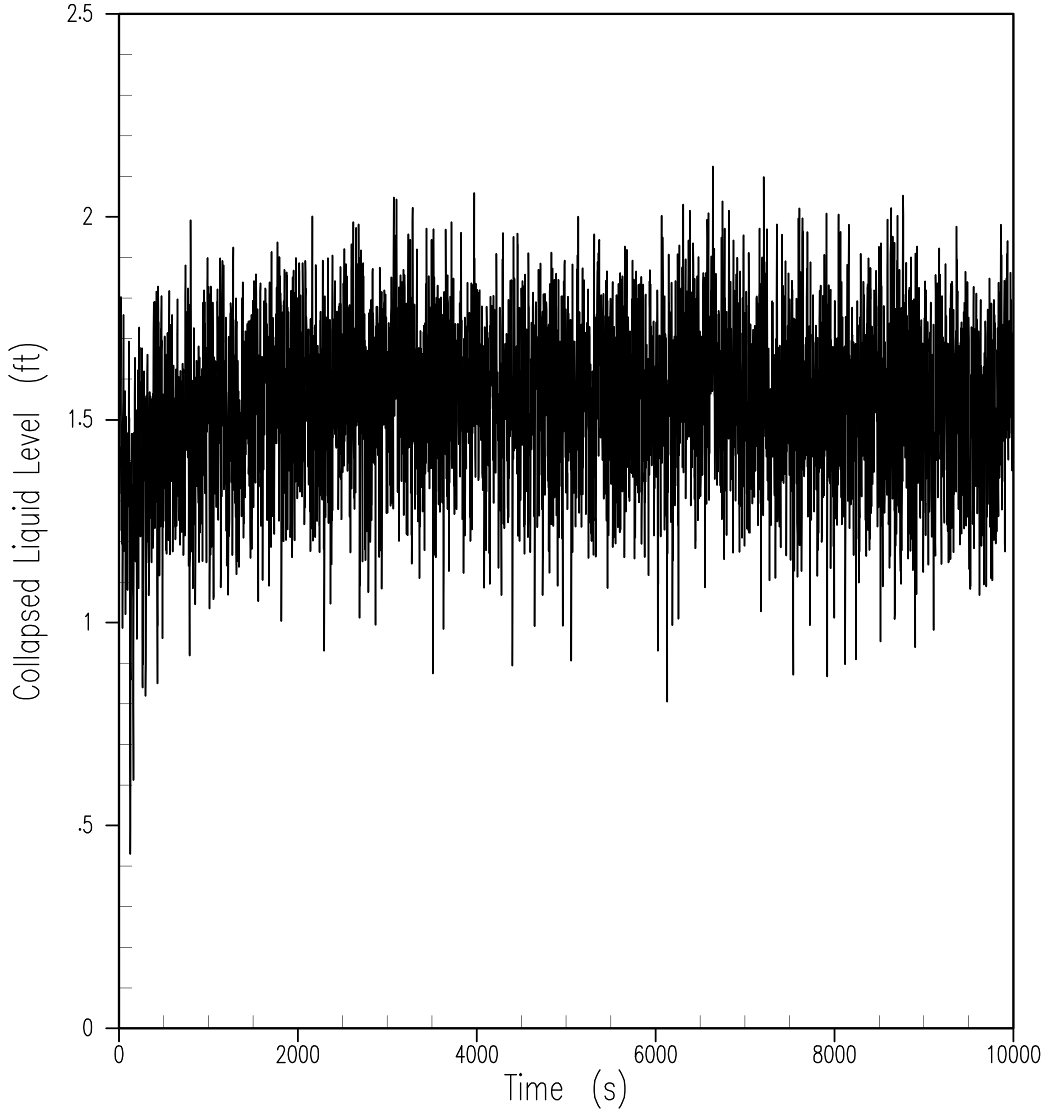

Figure 15.6.5.4C-8

Collapsed Liquid Level in the Upper Plenum (DEDVI Case)

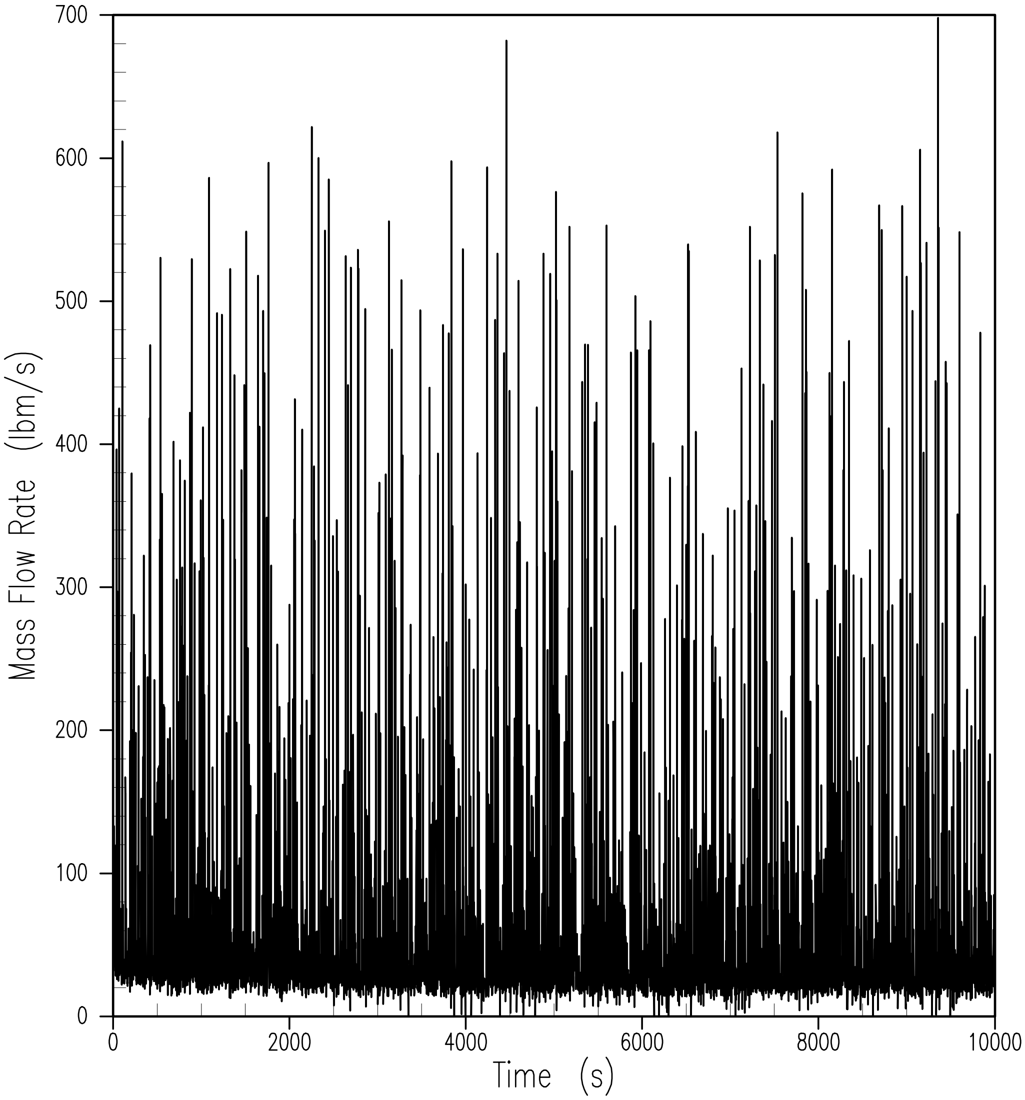

Figure 15.6.5.4C-9

Mixture Flow Rate Through ADS Stage 4A Valves (DEDVI Case)

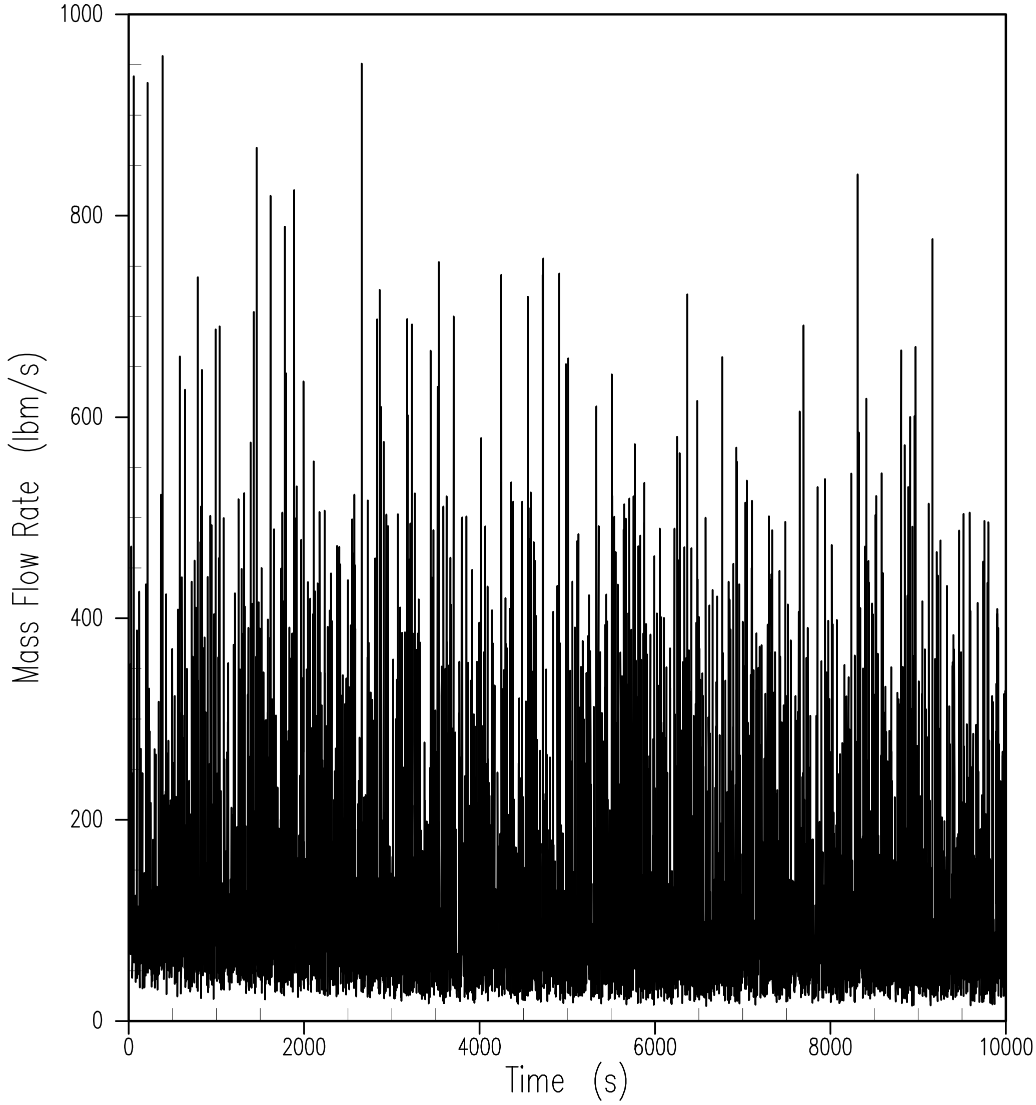

Figure 15.6.5.4C-10

Mixture Flow Rate Through ADS Stage 4B Valves (DEDVI Case)

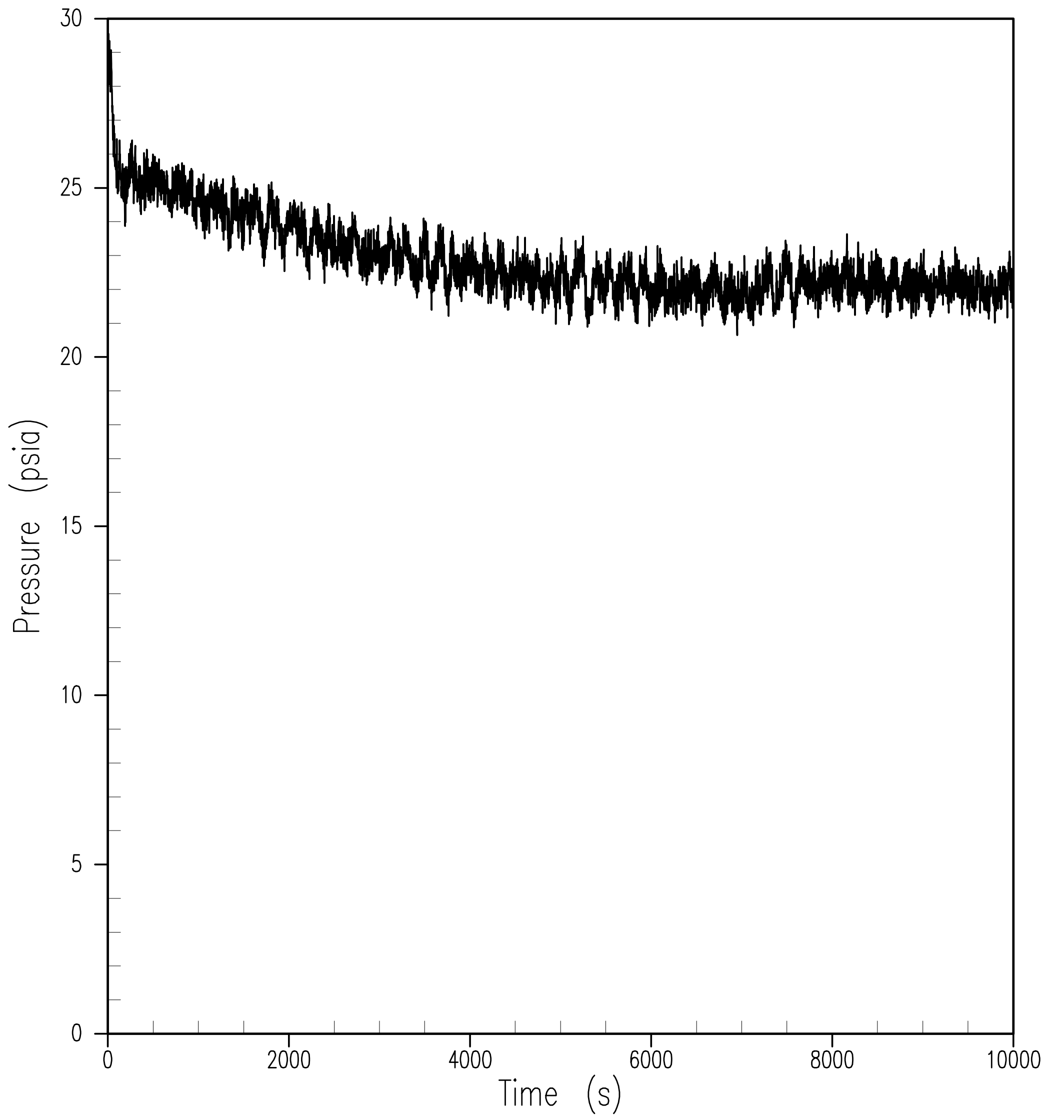

Figure 15.6.5.4C-11

Upper Plenum Pressure (DEDVI Case)

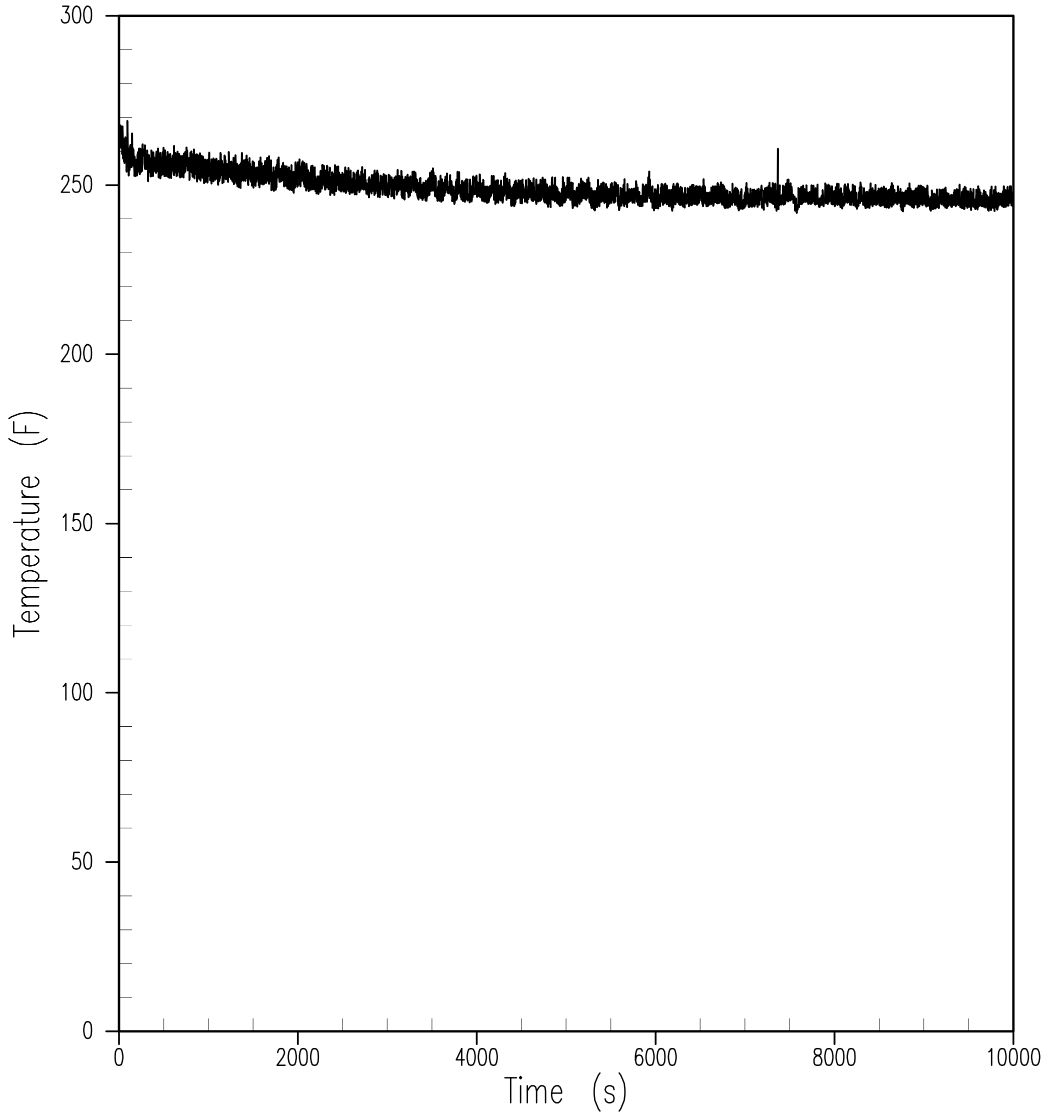

Figure 15.6.5.4C-12

Peak Cladding Temperature
(DEDVI Case)

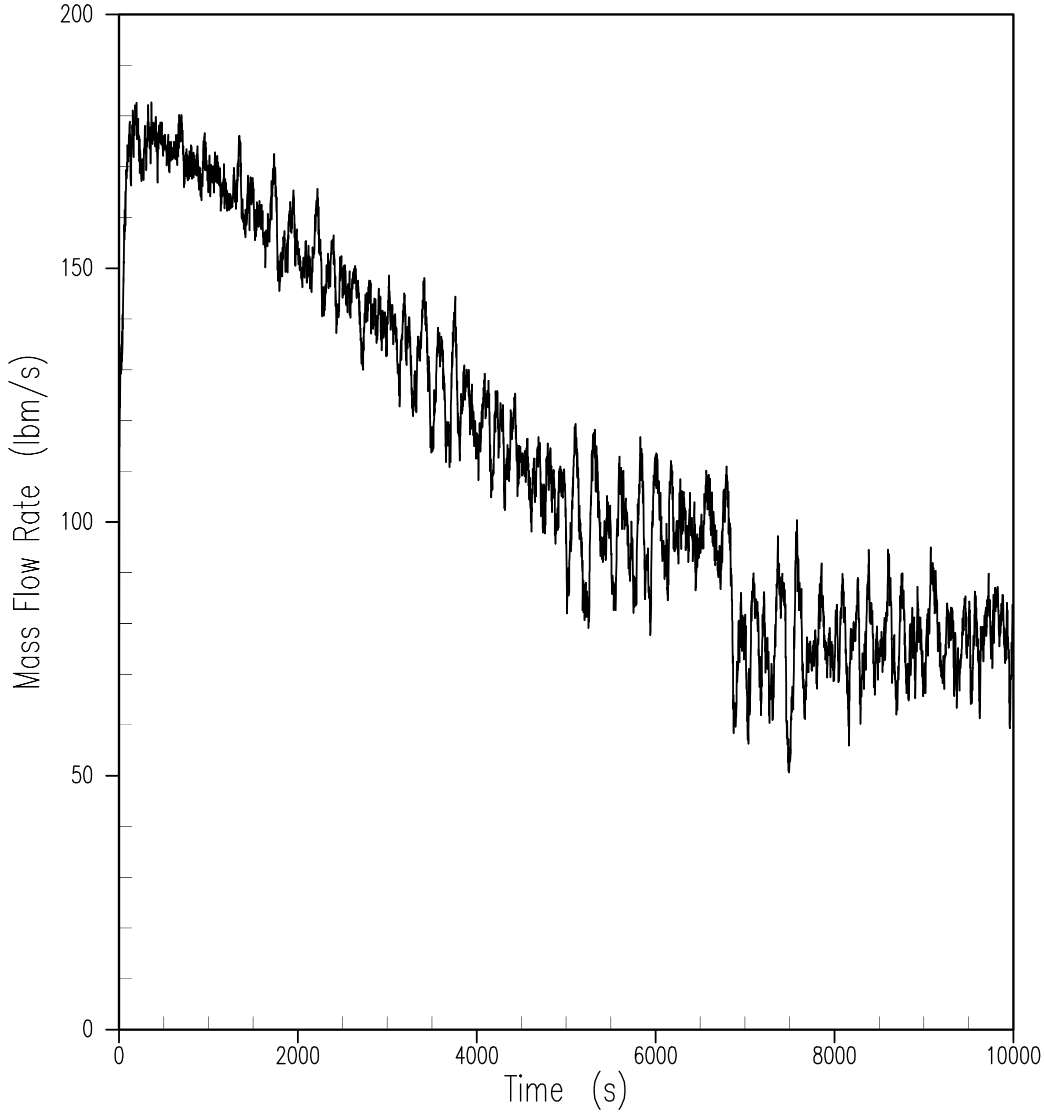

Figure 15.6.5.4C-13

DVI–A Mixture Flow Rate (DEDVI Case)

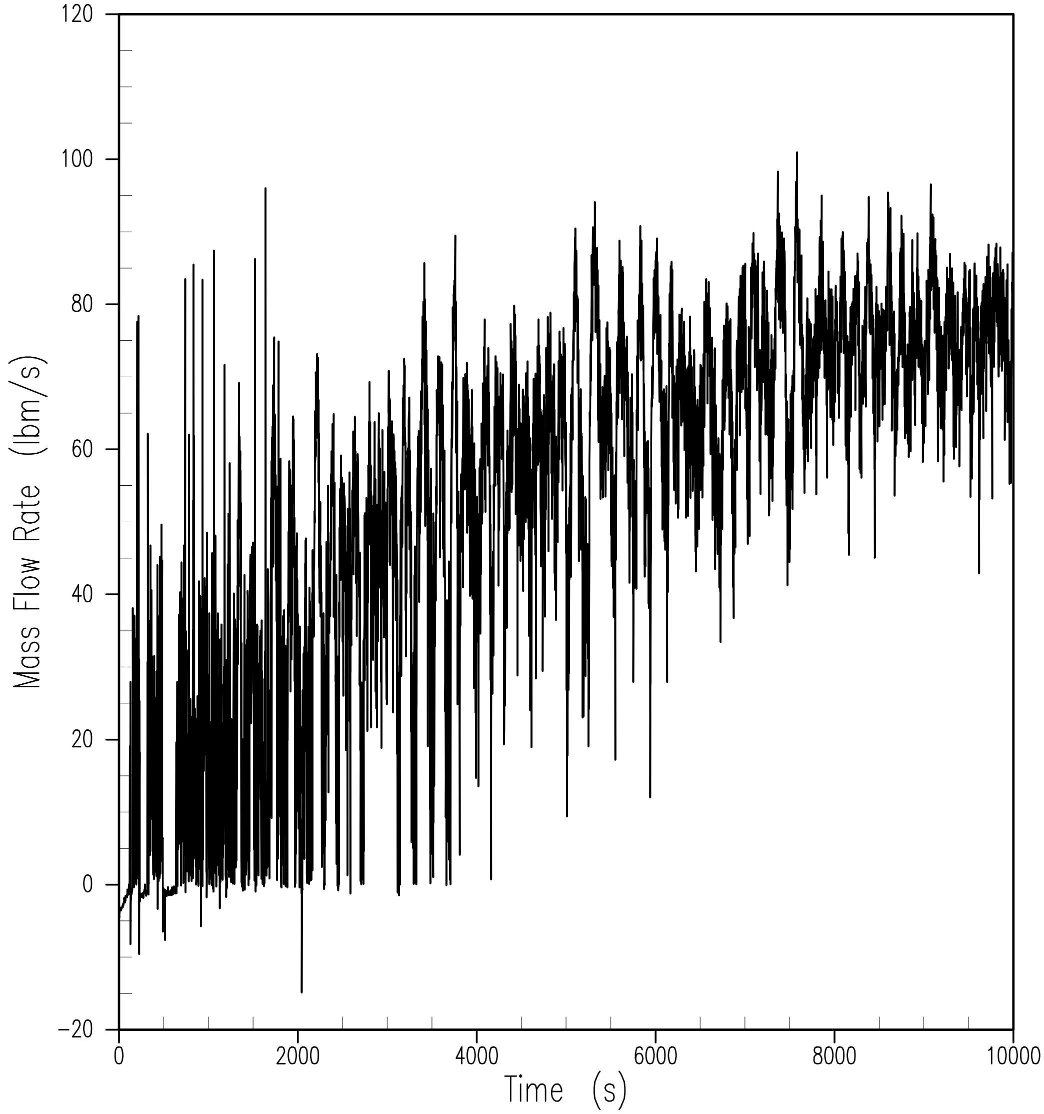

Figure 15.6.5.4C-14

DVI–B Mixture Flow Rate (DEDVI Case)

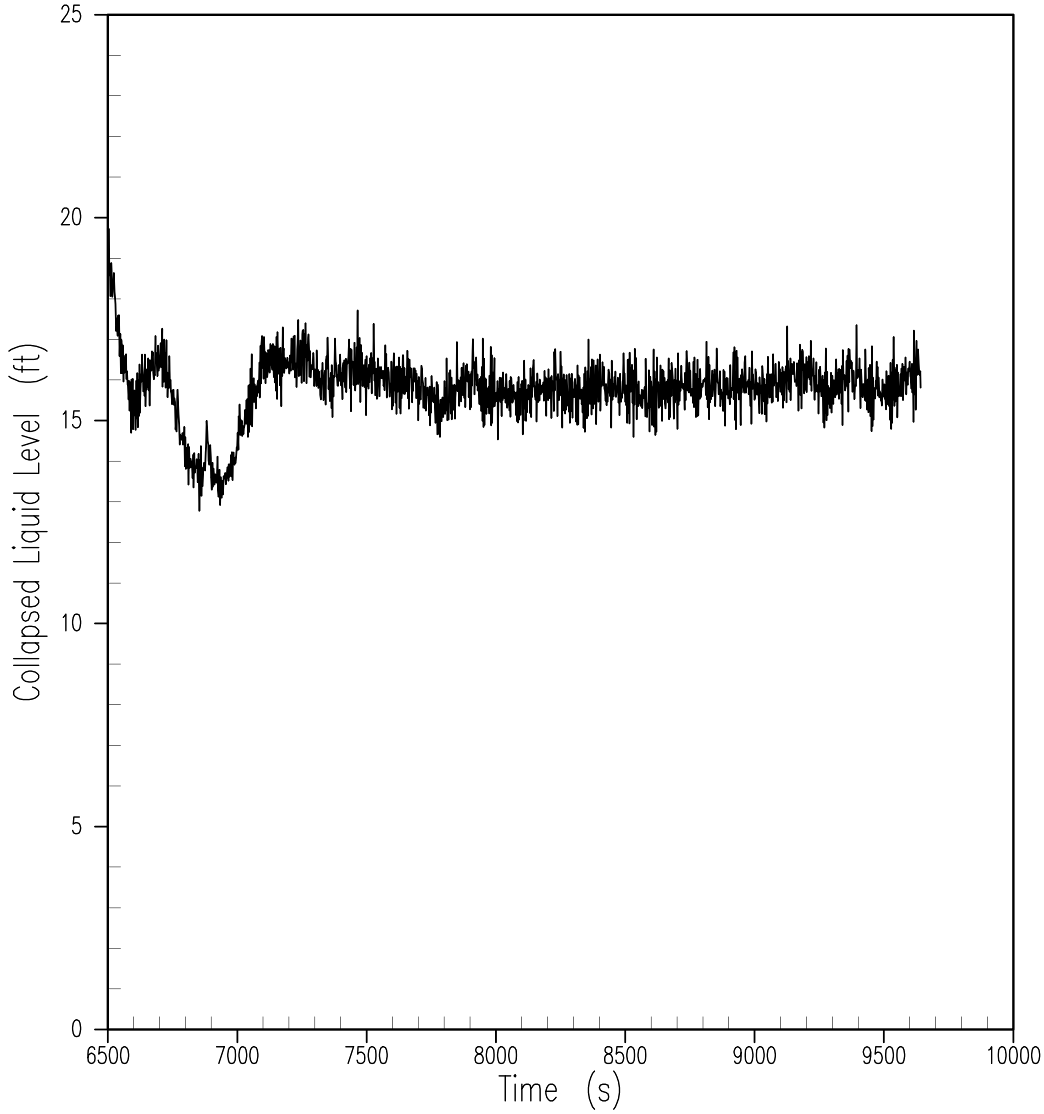

Figure 15.6.5.4C-1A

Collapsed Level of Liquid in the Downcomer (DEDVI Case) – 14.7 psi

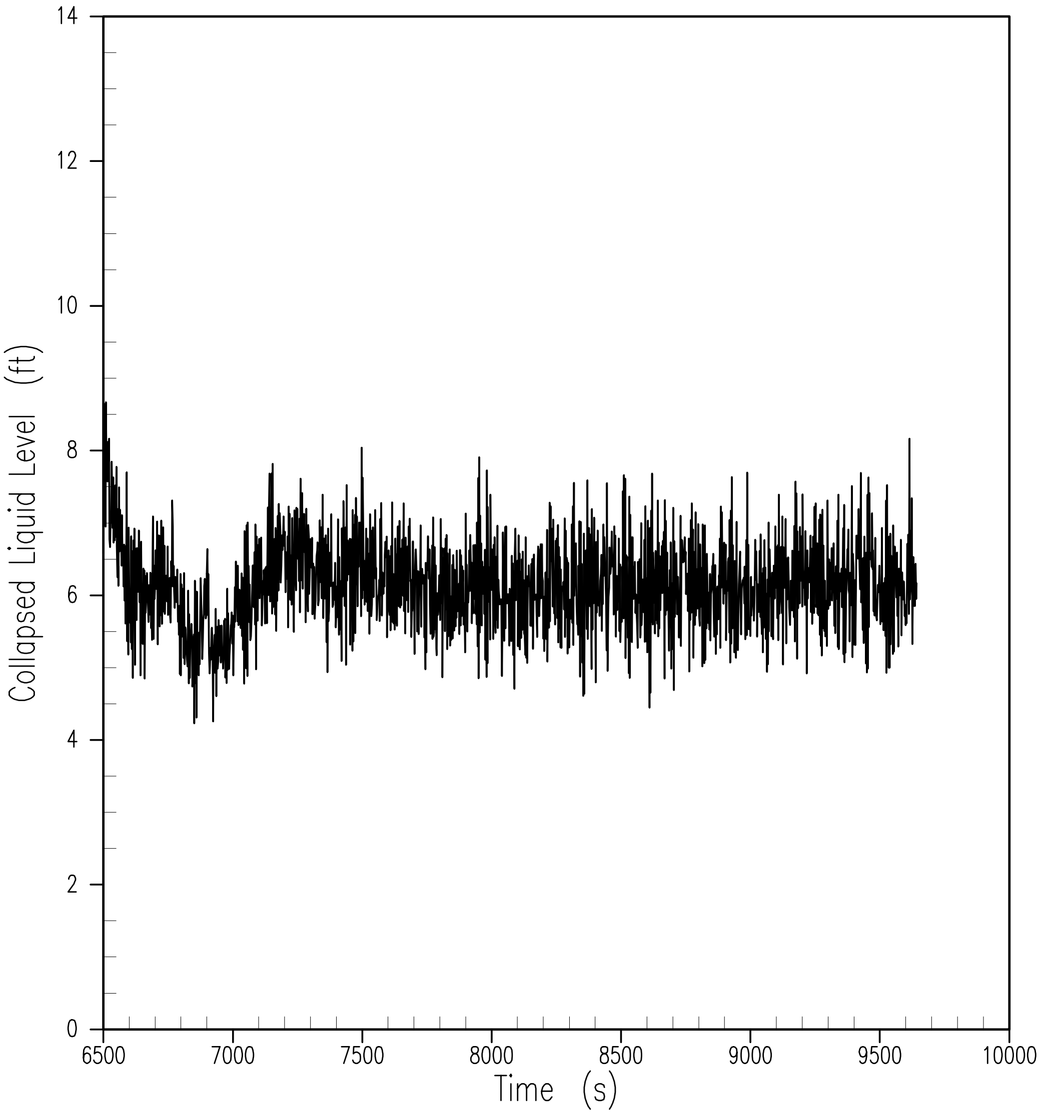

Figure 15.6.5.4C-2A

Collapsed Level of Liquid over the Heated Length of the Fuel (DEDVI Case) – 14.7 psi

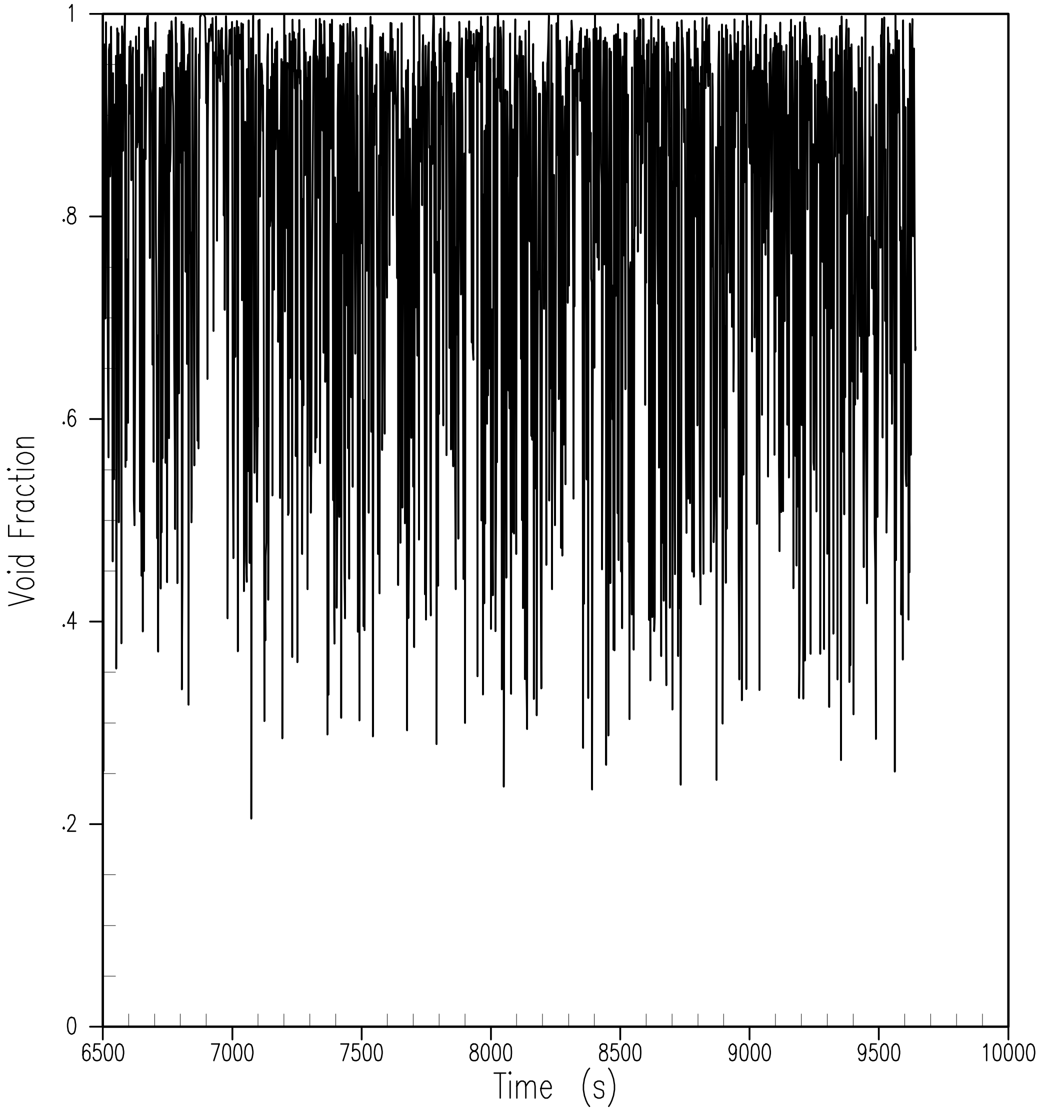

Figure 15.6.5.4C-3A

Void Fraction in Core Hot Assembly Top Cell (DEDVI Case) – 14.7 psi

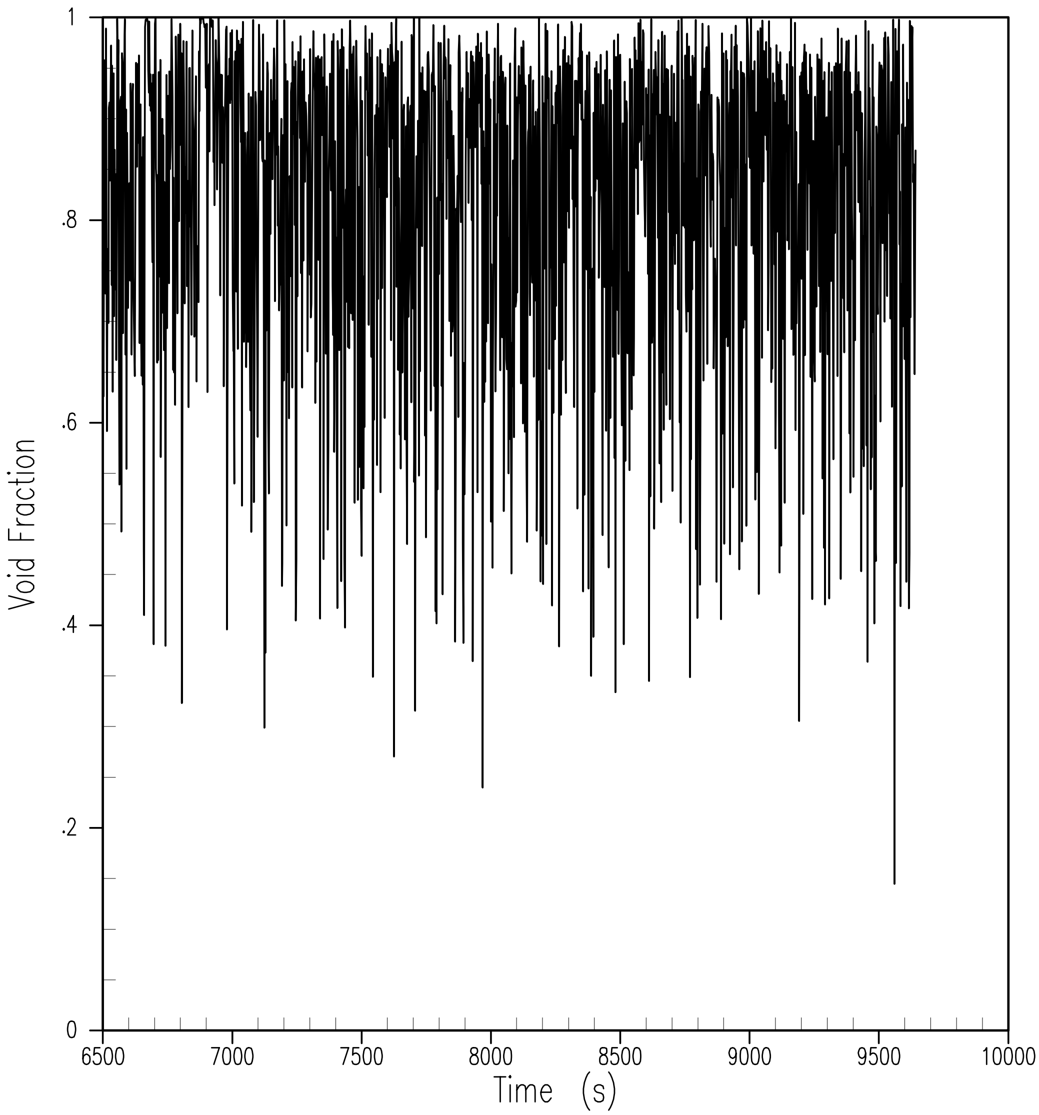

Figure 15.6.5.4C-4A

Void Fraction in Core Hot Assembly Second from Top Cell (DEDVI Case) – 14.7 psi

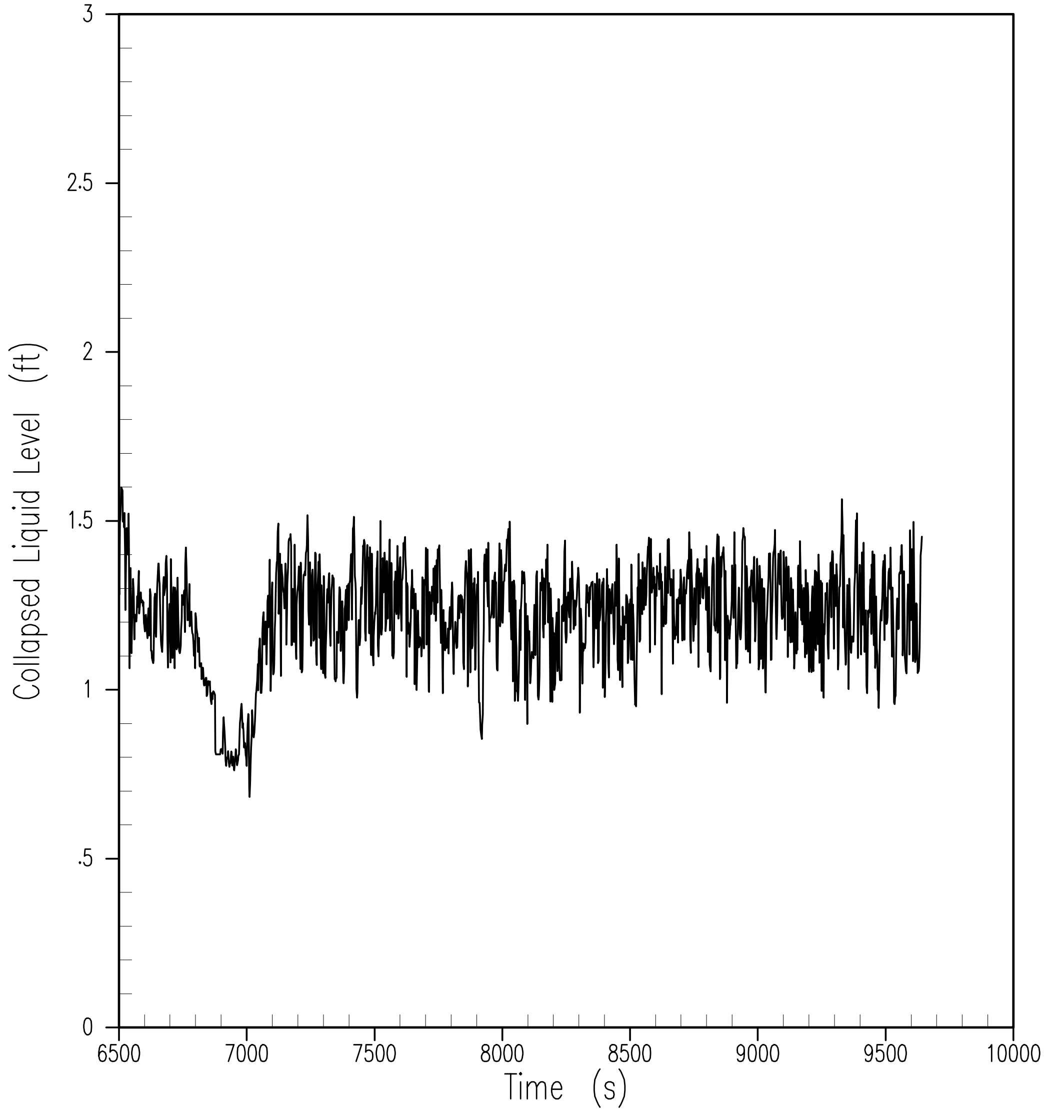

Figure 15.6.5.4C-5A

Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (DEDVI Case) – 14.7 psi

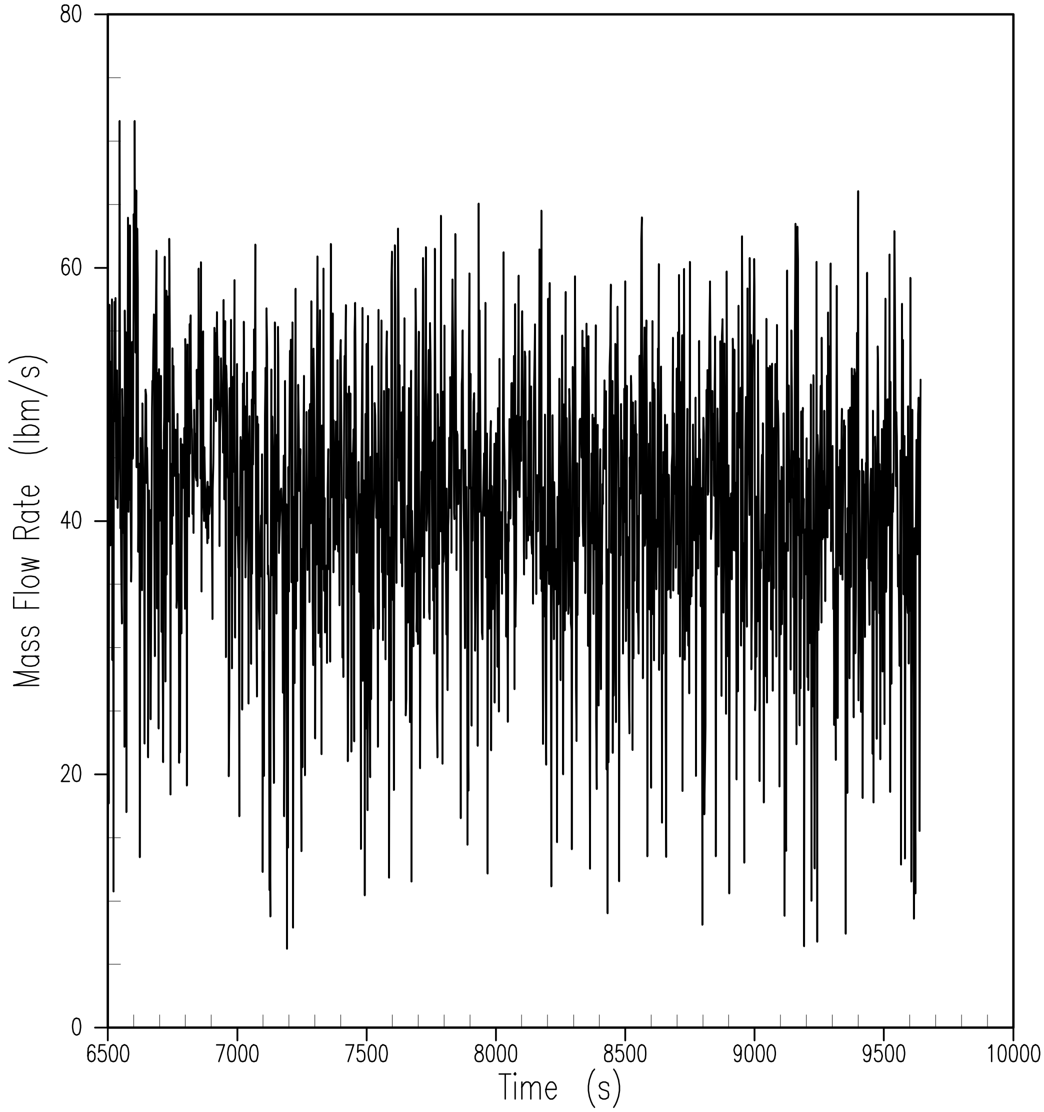

Figure 15.6.5.4C-6A

Vapor Rate out of the Core (DEDVI Case) – 14.7 psi

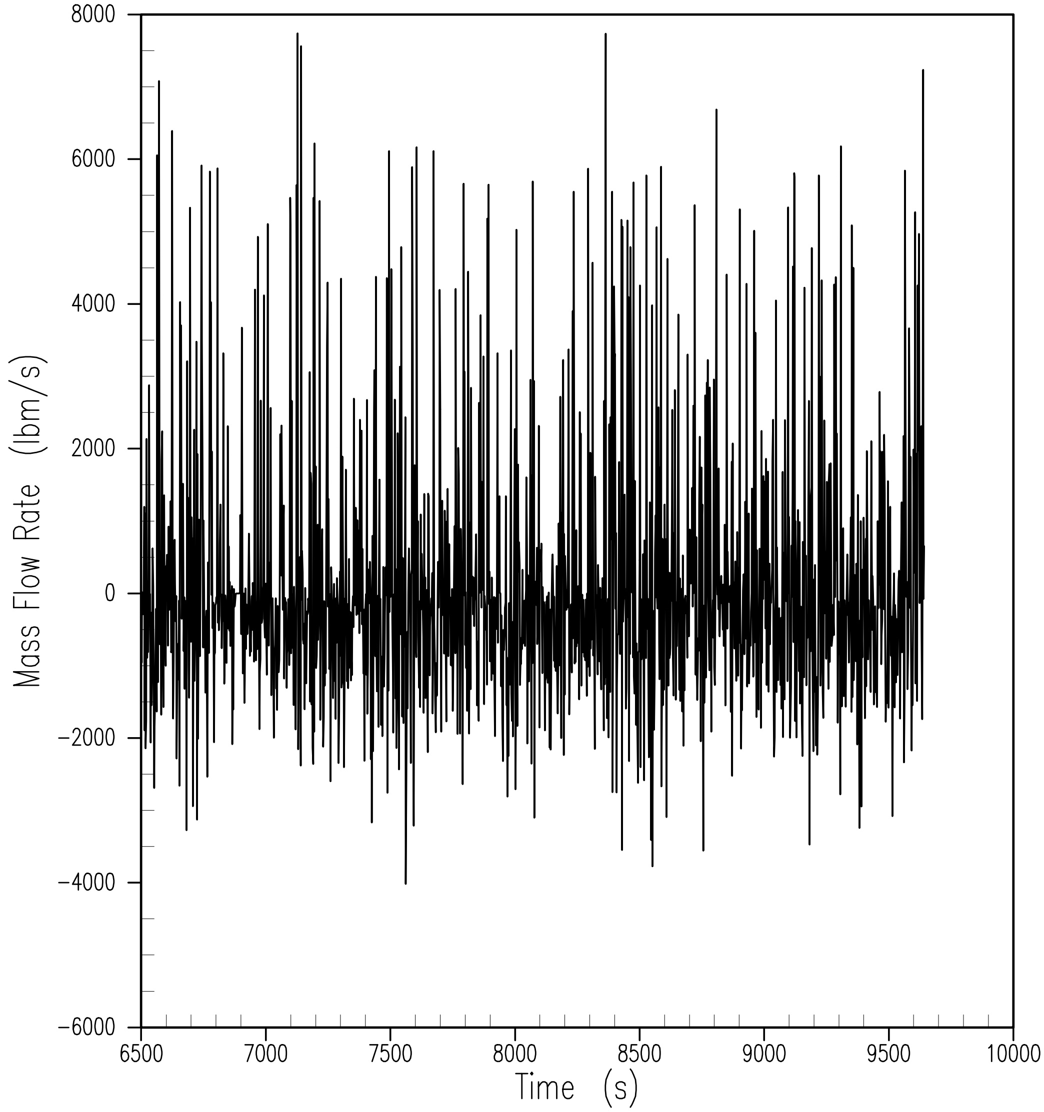

Figure 15.6.5.4C-7A

Liquid Flow Rate out of the Core (DEDVI Case) – 14.7 psi

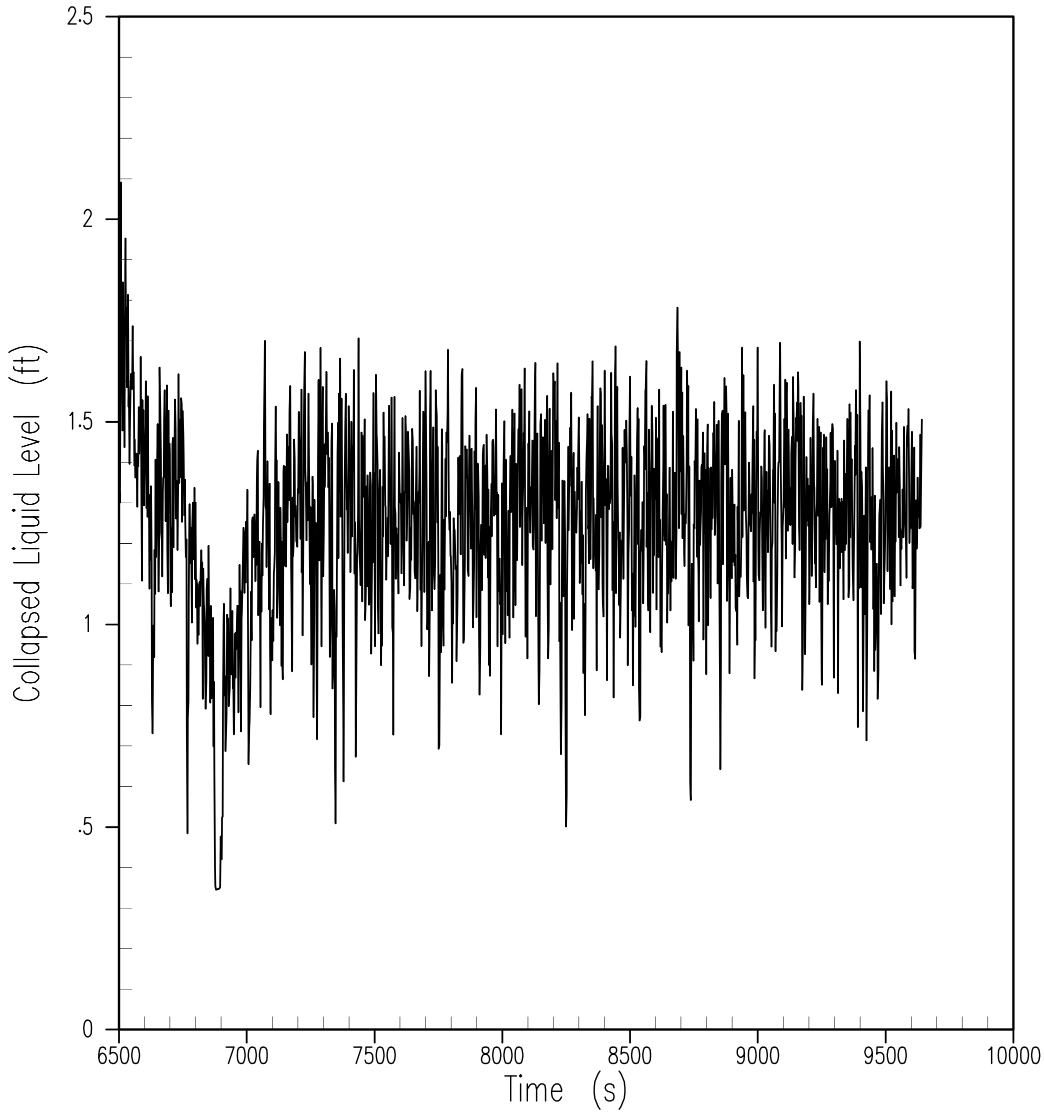

Figure 15.6.5.4C-8A

Collapsed Liquid Level in the Upper Plenum (DEDVI Case) – 14.7 psi

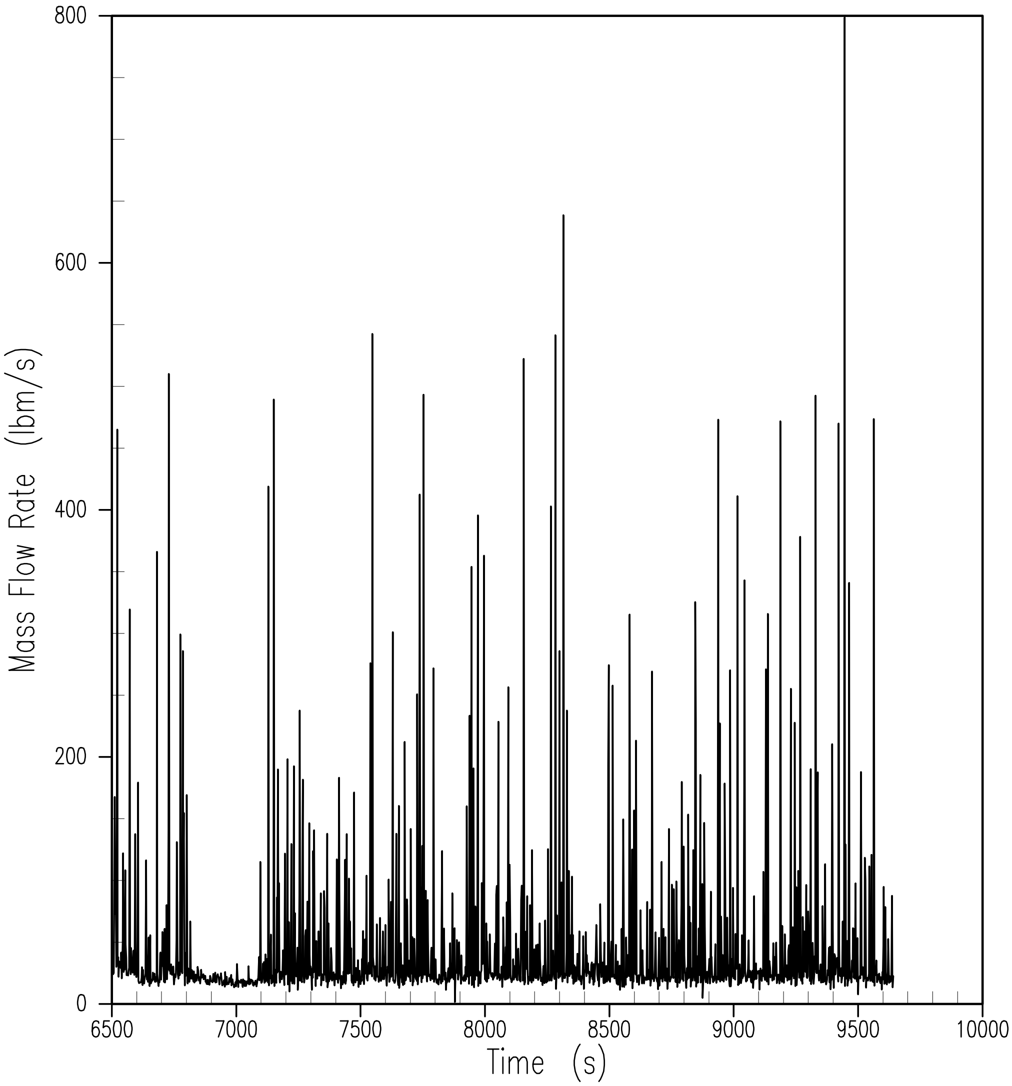

Figure 15.6.5.4C-9A

Mixture Flow Rate Through ADS Stage 4A Valves (DEDVI Case) – 14.7 psi

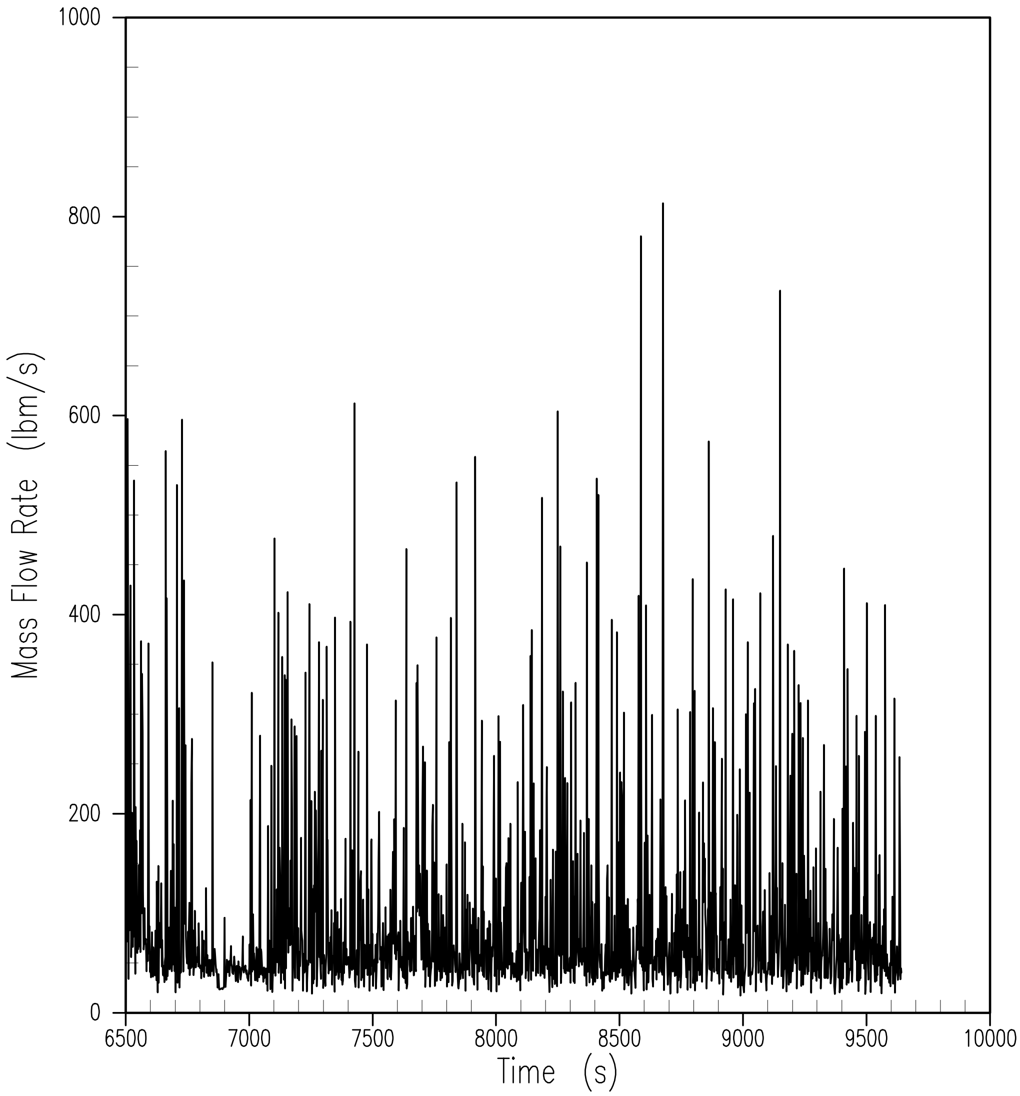

Figure 15.6.5.4C-10A

Mixture Flow Rate Through ADS Stage 4B Valves (DEDVI Case) – 14.7 psi

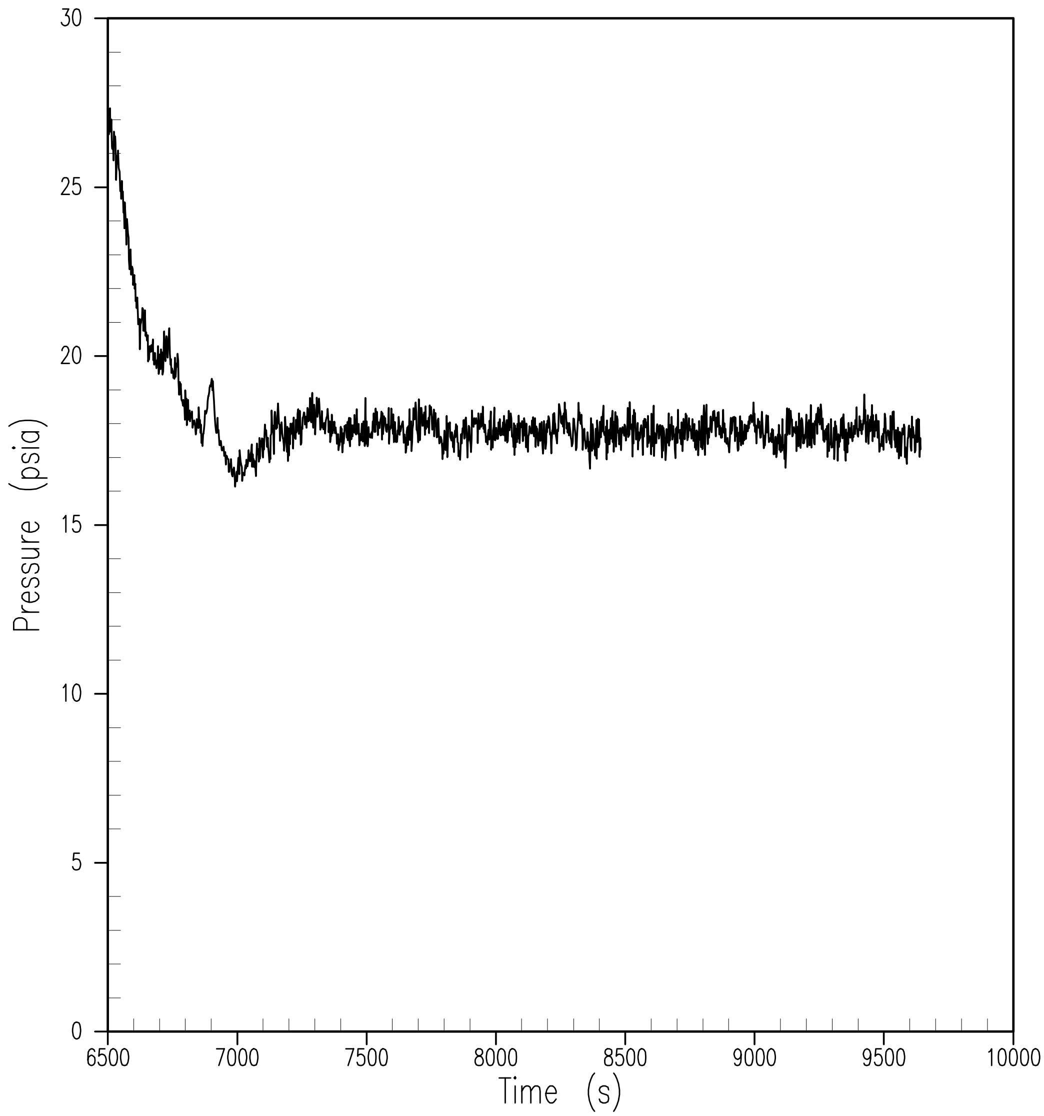

Figure 15.6.5.4C-11A

Upper Plenum Pressure (DEDVI Case) – 14.7 psi

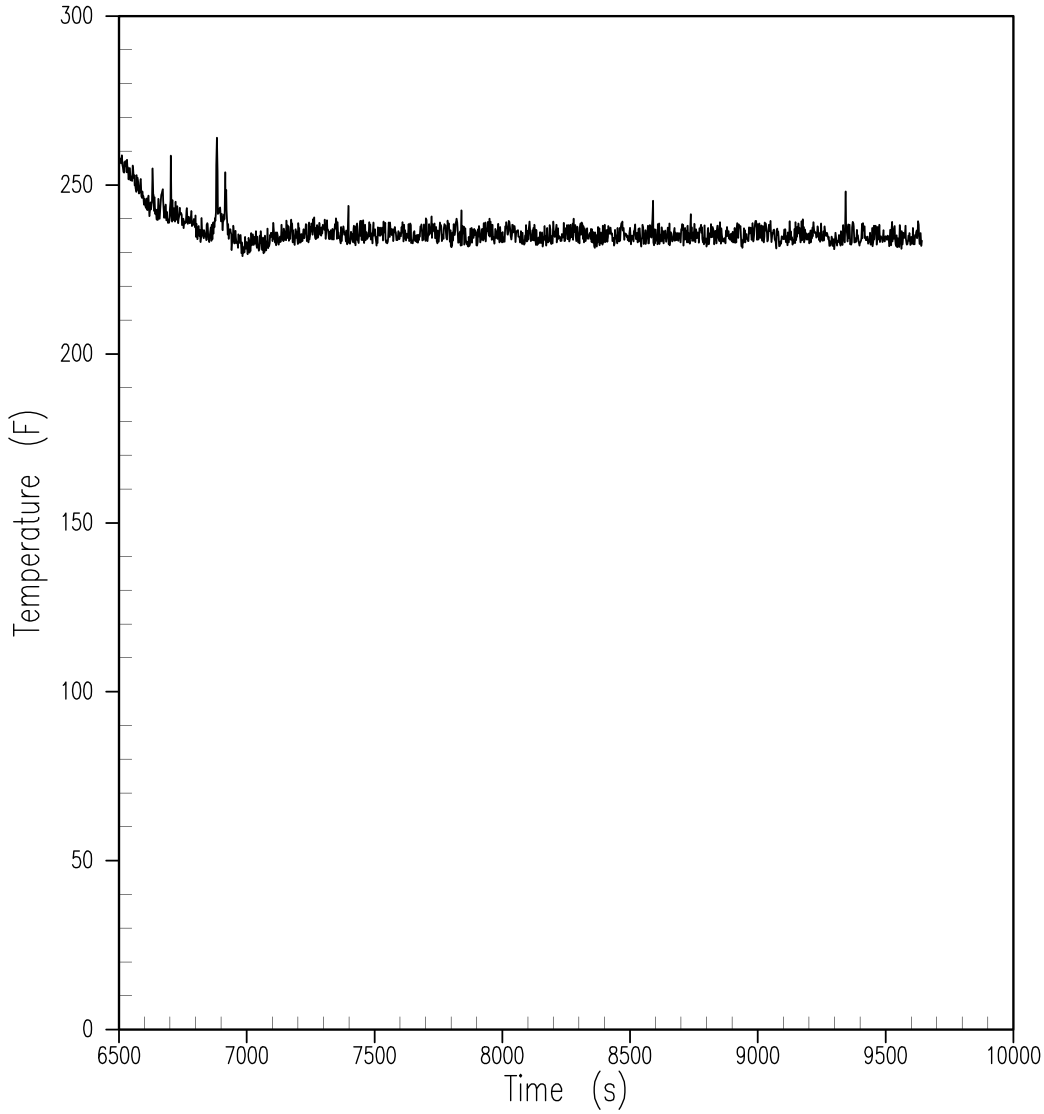

Figure 15.6.5.4C-12A

Peak Cladding Temperature (DEDVI Case) – 14.7 psi

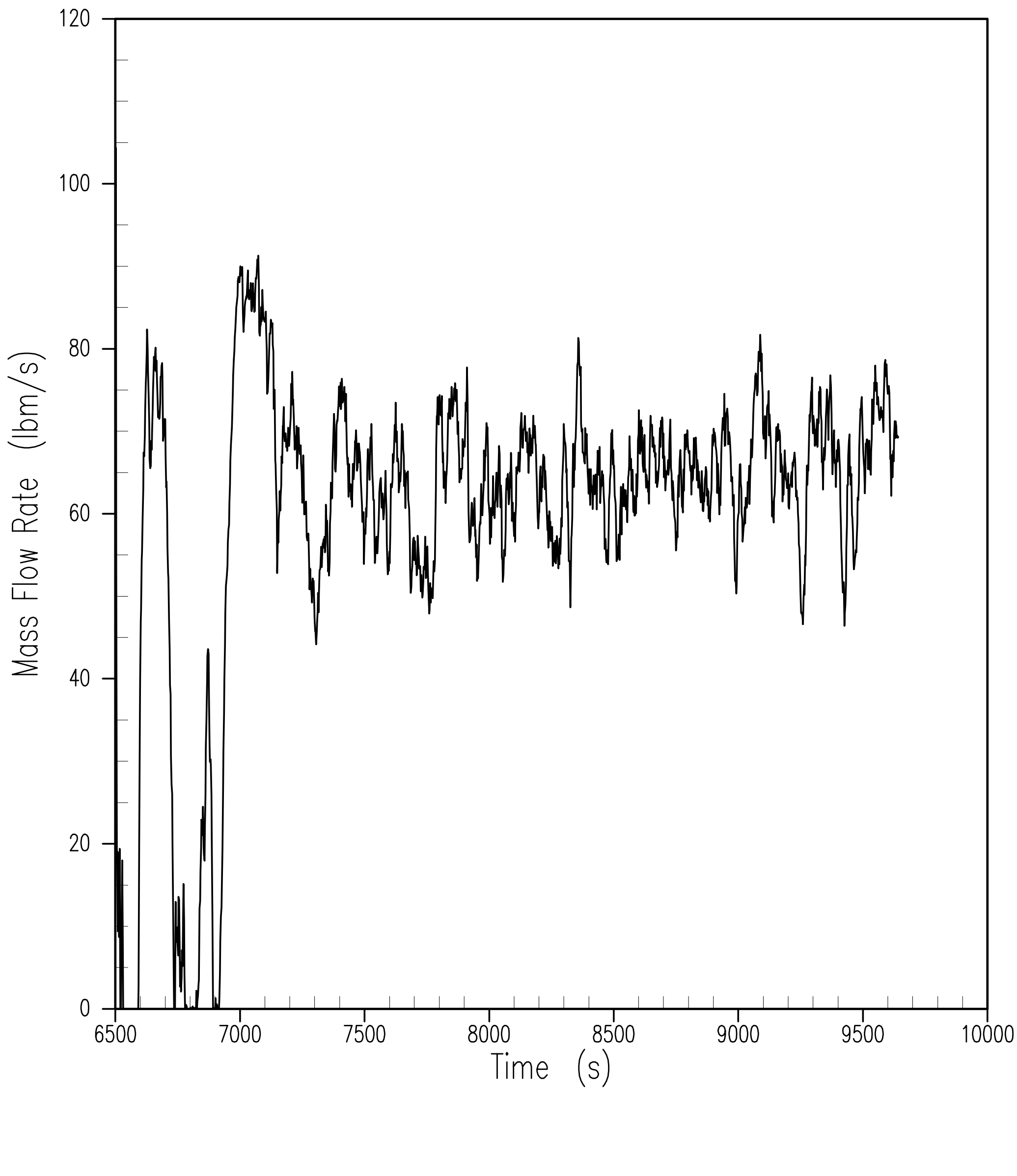

Figure 15.6.5.4C-13A

DVI–A Mixture Flow Rate (DEDVI Case) – 14.7 psi

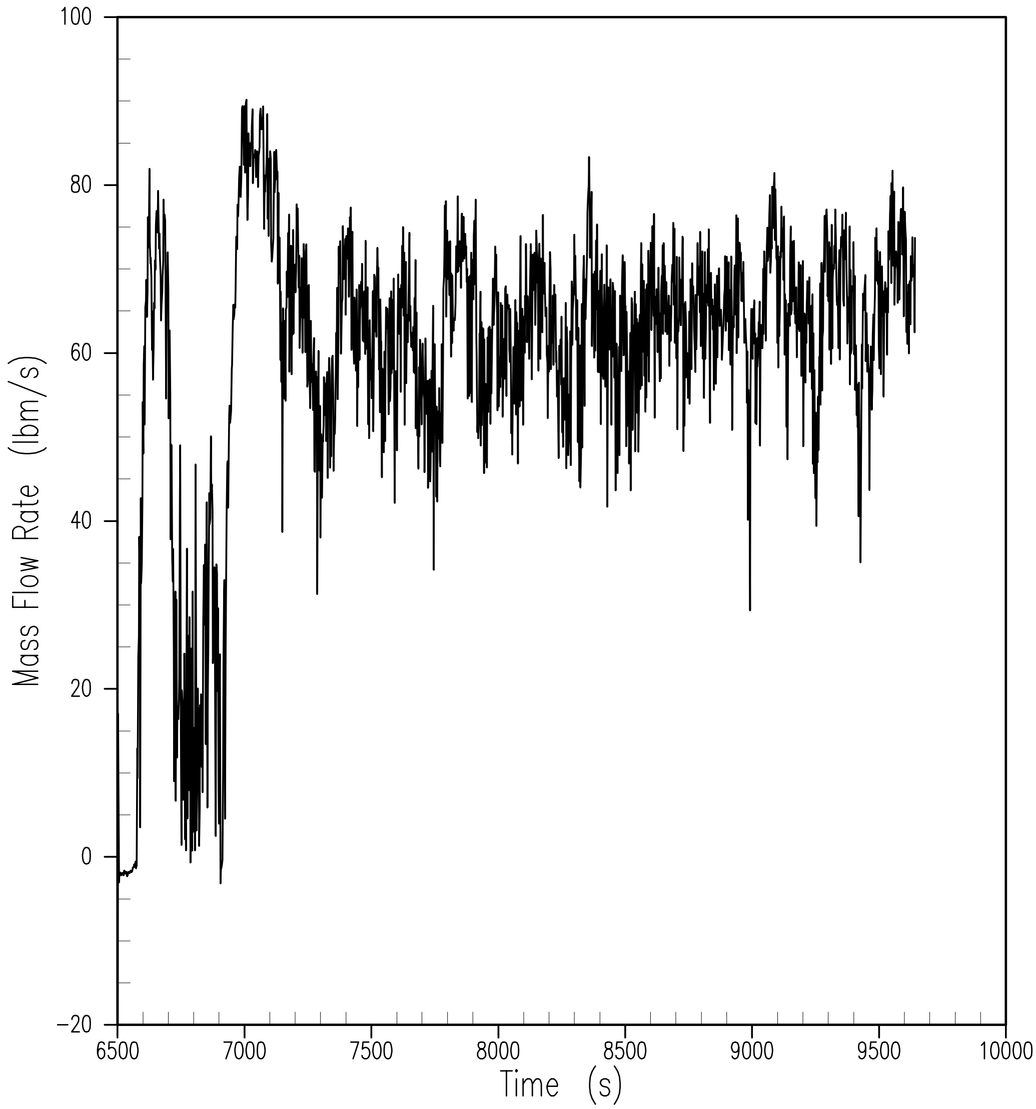

Figure 15.6.5.4C-14A

DVI–B Mixture Flow Rate (DEDVI Case) – 14.7 psi

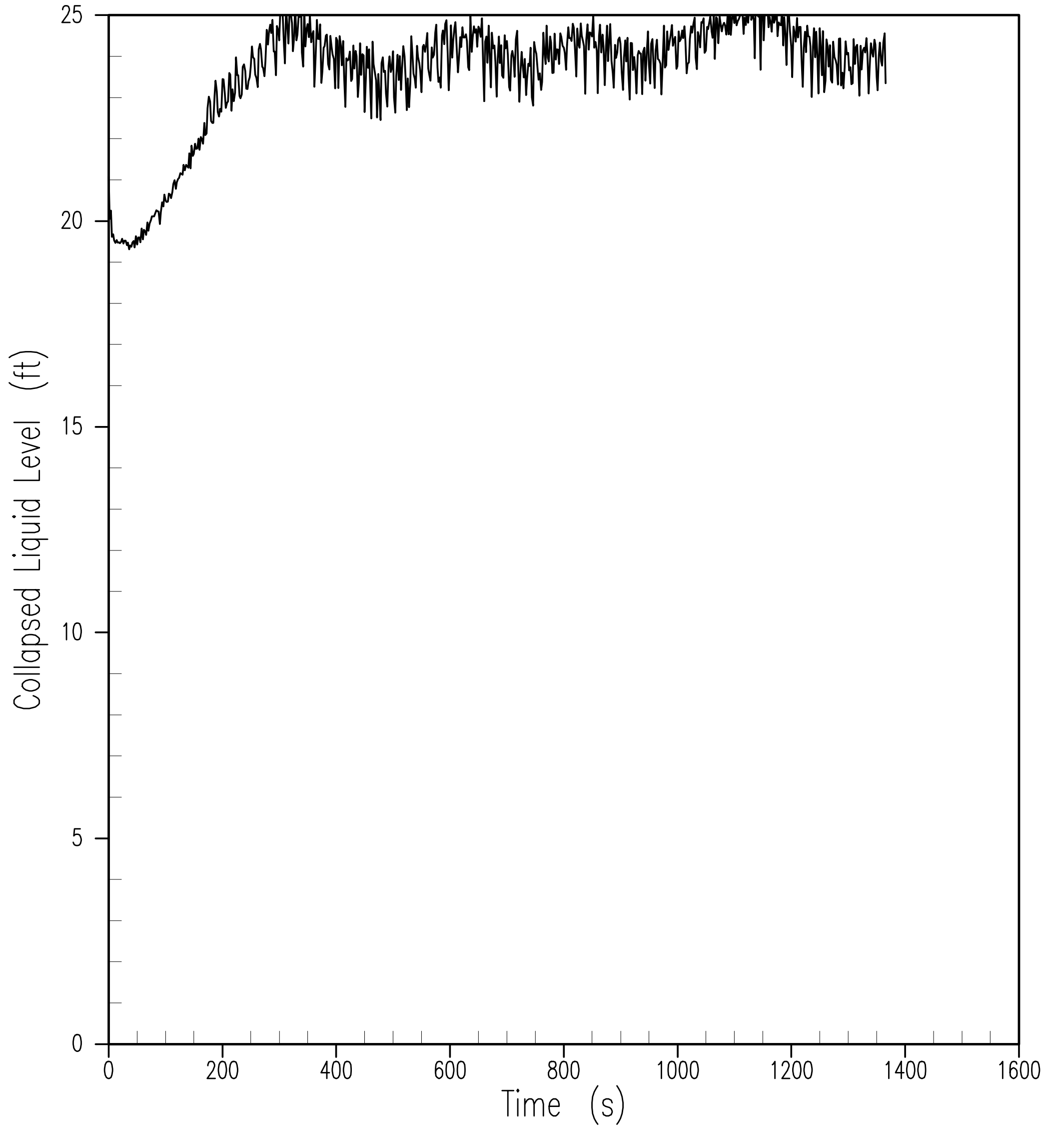

Figure 15.6.5.4C-15

Collapsed Level of Liquid in the Downcomer (Wall-to-Wall Floodup Case) – 14.7 psi

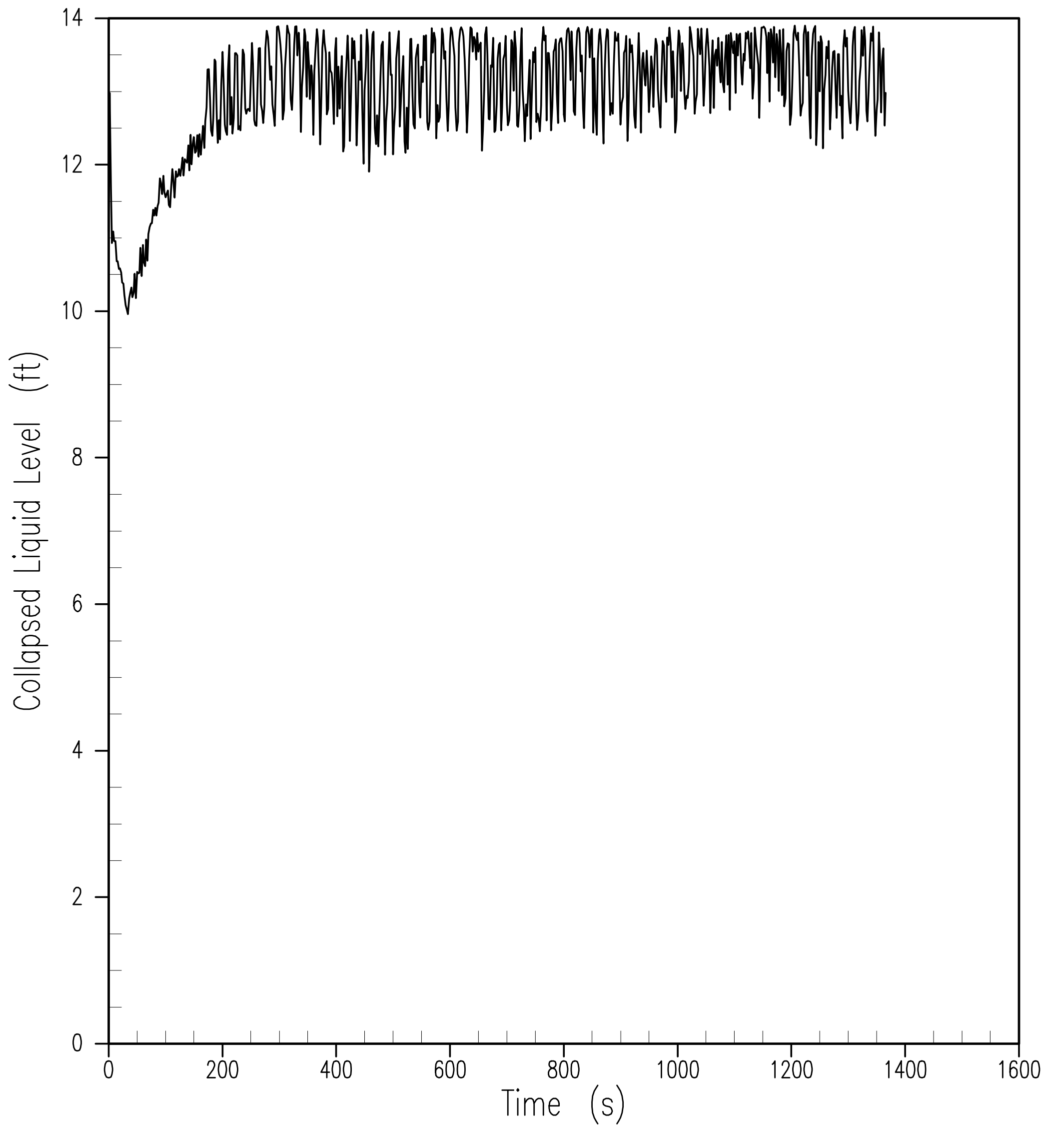

Figure 15.6.5.4C-16

Collapsed Level of Liquid Over the Heated Length of the Fuel (Wall-to-Wall Floodup Case) – 14.7 psi

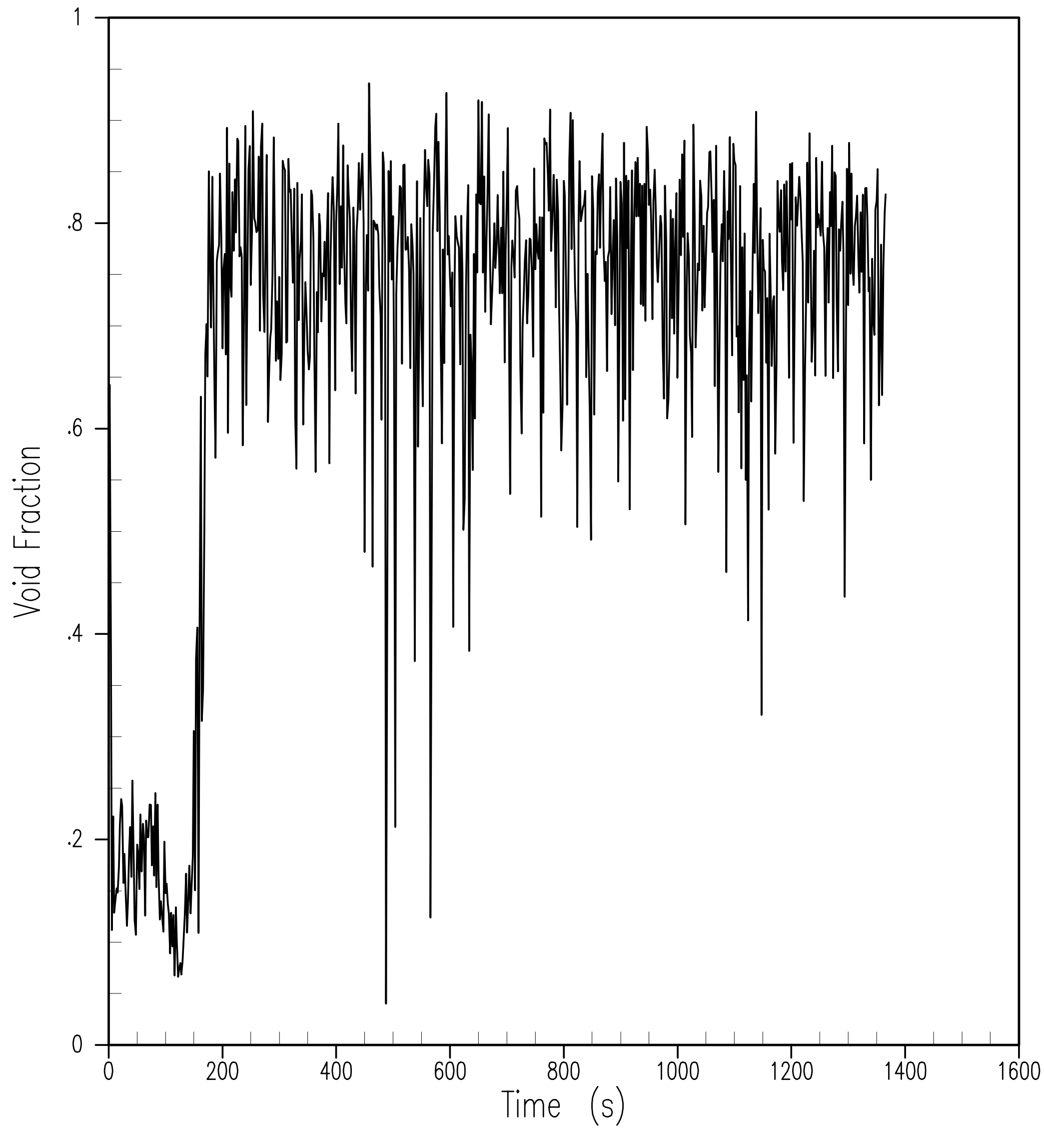

Figure 15.6.5.4C-17

Void Fraction in Core Hot Assembly Top Cell (Wall-to-Wall Floodup Case) – 14.7 psi

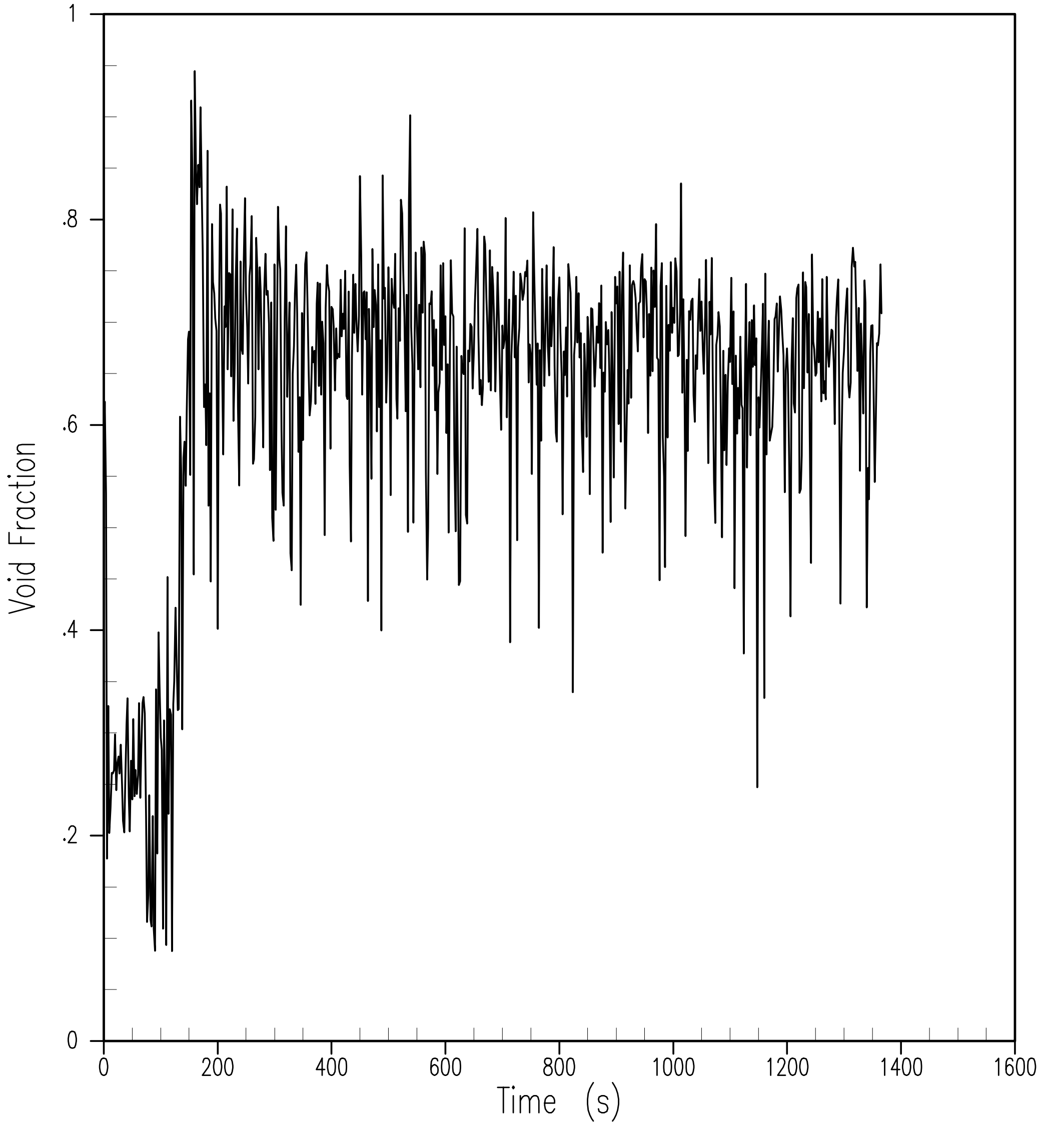

Figure 15.6.5.4C-18

Void Fraction in Core Hot Assembly Second from Top Cell (Wall-to-Wall Floodup Case) – 14.7 psi

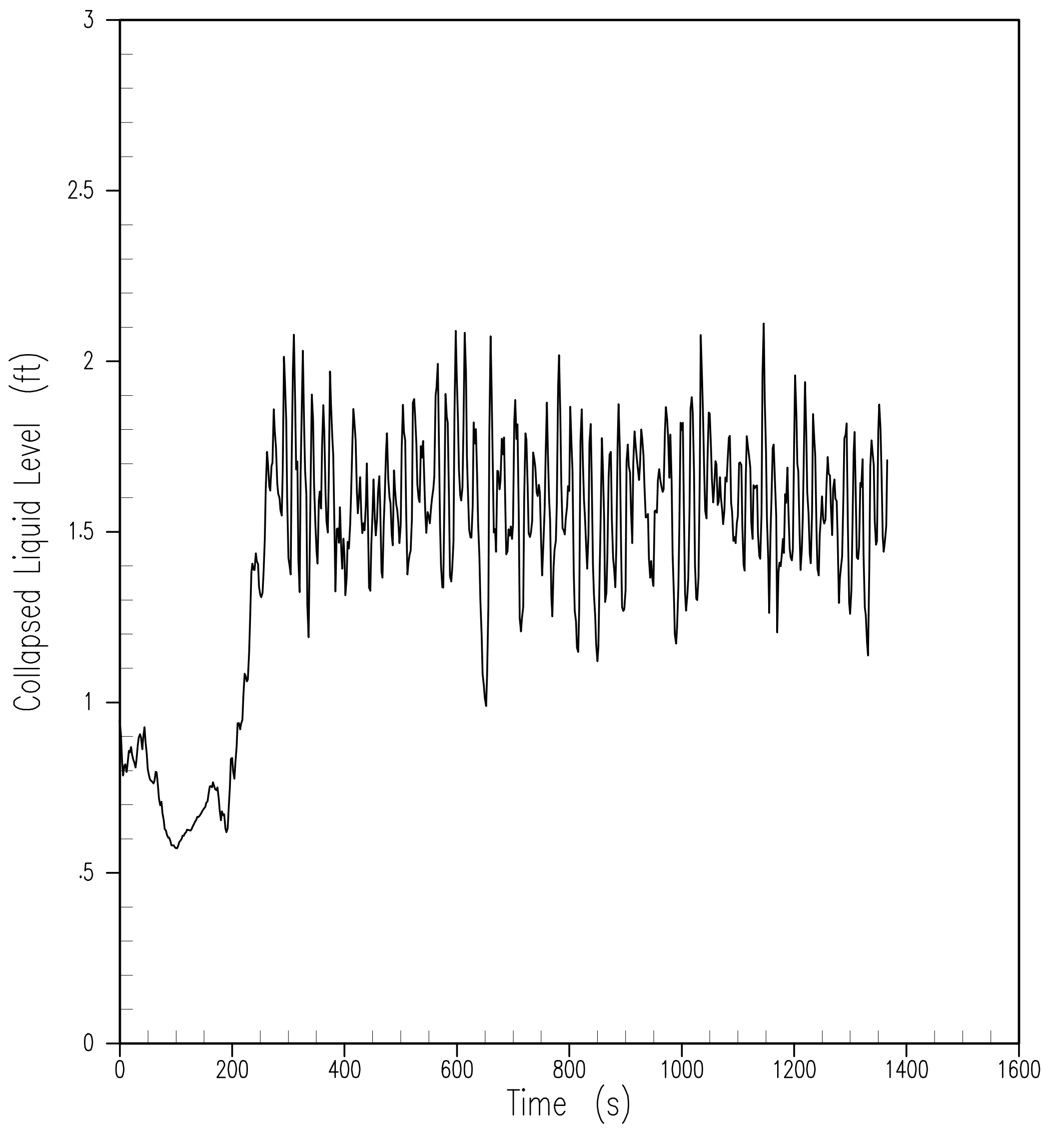

Figure 15.6.5.4C-19

Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (Wall-to-Wall Floodup Case) – 14.7 psi

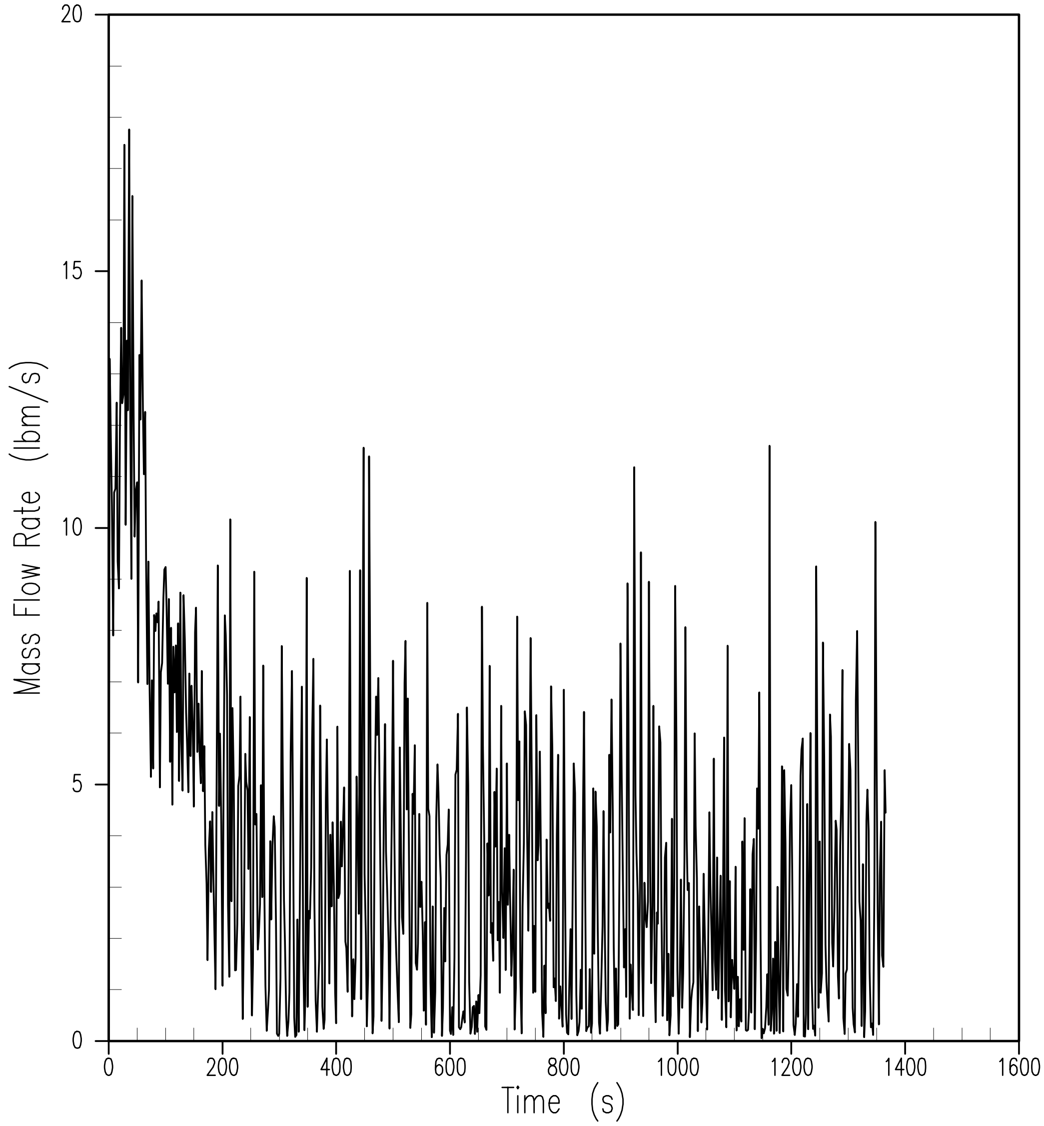

Figure 15.6.5.4C-20

Vapor Rate out of the Core
(Wall-to-Wall Floodup Case) – 14.7 psi

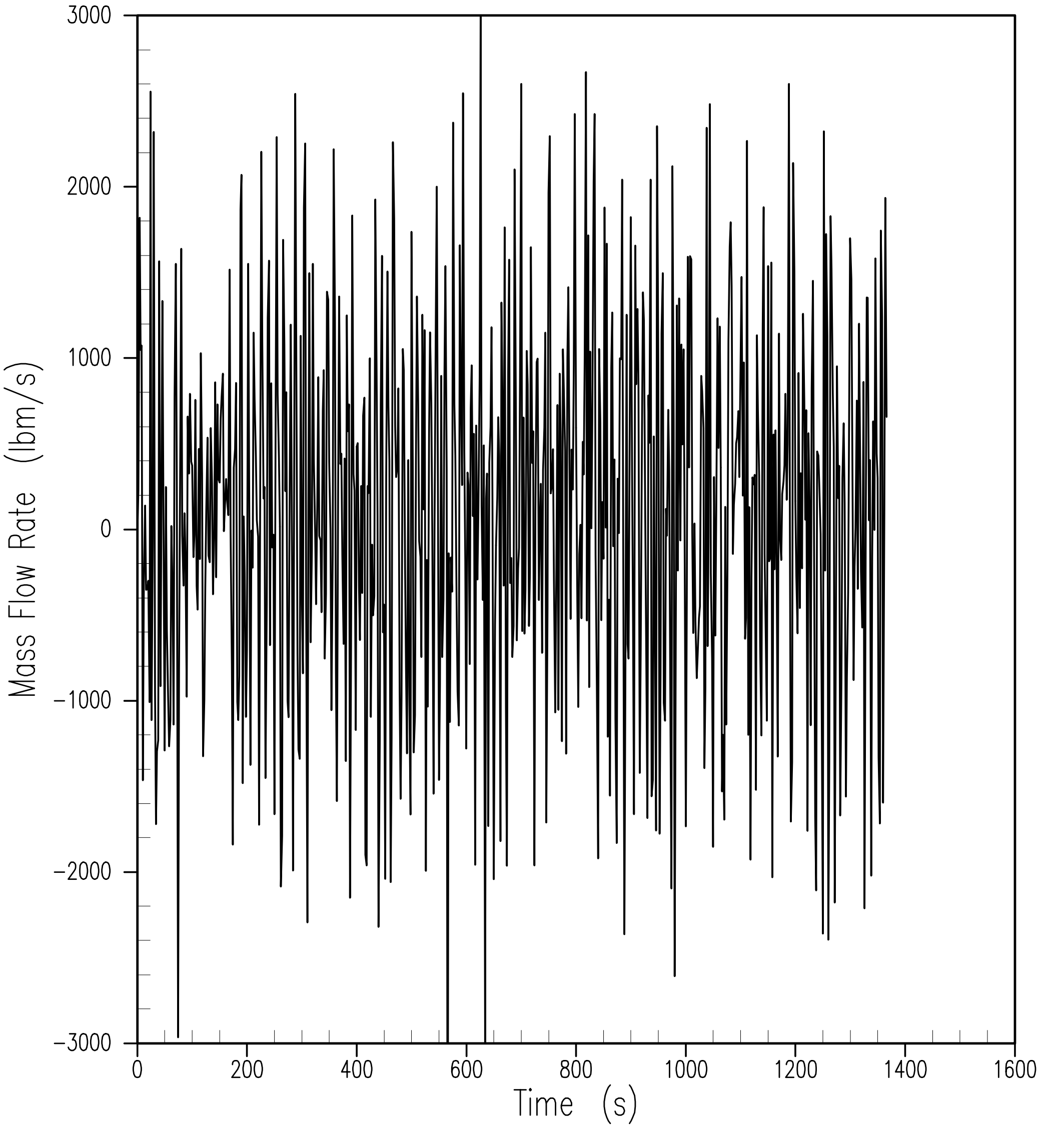

Figure 15.6.5.4C-21

Liquid Flow Rate out of the Core (Wall-to-Wall Floodup Case) – 14.7 psi

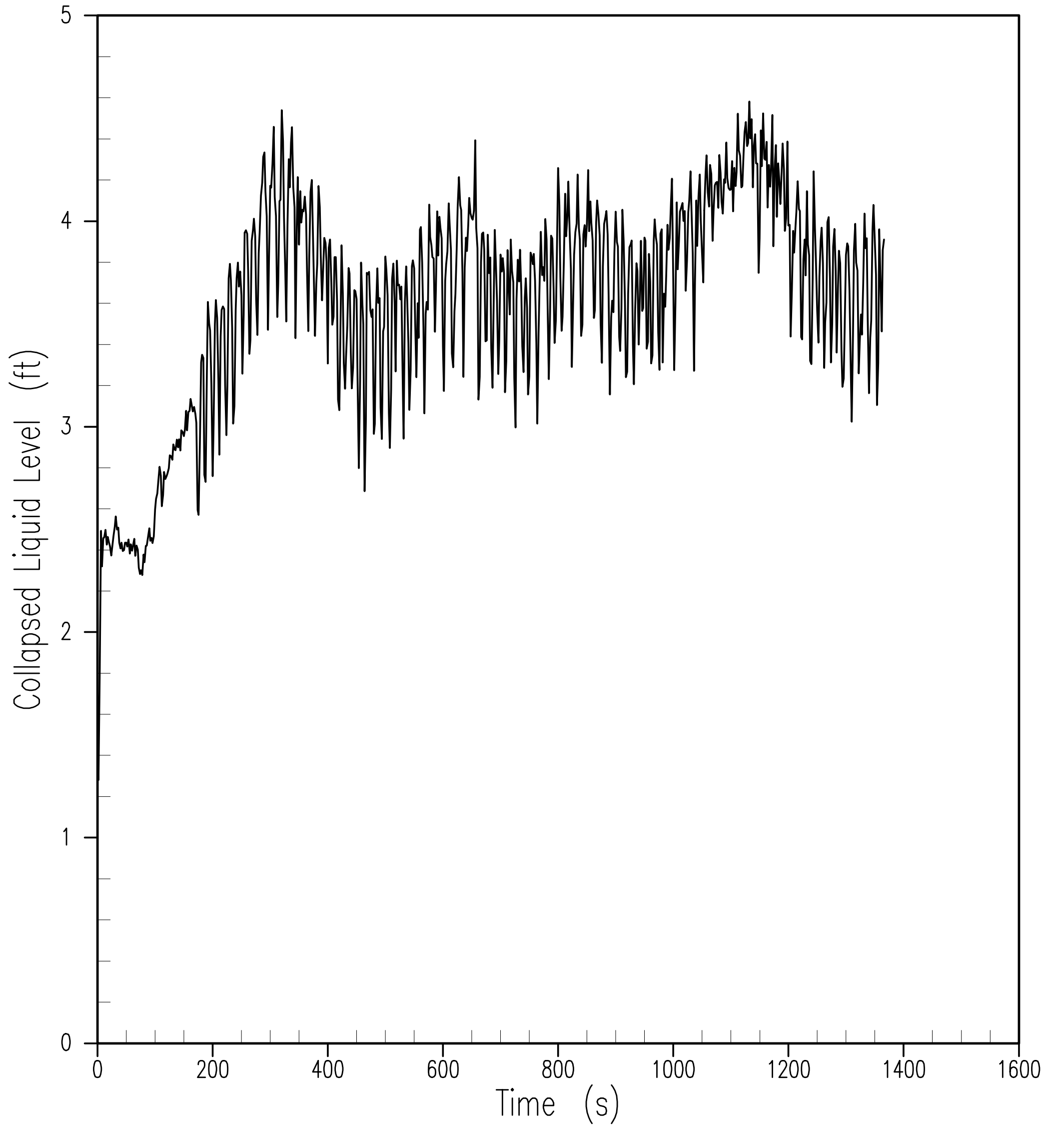

Figure 15.6.5.4C-22

Collapsed Liquid Level in the Upper Plenum (Wall-to-Wall Floodup Case) – 14.7 psi

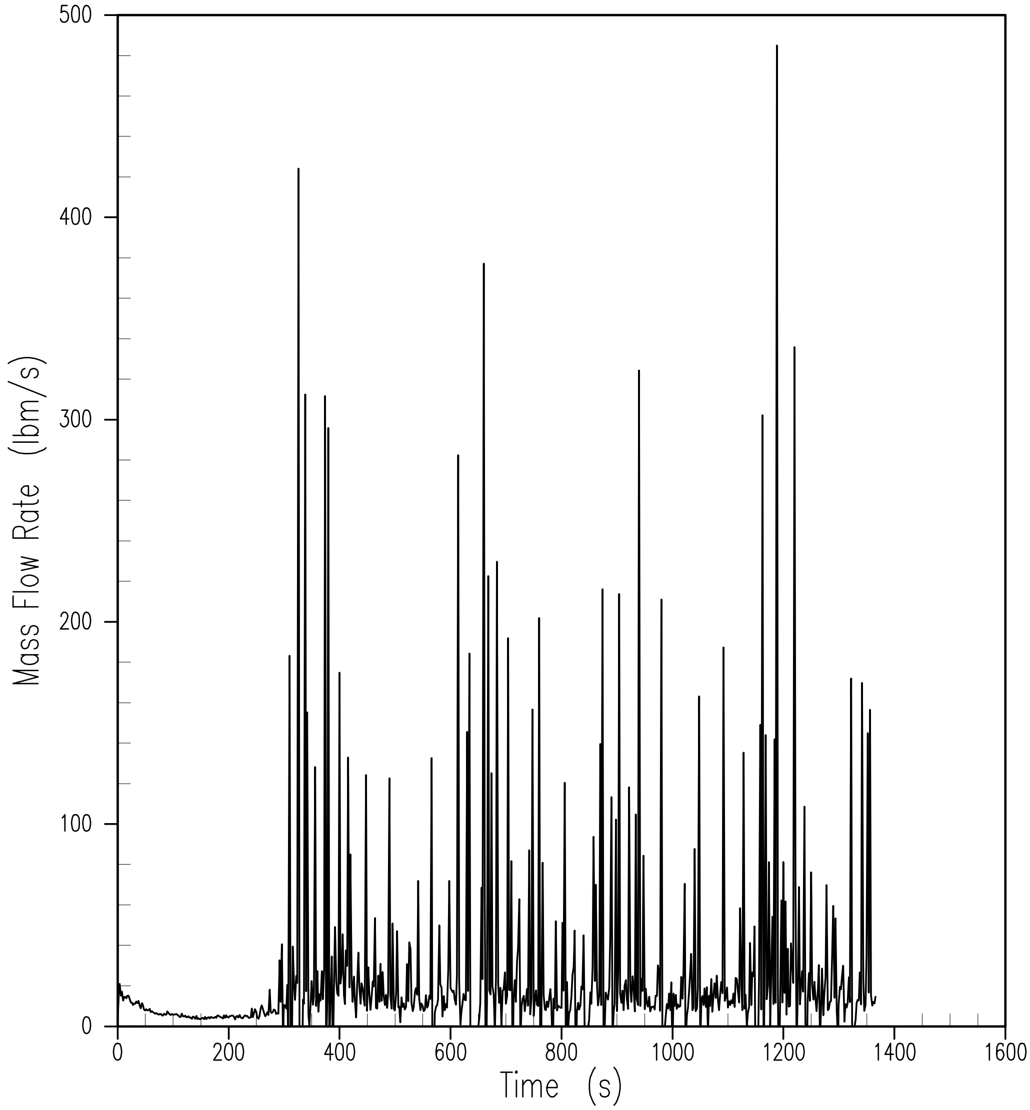

Figure 15.6.5.4C-23

Mixture Flow Rate Through ADS Stage 4A Valves (Wall-to-Wall Floodup Case) – 14.7 psi

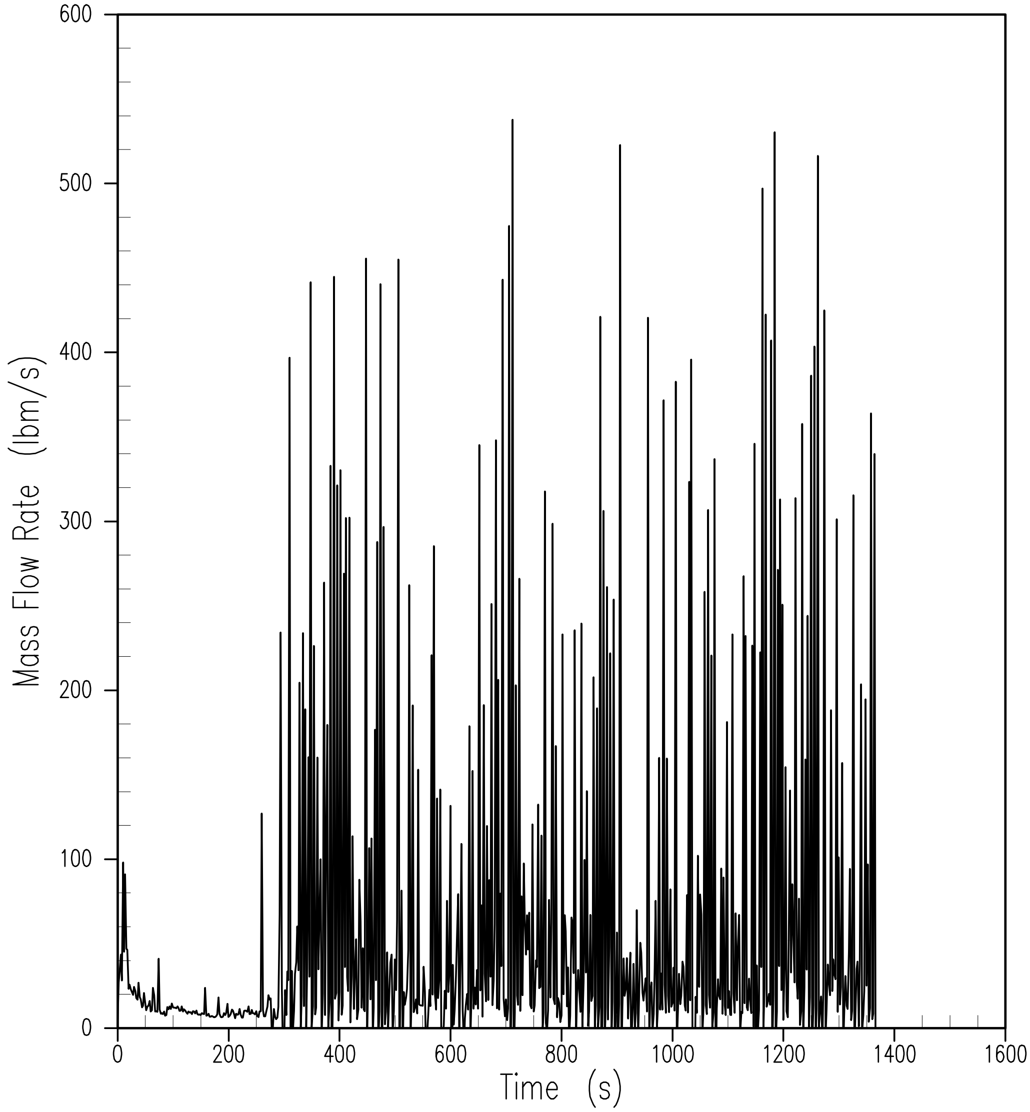

Figure 15.6.5.4C-24

Mixture Flow Rate Through ADS Stage 4B Valves (Wall-to-Wall Floodup Case) – 14.7 psi

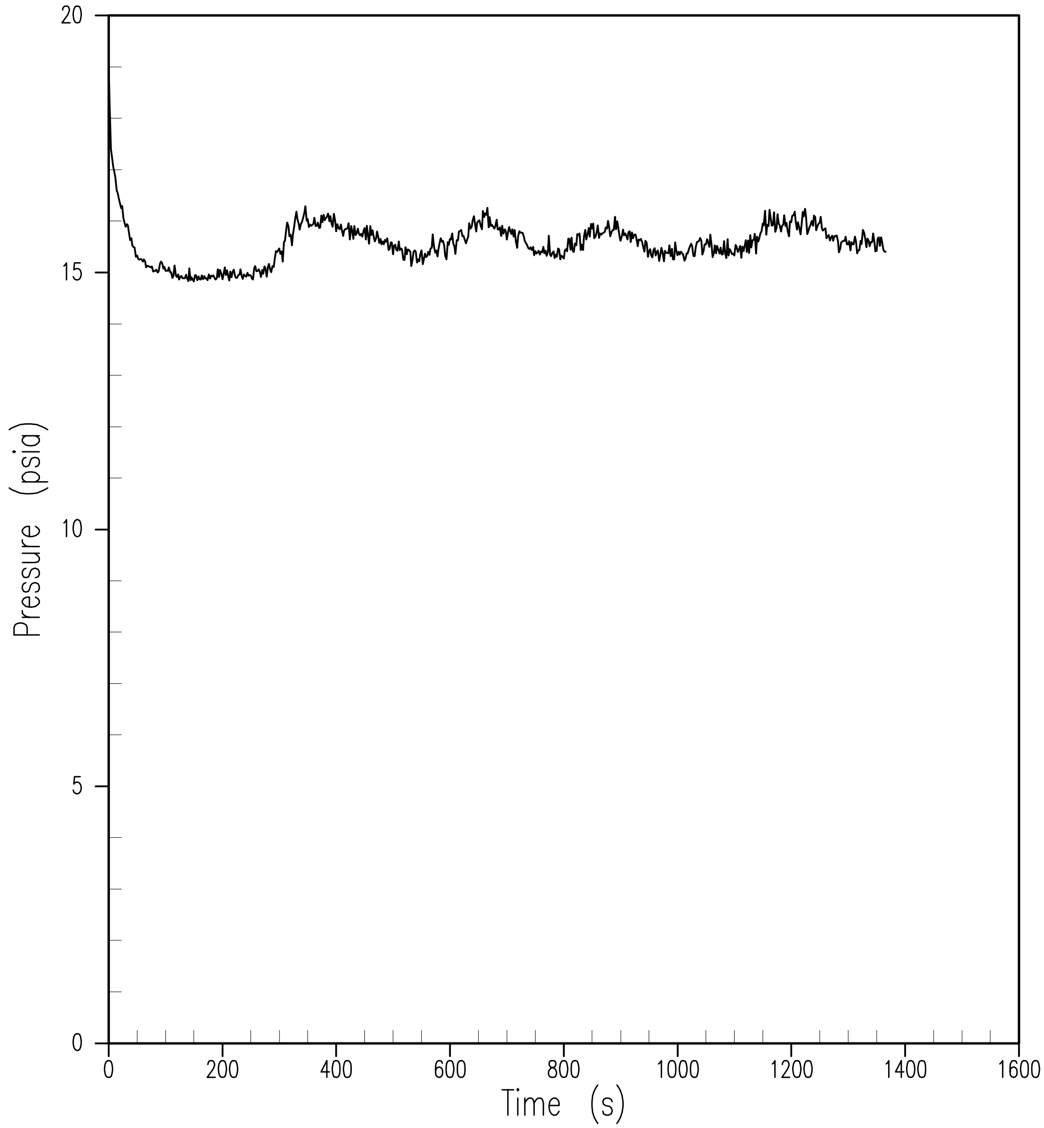

Figure 15.6.5.4C-25

Upper Plenum Pressure
(Wall-to-Wall Floodup Case) – 14.7 psi

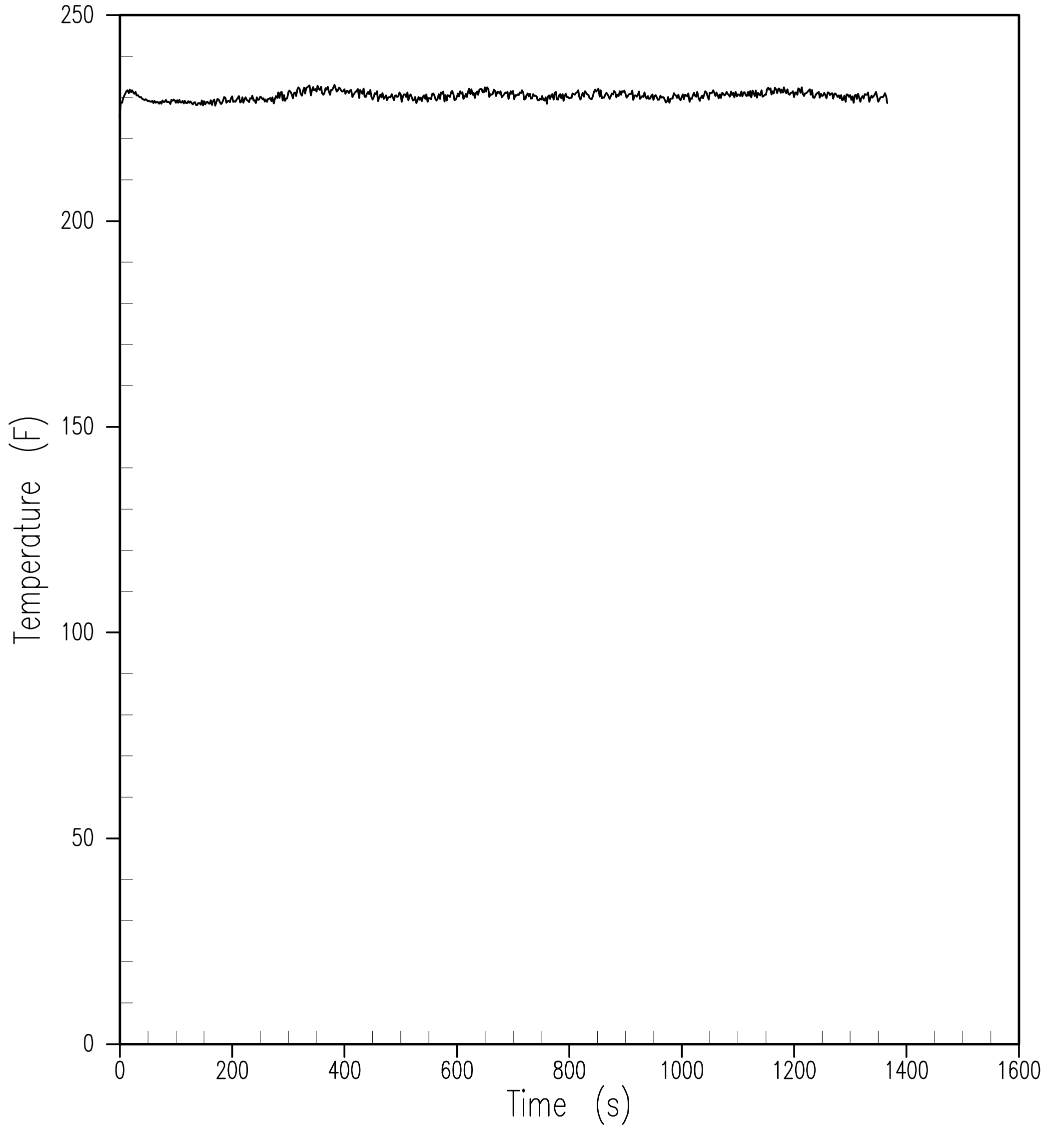

Figure 15.6.5.4C-26

Hot Rod Cladding Temperature Near Top of Core (Wall-to-Wall Floodup Case) – 14.7 psi

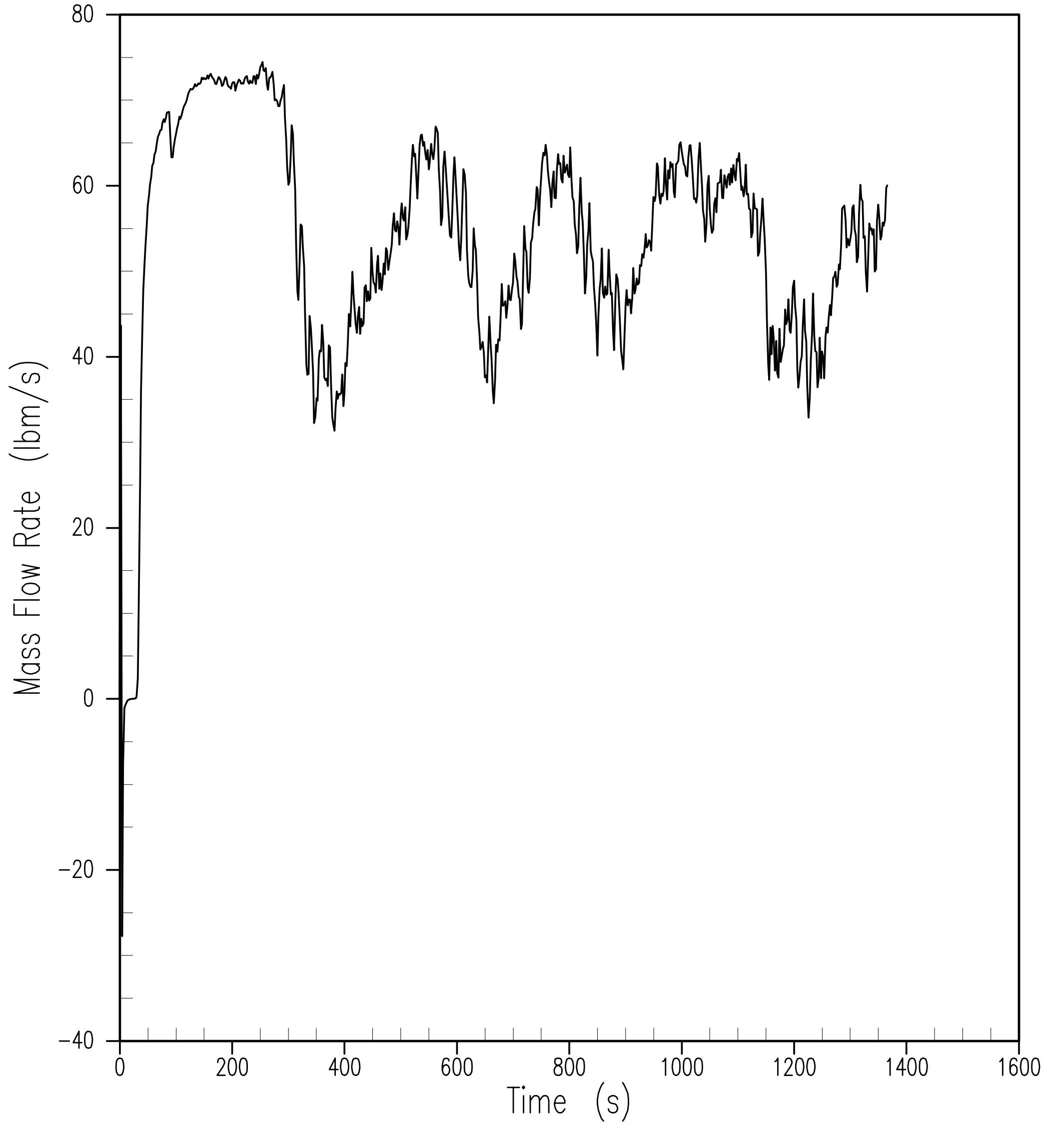

Figure 15.6.5.4C-27

DVI-A Mixture Flow Rate (Wall-to-Wall Floodup Case) – 14.7 psi

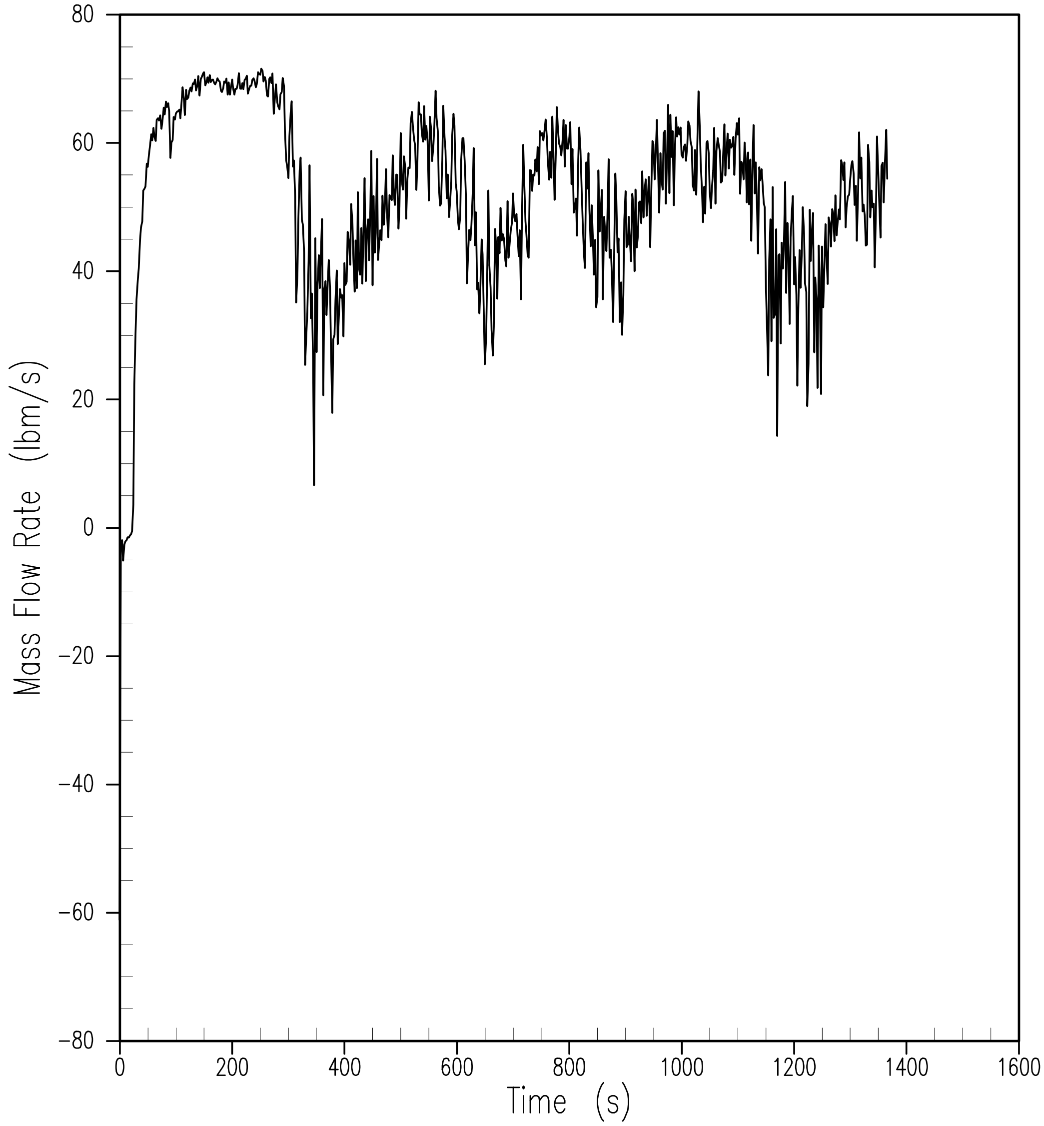

Figure 15.6.5.4C-28

DVI-B Mixture Flow Rate
(Wall-to-Wall Floodup Case) – 14.7 psi

15.7 Radioactive Release from a Subsystem or Component

This group of events includes the following:

- Gas waste management system leak or failure
- Liquid waste management system leak or failure (atmospheric release)
- Release of radioactivity to the environment via liquid pathways
- Fuel handling accident
- Spent fuel cask drop accident

15.7.1 Gas Waste Management System Leak or Failure

The AP1000 gaseous radwaste system is a low-pressure, low-flow charcoal delay process. Failure of the gaseous radwaste system results in a minor release of activity that is not significant. The Standard Review Plan no longer includes this event as part of the review. Therefore, no analysis is provided.

15.7.2 Liquid Waste Management System Leak or Failure (Atmospheric Release)

The AP1000 liquid radwaste system tanks do not contain significant levels of gaseous activity because liquids expected to contain gaseous radioactivity are processed by a gas stripper before being directed to storage. The tanks are open to the atmosphere so that any evolution of gaseous activity is continually released through the monitored plant vent. The Standard Review Plan no longer includes this event as part of the review. Therefore, no analysis is provided.

15.7.3 Release of Radioactivity to the Environment Due to a Liquid Tank Failure

Tanks containing radioactive fluids are located inside plant structures.

In the event of a tank failure, the liquid would be drained by the floor drains to the auxiliary building sump. From the sump, the water would be directed to the waste holdup tank. The basemat of the auxiliary building is 6-feet thick, the exterior walls are 3-feet thick, and the building is seismic Category I. The exterior walls are sealed to prevent leakage. Thus, it is assumed that there is no release of the spilled liquid waste to the environment. However, the Standard Review Plan states that credit cannot be taken for liquid retention by unlined building foundations. Analysis of the impact of this event is the responsibility of the Combined License applicant. This analysis should include consideration of tank liquid level, processing and decay of tank contents, potential paths of spilled waste to the environment, as well as other pertinent factors.

15.7.4 Fuel Handling Accident

A fuel handling accident can be postulated to occur either inside the containment or in the fuel handling area inside the auxiliary building. The fuel handling accident is defined as the dropping of a spent fuel assembly such that every rod in the dropped assembly has its cladding breached so that the activity in the fuel/cladding gap is released.

The possibility of a fuel handling accident is remote because of the many administrative controls and the equipment operating limits that are incorporated in the fuel handling operations (see subsection 9.1.4). Only one spent fuel assembly is lifted at a time, and the fuel is moved at low speeds, exercising caution that the fuel assembly not strike anything during movement. The containment, auxiliary building, refueling pool, and spent fuel pool are designed to seismic Category I requirements to thus provide their integrity in the event of a safe shutdown earthquake. The spent fuel storage racks are located to prevent a credible external missile from reaching the stored fuel assemblies. The fuel handling equipment is designed to prevent the handling equipment from falling onto the fuel in the reactor vessel or that stored in the spent fuel pool. The facility is designed so that heavy objects, such as the spent fuel shipping cask, cannot be carried over or tipped into the spent fuel pool.

15.7.4.1 Source Term

The inventory of fission products available for release at the time of the accident is dependent on a number of factors, such as the power history of the fuel assembly, the time delay between reactor shutdown and the beginning of fuel handling operations, and the volatility of the nuclides.

The fuel handling accident source term is derived from the core source term detailed in Appendix 15A by taking into account the factors below. The assumptions used to define the fuel handling accident initial airborne release source term are provided in Table 15.7-1 along with the derived source term.

15.7.4.1.1 Fission Product Gap Fraction

During power operation, a portion of the fission products generated in the fuel pellet matrix diffuses into the fuel/cladding gap. The fraction of the assembly fission products found in the gap depends on the rate of diffusion for the nuclide in question as well as the rate of radioactive decay. In the event of a fuel handling accident, the gaseous and volatile radionuclides contained in the fuel/cladding gap are free to escape from the fuel assembly. The radionuclides of concern are the noble gases (kryptons and xenons) and iodines. Based on NUREG-1465 (Reference 1), the fission product gap fraction is 3-percent of fuel inventory. For this analysis, the gap fractions are increased to be consistent with the guidance of Regulatory Guide 1.183 (Reference 2). The gap fractions are listed in Table 15.7-1.

15.7.4.1.2 Iodine Chemical Form

Consistent with NUREG-1465 guidance, the iodine released from the damaged fuel rods is assumed to be 95-percent cesium iodide, 4.85-percent elemental iodine, and 0.15-percent organic iodine.

Cesium iodide is nonvolatile, and the iodine in this form dissolves in water but does not readily become airborne. However, consistent with the guidance in Regulatory Guide 1.183, it is assumed that the cesium iodide is instantaneously converted to the elemental form when released from the fuel into the low pH water pool.

15.7.4.1.3 Assembly Power Level

All fuel assemblies are assumed to be handled inside the containment during the core shuffle so a peak power assembly is considered for the accident. Any fuel assembly can be transferred to the spent fuel pool; during a core off-load, all fuel assemblies are discharged to the spent fuel pool. To obtain a bounding condition for the fuel handling accident analysis, it is assumed that the accident involves a fuel assembly that operated at the maximum rated fuel rod peaking factor. This is conservative because the entire fuel assembly does not operate at this level.

15.7.4.1.4 Radiological Decay

The fission product decay time experienced prior to the fuel handling accident is at least 100 hours.

15.7.4.2 Release Pathways

The spent fuel handling operations take place underwater. Thus, activity releases are first scrubbed by the column of water 23 feet in depth. This has no effect on the releases of noble gases or organic iodine but there is a significant removal of elemental iodine. Consistent with the guidance in Regulatory Guide 1.183, the overall pool scrubbing decontamination factor for iodine is assumed to be 200.

After the activity escapes from the water pool, it is assumed that it is released directly to the environment within a 2-hour period without credit for any additional iodine removal process.

If the fuel handling accident occurs in the containment, the release of activity can be terminated by closure of the containment purge lines on detection of high radioactivity. No credit is taken for this in the analysis. Additionally, no credit is taken for removal of airborne iodine by the filters in the containment purge lines.

For the fuel handling accident postulated to occur in the spent fuel pool, there is assumed to be no filtration in the release pathway. Activity released from the pool is assumed to pass directly to the environment with no credit for holdup or delay of release in the building.

15.7.4.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

Table 15.7-1 lists the assumptions used in the analysis. The guidance of Regulatory Guide 1.183 is reflected in the analysis assumptions.

15.7.4.4 Identification of Conservatisms

The fuel handling accident dose analysis assumptions contain a number of conservatisms. Some of these conservatisms are described in the following subsections.

15.7.4.4.1 Fuel Assembly Power Level

The source term is based on the assumption that all of the fuel rods in the damaged assembly have been operating at the maximum fuel rod radial peaking factor. In actuality, this is true for only a small fraction of the fuel rods in any assembly. The overall assembly power level is less than the maximum radial peaking factor.

15.7.4.4.2 Fission Product Gap Fraction

The assumption of Regulatory Guide 1.183 gap fractions for the short-lived nuclides is conservative by a factor of 2 or more, depending on the nuclide.

15.7.4.4.3 Amount of Fuel Damage

It is assumed that all fuel rods in a fuel assembly are damaged so as to release the fission product inventory in the fuel/cladding gap. In an actual fuel handling accident, it is expected that there would be few rods damaged to this extent.

15.7.4.4.4 Iodine Plateout on Fuel Cladding

Although it is expected that virtually all elemental iodine plates out on the fuel cladding and is unavailable for atmospheric release, no credit is taken for plateout.

15.7.4.4.5 Presence of Organic Iodine

Although 0.15% of the iodine is assumed to be in the organic form (and thus not subject to scrubbing removal in the water pool), there would be no organic iodine in the fuel rods. Any formation of organic iodine would occur gradually and would not contribute to early releases of activity.

15.7.4.4.6 Conversion of Cesium Iodide to Form Elemental Iodine

The analysis assumes that all of the cesium iodide converts immediately to the elemental iodine form after release to the water pool and is treated in the same manner as the iodine initially in the elemental form. While the low pH solution does support conversion to the elemental form, the conversion would not occur unless the cesium iodide was dissolved in the water. The elemental iodine that is formed would thus be in the water solution and not in the bubbles of gas released from the damaged fuel. Additionally, conversion of cesium iodide would occur slowly and the elemental iodine formed would not be immediately available for release.

15.7.4.4.7 Meteorology

It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.7.4.4.8 Time Available for Radioactive Decay

The dose analysis assumes that the fuel handling accident involves one of the first fuel assemblies handled. If it were one of the later fuel handling operations, there is additional decay and a reduction in the source term.

The dose evaluation was performed assuming 24 hours decay, which bounds any credible refueling operation.

15.7.4.5 Offsite Doses

Using the assumptions from Table 15.7-1, the calculated doses from the initial releases are determined to be 5.6 rem TEDE at the site boundary and 3.5 rem TEDE at the low population zone outer boundary. These doses are well within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase "well within" is taken as meaning 25 percent or less.

15.7.5 Spent Fuel Cask Drop Accident

The spent fuel cask handling crane is prevented from travelling over the spent fuel. No radiological consequences analysis is necessary for the dropped cask event.

15.7.6 Combined License Information

Combined License applicant referencing the AP1000 certified design will perform an analysis of the consequences of potential release of radioactivity to the environment due to a liquid tank failure as outlined in subsection 15.7.3.

15.7.7 References

1. Sofer, L., et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

2. U. S. NRC Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, " July 2000.

Table 15.7-1

ASSUMPTIONS USED TO DETERMINE FUEL HANDLING ACCIDENT RADIOLOGICAL CONSEQUENCES

Source term assumptions	
– Core power (MWt)	3468
– Decay time (hr)	24
Core source term after 24 hours decay (Ci)	
I-130	9.559 E+05
I-131	8.951 E+07
I-132	1.147 E+08
I-133	9.139 E+07
I-135	1.499 E+07
Kr-85m	6.505 E+05
Kr-85	1.055 E+06
Kr-88	2.037 E+05
Xe-131m	1.055 E+06
Xe-133m	5.331 E+06
Xe-133	1.838 E+08
Xe-135m	2.401 E+06
Xe-135	4.738 E+07
Number of fuel assemblies in core	157
Amount of fuel damage	One assembly
Maximum rod radial peaking factor	1.65
Percentage of fission products in gap	
I-131	8
Other iodines	5
Kr-85	10
Other noble gases	5
Pool decontamination factor for iodine	200
Activity release period (hr)	2
Atmospheric dispersion factors	See Table 15A-5 in Appendix 15A
Breathing rates (m^3/sec)	3.5 E-4
Nuclide data	See Appendix 15A

15.8 Anticipated Transients Without Scram

15.8.1 General Background

An anticipated transient without scram (ATWS) is an anticipated operational occurrence during which an automatic reactor scram is required but fails to occur due to a common mode fault in the reactor protection system. Under certain circumstances, failure to execute a required scram during an anticipated operational occurrence could transform a relatively minor transient into a more severe accident. ATWS events are not considered to be in the design basis for Westinghouse plants.

15.8.2 Anticipated Transients Without Scram in the AP1000

For Westinghouse plants, the ATWS rule (10 CFR 50.62) requires the installation of ATWS mitigation systems actuation circuitry (AMSAC), which consists of circuitry separate from the reactor protection system, to trip the turbine and initiate decay heat removal.

The basis for the ATWS rule requirements, as outlined in SECY-83-293 (Reference 1), is to reduce the risk of core damage because of ATWS to less than 10^{-5} per reactor year.

The AP1000 includes a diverse actuation system, which provides the AMSAC protection features mandated for Westinghouse plants by 10 CFR 50.62, plus a diverse reactor scram (see Section 7.7). Thus, the ATWS rule is met.

15.8.3 Conclusion

The AP1000 is equipped with a diverse actuation system, which provides the functions of AMSAC. The ATWS core damage frequency for the AP1000 is well below the SECY-83-293 goal of 10^{-5} per reactor year. The AP1000 ATWS core damage frequency is discussed in Chapter 33 of the Probabilistic Risk Assessment (PRA). The AP1000 design meets the ATWS rule (10 CFR 50.62) and its ATWS core damage frequency safety goal basis.

15.8.4 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.8.5 References

1. Dircks, W. J., "Amendments to 10 CFR 50 Related to Anticipated Transients Without Scram (ATWS) Events," SECY-83-293, U.S. NRC, July 19, 1983.

APPENDIX 15A

EVALUATION MODELS AND PARAMETERS FOR ANALYSIS OF RADIOLOGICAL CONSEQUENCES OF ACCIDENTS

This appendix contains the parameters and models that form the basis of the radiological consequences analyses for the various postulated accidents.

15A.1 Offsite Dose Calculation Models

Radiological consequences analyses are performed to determine the total effective dose equivalent (TEDE) doses associated with the postulated accident. The determination of TEDE doses takes into account the committed effective dose equivalent (CEDE) dose resulting from the inhalation of airborne activity (that is, the long-term dose accumulation in the various organs) as well as the effective dose equivalent (EDE) dose resulting from immersion in the cloud of activity.

15A.1.1 Immersion Dose (Effective Dose Equivalent)

Assuming a semi-infinite cloud, the immersion doses are calculated using the equation:

$$D_{im} = \sum_{i} DCF_i \sum_{j} R_{ij} (\chi / Q)_j$$

where:

D_{im} = Immersion (EDE) dose (rem)

DCF_i = EDE dose conversion factor for isotope i (rem-m^3/Ci-s)

R_{ij} = Amount of isotope i released during time period j (Ci)

$(\chi/Q)_j$ = Atmospheric dispersion factor during time period j (s/m^3)

15A.1.2 Inhalation Dose (Committed Effective Dose Equivalent)

The CEDE doses are calculated using the equation:

$$D_{CEDE} = \sum_{i} DCF_i \sum_{j} R_{ij} (BR)_j (\chi / Q)_j$$

where:

D_{CEDE} = CEDE dose (rem)

DCF_i = CEDE dose conversion factor (rem per curie inhaled) for isotope i

R_{ij} = Amount of isotope i released during time period j (Ci)

$(BR)_j$ = Breathing rate during time period j (m^3/s)

$(\chi/Q)_j$ = Atmospheric dispersion factor during time period j (s/m^3)

15A.1.3 Total Dose (Total Effective Dose Equivalent)

The TEDE doses are the sum of the EDE and the CEDE doses.

15A.2 Main Control Room Dose Models

Radiological consequences analyses are performed to determine the TEDE doses associated with the postulated accident. The determination of TEDE doses takes into account the CEDE dose resulting from the inhalation of airborne activity (that is, the long-term dose accumulation in the various organs) as well as the EDE dose resulting from immersion in the cloud of activity.

15A.2.1 Immersion Dose Models

Due to the finite volume of air contained in the main control room, the immersion dose for an operator occupying the main control room is substantially less than it is for the case in which a semi-infinite cloud is assumed. The finite cloud doses are calculated using the geometry correction factor from Murphy and Campe (Reference 1).

The equation is:

$$D_{im} = \frac{1}{GF} \sum_i DCF_i \sum_j (IAR)_{ij} O_j$$

where:

D_{im} = Immersion (EDE) dose (rem)

GF = Main control room geometry factor
= $1173/V^{0.338}$

V = Volume of the main control room (ft^3)

DCF_i = EDE dose conversion factor for isotope i (rem-m^3/Ci-s)

$(IAR)_{ij}$ = Integrated activity for isotope i in the main control room during time period j (Ci-s/m^3)

O_j = Fraction of time period j that the operator is assumed to be present

15A.2.2 Inhalation Dose

The CEDE doses are calculated using the equation:

$$D_{CEDE} = \sum_i DCF_i \sum_j (IAR)_{ij} (BR)_j O_j$$

where:

D_{CEDE} = CEDE dose (rem)

DCF_i = CEDE dose conversion factor (rem per curie inhaled) for isotope i

$(IAR)_{ij}$ = Integrated activity for isotope i in the main control room during time period j ($Ci\text{-}s/m^3$)

$(BR)_j$ = Breathing rate during time period j (m^3/s)

O_j = Fraction of time period j that the operator is assumed to be present

15A.2.3 Total Dose (Total Effective Dose Equivalent)

The TEDE doses are the sum of the EDE and the CEDE doses.

15A.3 General Analysis Parameters

15A.3.1 Source Terms

The sources of radioactivity for release are dependent on the specific accident. Activity may be released from the primary coolant, from the secondary coolant, and from the core if the accident involves fuel failures. The radiological consequences analyses use conservative design basis source terms.

15A.3.1.1 Primary Coolant Source Term

The design basis primary coolant source terms are listed in Table 11.1-2. These source terms are based on continuous plant operation with 0.25-percent fuel defects. The remaining assumptions used in determining the primary coolant source terms are listed in Table 11.1-1.

The accident dose analyses take into account increases in the primary coolant source terms for iodines and noble gases above those listed in Table 11.1-2, consistent with the Tech Spec limits of 1.0 μCi/g dose equivalent I-131 for the iodines and 280 μCi/g dose equivalent Xe-133 for the noble gases.

The radiological consequences analyses for certain accidents also take into account the phenomenon of iodine spiking, which causes the concentration of radioactive iodines in the primary coolant to increase significantly. Table 15A-1 lists the concentrations of iodine isotopes associated with a pre-existing iodine spike. This is an iodine spike that occurs prior to the accident

and for which the peak primary coolant activity is reached at the time the accident is assumed to occur. These isotopic concentrations are also defined as 60 μCi/g dose equivalent I-131. The probability of this adverse timing of the iodine spike and accident is small.

Although it is unlikely for an accident to occur at the same time that an iodine spike is at its maximum reactor coolant concentration, for many accidents it is expected that an iodine spike would be initiated by the accident or by the reactor trip associated with the accident. Table 15A-2 lists the iodine appearance rates (rates at which the various iodine isotopes are transferred from the core to the primary coolant by way of the assumed cladding defects) for normal operation. The iodine spike appearance rates are assumed to be as much as 500 times the normal appearance rates.

15A.3.1.2 Secondary Coolant Source Term

The secondary coolant source term used in the radiological consequences analyses is conservatively assumed to be 10 percent of the primary coolant equilibrium source term. This is more conservative than using the design basis secondary coolant source terms listed in Table 11.1-5.

Because the iodine spiking phenomenon is short-lived and there is a high level of conservatism for the assumed secondary coolant iodine concentrations, the effect of iodine spiking on the secondary coolant iodine source terms is not modeled.

There is assumed to be no secondary coolant noble gas source term because the noble gases entering the secondary side due to primary-to-secondary leakage enter the steam phase and are discharged via the condenser air removal system.

15A.3.1.3 Core Source Term

Table 15A-3 lists the core source terms at shutdown for an assumed three-region equilibrium cycle at end of life after continuous operation at 2 percent above full core thermal power. In addition to iodines and noble gases, the source terms listed include nuclides that are identified as potentially significant dose contributors in the event of a degraded core accident. The design basis loss-of-coolant accident analysis is not expected to result in significant core damage, but the radiological consequences analysis assumes severe core degradation.

15A.3.2 Nuclide Parameters

The radiological consequence analyses consider radioactive decay of the subject nuclides prior to their release, but no additional decay is assumed after the activity is released to the environment. Table 15A-4 lists the decay constants for the nuclides of concern.

Table 15A-4 also lists the dose conversion factors for calculation of the CEDE doses due to inhalation of iodines and other nuclides and EDE dose conversion factors for calculation of the dose due to immersion in a cloud of activity. The CEDE dose conversion factors are from EPA Federal Guidance Report No. 11 (Reference 2) and the EDE dose conversion factors are from EPA Federal Guidance Report No. 12 (Reference 3).

15A.3.3 Atmospheric Dispersion Factors

Subsection 2.3.4 lists the off-site short-term atmospheric dispersion factors (χ/Q) for the reference site. Table 15A-5 (Sheet 1 of 2) reiterates these χ/Q values.

The atmospheric dispersion factors (χ/Q) to be applied to air entering the main control room following a design basis accident are specified at the HVAC intake and at the annex building entrance (which would be the air pathway to the main control room due to ingress/egress). A set of χ/Q values is identified for each potential activity release location that has been identified and the two control room receptor locations. The χ/Q values have been selected in concert with the design basis accident radiological consequences analyses to obtain limiting values. In this manner, the maximum acceptable χ/Q values consistent with meeting dose acceptance criteria have been obtained. These χ/Q values are listed in Table 15A-6 and are provided in Table 2-1 (Sheet 3 of 3).

Combined License applicants referencing the AP1000 certified design will confirm that the site-specific χ/Q values are bounded by the values in Table 15A-6. For a site selected that has χ/Q values that exceed the values in Table 15A-6, the Combined License applicant will address how the radiological consequences associated with the controlling design basis accident continue to meet the control room operator dose limits given in General Design Criteria 19 using site-specific χ/Q values. The Combined License Applicant should consider topographical characteristics in the vicinity of the site for restrictions of horizontal and/or vertical plume spread, channeling or other changes in airflow trajectories, and other unusual conditions affecting atmospheric transport and diffusion between the source and the receptors. No further action is required for sites within the bounds of the site parameters for atmospheric dispersion.

Table 15A-7 identifies the AP1000 source and receptor data that the Combined License applicant can use when determining the site-specific control room χ/Q values using the ARCON96 code (References 4 and 5).

The main control room χ/Q values do not incorporate occupancy factors.

The locations of the potential release points and their relationship to the main control room air intake and the annex building access door are shown in Figure 15A-1.

15A.4 References

1. Murphy, K. G., Campe, K. M., "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," paper presented at the 13th AEC Air Cleaning Conference.

2. EPA Federal Guidance Report No. 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," EPA-520/1-88-020, September 1988.

3. EPA Federal Guidance Report No. 12, "External Exposure to Radionuclides in Air, Water, and Soil," EPA 402-R-93-081, September 1993.

4. NUREG/CR-6331, Ramsdell, J. V. and Simonen, C. A., "Atmospheric Relative Concentrations in Building Wakes," Revision 1, May 1997.

5. Regulatory Guide 1.194, Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants, June 2003.

Table 15A-1

REACTOR COOLANT IODINE CONCENTRATIONS FOR MAXIMUM IODINE SPIKE OF 60 μCi/g DOSE EQUIVALENT I-131

Nuclide	μCi/g
I-130	0.66
I-131	43.4
I-132	57.5
I-133	78.8
I-134	13.4
I-135	47.8

Table 15A-2

IODINE APPEARANCE RATES IN THE REACTOR COOLANT

Nuclide	Equilibrium Appearance Rate (Ci/min)
I-130	7.03×10^{-3}
I-131	3.39×10^{-1}
I-132	1.38
I-133	7.42×10^{-1}
I-134	6.81×10^{-1}
I-135	6.37×10^{-1}

Table 15A-3 (Sheet 1 of 2)

REACTOR CORE SOURCE TERM$^{(1)}$

	Nuclide	Inventory (Ci)		Nuclide	Inventory (Ci)
Iodines	I-130	3.66×10^{6}	**Noble Gases**	Kr-85m	2.63×10^{7}
	I-131	9.63×10^{7}		Kr-85	1.06×10^{6}
	I-132	1.40×10^{8}		Kr-87	5.07×10^{7}
	I-133	1.99×10^{8}		Kr-88	7.14×10^{7}
	I-134	2.18×10^{8}		Xe-131m	1.06×10^{6}
	I-135	1.86×10^{8}		Xe-133m	5.84×10^{6}
Cs Group	Cs-134	1.94×10^{7}		Xe-133	1.90×10^{8}
	Cs-136	5.53×10^{6}		Xe-135m	3.87×10^{7}
	Cs-137	1.13×10^{7}		Xe-135	4.84×10^{7}
	Cs-138	1.82×10^{8}		Xe-138	1.65×10^{8}
	Rb-86	2.29×10^{5}	**Sr & Ba**	Sr-89	9.66×10^{7}
Te Group	Te-127m	1.32×10^{6}		Sr-90	8.31×10^{6}
	Te-127	1.02×10^{7}		Sr-91	1.20×10^{8}
	Te-129m	4.50×10^{6}		Sr-92	1.29×10^{8}
	Te-129	3.04×10^{7}		Ba-139	1.78×10^{8}
	Te-131m	1.40×10^{7}		Ba-140	1.71×10^{8}
	Te-132	1.38×10^{8}	**Ce Group**	Ce-141	1.63×10^{8}
	Sb-127	1.03×10^{7}		Ce-143	1.52×10^{8}
	Sb-129	3.10×10^{7}		Ce-144	1.23×10^{8}
Ru Group	Ru-103	1.45×10^{8}		Pu-238	3.83×10^{5}
	Ru-105	9.83×10^{7}		Pu-239	3.37×10^{4}
	Ru-106	4.77×10^{7}		Pu-240	4.94×10^{4}
	Rh-105	9.00×10^{7}		Pu-241	1.11×10^{7}
	Mo-99	1.84×10^{8}		Np-239	1.93×10^{9}
	Tc-99m	1.61×10^{8}			

Note:

1. The following assumptions apply:
   - Core thermal power of 3468 MWt (2 percent above the design core power of 3400 MWt)
   - Three-region equilibrium cycle core at end of life

Table 15A-3 (Sheet 2 of 2)

REACTOR CORE SOURCE TERM(1)

	Nuclide	Inventory (Ci)
La Group	Y-90	8.66×10^{6}
	Y-91	1.24×10^{8}
	Y-92	1.30×10^{8}
	Y-93	1.49×10^{8}
	Nb-95	1.67×10^{8}
	Zr-95	1.66×10^{8}
	Zr-97	1.64×10^{8}
	La-140	1.82×10^{8}
	La-141	1.62×10^{8}
	La-142	1.57×10^{8}
	Pr-143	1.46×10^{8}
	Nd-147	6.48×10^{7}
	Am-241	1.25×10^{4}
	Cm-242	2.95×10^{6}
	Cm-244	3.62×10^{5}

Note:
1. The following assumptions apply:
   - Core thermal power of 3468 MWt (2 percent above the design core power of 3400 MWt)
   - Three-region equilibrium cycle core at end of life

Table 15A-4 (Sheet 1 of 4)

NUCLIDE PARAMETERS

A. HALOGENS

Isotope	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
I-130	$5.61x10^{-2}$	$1.04x10^{-13}$	$7.14x10^{-10}$
I-131	$3.59x10^{-3}$	$1.82x10^{-14}$	$8.89x10^{-9}$
I-132	$3.01x10^{-1}$	$1.12x10^{-13}$	$1.03x10^{-10}$
I-133	$3.33x10^{-2}$	$2.94x10^{-14}$	$1.58x10^{-9}$
I-134	$7.91x10^{-1}$	$1.30x10^{-13}$	$3.55x10^{-11}$
I-135	$1.05x10^{-1}$	$7.98x10^{-14}$	$3.32x10^{-10}$

B. NOBLE GASES

Isotope	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	
Kr-85m	$1.55x10^{-1}$	$7.48x10^{-15}$	
Kr-85	$7.38x10^{-6}$	$1.19x10^{-16}$	
Kr-87	$5.45x10^{-1}$	$4.12x10^{-14}$	
Kr-88	$2.44x10^{-1}$	$1.02x10^{-13}$	
Xe-131m	$2.43x10^{-3}$	$3.89x10^{-16}$	
Xe-133m	$1.32x10^{-2}$	$1.37x10^{-15}$	
Xe-133	$5.51x10^{-3}$	$1.56x10^{-15}$	
Xe-135m	2.72	$2.04x10^{-14}$	
Xe-135	$7.63x10^{-2}$	$1.19x10^{-14}$	
Xe-138	2.93	$5.77x10^{-14}$	

Table 15A-4 (Sheet 2 of 4)

NUCLIDE PARAMETERS

C. ALKALI METALS

Nuclide	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
Cs-134	$3.84x10^{-5}$	$7.57x10^{-14}$	$1.25x10^{-8}$
Cs-136	$2.2x10^{-3}$	$1.06x10^{-13}$	$1.98x10^{-9}$
Cs-137(1)	$2.64x10^{-6}$	$2.88x10^{-14}$	$8.63x10^{-9}$
Cs-138	1.29	$1.21x10^{-13}$	$2.74x10^{-11}$
Rb-86	$1.55x10^{-3}$	$4.81x10^{-15}$	$1.79x10^{-9}$

D. TELLURIUM GROUP

Nuclide	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
Te-127m	$2.65x10^{-4}$	$1.47x10^{-16}$	$5.81x10^{-9}$
Te-127	$7.41x10^{-2}$	$2.42x10^{-16}$	$8.60x10^{-11}$
Te-129m	$8.6x10^{-4}$	$1.55x10^{-15}$	$6.47x10^{-9}$
Te-129	$5.98x10^{-1}$	$2.75x10^{-15}$	$2.42x10^{-11}$
Te-131m	$2.31x10^{-2}$	$7.01x10^{-14}$	$1.73x10^{-9}$
Te-132	$8.86x10^{-3}$	$1.03x10^{-14}$	$2.55x10^{-9}$
Sb-127	$7.5x10^{-3}$	$3.33x10^{-14}$	$1.63x10^{-9}$
Sb-129	$1.6x10^{-1}$	$7.14x10^{-14}$	$1.74x10^{-10}$

E. STRONTIUM AND BARIUM

Nuclide	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
Sr-89	$5.72x10^{-4}$	$7.73x10^{-17}$	$1.12x10^{-8}$
Sr-90	$2.72x10^{-6}$	$7.53x10^{-18}$	$3.51x10^{-7}$
Sr-91	$7.3x10^{-2}$	$3.45x10^{-14}$	$4.49x10^{-10}$
Sr-92	$2.56x10^{-1}$	$6.79x10^{-14}$	$2.18x10^{-10}$
Ba-139	$5.02x10^{-1}$	$2.17x10^{-15}$	$4.64x10^{-11}$
Ba-140	$2.27x10^{-3}$	$8.58x10^{-15}$	$1.01x10^{-9}$

Note:

1. The listed average gamma disintegration energy for Cs-137 is due to the production and decay of Ba-137m.

Table 15A-4 (Sheet 3 of 4)

NUCLIDE PARAMETERS

F. NOBLE METALS

Nuclide	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
Ru-103	$7.35x10^{-4}$	$2.25x10^{-14}$	$2.42x10^{-9}$
Ru-105	$1.56x10^{-1}$	$3.81x10^{-14}$	$1.23x10^{-10}$
Ru-106	$7.84x10^{-5}$	0.0	$1.29x10^{-7}$
Rh-105	$1.96x10^{-2}$	$3.72x10^{-15}$	$2.58x10^{-10}$
Mo-99	$1.05x10^{-2}$	$7.28x10^{-15}$	$1.07x10^{-9}$
Tc-99m	$1.15x10^{-1}$	$5.89x10^{-15}$	$8.80x10^{-12}$

G. CERIUM GROUP

Nuclide	Decay Constant (hr^{-1})	EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)	CEDE Dose Conversion Factor (Sv/Bq)
Ce-141	$8.89x10^{-4}$	$3.43x10^{-15}$	$2.42x10^{-9}$
Ce-143	$2.1x10^{-2}$	$1.29x10^{-14}$	$9.16x10^{-10}$
Ce-144	$1.02x10^{-4}$	$8.53x10^{-16}$	$1.01x10^{-7}$
Pu-238	$9.02x10^{-7}$	$4.88x10^{-18}$	$1.06x10^{-4}$
Pu-239	$3.29x10^{-9}$	$4.24x10^{-18}$	$1.16x10^{-4}$
Pu-240	$1.21x10^{-8}$	$4.75x10^{-18}$	$1.16x10^{-4}$
Pu-241	$5.5x10^{-6}$	$7.25x10^{-20}$	$2.23x10^{-6}$
Np-239	$1.23x10^{-2}$	$7.69x10^{-15}$	$6.78x10^{-10}$

Table 15A-4 (Sheet 4 of 4)

NUCLIDE PARAMETERS

H. LANTHANIDE GROUP

Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Y-90	$1.08x10^{-2}$	$1.90x10^{-16}$	$2.28x10^{-9}$
Y-91	$4.94x10^{-4}$	$2.60x10^{-16}$	$1.32x10^{-8}$
Y-92	$1.96x10^{-1}$	$1.30x10^{-14}$	$2.11x10^{-10}$
Y-93	$6.86x10^{-2}$	$4.80x10^{-15}$	$5.82x10^{-10}$
Nb-95	$8.22x10^{-4}$	$3.74x10^{-14}$	$1.57x10^{-9}$
Zr-95	$4.51x10^{-4}$	$3.60x10^{-14}$	$6.39x10^{-9}$
Zr-97	$4.1x10^{-2}$	$9.02x10^{-15}$	$1.17x10^{-9}$
La-140	$1.72x10^{-2}$	$1.17x10^{-13}$	$1.31x10^{-9}$
La-141	$1.76x10^{-1}$	$2.39x10^{-15}$	$1.57x10^{-10}$
La-142	$4.5x10^{-1}$	$1.44x10^{-13}$	$6.84x10^{-11}$
Nd-147	$2.63x10^{-3}$	$6.19x10^{-15}$	$1.85x10^{-9}$
Pr-143	$2.13x10^{-3}$	$2.10x10^{-17}$	$2.19x10^{-9}$
Am-241	$1.83x10^{-7}$	$8.18x10^{-16}$	$1.20x10^{-4}$
Cm-242	$1.77x10^{-4}$	$5.69x10^{-18}$	$4.67x10^{-6}$
Cm-244	$4.37x10^{-6}$	$4.91x10^{-18}$	$6.70x10^{-5}$

Table 15A-5

OFFSITE ATMOSPHERIC DISPERSION FACTORS (χ/Q) FOR ACCIDENT DOSE ANALYSIS

Site boundary χ/Q (s/m^3)	
0 – 2 hours[(1)]	5.1×10^{-4}
Low population zone χ/Q (s/m^3)	
0 – 8 hours	2.2×10^{-4}
8 – 24 hours	1.6×10^{-4}
24 – 96 hours	1.0×10^{-4}
96 – 720 hours	8.0×10^{-5}

Note:

1. Nominally defined as the 0- to 2-hour interval but is applied to the 2-hour interval having the highest activity releases in order to address 10 CFR Part 50.34 requirements.

Table 15A-6

CONTROL ROOM ATMOSPHERIC DISPERSION FACTORS (χ/Q) FOR ACCIDENT DOSE ANALYSIS

χ/Q (s/m^3) at HVAC Intake for the Identified Release Points[1]					
	Plant Vent or PCS Air Diffuser[3]	**Ground Level Containment Release Points[4]**	**PORV and Safety Valve Releases[5]**	**Steam Line Break Releases**	**Fuel Handling Area[6]**
0 - 2 hours	2.2E-3	2.2E-3	2.0E-2	2.4E-2	6.0E-3
2 - 8 hours	1.4E-3	1.4E-3	1.8E-2	2.0E-2	4.0E-3
8 - 24 hours	6.0E-4	6.0E-4	7.0E-3	7.5E-3	2.0E-3
1 - 4 days	4.5E-4	4.5E-4	5.0E-3	5.5E-3	1.5E-3
4 - 30 days	3.6E-4	3.6E-4	4.5E-3	5.0E-3	1.0E-3
χ/Q (s/m^3) at Control Room Door for the Identified Release Points[2]					
	Plant Vent or PCS Air Diffuser[3]	**Ground Level Containment Release Points[4]**	**PORV and Safety Valve Releases[5]**	**Steam Line Break Releases**	**Fuel Handling Area[6]**
0 - 2 hours	6.6E-4	6.6E-4	4.0E-3	4.0E-3	6.0E-3
2 - 8 hours	4.8E-4	4.8E-4	3.2E-3	3.2E-3	4.0E-3
8 - 24 hours	2.1E-4	2.1E-4	1.2E-3	1.2E-3	2.0E-3
1 - 4 days	1.5E-4	1.5E-4	1.0E-3	1.0E-3	1.5E-3
4 - 30 days	1.3E-4	1.3E-4	8.0E-4	8.0E-4	1.0E-3

Notes:

1. These dispersion factors are to be used 1) for the time period preceding the isolation of the main control room and actuation of the emergency habitability system, 2) for the time after 72 hours when the compressed air supply in the emergency habitability system would be exhausted and outside air would be drawn into the main control room, and 3) for the determination of control room doses when the non-safety ventilation system is assumed to remain operable such that the emergency habitability system is not actuated.
2. These dispersion factors are to be used when the emergency habitability system is in operation and the only path for outside air to enter the main control room is that due to ingress/egress.
3. These dispersion factors are used for analysis of the doses due to a postulated small line break outside of containment. The plant vent and PCS air diffuser are potential release paths for other postulated events (loss-of-coolant accident, rod ejection accident, and fuel handling accident inside the containment); however, the values are bounded by the dispersion factors for ground level releases.
4. The listed values represent modeling the containment shell as a diffuse area source, and are used for evaluating the doses in the main control room for a loss-of-coolant accident, for the containment leakage of activity following a rod ejection accident, and for a fuel handling accident occurring inside the containment.

5. The listed values bound the dispersion factors for releases from the steam line safety & power-operated relief valves and the condenser air removal stack. These dispersion factors would be used for evaluating the doses in the main control room for a steam generator tube rupture, a main steam line break, a locked reactor coolant pump rotor, and for the secondary side release from a rod ejection accident. Additionally, these dispersion coefficients are conservative for the small line break outside containment.
6. The listed values bound the dispersion factors for releases from the fuel storage and handling area. The listed values also bound the dispersion factors for releases from the fuel storage area in the event that spent fuel boiling occurs and the fuel building relief panel opens on high temperature. These dispersion factors are used for the fuel handling accident occurring outside containment and for evaluating the impact of releases associated with spent fuel pool boiling.

Table 15A-7

CONTROL ROOM SOURCE/RECEPTOR DATA FOR DETERMINATION OF ATMOSPHERIC DISPERSION FACTORS

Source Description	Release Elevation Note 1 (m)	Horizontal Straight-Line Distance to Receptor (m)		
		Control Room HVAC Intake (Elevation 19.9 m)	Annex Building Access (Elevation 1.5 m)	Comment
Plant Vent	55.7	39.6	76.8	
PCS Air Diffuser	71.3	32.3	68.9	
Containment Shell (Diffuse Area Source)	Same as receptor elevation (19.9 m or 1.5 m)	11.0	47.2	Note 2
Fuel Building Blowout Panel	17.4	50.0	89.7	Note 3
Fuel Building Rail Bay Door	1.5	52.4	92.1	Note 3
Steam Vent	17.1	18.3	48.8	
PORV/Safety Valves	19.2	19.8	44.1	
Condenser Air Removal Stack	7.6	63.0	59.9	Note 3

Notes:
1. All elevations relative to grade at 0.0 m.
2. For calculating distance, the source is defined as the point on the containment shell closest to receptor.
3. Vertical distance traveled is conservatively neglected.

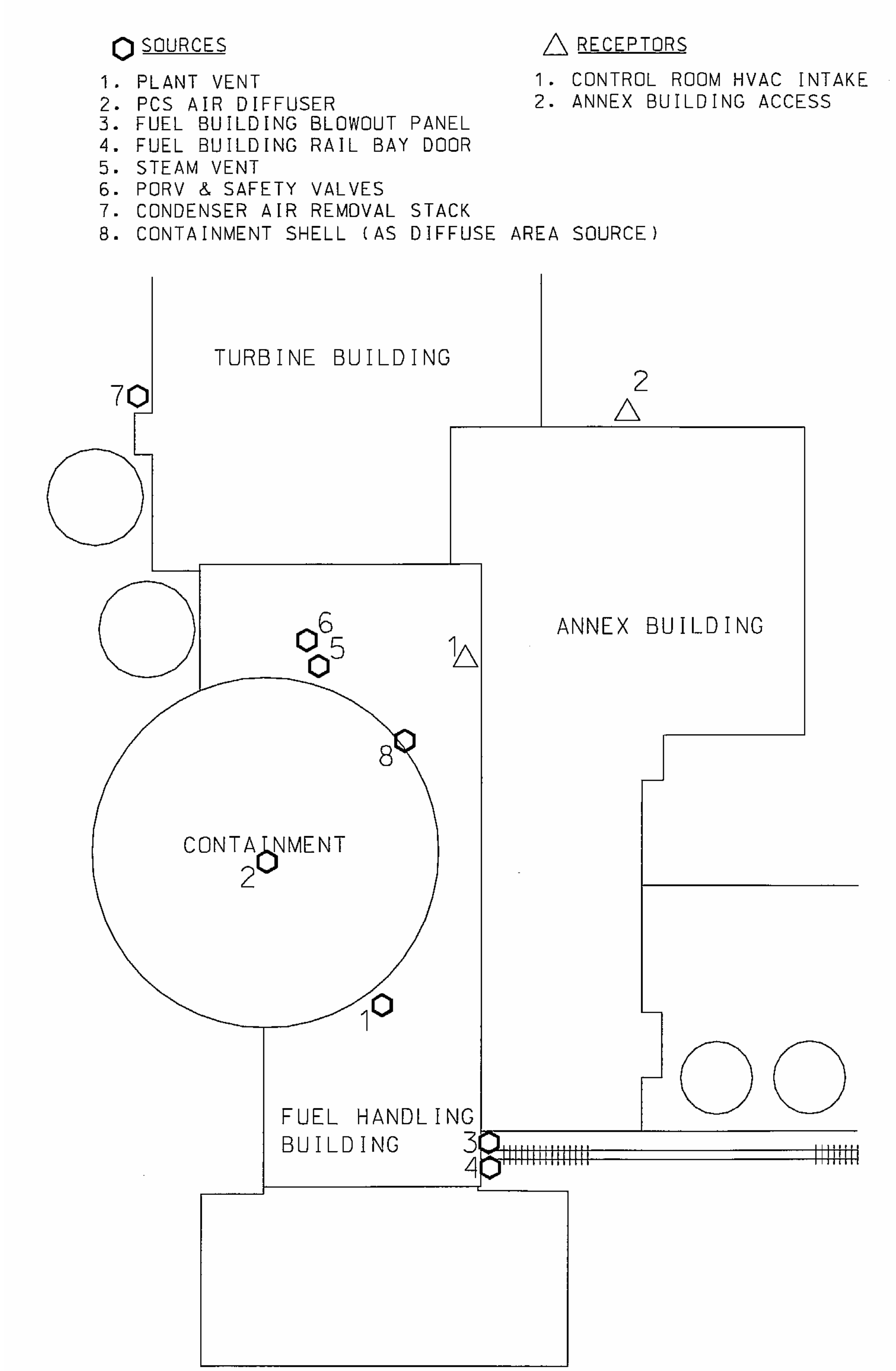

Figure 15A-1

Site Plan with Release and Intake Locations

APPENDIX 15B

REMOVAL OF AIRBORNE ACTIVITY FROM THE CONTAINMENT ATMOSPHERE FOLLOWING A LOCA

The AP1000 design does not depend on active systems to remove airborne particulates or elemental iodine from the containment atmosphere following a postulated loss-of-coolant accident (LOCA) with core melt. Naturally occurring passive removal processes provide significant removal capability such that airborne elemental iodine is reduced to very low levels within a few hours and the airborne particulates are reduced to extremely low levels within 12 hours.

15B.1 Elemental Iodine Removal

Elemental iodine is removed by deposition onto the structural surfaces inside the containment. The removal of elemental iodine is modeled using the equation from the Standard Review Plan (Reference 1):

$$\lambda_d = \frac{K_w A}{V}$$

where:

λ_d = first order removal coefficient by surface deposition

K_w = mass transfer coefficient (specified in Reference 1 as 4.9 m/hr)

A = surface area available for deposition

V = containment building volume

The available deposition surface is 219,000 ft^2, and the containment building net free volume is 2.06×10^6 ft^3. From these inputs, the elemental iodine removal coefficient is 1.7 hr^{-1}.

Consistent with the guidance of Reference 1, credit for elemental iodine removal is assumed to continue until a decontamination factor (DF) of 200 is reached in the containment atmosphere. Because the source term for the LOCA (defined in subsection 15.6.5.3) is modeled as a gradual release of activity into the containment, the determination of the time at which the DF of 200 is reached needs to be based on the amount of elemental iodine that enters the containment atmosphere over the duration of core activity release.

15B.2 Aerosol Removal

The deposition removal of aerosols from the containment atmosphere is accomplished by a number of processes including sedimentation, diffusiophoresis, and thermophoresis. All three of the deposition processes are significant contributors to the overall removal process in the AP1000. The large contributions from diffusiophoresis and thermophoresis to the total removal are a direct

consequence of the high heat transfer rates from the containment atmosphere to the containment wall that characterize the passive containment cooling system.

Because of the AP1000 passive containment cooling system design, there are high sensible heat transfer rates (resulting in higher thermophoretic removal of aerosols) when condensational heat transfer is low (and the aerosol removal by diffusiophoresis is also low). The reverse is also true. Thus, there is an appreciable deposition removal throughout the accident from either diffusiophoresis or thermophoresis, in addition to the removal by sedimentation.

15B.2.1 Mathematical Models

The models used for the three aerosol removal processes are discussed as follows.

15B.2.1.1 Sedimentation

Gravitational sedimentation is a major mechanism of aerosol removal in a containment. A standard model (Stokes equation with the Cunningham slip correction factor) for this process is used. The Stokes equation (Reference 2) is:

$$\upsilon_s = \frac{2\,\rho_p\, g\, r^2\, Cn}{9\mu}$$

where:

υ_s = settling velocity of an aerosol particle

ρ_p = material density of the particle

g = gravitational acceleration

r = particle radius

μ = gas viscosity

Cn = Cunningham slip correction factor, a function of the Knudsen number (Kn) which is the gas molecular mean free path divided by the particle radius

However, the Stokes equation makes the simplifying assumption that the particles are spherical. The particles are expected to be nonspherical, and it is conventional to address this by introducing a "dynamic shape factor" (Reference 2) in the denominator of the Stokes equation, such that the settling velocity for the nonspherical particle is the same as for a spherical particle of equal volume. The value of the dynamic shape factor (ϕ) thus depends on the shape of the particle and, in general, must be experimentally determined.

The concept of dynamic shape factor can also be applied to a spherical particle consisting of two components, one of which has the density of the particle material, while the other component has a different density (Reference 9). In this manner, the impact of the void fraction in the particle can be modeled. Thus, the revised Stokes equation is:

$$\upsilon_s = \frac{2\,\rho_p\,g\,r^2\,Cn}{9\mu\phi}$$

The derivation of ϕ follows.

The two-component particle is considered to have a density ρ_{av} and an effective radius of r_e. Assuming that the second component of the particle is the void volume and letting the void fraction be ε, then the average density of the particle is:

$$\rho_{av} = \text{the average density of the particle} = \rho_p\,(1-\varepsilon) + \rho_v\varepsilon$$

where:

ρ_v	=	density of the void material (0.0 for gas filled, 1.0 for water filled)
ε	=	void fraction
ρ_p	=	material density (solid particle with no voids)

The definition of ϕ is obtained from the Stokes equation and the equation for mass of a sphere:

$$\frac{2\rho_p g r^2 Cn}{9\mu\phi} = \frac{2\rho_{av} g r_e^2 Cn}{9\mu}$$

which reduces to:

$$\rho_p r^2 = \phi\rho_{av} r_e^2$$

and

$$\frac{4\rho_p \pi r_0^3}{3} = \frac{4\rho_{av}\pi r_e^3}{3}$$

which reduces to:

$$\rho_p r_0^3 = \rho_{av} r_e^3$$

Then:

$$\phi = \frac{\rho_p r^2}{\rho_{av} r_e^2}$$

and

$$r_e = r\left(\frac{\rho_{av}}{\rho_p}\right)^{-1/3}$$

From these two relationships, the dynamic shape factor is given by:

$$\phi = \left(\frac{\rho_{av}}{\rho_p}\right)^{-1/3}$$

15B.2.1.2 Diffusiophoresis

Diffusiophoresis is the process whereby particles are swept to a surface (for example, containment wall) by the flow set up by a condensing vapor (Stefan flow). The deposition rate is independent of the particle size and is proportional to the steam condensation rate on the surface. The standard equation for this phenomenon is due to Waldmann and Schmitt (Reference 3):

$$\upsilon_d = \frac{\sqrt{M_v}}{\sqrt{M_v} + \chi_{a/v}\sqrt{M_a}} \frac{W}{\rho_v}$$

where:

υ_d = diffusiophoretic deposition velocity

$\chi_{a/v}$ = ratio of mole fraction of air to mole fraction of steam in the containment atmosphere

M_v = molecular weight of steam

M_a = molecular weight of air

W = steam condensation rate on the wall

ρ_v = mass density of steam in the containment atmosphere

Because of the design of the passive containment cooling system, steam condensation rates are high at certain times in the design basis LOCA; thus at these times, diffusiophoretic deposition rates are significant.

15B.2.1.3 Thermophoresis

Thermophoresis is the process whereby particles drift toward a surface (for example, the containment wall) under the influence of a temperature gradient in the containment atmosphere at the surface. The effect arises because the gas molecules on the hot side of the particles undergo more collisions with the particle than do those on the cold side. Therefore, there is a net momentum transfer to the particle in the hot-to-cold direction. There are several models in the literature for this effect; the one used is the Brock equation in a form due to Talbot et al. (Reference 4). As indicated below, this model is in agreement with experimental data. The thermophoretic deposition rate is somewhat dependent on particle size and is proportional to the temperature gradient at the wall, or equivalently, the sensible heat transfer rate to the wall. The Talbot equation is:

$$\upsilon_{th} = \frac{2\,C_s\,Cn\,(\mu_g/\rho_g)\,[\alpha + C_T\,Kn]\,dT}{[1 + 2(\alpha + C_T\,Kn)][1 + 3\,C_M\,Kn]}\left(\frac{1}{T}\right)\frac{dT}{dy}$$

where:

υ_{th} = thermophoretic deposition velocity

α = k_g/k_p which is the ratio of the thermal conductivities of the gas (evaluated at the gas temperature at each time step) and the aerosol particle (k_p is set equal to the thermal conductivity of water – the results are not sensitive to k_p or α.)

Kn = Knudsen number (equal to the gas molecular mean free path divided by the particle radius)

Cn = Cunningham slip correction factor, a function of the Knudsen number

μ_g = gas viscosity

ρ_g = gas density

C_S = slip accommodation coefficient (Reference 4 gives the best value as 1.17.)

C_T = thermal accommodation coefficient (Reference 4 gives the best value as 2.18.)

C_M = momentum accommodation coefficient (Reference 4 gives the best value as 1.14.)

The temperature gradient at the wall, dT/dy, can be evaluated as

$$\frac{dT}{dy} = \frac{\phi_s}{k_g}$$

where ϕ_s is the sensible heat flux to the wall, and k_g is the thermal conductivity of the gas. The sensible heat flux used in the analysis is the convective heat transfer calculated as discussed in subsection 15B.2.4.7.

15B.2.2 Other Removal Mechanisms

In addition to the above mechanisms, there are others that were not considered, including turbulent diffusion and turbulent agglomeration. The neglect of these mechanisms adds further conservatism to the calculation.

15B.2.3 Validation of Removal Mechanisms

The aerosol processes are well established and have been confirmed in many separate effects experiments, which are discussed in standard references (References 2 through 4). The Stokes formula for sedimentation velocity has been well confirmed for particles whose diameters are less than about 50 μm. In the present calculations, these make up basically all of the aerosol.

There are some separate effects validations of the diffusiophoretic effect, but the best confirmation comes from integral experiments such as the LACE tests (Reference 5). Calculations of these and other integral tests accurately predict the integrated mass of plated aerosol material only if diffusiophoresis is taken into account. If it is neglected, the predicted plated mass is about two orders of magnitude too small, compared to the observed plated mass.

The Talbot equation for the thermophoretic effect has been experimentally confirmed to within about 20 to 50 percent over a wide range of particle sizes (Reference 4). The temperature gradient at the wall, which drives this phenomenon, can be approximated by the temperature difference between the bulk gas and the wall divided by an appropriate length scale obtained from heat transfer correlations. Alternatively, because sensible heat transfer rates to the wall are available, it is easier and more accurate to use these rates directly to infer the temperature gradient.

15B.2.4 Parameters and Assumptions for Calculating Aerosol Removal Coefficients

The parameters and assumptions were selected to conservatively model the environment that would be expected to exist as a result of a LOCA with concurrent core melt.

15B.2.4.1 Containment Geometry

The containment is assumed to be a cylinder with a volume of 55,481 m^3 (1.959 x 10^6 ft^3). This volume includes those portions of the containment volume that would be participating in the aerosol transport and mixing; this excludes dead-ended volumes and flooded compartments. The horizontal surface area available for aerosol deposition by sedimentation is 2900 m^2 (31,200 ft^2). This includes projecting areas such as decks in addition to the floor area and excludes areas in dead-ended volumes and areas that would be flooded post-LOCA. The surface area for Brownian diffusive plateout of aerosols is 8008 m^2 (86,166 ft^2).

15B.2.4.2 Source Size Distribution

The aerosol source size distribution is assumed to be lognormal, with a geometric mean radius of 0.22 μm and a geometric standard deviation equal to 1.81. These values are derived from an evaluation of a large number of aerosol distributions measured in a variety of degraded-fuel tests and experiments. The sensitivity of aerosol removal coefficient calculations to these values is small.

15B.2.4.3 Aerosol Void Fraction

Review of scanning electron microscope photographs of deposited aerosol particles from actual core melt and fission product vaporization and aerosolization experiments (the Argonne STEP-4 test and the INEL Power Burst Facility SFD 1-4 test) indicates that the deposited particles are relatively dense, supporting a void fraction of 0.2.

The above-mentioned test results indicate that a void fraction of 0.2 is appropriate for modeling the aerosols resulting from a core melt. As part of the sensitivity study that was performed for the AP600 project, a case was run with a void fraction of 0.9. That analysis showed that the high void fraction resulted in an integrated release of aerosols over a 24-hour period that was less than 14 percent greater than that calculated when using the void fraction of 0.2. Thus, it is clear that the removal of aerosols from the containment atmosphere is not highly sensitive to the value selected for the void fraction. This is largely due to the fact that, while the selected value for void fraction has a significant impact on the calculated sedimentation removal, the impact on thermophoresis and diffusiophoresis removal is slight or none. The impact for AP1000 of using the higher value for void fraction would be less than was determined for the AP600 since sedimentation removal comprises a smaller fraction of the total removal calculated for the AP1000.

For additional conservatism, the AP1000 aerosol removal analysis uses a void fraction of 0.4 and assumes the voids are filled with air.

15B.2.4.4 Fission Product Release Fractions

Core inventories of fission products are from ORIGEN calculations for the AP1000 at end of the fuel cycle. Fractional releases to the containment of the fission products are those specified in subsection 15.6.5.3.

15B.2.4.5 Inert Aerosol Species

The inert species include SnO_2, UO_2, Cd, Ag, and Zr. These act as surrogates for all inert materials forming aerosols. The ratio of the total mass of inert species to fission product species was assumed to be 1.5:1. This value and the partitioning of the total inert mass among its constituents are consistent with results from degraded fuel experiments (Reference 6).

15B.2.4.6 Aerosol Release Timing and Rates

Aerosol release timing is in accordance with the source term defined in subsection 15.6.5.3. Aerosol release takes place in two main phases: a gap release lasting for 0.5 hour, followed by an early in-vessel release of 1.3 hours duration. During each phase, the aerosols are assumed to be released at a constant rate. These rates were obtained for each species by combining its core inventory, release fraction, and times of release.

Only cesium and iodine are released during the gap release phase. During the in-vessel release phase, the other fission product and inert species are released as well.

15B.2.4.7 Containment Thermal-hydraulic Data

The thermal-hydraulic parameters used in the aerosol removal calculation are the containment gas temperature, the containment pressure, the steam condensation rate on the wall, the steam mole fraction, and the convective heat transfer rate, all as functions of time. The AP1000-specific parameters were obtained using MAAP4 (Reference 7) for the 3BE-1 severe accident sequence (medium LOCA with failure to inject water from the refueling water storage tank into the reactor vessel). The thermal-hydraulic data are thus consistent with a core melt sequence.

15B.2.5 Aerosol Removal Coefficients

The aerosol removal coefficients are provided in Table 15B-1 starting at the onset of core damage through 24 hours. The removal coefficients for times beyond 24 hours are not of concern because there would be so little aerosol remaining airborne at that time. The values range between 0.29 hr^{-1} and 1.1 hr^{-1} during the time between the onset of core damage (0.167 hour) and 24 hours.

These removal coefficients conservatively neglect steam condensation on the airborne particles, turbulent diffusion, and turbulent agglomeration. Additionally, the assumed source aerosol size is conservatively small being at the low end of the mass mean aerosol size range of 1.5 to 5.5 μm used in NUREG/CR-5966 (Reference 8). Selection of smaller aerosol size would underestimate sedimentation.

Unlike the case for the elemental iodine removal, there is no limit assumed on the removal of aerosols from the containment atmosphere.

15B.3 References

1. NUREG-0800, Section 6.5.2, Revision 2, "Containment Spray as a Fission Product Cleanup System."

2. Fuchs, N. A., The Mechanics of Aerosols, Pergamon Press, Oxford, 1964.

3. Waldmann, L., and Schmitt, K. H., "Thermophoresis and Diffusiophoresis of Aerosols," Aerosol Science, C. N. Davies, ed., Academic Press, 1966.

4. Talbot, L., Chang, R. K., Schefer, R. W., and Willis, D. R., "Thermophoresis of Particles in a Heated Boundary Layer," J. Fluid Mech. 101, 737-758 (1980).

5. Rahn, F. J., "The LWR Aerosol Containment Experiments (LACE) Project," Summary Report, EPRI-NP-6094D, Electric Power Research Institute, Palo Alto, Nov. 1988.

6. Petti, D. A., Hobbins, R. R., and Hagrman, D. L., "The Composition of Aerosols Generated during a Severe Reactor Accident: Experimental Results from the Power Burst Facility Severe Fuel Damage Test 1-4," Nucl. Tech. 105, p.334 (1994).

7. MAAP4 - Modular Accident Analysis Program for LWR Power Plants, Computer Code Manual, May 1994.

8. Powers D. A., and Burson, S. B., "A Simplified Model of Aerosol Removal by Containment Sprays," NUREG/CR-5966, June 1993.

9. Powers, D. A., "Monte Carlo Uncertainty Analysis of Aerosol Behavior in the AP600 Reactor Containment under Conditions of a Specific Design-Basis Accident, Part 1," Technical Evaluation Report, Sandia National Laboratories, June 1995.

Table 15B-1 (Sheet 1 of 3)

AEROSOL REMOVAL COEFFICIENTS IN THE AP1000 CONTAINMENT FOLLOWING A DESIGN BASIS LOCA WITH CORE MELT

Time Interval (hours)	Removal Coefficient (hr^{-1})
0.167 - 0.179	1.141
0.179 - 0.200	1.013
0.200 - 0.251	0.944
0.251 - 0.292	0.882
0.292 - 0.433	0.842
0.433 - 0.631	0.901
0.631 - 0.684	0.821
0.684 - 0.801	0.781
0.801 - 0.893	0.735
0.893 - 1.033	0.699
1.033 - 1.171	0.662
1.171 - 1.233	0.627
1.233 - 1.331	0.594
1.331 - 1.395	0.562
1.395 - 1.429	0.551
1.429 - 1.475	0.576
1.475 - 1.519	0.537
1.519 - 1.579	0.510
1.579 - 1.653	0.483
1.653 - 1.776	0.458
1.776 - 1.903	0.430
1.903 - 1.991	0.462
1.991 - 2.067	0.429
2.067 - 2.176	0.396
2.176 - 2.371	0.380
2.371 - 2.621	0.337

Table 15B-1 (Sheet 2 of 3)

AEROSOL REMOVAL COEFFICIENTS IN THE AP1000 CONTAINMENT FOLLOWING A DESIGN BASIS LOCA WITH CORE MELT

Time Interval (hours)	Removal Coefficient (hr^{-1})
2.621 - 2.822	0.320
2.822 - 2.872	0.357
2.872 - 2.973	0.327
2.973 - 3.176	0.302
3.176 - 3.684	0.287
3.684 - 3.737	0.328
3.737 - 3.839	0.304
3.839 - 3.990	0.298
3.990 - 4.090	0.317
4.090 - 4.438	0.346
4.438 - 4.684	0.369
4.684 - 4.880	0.396
4.880 - 4.928	0.449
4.928 - 5.362	0.435
5.362 - 5.460	0.459
5.460 - 5.511	0.518
5.511 - 5.608	0.487
5.608 - 6.040	0.479
6.040 - 6.090	0.537
6.090 - 6.615	0.506
6.615 - 6.753	0.567
6.753 - 7.194	0.513
7.194 - 7.285	0.594
7.285 - 7.814	0.518
7.814 - 7.904	0.581

Table 15B-1 (Sheet 3 of 3)

AEROSOL REMOVAL COEFFICIENTS IN THE AP1000 CONTAINMENT FOLLOWING A DESIGN BASIS LOCA WITH CORE MELT

Time Interval (hours)	Removal Coefficient (hr^{-1})
7.904 - 8.431	0.528
8.431 - 8.521	0.589
8.521 - 9.387	0.529
9.387 - 9.553	0.568
9.553 - 11.189	0.530
11.189 - 14.937	0.516
14.937 - 17.610	0.506
17.610 - 24	0.492

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16.1 Technical Specifications

16.1.1 Introduction to Technical Specifications

LCO Selection Criteria

The screening criteria of 10CFR50.36, c(2)(ii) stated below has been used to identify the structures, systems, and parameters for which Limiting Conditions for Operation (LCOs) have been included in the AP1000 Technical Specifications.

1. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

2. A process variable, design feature, or operating restriction that is an initial condition of a Design Basis Accident or Transient Analyses that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

3. A structure, system or component that is part of the primary success path and which functions or actuates to mitigate a Design Basis Accident or Transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

4. Structures, systems, and components which operating experience or probabilistic safety assessment has shown to be important to public health and safety.

Technical Specification Content

The content of the AP1000 Technical Specifications meets the 10CFR50.36 requirements and is consistent with the Technical Specification Improvement Program, NUREG 1431, Rev. 2, to the maximum extent possible. The content differs from NUREG 1431 only as necessary to reflect technical differences between the “typical” Westinghouse design and the AP1000 design.

<u>Completion Times and Surveillance Frequencies</u>

The Completion Times and Surveillance Frequencies specified in NUREG 1431 have been applied to similar Actions and Surveillances Requirements in AP1000. Refer to Westinghouse letter DCP/NRC0891 for a discussion regarding selection of Completion Times and Surveillance Frequencies for those AP1000 Tech Specs for which no comparable NUREG 1431 system/function exists and for those AP1000 system design differences which lead to deviations from NUREG 1431 Completion Times and Surveillance Frequencies.

<u>Shutdown Completion Times/Mode Definitions</u>

The AP1000 plant design is different from current Westinghouse designs in that the systems normally used for MODE reduction are non-safety systems; and therefore, are <u>not</u> covered by LCO requirements in Technical Specifications. The passive safety systems, which shut down the plant require a longer period of time to accomplish mode changes and can not reduce the RCS temperature to below 200°F.

LCO and Bases "TBD" Information

In cases where the detailed design, equipment selection, or other efforts are not sufficiently complete to establish the information required to be specified in Technical Specifications, "[TBD]" (to be determined) has been specified. Additionally, some of the information, such as that established by startup testing, will not be available until a plant is constructed.

Combined License Information

This set of technical specifications is intended to be used as a guide in the development of the plant-specific technical specifications. Combined License applicants referencing the AP1000 will replace preliminary information provided in brackets [ ] with final plant specific values.

3.4 REACTOR COOLANT SYSTEM (continued)

3.7 PLANT SYSTEMS (continued)

B 3.4 REACTOR COOLANT SYSTEM (continued)

B 3.7 PLANT SYSTEMS (continued)

1.0 USE AND APPLICATION

1.1 Definitions

- NOTE -

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION DEVICE TEST	An ACTUATION DEVICE TEST is a test of the actuated equipment. This test may consist of verification of actual operation but shall, at a minimum, consist of a continuity check of the associated actuated devices. The ACTUATION DEVICE TEST shall be conducted such that it provides component overlap with the ACTUATION LOGIC TEST.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state and the verification of the required logic output. The ACTUATION LOGIC TEST shall be conducted such that it provides component overlap with the ACTUATION DEVICE TEST.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two-section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for OPERABILITY. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable

1.1 Definitions

CHANNEL CALIBRATION (continued)

	devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of all devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY such that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping, or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these parameter limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same committed effective dose equivalent as the quantity and isotopic mixture of I-130, I-131, I-132, I-133, I-134, and I-135 actually present. The dose conversion factors used for this calculation shall be those listed in Table 2.1 of EPA Federal Guidance Report No. 11, “Limiting Values of Radionuclide

1.1 Definitions

DOSE EQUIVALENT I-131 (continued)

Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," EPA-520/1-88-020, September 1988.

DOSE EQUIVALENT XE-133

DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same effective dose equivalent as the quantity and isotopic mixture of noble gases (Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138) actually present. The dose conversion factors used for this calculation shall be those listed in Table III.1 of EPA Federal Guidance Report No. 12, "External Exposure to Radionuclides in Air, Water, and Soil," EPA 402-R-93-081, September 1993.

ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME

The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

   1. LEAKAGE, such as that from seals or valve packing, that is captured and conducted to collection systems or a sump or collecting tank;

   2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE;

1.1 Definitions

LEAKAGE (continued)

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System; or

4. RCS LEAKAGE through the passive residual heat removal heat exchanger (PRHR HX) to the In-containment Refueling Water Storage Tank (IRWST).

b. Unidentified LEAKAGE

All LEAKAGE that is not identified LEAKAGE.

c. Pressure Boundary LEAKAGE

LEAKAGE (except SG LEAKAGE and PRHR HX tube LEAKAGE) through a nonisolatable fault in a RCS component body, pipe wall, or vessel wall.

MODE

A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

OPERABLE-OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Chapter 14, Initial Test Program;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

1.1 Definitions

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits" and LCO 3.4.15, "Low Temperature Overpressure Protection (LTOP) System."
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3400 MWt.
REACTOR TRIP CHANNEL OPERATIONAL TEST (RTCOT)	A RTCOT shall be the injection of a simulated or actual signal into the RT (Reactor Trip) CHANNEL as close to the sensor as practicable to verify OPERABILITY of the required interlock and/or trip functions. The REACTOR TRIP CHANNEL OPERATIONAL TEST may be performed by means of a series of sequential, overlapping, or total channel steps so that the entire channel is tested from the signal conditioner through the trip logic.
REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) and grey rod cluster assemblies (GRCAs) are fully inserted except for the single assembly of highest reactivity worth, which is

1.1 Definitions

SHUTDOWN MARGIN (continued)

assumed to be fully withdrawn. However, with all RCCAs and GRCAs verified fully inserted by two independent means, it is not necessary to account for a stuck RCCA or GRCA in the SDM calculation. With any rod assembly(s) not capable of being fully inserted, the reactivity worth of these assemblies must be accounted for in the determination of SDM; and

b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.

STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during n Surveillance Frequency intervals, where n is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of all devices in the channel required for trip actuating device OPERABILITY. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy. The TADOT may be performed by means of any series of sequential, overlapping, or total channel steps.

Table 1.1-1 (page 1 of 1)
MODES

MODES	TITLE	REACTIVITY CONDITION (K_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	> 420
4	Safe Shutdown[b]	< 0.99	NA	$420 \geq T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.

(b) All reactor vessel head closure bolts fully tensioned.

(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Specifications to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in Technical Specifications are <u>AND</u> and <u>OR</u>. The physical arrangement of these connectors constitutes logical conventions with specific meaning.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentions of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.
EXAMPLES	The following examples illustrate the use of logical connectors.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example, the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip ... OR A.2.1 Verify ... AND A.2.2.1 Reduce ... OR A.2.2.2 Perform ... OR A.3 Align ...	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a <u>subsequent</u> train, subsystem, component, or variable, expressed in the Condition, is discovered to be inoperable or not within

1.3 Completion Times

DESCRIPTION (continued)

limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified “time zero.” This modified “time zero” may be expressed as a repetitive time (i.e., “once per 8 hours,” where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase “from discovery ....” Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Conditions A and B in example 1.3-3 may not be extended.

1.3 Completion Times

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 in 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One valve inoperable.	A.1 Restore valve to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a valve is declared inoperable, Condition A is entered. If the valve is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion time clocks for Required Actions B.1 and B.2 start. If the inoperable valve is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second valve is declared inoperable while the first valve is still inoperable, Condition A is not re-entered for the second valve. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable valve. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable valves is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

While in LCO 3.0.3, if one of the inoperable valves is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

1.3 Completion Times

EXAMPLES (continued)

On restoring one of the valves to OPERABLE status the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. This Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second valve being inoperable for > 7 days.

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion

1.3 Completion Times

EXAMPLES (continued)

Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected train was declared inoperable (i.e., initial entry into Condition A).

The Completion Times of Conditions A and B are modified by a logical connector with a separate 10 day Completion Time measured from the time it was discovered the LCO was not met. In this example, without the separate Completion Time, it would be possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. The separate Completion Time modified by the phrase “from discovery of failure to meet the LCO” is designed to prevent indefinite continued operation while not meeting the LCO. This Completion Time allows for an exception to the normal “time zero” for beginning the Completion Time “clock”. In this instance, the Completion Time “time zero” is specified as commencing at the time the LCO was initially not met, instead of at the time the associated Condition was entered.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours. If the Completion Time of 4 hours (including the extension) expires while one or more valves are still inoperable, Condition B is entered.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

- NOTE -
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was only applicable to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve which caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve. Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a “once per” Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hours interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour, or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

1.3 Completion Times

IMMEDIATE COMPLETION TIME	When “Immediately” is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The “specified Frequency” is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The “specified Frequency” consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are “otherwise stated” conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillances, or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only “required” when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of “met” or “performed” in these instances conveys specific meanings. A Surveillance is “met” only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not “met.” “Performance” refers only to the requirement to specifically determine the ability to meet the acceptance criteria.

Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be

1.4 Frequency

DESCRIPTION (continued)

performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discusses these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated surveillance must be performed at least one time. Performance of the surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR in not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside the specified limits, or the Unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector “AND” indicates that both Frequency requirements must be met. Each time the reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the surveillance must be performed within 12 hours.

The use of “Once” indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by “AND”). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. “Thereafter” indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the “once” performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-- **- NOTE -** Not required to be performed until 12 hours after ≥ 25% RTP. -- Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the “specified Frequency.” Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the “specified Frequency.” Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
--- **- NOTE -** Only required to be met in MODE 1. --- Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an “otherwise stated” exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
--- **- NOTE -** Only required to be performed in MODE 1. --- Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
--- **- NOTE -** Not required to be met in MODE 3. --- Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained ≥ [1.14 for the WRB-2M DNB correlations].

2.1.1.2 The peak fuel centerline temperature shall be maintained < [5080°F, decreasing by 58°F per 10,000 MWD/MTU of burnup].

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5 the RCS pressure shall be maintained ≤ 2733.5 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.0 LIMITING CONDITIONS FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and 3.0.6.

If the LCO is met, or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours; and

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall not be made except when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or are part of a shutdown of the unit.

Exceptions to this Specification are stated in the individual Specifications.

LCO 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, 3, and 4.

3.0 LCO Applicability

LCO 3.0.5	Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the test required to demonstrate OPERABILITY.
LCO 3.0.6	When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.5.7, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.
LCO 3.0.7	Test Exception LCO 3.1.8 allows specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.
LCO 3.0.8	When an LCO is not met and the associated ACTIONS are not met or an associated ACTION is not provided, action shall be initiated within 1 hour to: a. Restore inoperable equipment and b. Monitor Safety System Shutdown Monitoring Trees parameters Exceptions to this Specification are stated in the individual Specifications.

3.0 LCO Applicability

LCO 3.0.8 (continued)

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.8 is not required.

LCO 3.0.8 is only applicable in MODES 5 and 6.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified Conditions in the Applicability of individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the surveillance or between performances of the Surveillance, shall be a failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as “once”, the above interval extension does not apply.

If a Completion Time requires periodic performance on a “once per...” basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, which ever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

When the Surveillance is performed within the delay period, and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

3.0 SR Applicability

SR 3.0.4

Entry into a MODE or other specified condition in the Applicability of a LCO shall not be made unless the LCO's Surveillances have been met within their specified Frequency. This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

SR 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, 3, and 4.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 The SDM shall be within the limits specified in the COLR.

APPLICABILITY: MODE 2 with keff < 1.0,
MODES 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limits.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within limits.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ±1% Δk/k of the normalized predicted values.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Measured core reactivity not within limit.	A.1	Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	7 days
	<u>AND</u>		
	A.2	Establish appropriate operating restrictions and SRs.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	-------------------- - NOTE - -------------------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. -- Verify measured core reactivity is within ±1% Δk/k of predicted values.	Prior to entering MODE 1 after each refueling AND ---------- - NOTE - ---------- Only required after 60 EFPD -------------------- 31 EFPD thereafter

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR.

APPLICABILITY: MODE 1, and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. MTC not within upper limit.	A.1	Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC within upper limit.	Prior to entering MODE 1 after each refueling

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.3.2	- NOTES - 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. Verify MTC is within lower limit.	Once each cycle

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE. Individual indicated rod positions shall be within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM within limit.	1 hour
	<u>AND</u>	
	A.2 Be in MODE 3.	6 hours
B. One rod not within alignment limits.	B.1 Restore rod, to within alignment limits.	8 hours with the On-Line Power Distribution Monitoring System (OPDMS) OPERABLE <u>OR</u> 1 hour with the OPDMS inoperable
	<u>OR</u>	
	B.2.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	<u>OR</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.2.1.2 Initiate boration to restore SDM within limit.	1 hour
	AND	
	B.2.2 Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	AND	
	B.2.3 Verify SDM is within the limits specified in the COLR.	Once per 12 hours
	AND	
	- NOTE - Only required to be performed when OPDMS is inoperable.	
	B.2.4 Perform SR 3.2.1.1 ($F_Q(Z)$ verification) and SR 3.2.1.2 ($F_Q^W(Z)$ verification).	72 hours
	AND	
	- NOTE - Only required to be performed when OPDMS is inoperable.	
	B.2.5 Perform SR 3.2.2.1 ($F_{\Delta H}^N$ verification).	72 hours
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	B.2.6	Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C. Required Action and associated Completion Time for Condition B not met.	C.1	Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1	Verify SDM is within the limits specified in the COLR.	1 hour
	OR		
	D.1.2	Initiate boration to restore required SDM to within limit.	1 hour
	AND		
	D.2	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	12 hours
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is $\leq$ [2.47] seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$, and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each Shutdown Bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODES 1 and 2.

- NOTE -

This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Restore shutdown banks to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the insertion limits specified in the COLR.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

- NOTE -

This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control Bank insertion limits not met.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Restore control bank(s) to within limits.	2 hours
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	B.2	Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify the estimated critical control bank position is within limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	12 hours
SR 3.1.6.3	Verify sequence and overlap limits, specified in the COLR, are met for control banks not fully withdrawn from the core.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Digital Rod Position Indication (DRPI) System and the Bank Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DRPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators by using the On-line Power Distribution Monitoring System (OPDMS).	Once per 8 hours
	OR	
	A.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
B. More than one DRPI per group inoperable.	B.1 Place the control rods under manual control.	Immediately
	AND	
	B.2 Monitor and Record RCS T_{avg}.	Once per 1 hour
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	B.3	Verify the position of the rods with inoperable position indicators indirectly by using the incore detectors.	Once per 8 hours
	<u>AND</u>		
	B.4	Restore inoperable position indicators to OPERABLE status such that a maximum of one DRPI per group is inoperable.	24 hours
C. One or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	C.1	Verify the position of the rods with inoperable position indicators by using the OPDMS.	4 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
D. One demand position indicator per bank inoperable for one or more banks.	D.1.1	Verify by administrative means all DRPIs for the affected banks are OPERABLE.	Once per 8 hours
	<u>AND</u>		
	D.1.2	Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart.	Once per 8 hours
	<u>OR</u>		
	D.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Required Action and associated Completion Time not met.	E.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify each DRPI agrees within 12 steps of the group demand position for the [full indicated range] of rod travel.	Prior to criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions – MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of:

LCO 3.1.3 "Moderator Temperature Coefficient,"
LCO 3.1.4 "Rod Group Alignment Limits,"
LCO 3.1.5 "Shutdown Bank Insertion Limit,"
LCO 3.1.6 "Control Bank Insertion Limits," and
LCO 3.4.2 "RCS Minimum Temperature for Criticality"

may be suspended, and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, 6, and 16.c, may be reduced to 3 provided:

a. RCS lowest loop average temperature is ≥ [535]°F,

b. SDM is within the limits specified in the COLR, and

c. THERMAL POWER is < 5% RTP.

APPLICABILITY: During PHYSICS TESTS initiated in MODE 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. AND A.2 Suspend PHYSICS TESTS exceptions.	15 minutes 1 hour
B. THERMAL POWER not within limit.	B.1 Open reactor trip breakers.	Immediately
C. RCS lowest loop average temperature not within limit.	C.1 Restore RCS lowest loop average temperature to within limit.	15 minutes

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and Associated Completion Time of Condition C not met.	D.1	Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.7.	Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the RCS lowest loop average temperature is ≥ [535]°F.	30 minutes
SR 3.1.8.3	Verify THERMAL POWER is < 5% RTP.	30 minutes
SR 3.1.8.4	Verify SDM is within the limits specified in the COLR.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.9 Chemical and Volume Control System (CVS) Demineralized Water Isolation Valves

LCO 3.1.9 Two CVS Demineralized Water Isolation Valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One CVS demineralized water isolation valve inoperable.	A.1	Restore two CVS demineralized water isolation valves to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition not met. <u>OR</u> Two CVS demineralized water isolation valves inoperable.	B.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------ Isolate the flow path from the demineralized water storage tank to the Reactor Coolant System by use of at least one closed manual or one closed and de-activated automatic valve.	 1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.9.1	Verify two CVS demineralized water isolation valves are OPERABLE by stroking the valve closed.	In accordance with the Inservice Testing Program

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (F_Q Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1 with On-line Power Distribution Monitoring System (OPDMS) inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------------------------- **- NOTE -** Required Action A.4 shall be completed whenever this Condition is entered. --------------------------------	A.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit.	15 minutes after each $F_Q^C(Z)$ determination
	<u>AND</u>	
$F_Q^C(Z)$ not within limit.	A.2 Reduce Power Range Neutron Flux – High trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	<u>AND</u>	
	A.3 Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	<u>AND</u>	
	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. -------------------------------- **- NOTE -** Required Action B.4 shall be completed whenever this Condition is entered. -------------------------------- $F_Q^W(Z)$ not within limits.	B.1	Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	<u>AND</u>		
	B.2	Reduce Power Range Neutron Flux – High trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>		
	B.3	Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>		
	B.4	Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

- NOTES -

1. During power escalation at the beginning of each cycle, THERMAL POWER may be increased until a power level for extended operation has been achieved at which a power distribution map is obtained.

2. If the OPDMS becomes inoperable while in MODE 1 these surveillances must be performed within 31 days of the last verification of OPDMS parameters.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q^C(Z)$ within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> 31 EFPD thereafter

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	-------------------- **- NOTE -** -------------------- If $F_Q^W(Z)$ measurements indicate maximum over z$[F_Q^C(Z)]$ has increased since the previous evaluation of $F_Q^C(Z)$: a. Increase $F_Q^W(Z)$ by the appropriate factor and reverify $F_Q^W(Z)$ is within limits; or b. Repeat SR 3.2.1.2 once per 7 EFPD until two successive flux maps indicate maximum over z$[F_Q^C(Z)]$ has not increased. ---	
	Verify $F_Q^W(Z)$ within limits.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^W(Z)$ was last verified <u>AND</u> 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1 with On-line Power Distribution Monitoring System (OPDMS) inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------------------------- **- NOTE –** Required Actions A.2 and A.3 must be completed whenever Condition A is entered. -------------------------------- $F^N_{\Delta H}$ not within limit.	A.1.1 Restore $F^N_{\Delta H}$ to within limit. <u>OR</u> A.1.2.1 Reduce THERMAL POWER to < 50% RTP. <u>AND</u> A.1.2.2 Reduce Power Range Neutron Flux – High trip setpoints to ≤ 55% RTP. <u>AND</u> A.2 Perform SR 3.2.2.1. <u>AND</u>	4 hours 4 hours 72 hours 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.3	------------------------------------ **- NOTE -** THERMAL POWER does not have to be reduced to comply with this Required Action. ------------------------------------ Perform SR 3.2.2.1.	Prior to THERMAL POWER exceeding 50% RTP <u>AND</u> Prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.2.1	--- **- NOTE -** If the OPDMS becomes inoperable while in MODE 1 these Surveillances must be performed within 31 days of the last verification of OPDMS parameters. --- Verify $F^N_{\Delta H}$ within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Relaxed Axial Offset Control (RAOC) Methodology)

LCO 3.2.3 The AFD in %-flux-difference units shall be maintained within the limits specified in the COLR.

- NOTE -

The AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

APPLICABILITY: MODE 1 with THERMAL POWER ≥ 50% RTP and with the On-Line Power Distribution Monitoring System (OPDMS) inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits.	A.1 Reduce THERMAL POWER to < 50% RTP.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD within limits for each OPERABLE excore channel.	7 days

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP and with the OPDMS inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. QPTR not within limit.	A.1 Reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR > 1.00.	2 hours after each QPTR determination
	AND	
	A.2 Perform SR 3.2.4.1.	Once per 12 hours
	AND	
	A.3 Perform SR 3.2.1.1 and SR 3.2.2.1.	24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 AND Once per 7 days thereafter
	AND	
	A.4 Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.5	------------------------------------ **- NOTES -** 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. ------------------------------------	
		Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>		
	A.6	------------------------------------ **- NOTE -** Perform Required Action A.6 only after Required Action A.5 is completed. ------------------------------------	
		Perform SR 3.2.1.1, SR 3.2.1.2, and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Action A.1
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	-- **- NOTES -** 1. With one power range channel inoperable and THERMAL POWER < 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. -- Verify QPTR within limit by calculation.	7 days
SR 3.2.4.2	-- **- NOTE -** Not required to be performed until 12 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER ≥ 75% RTP. -- Verify QPTR is within limit using a minimum of 4 symmetric pairs of fixed incore detectors.	12 hours

3.2 POWER DISTRIBUTION LIMITS

3.2.5 OPDMS-Monitored Power Distribution Parameters

LCO 3.2.5 The following parameters shall not exceed their operating limits as specified in the COLR:

a. Peak kw/ft(Z)
b. $F^N_{\Delta H}$
c. DNBR.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP with OPDMS OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the parameters a. through c. above not within limits.	A.1 Restore all parameters to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1 ------------------------------------ **- NOTE -** If the power distribution parameters are restored to within their limits while power is being reduced, operation may continue at the power level where this occurs. ------------------------------------ Reduce THERMAL POWER to < 50% RTP.	 4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.5.1	Verify the parameters a. through c. to be within their limits.	24 hours with OPDMS alarms OPERABLE <u>OR</u> 12 hours with OPDMS alarms inoperable

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s).	Immediately
B. One manual initiation device inoperable.	B.1 Restore manual initiation device to OPERABLE status.	48 hours
	<u>OR</u>	
	B.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	B.2.2 Open reactor trip breakers (RTBs).	55 hours
C. One manual initiation device inoperable.	C.1 Restore manual initiation device to OPERABLE status.	48 hours
	<u>OR</u>	
	C.2 Open RTBs.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or two Power Range Neutron Flux – High channels inoperable.	D.1.1 Reduce THERMAL POWER to ≤ 75% RTP.	12 hours
	AND	
	D.1.2 Place one inoperable channel in bypass or trip.	[6] hours
	AND	
	D.1.3 With two inoperable channels, place one channel in bypass and one channel in trip.	[6] hours
	OR	
	D.2.1 Place inoperable channel(s) in bypass.	[6] hours
	AND	
	------------------------------------ **- NOTE -** Only required to be performed when OPDMS is inoperable and the Power Range Neutron Flux input to QPTR is inoperable. ------------------------------------	
	D.2.2 Perform SR 3.2.4.2 (QPTR verification).	Once per 12 hours
	OR	
	D.3 Be in MODE 3.	12 hours
E. One or two channels inoperable.	E.1.1 Place one inoperable channel in bypass or trip.	[6] hours
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	E.1.2 With two channels inoperable, place one channel in bypass and one channel in trip.	[6] hours
	OR	
	E.2 Be in MODE 3.	12 hours
F. THERMAL POWER between P-6 and P-10, one or two Intermediate Range Neutron Flux channels inoperable.	F.1.1 Place one inoperable channel in bypass or trip.	[2] hours
	AND	
	F.1.2 With two channels inoperable, place one channel in bypass and one channel in trip.	[2] hours
	OR	
	F.2 Reduce THERMAL POWER to < P-6.	2 hours
	OR	
	F.3 Increase THERMAL POWER to > P-10.	2 hours
G. THERMAL POWER between P-6 and P-10, three Intermediate Range Neutron Flux channels inoperable.	G.1 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours
H. THERMAL POWER < P-6, one or two Intermediate Range Neutron Flux channels inoperable.	H.1 Restore three of four channels to OPERABLE status.	Prior to increasing THERMAL POWER to > P-6

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One or two Source Range Neutron Flux channels inoperable.	I.1 Suspend operations involving positive reactivity additions.	Immediately
J. Three Source Range Neutron Flux channels inoperable.	J.1 Open RTBs.	Immediately
K. One or two channels inoperable.	K.1.1 Place one inoperable channel in bypass or trip.	[6] hours
	AND	
	K.1.2 With two channels inoperable, place one channel in bypass and one channel in trip.	[6] hours
	OR	
	K.2 Reduce THERMAL POWER to < P-10.	12 hours
L. One or two channels inoperable.	L.1.1 Place one inoperable channel in bypass or trip.	[6] hours
	AND	
	L.1.2 With two channels inoperable, place one channel in bypass and one channel in trip.	[6] hours
	OR	
	L.2 Reduce THERMAL POWER to < P-8.	10 hours
M. One or two channels/ divisions inoperable.	M.1 Restore three of four channels/divisions to OPERABLE status.	6 hours
	OR	
	M.2 Be in MODE 3.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
N. One or two interlock channels inoperable.	N.1	Verify the interlocks are in required state for existing plant conditions.	1 hour
	OR		
	N.2.1	Place the Functions associated with one inoperable interlock channel in bypass or trip.	[7] hours
	AND		
	N.2.2	With two interlock channels inoperable, place the Functions associated with one inoperable interlock channel in bypass and with one inoperable interlock channel in trip.	[7] hours
	OR		
	N.3	Be in MODE 3.	13 hours
O. One or two interlock channels inoperable.	O.1	Verify the interlocks are in required state for existing plant conditions.	1 hour
	OR		
	O.2.1	Place the Functions associated with one inoperable interlock channel in bypass.	[7] hours
	AND		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	O.2.2 With two interlock channels inoperable, place the Functions associated with one inoperable interlock channel in bypass and with one inoperable interlock channel in trip.	[7] hours
	OR	
	O.3 Be in MODE 2.	13 hours
P. One division inoperable.	P.1 Open RTBs in inoperable division.	8 hours
	OR	
	P.2.1 Be in MODE 3, 4, or 5.	14 hours
	AND	
	P.2.2 Open RTBs.	14 hours
Q. Two divisions inoperable.	Q.1 Restore three of four divisions to OPERABLE status.	1 hour
	OR	
	Q.2.1 Be in MODE 3, 4, or 5.	7 hours
	AND	
	Q.2.2 Open RTBs.	7 hours
R. One or two channels/ divisions inoperable.	R.1 Restore three of four channels/divisions to OPERABLE status.	48 hours
	OR	
	R.2 Open RTBs.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
S. One or two Source Range Neutron Flux channel inoperable.	S.1 Restore three of four channels to OPERABLE status. <u>OR</u> S.2 Open RTBs.	[48] hours [49] hours
T. Required Source Range Neutron Flux channel inoperable.	T.1 Suspend operations involving positive reactivity additions. <u>AND</u> T.2 Close unborated water source isolation valves. <u>AND</u> T.3 Perform SR 3.1.1.1.	Immediately 1 hour 1 hour <u>AND</u> Once per 12 hours thereafter

SURVEILLANCE REQUIREMENTS

- NOTE -

Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.2	-- **- NOTES -** 1. Adjust nuclear instrument channel in the Protection and Safety Monitoring System (PMS) if absolute difference is > 1% RTP. 2. Required to be met within 12 hours after reaching 15% RTP. 3. If the calorimetric heat balance is < 70% RTP, and if the nuclear instrumentation channel indicated power is: a. lower than the calorimetric measurement by > 1%, then adjust the nuclear instrumentation channel upward to match the calorimetric measurement. b. higher than the calorimetric measurement, then no adjustment is required. -- Compare results of calorimetric heat balance to nuclear instrument channel output.	24 hours
SR 3.3.1.3	-- **- NOTES -** 1. Adjust nuclear instrument channel in PMS if absolute difference is ≥ 3% AFD. 2. Required to be met within 24 hours after reaching 20% RTP. -- Compare results of the incore detector measurements to nuclear instrument channel AXIAL FLUX DIFFERENCE.	31 effective full power days (EFPD)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.4	-- **- NOTE -** Required to be met within 24 hours after reaching 50% RTP. -- Calibrate excore channels to agree with incore detector measurements.	92 EFPD
SR 3.3.1.5	-- **- NOTE -** This Surveillance must be performed on both reactor trip breakers associated with a single division. -- Perform TADOT.	92 days on a STAGGERED TEST BASIS
SR 3.3.1.6	-- **- NOTE -** Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. -- Perform RTCOT.	[92] days

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.7	--- **- NOTE -** This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform RTCOT.	------------------------ **- NOTE -** Only required when not performed within previous 92 days ------------------------ Prior to reactor startup <u>AND</u> Four hours after reducing power below P-10 for power and intermediate instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> Every 92 days thereafter
SR 3.3.1.8	--- **- NOTE -** This Surveillance shall include verification that the time constants are adjusted to the prescribed values. --- Perform CHANNEL CALIBRATION.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	-- **- NOTE -** Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.10	-- **- NOTE -** Verification of setpoint is not required. -- Perform TADOT.	24 months
SR 3.3.1.11	-- **- NOTE -** Neutron detectors are excluded from response time testing. -- Verify RTS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.1-1 (page 1 of 5)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.10	N/A	N/A
	3(a),4(a),5(a)	2	C	SR 3.3.1.10	N/A	N/A
2. Power Range Neutron Flux						
a. High Setpoint	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.11		≤ [118]% RTP
b. Low Setpoint	1(b),2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.9 SR 3.3.1.11		≤ [35]% RTP
3. Power Range Neutron Flux High Positive Rate	1,2	4	E	SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.11		≤ [5.0]% RTP with time constant ≥ [2] sec*
4. Intermediate Range Neutron Flux	1(b),2(c)	4	F,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.9		≤ [25]% RTP*
	2(d)	4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.9		≤ [25]% RTP*
5. Source Range Neutron Flux High Setpoint	2(d)	4	I,J	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.9 SR 3.3.1.11		≤ [1.0E5] cps*
	3(a),4(a),5(a)	4	J,S	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.11		≤ [1.0E5] cps*
	3(e),4(e),5(e)	1	T	SR 3.3.1.1 SR 3.3.1.9	N/A	N/A

(a) With Reactor Trip Breakers (RTBs) closed and Plant Control System capable of rod withdrawal.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(e) With RTBs open. In this condition, Source Range Function does not provide reactor trip but does provide indication.

[Reviewer Note: The values specified in brackets in the Trip Setpoint column are the Chapter 15 safety analysis values and are included for reviewer information only.

The values specified in brackets followed by " * " in the Trip Setpoint column are typical values for the Function. No credit was assumed for these Functions (typically diverse trips/actuations) in the Chapter 15 safety analyses and no safety analysis value is available.

In all cases, the values specified in brackets must be replaced, following the plant-specific setpoint study, with the actual Trip Setpoints. Upon selection of the plant specific instrumentation, the Trip Setpoints will be calculated in accordance with the setpoint methodology described in WCAP-14606. (WCAP-14606 is an AP600 document that describes a methodology that is applicable to AP1000. AP1000 has some slight differences in instrument spans as a result of the higher power level.) Allowable Values will be calculated in accordance with the setpoint methodology and specified in the Allowable Value column. The plant specific setpoint calculations will reflect the latest licensing analysis/design basis and may incorporate NRC accepted improvements in setpoint methodology.]

Table 3.3.1-1 (page 2 of 5)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
6. Overtemperature ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.4 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11	Refer to Note 1 (Page 3.3.1-16)	Refer to Note 1 (Page 3.3.1-16)
7. Overpower ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11	Refer to Note 2 (Page 3.3.1-16)	Refer to Note 2 (Page 3.3.1-16)
8. Pressurizer Pressure a. Low Setpoint	1(f)	4	K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≥ [1785] psig
b. High Setpoint	1,2	4	E	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≤ [2445] psig
9. Pressurizer Water Level – High 3	1(f)	4	K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8		≤ [80]%*
10. Reactor Coolant Flow – Low						
a. Single Hot Leg	1(g)	4 per hot leg	L	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≥ [87]%(i)
b. Both Hot Legs	1(h)	4 per hot leg	K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≥ [87]%(i)

(f) Above the P-10 (Power Range Neutron Flux) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-10 (Power Range Neutron Flux) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(i) Percent of thermal design flow.

Table 3.3.1-1 (page 3 of 5)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11. Reactor Coolant Pump (RCP) Bearing Water Temperature – High						
a. Single Pump	1(g)	4 per RCP	L	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8		≥ [320]°F*
b. Two Pumps	1(h)	4 per RCP	K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8		≥ [320]°F*
12. RCP Speed – Low	1(f)	4	K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8		≥ [90]%
13. Steam Generator (SG) Narrow Range Water Level – Low	1,2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≥ [95,000] lbm
14. Steam Generator (SG) Narrow Range Water Level – High 2	1,2(k)	4 per SG	E	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.11		≤ [100]%
15. Safeguards Actuation Input from Engineered Safety Feature Actuation System						
a. Manual	1,2	2	B	SR 3.3.1.10	N/A	N/A
b. Automatic	1,2	4	M	SR 3.3.1.6	N/A	N/A

(f) Above the P-10 (Power Range Neutron Flux) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-10 (Power Range Neutron Flux) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) Above the P-11 (Pressurizer Pressure) interlock.

Table 3.3.1-1 (page 4 of 5)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
16. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	2	4	N	SR 3.3.1.6 SR 3.3.1.9		≥ [1E-10] amps
b. Power Range Neutron Flux, P-8	1	4	O	SR 3.3.1.6 SR 3.3.1.9		≤ [48]% RTP*
c. Power Range Neutron Flux, P-10	1,2	4	N	SR 3.3.1.6 SR 3.3.1.9		[10]% RTP
d. Pressurizer Pressure, P-11	1,2	4	N	SR 3.3.1.6 SR 3.3.1.9		≤ [1970] psig
17. Reactor Trip Breakers	1,2 3(j),4(j),5(j)	4 divisions with 2 RTBs per division	P,Q	SR 3.3.1.5	N/A	N/A
18. Reactor Trip Breaker (RTB) Undervoltage and Shunt Trip Mechanisms	1,2 3(j),4(j),5(j)	1 each per RTB mechanism	P,Q	SR 3.3.1.5	N/A	N/A
19. Automatic Trip Logic	1,2 3(j),4(j),5(j)	4 divisions 4 divisions	M R	SR 3.3.1.6 SR 3.3.1.6	N/A N/A	N/A N/A
20. ADS Stages 1, 2, and 3 Actuation input from engineered safety feature actuation system						
a. Manual	1,2 3(j),4(j),5(j)	2 switch sets 2 switch sets	B B	SR 3.3.1.10 SR 3.3.1.10	N/A N/A	N/A N/A
b. Automatic	1,2 3(j),4(j),5(j)	4 4	M R	SR 3.3.1.6 SR 3.3.1.6	N/A N/A	N/A N/A
21. Core Makeup Tank Actuation input from engineered safety feature actuation system						
a. Manual	1,2 3(j),4(j),5(j)	2 switch sets 2 switch sets	B B	SR 3.3.1.10 SR 3.3.1.10	N/A N/A	N/A N/A
b. Automatic	1,2 3(j),4(j),5(j)	4 4	M R	SR 3.3.1.6 SR 3.3.1.6	N/A N/A	N/A N/A

(j) With Reactor Trip Breakers closed and Plant Control System capable of rod withdrawal.

Table 3.3.1-1 (page 5 of 5)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following nominal Trip Setpoint by more than [TBD]% of ΔT span.

$$\Delta T \frac{(1+\tau_4 s)}{(1+\tau_5 s)} \leq \Delta T_0 \left\{ K_1 - K_2 \frac{(1+\tau_1 s)}{(1+\tau_2 s)} \left[T - T' \right] + K_3 (P - P') - f_1(\Delta I) \right\}$$

Where: ΔT is measured RCS ΔT, °F.

ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.

T′ is the indicated T_{avg} at RTP, ≤ [*]°F.

P is the measured pressurizer pressure, psig.

P′ is the nominal RCS operating pressure, 2235 psig.

$K_1 \leq$ [*] $K_2 \geq$ [*]/°F $K_3 \geq$ [*]/psig

$\tau_1 \geq$ [*] sec $\tau_2 \leq$ [*] sec

$\tau_4 \geq$ [*] sec $\tau_5 \leq$ [*] sec

$f_1(\Delta I)$ = [*] {[*] + $(q_t - q_b)$} when $q_t - q_b \leq$ -[*]% RTP

0% of RTP when -[*]% RTP < $q_t - q_b \leq$ [*]% RTP

-[*]{$(q_t - q_b)$ - [*]} when $q_t - q_b$ > [*]% RTP

Where q_t and q_b are percent RTP in the upper and lower halves of the core respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

*These values denoted with [*] are specified in the COLR.

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following nominal Trip Setpoint by more than [TBD]% of ΔT span.

$$\Delta T \frac{(1+\tau_4 s)}{(1+\tau_5 s)} \leq \Delta T_0 \left\{ K_4 - K_5 \frac{\tau_3 s}{1+\tau_3 s} T - K_6 \left[T - T'' \right] - f_2(\Delta I) \right\}$$

Where: ΔT is measured RCS ΔT, °F.

ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.

T″ is the nominal T_{avg} at RTP, ≤ [*]°F.

$K_4 \leq$ [*] $K_5 \geq$ [*]/°F for increasing T_{avg} $K_6 \geq$ [*]/°F when T > T″

[*]/°F for decreasing T_{avg} [*]/°F when T ≤ T″

$\tau_3 \geq$ [*] sec $\tau_4 \geq$ [*] sec $\tau_5 \leq$ [*] sec

$f_2(\Delta I)$ = [*]

*These values denoted with [*] are specified in the COLR.

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

- NOTES -

1. Separate condition entry is allowed for each Function.
2. The Conditions for each Function are given in Table 3.3.2-1. If the Required Actions and associated Completion Times of the first Condition are not met, refer to the second Condition.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or divisions inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or division(s).	Immediately
B. One or two channels or divisions inoperable.	B.1 Place one inoperable channel or division in bypass or trip.	[6] hours
	<u>AND</u>	
	B.2 With two inoperable channels or divisions, place one inoperable channel or division in bypass and one inoperable channel or division in trip.	[6] hours
C. One channel inoperable.	C.1 Place inoperable channel in bypass.	[6] hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required division inoperable.	D.1 Restore required division to OPERABLE status.	6 hours
E. One switch or switch set inoperable.	E.1 Restore switch and switch set to OPERABLE status.	48 hours
F. One channel inoperable.	F.1 Restore channel to OPERABLE status.	72 hours
	OR	
	F.2.1 Verify alternate radiation monitors are OPERABLE.	72 hours
	AND	
	F.2.2 Verify control room isolation and air supply initiation manual controls are OPERABLE.	72 hours
G. One switch, switch set, channel, or division inoperable.	G.1 Restore switch, switch set, channel, and division to OPERABLE status.	72 hours
H. One channel inoperable.	H.1 Place channel in trip.	6 hours
I. One or two channels inoperable.	I.1 Place one inoperable channel in bypass or trip.	[6] hours
	AND	
	I.2 With two inoperable channels, place one channel in bypass and one channel in trip.	[6] hours
J. One or two interlock channels inoperable.	J.1 Verify the interlocks are in the required state for the existing plant conditions.	1 hour
	OR	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	J.2.1	Place the Functions associated with one inoperable interlock channel in bypass or trip.	[7] hours
	<u>AND</u>		
	J.2.2	With two interlock channels inoperable, place the Functions associated with one inoperable interlock channel in bypass and with one inoperable interlock channel in trip.	[7] hours
K. Required Action and associated Completion Time not met.	K.1	------------------------------------ **- NOTE -** LCO 3.0.8 is not applicable. ------------------------------------ Suspend movement of irradiated fuel assemblies.	Immediately
L. Required Action and associated Completion Time not met.	L.1	Be in MODE 3.	6 hours
M. Required Action and associated Completion Time not met.	M.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	M.2	Be in MODE 4.	12 hours
N. Required Action and associated Completion Time not met.	N.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	N.2	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
O. Required Action and associated Completion Time not met.	O.1	Be in MODE 3.	6 hours
	AND		
	O.2	Be in MODE 5.	36 hours
P. Required Action and associated Completion Time not met.	P.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s).	24 hours
	AND		
	P.2.1	Isolate the affected flow path(s) by use of at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	7 days
	OR		
	P.2.2	Verify the affected flow path is isolated.	Once per 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Q. Required Action and associated Completion Time not met.	Q.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s) by use of at least one closed manual or closed and de-activated automatic valve.	6 hours
	<u>OR</u>		
	Q.2.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	Q.2.2	Be in MODE 4.	18 hours
R. Required Action and associated Completion Time not met.	R.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	R.2.1.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s).	12 hours
	<u>AND</u>		
	R.2.1.2	Verify the affected flow path is isolated.	Once per 7 days
	<u>OR</u>		
	R.2.2	Be in MODE 4 with the RCS cooling provided by the RNS.	30 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
S. Required Action and associated Completion Time not met.	S.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	S.2.1.1	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours
	<u>AND</u>		
	S.2.1.2	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s).	30 hours
	<u>AND</u>		
	S.2.1.3	Verify the affected flow path is isolated.	Once per 7 days
	<u>OR</u>		
	S.2.2	Be in MODE 5.	42 hours
T. Required Action and associated Completion Time not met.	T.1.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s).	6 hours
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	T.1.2.1 Isolate the affected flow path(s) by use of at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	7 days
	<u>OR</u>	
	T.1.2.2 Verify the affected flow path is isolated.	Once per 7 days
	<u>OR</u>	
	T.2.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	T.2.2 Be in MODE 5.	42 hours
U. Required Action and associated Completion Time not met.	U.1 Be in MODE 5.	12 hours
	<u>AND</u>	
	U.2 Initiate action to open the RCS pressure boundary and establish a pressurizer level ≥ 20%.	12 hours
V. Required Action and associated Completion Time not met.	V.1 Restore the inoperable channel(s).	168 hours
	<u>OR</u>	
	V.2.1 Be in MODE 5.	180 hours
	<u>AND</u>	
	V.2.2 Initiate action to open the RCS pressure boundary and establish a pressurizer level ≥ 20%.	180 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
W. Required Action and associated Completion Time not met.	W.1	If in MODE 5 with the RCS open and < 20% pressurizer level, initiate action to be MODE 5 with the RCS pressure boundary open and ≥ 20% pressurizer level.	Immediately
	AND		
	W.2	If in MODE 5, isolate the flow path from the demineralized water storage tank to the RCS by use of at least one closed and de-activated automatic valve or closed manual valve.	Immediately
	AND		
	W.3	If in MODE 6, initiate action to be in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange.	Immediately
	AND		
	W.4	Suspend positive reactivity additions.	Immediately
X. Required Action and associated Completion Time not met.	X.1	If in MODE 5 with RCS open and < 20% pressurizer level, initiate action to be in MODE 5 with RCS open and ≥ 20% pressurizer level.	Immediately
	AND		

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	X.2	If in MODE 6 with upper internals in place, initiate action to be in MODE 6 with the upper internals removed.	Immediately
	<u>AND</u>		
	X.3	Suspend positive reactivity additions.	Immediately
Y. Required Action and associated Completion Time not met.	Y.1	Suspend positive reactivity additions.	Immediately
	<u>AND</u>		
	Y.2	If in MODE 4, be in MODE 5.	12 hours
	<u>AND</u>		
	Y.3	If in MODE 4 or 5, initiate action to establish a pressurizer level $\geq$ 20% with the RCS pressure boundary intact.	12 hours
	<u>AND</u>		
	Y.4	If in MODE 6, initiate action to be in MODE 6 with the water level $\geq$ 23 feet above the top of the reactor vessel flange.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Z. Required Action and associated Completion Time not met.	Z.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s) by use of at least one closed manual or closed and deactivated automatic valve.	6 hours
	<u>OR</u>		
	Z.2.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	Z.2.2	Be in MODE 4 with the RCS cooling provided by the RNS.	30 hours
AA. Required Action and associated Completion Time not met.	AA.1.1	------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------	
		Isolate the affected flow path(s).	24 hours
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	AA.1.2.1 Isolate the affected flow path(s) by use of at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	7 days
	<u>OR</u>	
	AA.1.2.2 Verify the affected flow path is isolated.	Once per 7 days
	<u>OR</u>	
	AA.2.1 If in MODE 4, be in MODE 5.	12 hours
	<u>AND</u>	
	AA.2.2 If in MODE 4 or 5, initiate action to establish a pressurizer level ≥ 20%.	12 hours
	<u>AND</u>	
	AA.2.3 If in MODE 6, initiate action to be in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange.	Immediately
BB. One channel inoperable.	BB.1 Place channel in bypass.	6 hours
	<u>AND</u>	
	BB.2 Continuously monitor hot leg level.	6 hours

SURVEILLANCE REQUIREMENTS

- NOTE -

Refer to Table 3.3.2-1 to determine which SRs apply for each Engineered Safety Features (ESF) Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.2.3	---------- **- NOTE -** Verification of setpoint not required for manual initiation functions. ---------- Perform TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT).	24 months
SR 3.3.2.4	---------- **- NOTE -** This surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.2.5	Perform CHANNEL OPERATIONAL TEST (COT).	[92] days
SR 3.3.2.6	Verify ESFAS RESPONSE TIMES are within limit.	24 months on a STAGGERED TEST BASIS
SR 3.3.2.7	---------- **- NOTE -** This Surveillance is not required to be performed for actuated equipment which is included in the Inservice Test (IST) Program. ---------- Perform ACTUATION DEVICE TEST.	24 months
SR 3.3.2.8	Perform ACTUATION DEVICE TEST for squib valves.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.9	Perform ACTUATION DEVICE TEST for pressurizer heater circuit breakers.	24 months

Table 3.3.2-1 (page 1 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
1. Safeguards Actuation						
a. Manual Initiation	1,2,3,4	2 switches	E,O	SR 3.3.2.3	N/A	N/A
	5	2 switches	G,Y	SR 3.3.2.3	N/A	N/A
b. Containment Pressure – High 2	1,2,3,4	4	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [8.0] psig
c. Pressurizer Pressure – Low	1,2,3[(a)]	4	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1685] psig
d. Steam Line Pressure – Low	1,2,3[(a)]	4 per steam line	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [390] psig[(b)]
e. RCS Cold Leg Temperature (T_{cold}) – Low	1,2,3[(a)]	4 per loop	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [500]°F

(a) Above the P-11 (Pressurizer Pressure) interlock, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F.

(b) Time constants used in the lead/lag controller are $\tau_1 \geq$ [50] seconds and $\tau_2 \leq$ [5] seconds.

Reviewer Note: The values specified in brackets in the Trip Setpoint column are the Chapter 15 safety analysis values and are included for reviewer information only.

The values specified in brackets followed by " * " in the Trip Setpoint column are typical values for the Function. No credit was assumed for these Functions (typically diverse trips/actuations) in the Chapter 15 safety analyses and no safety analysis value is available.

The "Battery Charger Input Voltage – Low" Functions (15.c and 20.b) value specified is a typical value for the Function. The actual value will depend on the capabilities of the equipment selected with regard to its ability to function with degraded voltage as well as the setpoint methodology.

Following the setpoint study, the values specified in brackets must be replaced with the actual Trip Setpoints. Upon selection of the instrumentation the Trip Setpoints will be calculated in accordance with the setpoint methodology described in WCAP-14606. (WCAP-14606 is an AP600 document that describes a methodology that is applicable to AP1000. AP1000 has some slight differences in instrument spans as a result of the higher power level.) Allowable Values will be calculated in accordance with the setpoint methodology and specified in the Allowable Value column. The setpoint calculations will reflect the design basis and incorporate NRC accepted setpoint methodology.

The Containment Pressure – High 2 setpoint (Functions 1.b, 4.b, and 12.b) should be specified as low as reasonable, without creating potential for spurious trips during normal operations, consistent with the TMI action item (II.E.4.2) guidance.

Table 3.3.2-1 (page 2 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
2. Core Makeup Tank (CMT) Actuation						
a. Manual Initiation	1,2,3,4(j)	2 switches	E,N	SR 3.3.2.3	N/A	N/A
	4(n), 5(l)	2 switches	E,U	SR 3.3.2.3	N/A	N/A
b. Pressurizer Water Level – Low 2	1,2,3,4(j)	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [7.0]%* ≥ [1.0]%
	4(n), 5(l)	4	B,V	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [7.0]%* ≥ [1.0]%
c. Safeguards Actuation	1,2,3,4,5(l)	Refer to Function 1 (Safeguards Actuation) for initiating functions and requirements.				
d. ADS Stages 1, 2, & 3 Actuation	1,2,3,4,5(l)	Refer to Function 9 (ADS Stages 1, 2 & 3 Actuation) for all initiating functions and requirements.				
3. Containment Isolation						
a. Manual Initiation	1,2,3,4	2 switches	E,O	SR 3.3.2.3	N/A	N/A
	5(m), 6(m)	2 switches	G,Y	SR 3.3.2.3	N/A	N/A
b. Manual Initiation of Passive Containment Cooling	1,2,3,4,5(e,m), 6(e,m)	Refer to Function 12.a (Passive Containment Cooling Actuation) for initiating functions and requirements.				
c. Safeguards Actuation	1,2,3,4,5(m)	Refer to Function 1 (Safeguards Actuation) for initiating functions and requirements.				

(e) With decay heat > 9.0 MWt.

(l) With the RCS pressure boundary intact.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(m) Not applicable for valve isolation Functions whose associated flow path is isolated.

(n) With the RCS being cooled by the RNS.

Table 3.3.2-1 (page 3 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
4.	Steam Line Isolation						
	a. Manual Initiation	1,2[l],3[l],4[l]	2 switches	E,S	SR 3.3.2.3	N/A	N/A
	b. Containment Pressure – High 2	1,2[l],3[l],4[l]	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [8.0] psig
	c. Steam Line Pressure						
	(1) Steam Line Pressure – Low	1,2[l],3[a,l]	4 per steam line	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [390] psig[b]
	(2) Steam Line Pressure – Negative Rate – High	3[d,l]	4 per steam line	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100] psi with time constant ≥ [50] seconds
	d. T_{cold} – Low	1,2[l],3[a,l]	4 per loop	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [500]°F
5.	Turbine Trip						
	a. Manual Main Feedwater Isolation	1,2	Refer to Function 6.a (Manual Main Feedwater Control Valve Isolation) for requirements.				
	b. SG Narrow Range Water Level – High 2	1,2	4 per SG	B,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100]%
	c. Safeguards Actuation	1,2	Refer to Function 1 (Safeguards Actuation) for initiating functions and requirements.				
	d. Reactor Trip	1,2	Refer to Function 18.a (ESFAS Interlocks, Reactor Trip, P-4) for requirements.				

(a) Above the P-11 (Pressurizer Pressure) interlock, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F.

(b) Time constants used in the lead/lag controller are τ_1 ≥ [50] seconds and τ_2 ≤ [5] seconds.

(d) Below the P-11 (Pressurizer Pressure) interlock.

(l) Not applicable if all MSIVs are closed.

Table 3.3.2-1 (page 4 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
6.	Main Feedwater Control Valve Isolation						
	a. Manual Initiation	1,2,3,4[(m)]	2 switches	E,S	SR 3.3.2.3	N/A	N/A
	b. SG Narrow Range Water Level – High 2	1,2,3,4[(j,m)]	4 per SG	B,R	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100]%
	c. Safeguards Actuation	1,2,3,4[(m)]	Refer to Function 1 (Safeguards Actuation) for all initiating functions and requirements.				
	d. Reactor Coolant Average Temperature (T_{avg}) – Low 1	1,2	4	B,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [542]°F
	Coincident with Reactor Trip	1,2	Refer to Function 18.a (ESFAS Interlocks, Reactor Trip, P-4) for requirements.				
7.	Main Feedwater Pump Trip and Valve Isolation						
	a. Manual Initiation	Refer to Function 6.a (Manual Main Feedwater Control Valve Isolation) for requirements.					
	b. SG Narrow Range Water Level – High 2	1,2,3,4[(j,m)]	4 per SG	B,R	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100]%
	c. Safeguards Actuation	1,2,3,4[(m)]	Refer to Function 1 (Safeguards Actuation) for all initiating functions and requirements.				
	d. Reactor Coolant Average Temperature T_{avg} – Low 2	1,2	2 per loop	B,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [542]°F*
	Coincident with Reactor Trip	1,2	Refer to Function 18.a (ESFAS Interlocks, Reactor Trip, P-4) for requirements.				

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(m) Not applicable for valve isolation Functions whose associated flow path is isolated.

Table 3.3.2-1 (page 5 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
8. Startup Feedwater Isolation						
a. SG Narrow Range Water Level – High 2	1,2,3,4[(o)]	4 per SG	B,S	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100]%
b. T_{cold} – Low	1,2,3[(a)]	4 per loop	B,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [500]°F*
c. Manual Initiation	Refer to Function 6.a (Manual Main Feedwater Control Valve Isolation) for requirements.					
9. ADS Stages 1, 2 & 3 Actuation						
a. Manual Initiation	1,2,3,4	2 switch sets	E,O	SR 3.3.2.3	N/A	N/A
	5[(k)],6[(g,k)]	2 switch sets	G,X	SR 3.3.2.3	N/A	N/A
b. Core Makeup Tank (CMT) Level – Low 1	1,2,3,4	4 per tank	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [67.5]% volume
	5[(c,k)]	4 per OPERABLE tank	B,V	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [67.5]% volume
Coincident with CMT Actuation	Refer to Function 2 (CMT Actuation) for all initiating functions and requirements.					

(a) Above the P-11 (Pressurizer Pressure) interlock, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F.

(c) With pressurizer level ≥ 20%.

(g) With upper internals in place.

(o) Not applicable when the startup feedwater flow paths are isolated.

(k) Not applicable when the required ADS valves are open. See LCO 3.4.13 and LCO 3.4.14 for ADS valve and equivalent relief area requirements.

Table 3.3.2-1 (page 6 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
10.	ADS Stage 4 Actuation						
	a. Manual Initiation Coincident with	1,2,3,4	2 switch sets	E,O	SR 3.3.2.3	N/A	N/A
		$5^{(k)},6^{(g,k)}$	2 switch sets	G,X	SR 3.3.2.3	N/A	N/A
	RCS Wide Range Pressure – Low, or	1,2,3,4	4	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1200] psig
		$5^{(k)},6^{(g,k)}$	4	B,X	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1200] psig
	ADS Stages 1, 2 & 3 Actuation	Refer to Function 9 (Stages 1, 2, & 3 Actuation) for initiating functions and requirements					
	b. CMT Level – Low 2	1,2,3,4	4 per tank	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [20]% volume level span
		$5^{(c,k)}$	4 per OPERABLE tank	B,V	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [20]% volume level span
	Coincident with RCS Wide Range Pressure – Low, and	1,2,3,4	4	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1200] psig
		$5^{(c,k)}$	4	B,V	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1200] psig
	Coincident with ADS Stages 1, 2 & 3 Actuation	$1,2,3,4,5^{(c,k)}$	Refer to Function 9 (ADS Stages 1, 2 & 3 Actuation) for initiating functions and requirements				
	c. Coincident RCS Loop 1 and 2 Hot Leg Level – Low 2	$4^{(n)},5^{(k)},6^{(k)}$	1 per loop	BB,Y	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [3] in. above inside surface of the bottom of the hot legs

(c) With pressurizer level ≥ 20%.

(g) With upper internals in place.

(k) Not applicable when the required ADS valves are open. See LCO 3.4.13 and LCO 3.4.14 for ADS valve and equivalent relief area requirements.

Table 3.3.2-1 (page 7 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11.	Reactor Coolant Pump Trip						
	a. ADS Stages 1, 2 & 3 Actuation	Refer to Function 9 (ADS Stages 1, 2 & 3 Actuation) for initiating functions and requirements.					
	b. Reactor Coolant Pump Bearing Water Temperature – High	1,2	4 per RCP	B,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [320]°F*
	c. Manual CMT Actuation	Refer to Function 2.a (Manual CMT Actuation) for requirements.					
	d. Pressurizer Water Level – Low 2	1,2,3,4$^{(j)}$	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [7.0]%* ≥ [1.0]%
		4$^{(n)}$,5$^{(c,j)}$	4	B,V	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [7.0]%* ≥ [1.0]%
	e. Safeguards Actuation	Refer to Function 1 (Safeguards Actuation) for initiating functions and requirements.					
12.	Passive Containment Cooling Actuation						
	a. Manual Initiation	1,2,3,4	2 switches	E,O	SR 3.3.2.3	N/A	N/A
		5$^{(e)}$,6$^{(e)}$	2 switches	G,Y	SR 3.3.2.3	N/A	N/A
	b. Containment Pressure – High 2	1,2,3,4	4	B,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [8.0] psig

(c) With pressurizer level ≥ 20%.

(e) With decay heat > 9.0 MWt.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(n) With the RCS being cooled by the RNS.

Table 3.3.2-1 (page 8 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
13.	Passive Residual Heat Removal Heat Exchanger Actuation						
	a. Manual Initiation	1,2,3,4	2 switches	E,O	SR 3.3.2.3	N/A	N/A
		5(l)	2 switches	E,U	SR 3.3.2.3	N/A	N/A
	b. SG Narrow Range Water Level – Low	1,2,3,4(j)	4 per SG	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [95,000] lbm
	Coincident with Startup Feedwater Flow – Low	1,2,3,4(j)	2 per feedwater line	H,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [200] gpm per SG*
	c. SG Wide Range Water Level – Low	1,2,3,4(j)	4 per SG	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [55,000] lbm
	d. ADS Stages 1, 2 & 3 Actuation	1,2,3,4,5(l)	Refer to Function 9 (ADS Stages 1, 2 & 3 Actuation) for initiating functions and requirements.				
	e. CMT Actuation	Refer to Function 2 (CMT Actuation) for initiating functions and requirements.					
	f. Pressurizer Water Level, High 3	1,2,3,4(j,p)	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [80]%*

(l) With the RCS pressure boundary intact.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(p) Above the P-19 (RCS Pressure) interlock.

Table 3.3.2-1 (page 9 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
14.	SG Blowdown Isolation						
	a. Passive Residual Heat Removal Heat Exchanger Actuation	$1,2,3,4^{(j,m)}$	Refer to Function 13 (Passive Residual Heat Removal Heat Exchanger Actuation) for all initiating functions and requirements.				
	b. SG Narrow Range Water Level – Low	$1,2,3,4^{(j)}$	4 per SG	B,R	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [95,000] lbm
15.	Boron Dilution Block						
	a. Source Range Neutron Flux Multiplication	$2^{(f)},3,4^{(m)}$	4	B,T	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ Source Range Flux X [1.6 in 50] minutes
		$5^{(m)}$	4	B,P	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ Source Range Flux X [1.6 in 50] minutes
	b. Reactor Trip	Refer to Function 18.a (ESFAS Interlocks, Reactor Trip, P-4) for all requirements.					
	c. Battery Charger Input Voltage – Low	$1,2,3,4^{(m)}$	4 divisions	B,T	SR 3.3.2.3 SR 3.3.2.4		≥ [343] V*
		$5^{(m)}$	4 divisions	B,P	SR 3.3.2.3 SR 3.3.2.4		≥ [343] V*
16.	Chemical Volume and Control System Makeup Isolation						
	a. SG Narrow Range Water Level – High 2	$1,2,3^{(m)},4^{(j,m)}$	4 per SG	B,R	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100]%
	b. Pressurizer Water Level – High 1	$1,2,3^{(m)}$	4	B,Q	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [30]%*
	Coincident with Safeguards Actuation	$1,2,3^{(m)}$	Refer to Function 1 (Safeguards Actuation) for initiating functions and requirements.				
	c. Pressurizer Water Level – High 2	$1,2,3,4^{(j,m,p)}$	4	B,T	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [67]%
	d. Containment Radioactivity – High 2	$1,2,3^{(m)}$	4	B,Q	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100] R/hr
	e. Manual Initiation	$1,2,3^{(m)},4^{(j,m)}$	2 switches	E,R	SR 3.3.2.3	N/A	N/A

(f) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(m) Not applicable for valve isolation Functions whose associated flow path is isolated.

(p) Above the P-19 (RCS Pressure) interlock.

Table 3.3.2-1 (page 10 of 13)
Engineered Safeguards Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
17.	Normal Residual Heat Removal System Isolation						
	a. Containment Radioactivity – High 2	1,2,3(m)	4	B,Q	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [100] R/hr
	b. Safeguards Actuation	1,2,3(m)	Refer to Function 1 (Safeguards Actuation) for all initiating functions and requirements.				
	c. Manual Initiation	1,2,3(m)	2 switch sets	E,Q	SR 3.3.2.3	N/A	N/A
18.	ESFAS Interlocks						
	a. Reactor Trip, P-4	1,2,3	3 divisions	D,M	SR 3.3.2.3	N/A	N/A
	b. Pressurizer Pressure, P-11	1,2,3	4	J,M	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [1970] sig
	c. Intermediate Range Neutron Flux, P-6	2	4	J,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [1E-10] amps
	d. Pressurizer Level, P-12	1,2,3,4,5,6	4	J,M BB,Y	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		Above Pressurizer Water Level – Low 1 setpoint of [20]%
	e. RCS Pressure, P-19	1,2,3,4(j)	4	J,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [700] psig
19.	Containment Air Filtration System Isolation						
	a. Containment Radioactivity – High 1	1,2,3,4(j)	4	B,Z	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [2] R/hr
	b. Containment Isolation	Refer to Function 3 (Containment Isolation) for initiating functions and requirements.					

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(m) Not applicable for valve isolation Functions whose associated flow path is isolated.

Table 3.3.2-1 (page 11 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
20. Main Control Room Isolation and Air Supply Initiation						
a. Control Room Air Supply Radiation – High 2	1,2,3,4	2	F,O	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [2×10^{-6}] curies/m^3 DOSE EQUIVALENT I-131
	Note (h)	2	G,K	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≤ [2×10^{-6}] curies/m^3 DOSE EQUIVALENT I-131
b. Battery Charger Input Voltage – Low	1,2,3,4	4 divisions	B,O	SR 3.3.2.3 SR 3.3.2.4		≥ [343] V*
	Note (h)	4 divisions	G,K	SR 3.3.2.3 SR 3.3.2.4		≥ [343] V*
21 Auxiliary Spray and Purification Line Isolation						
a. Pressurizer Water Level – Low 1	1,2	4	B,L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		[20.0]%*
b. Manual Initiation	1,2	Refer to Function 16.e (Manual Chemical Volume Control System (Makeup Isolation) for requirements.				
22. In-Containment Refueling Water Storage Tank (IRWST) Injection Line Valve Actuation						
a. Manual Initiation	1,2,3,4$^{(j)}$	2 switch sets	E,N	SR 3.3.2.3	N/A	N/A
	4$^{(n)}$,5,6	2 switch sets	G,Y	SR 3.3.2.3	N/A	N/A
b. ADS 4th Stage Actuation	Refer to Function 10 (ADS 4th Stage Actuation) for initiating functions and requirements.					
c. Coincident RCS Loop 1 and 2 Hot Leg Level – Low 2	4$^{(n)}$,5,6	1 per loop	BB,Y	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [3] in. above inside surface of the bottom of the hot legs

(h) During movement of irradiated fuel assemblies.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(n) With the RCS being cooled by the RNS.

Table 3.3.2-1 (page 12 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
23. IRWST Containment Recirculation Valve Actuation						
a. Manual Initiation	1,2,3,4$^{(j)}$	2 switch sets	E,N	SR 3.3.2.3	N/A	N/A
	4$^{(n)}$,5,6	2 switch sets	G,Y	SR 3.3.2.3	N/A	N/A
b. ADS Stage 4 Actuation	Refer to Function 10 (ADS Stage 4 Actuation) for all initiating functions and requirements.					
Coincident with IRWST Level – Low 3	1,2,3,4$^{(j)}$	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ Containment Elevation @ [107'2"]
	4$^{(n)}$,5$^{(k)}$,6$^{(k)}$	4	I,Y	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ Containment Elevation @ [107'2"]
24. Refueling Cavity Isolation						
a. Spent Fuel Pool Level – Low	6	3	H,P	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		[37.5] ft.
25. ESF Coincidence Logic						
a. Coincidence Logic	1,2,3,4	4 divisions, 1 battery-backed subsystem per division	D,O	SR 3.3.2.2	N/A	N/A
	5,6	4 divisions, 1 battery-backed subsystem per division	G,W	SR 3.3.2.2	N/A	N/A

(k) Not applicable when the required ADS valves are open. See LCO 3.4.13 and LCO 3.4.14 for ADS valve and equivalent relief area requirements.

Table 3.3.2-1 (page 13 of 13)
Engineered Safeguards Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
26. ESF Actuation						
a. ESF Actuation Subsystem	1,2,3,4	4 divisions, 1 battery-backed subsystem per division	D,O	SR 3.3.2.2 SR 3.3.2.7 SR 3.3.2.8	N/A	N/A
	5,6	4 divisions, 1 battery-backed subsystem per division	G,W	SR 3.3.2.2 SR 3.3.2.7	N/A	N/A
27. Pressurizer Heater Trip						
a. Core Makeup Tank Actuation	1,2,3,4(j,p)	Refer to Function 2 (Core Makeup Tank Actuation) for all initiating functions and requirements. In addition to the requirements for Function 2, SR 3.3.2.9 also applies.				
b. Pressurizer Water Level, High 3	1,2,3,4(j,p)	4	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		[80]%*
28. Chemical and Volume Control System Letdown Isolation						
a. Hot Leg Level – Low 1	4(n),5,6(q)	1 per loop	C,AA	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		≥ [18] in. above inside surface of the bottom of the hot legs
29. SG Power Operated Relief Valve and Block Valve Isolation						
a. Manual Initiation	1,2,3,4(j)	2 switches	E,N	SR 3.3.2.3	N/A	N/A
b. Steam Line Pressure – Low	1,2,3,4(j)	4 per steam line	B,N	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.5 SR 3.3.2.6		[390] psig(b)

(b) Time constants used in the lead/lag controller are $\tau_1 \geq [50]$ seconds and $\tau_2 \leq [5]$ seconds.

(j) With the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

(m) Not applicable for valve isolation Functions whose associated flow path is isolated.

(n) With the RCS being cooled by the RNS.

(p) Above the P-19 (RCS Pressure) interlock.

(q) With the water level < 23 feet above the top of the reactor vessel flange.

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

- NOTES -

1. LCO 3.0.4 not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.7.	Immediately
C. One or more Functions with two required channels inoperable.	C.1 Restore one channel to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3-1.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

- NOTE -
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	------------------------------------ **- NOTE -** Neutron detectors are excluded from CHANNEL CALIBRATION. ------------------------------------ Perform CHANNEL CALIBRATION.	24 months

Table 3.3.3-1 (page 1 of 1)
Post-Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS/ DIVISIONS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
1.	Neutron Flux (Intermediate Range)	2	E
2.	Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	2	E
3.	RCS Cold Leg Temperature (Wide Range)	2	E
4.	RCS Pressure (Wide Range)	2	E
5.	Pressurizer Pressure and RCS Subcooling Monitor[(a)]	2	E
6.	Containment Water Level	2	E
7.	Containment Pressure	2	E
8.	Containment Pressure (Extended Range)	2	E
9.	Containment Area Radiation (High Range)	2	E
10.	Pressurizer Level and Associated Reference Leg Temperature	2	E
11.	IRWST Water Level	2	E
12.	PRHR Flow and PRHR Outlet Temperature	2 flow & 1 temperature	E
13.	Core Exit Temperature -- Quadrant 1	2[(b)]	E
14.	Core Exit Temperature -- Quadrant 2	2[(b)]	E
15.	Core Exit Temperature -- Quadrant 3	2[(b)]	E
16.	Core Exit Temperature -- Quadrant 4	2[(b)]	E
17.	PCS Storage Tank Level and PCS Flow	2 level & 1 flow	E
18.	Remotely Operated Containment Isolation Valve Position	1/valve[(c)]	E
19.	IRWST to RNS Suction Valve Status	2	E

(a) RCS Subcooling calculated from pressurizer pressure and RCS hot leg temperature.

(b) A channel consists of two thermocouples within a single division. Each quadrant contains two divisions. The minimum requirement is two OPERABLE thermocouples in each of the two divisions.

(c) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown Workstation (RSW)

LCO 3.3.4 The Remote Shutdown Workstation (RSW) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and
MODE 4 with RCS average temperature (T_{avg}).

ACTIONS

- NOTE -

LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RSW inoperable.	A.1 Restore to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4 with T_{avg} < 350°F.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Verify each required transfer switch is capable of performing the required function.	24 months
SR 3.3.4.2	Verify that the RSW communicates indication and controls with Division A, B, C and D of the PMS.	24 months
SR 3.3.4.3	Verify the OPERABILITY of the RSW hardware and software.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.4	Perform TADOT of the reactor trip breaker open/closed indication.	24 months

3.3 INSTRUMENTATION

3.3.5 Diverse Actuation System (DAS) Manual Controls

LCO 3.3.5 The DAS manual controls for each function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more manual DAS controls inoperable.	A.1 Restore DAS manual controls to OPERABLE status.	30 days
B. Completion Time of Required Action A not met for inoperable DAS manual reactor trip control.	B.1 Perform SR 3.3.1.5. <u>AND</u> B.2 Restore all controls to OPERABLE status.	Once per 31 days on a STAGGERED TEST BASIS Prior to entering MODE 2 following next MODE 5 entry
C. Completion Time of Required Action A not met for inoperable DAS manual actuation control other than reactor trip.	C.1 Perform SR 3.3.2.2. <u>AND</u> C.2 Restore all controls to OPERABLE status.	Once per 31 days on a STAGGERED TEST BASIS Prior to entering MODE 2 following next MODE 5 entry
D. Completion Time of Required Action B not met. <u>OR</u> Completion Time of Required Action C not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	------------------------------------- **- NOTE -** Verification of setpoint not required. ------------------------------------- Perform TRIP ACTUATION DEVICE OPERATIONAL TEST (TADOT).	24 months

Table 3.3.5-1 (page 1 of 1)
DAS Manual Controls

FUNCTION		APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CONTROLS
1.	Reactor trip manual controls	1,2	2 switches
2.	PRHR HX control and IRWST gutter control valves	1,2,3,4,5(a)	2 switches
3.	CMT isolation valves	1,2,3,4,5(a)	2 switches
4.	ADS stage 1 valves	1,2,3,4,5(a)	2 switches
5.	ADS stage 2 valves	1,2,3,4,5(a)	2 switches
6.	ADS stage 3 valves	1,2,3,4,5(a)	2 switches
7.	ADS stage 4 valves	1,2,3,4,5,6(c)	2 switches
8.	IRWST injection squib valves	1,2,3,4,5,6	2 switches
9.	Containment recirculation valves	1,2,3,4,5,6	2 switches
10.	Passive containment cooling drain valves	1,2,3,4,5(b),6(b)	2 switches
11.	Selected containment isolation valves	1,2,3,4,5,6	2 switches

(a) With RCS pressure boundary intact.

(b) With the calculated reactor decay heat > 9.0 MWt.

(c) In MODE 6 with reactor internals in place.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer Pressure is greater than or equal to the limit specified in the COLR

b. RCS Average Temperature is less than or equal to the limit specified in the COLR, and

c. RCS total flow rate ≥ [301,670] gpm and greater than or equal to the limit specified in the COLR.

APPLICABILITY: MODE 1.

- NOTE -

Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute, or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is greater than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.2	Verify RCS average temperature is less than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ [301,670] gpm and greater than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.4	-- **- NOTE -** Not required to be performed until 24 hours after ≥ 90% RTP. -- Verify by precision heat balance that RCS total flow rate is ≥ [301,670] gpm and greater than or equal to the limit specified in the COLR.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ [551]°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 2 with k_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 Verify RCS T_{avg} in each loop ≥ [551]°F.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------------------------- **- NOTE -** Required Action A.2 shall be completed whenever this Condition is entered. -------------------------------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameters to within limits. <u>AND</u> A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4 with RCS pressure < 500 psig.	6 hours 24 hours
C. -------------------------------- **- NOTE -** Required Action C.2 shall be completed whenever this Condition is entered. -------------------------------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits. <u>AND</u> C.2 Determine RCS is acceptable for continued operation.	Immediately Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	--- **- NOTE -** Only required to be performed during RCS heatup and cooldown operations and inservice leak and hydrostatic testing. ---	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates within limits specified in the PTLR.	30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops

LCO 3.4.4 Two RCS loops shall be OPERABLE and in operation (Four Reactor Coolant Pumps (RCPs) operating with variable speed control bypassed).

- NOTES -

1. No RCP shall be started when the reactor trip breakers are closed.

2. No RCP shall be started with any RCS cold leg temperature ≤ [275]°F unless the secondary side water temperature of each steam generator (SG) is ≤ [50]°F above each of the RCS cold leg temperatures.

3. All RCPs may be de-energized in MODE 3, 4, or 5 for ≤ 1 hour per 8 hour period provided:

    a. No operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODES 1 and 2,
MODES 3, 4, and 5, whenever the reactor trip breakers are closed.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------------------------- **- NOTE -** Required Action A.1 must be completed whenever Condition A is entered. -------------------------------- Requirements of LCO not met in MODE 1 or 2.	A.1 Be in MODE 3 with the reactor trip breakers open.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. -------------------------------- **- NOTE -** Required Action B.1 must be completed whenever Condition B is entered. -------------------------------- Requirements of LCO not met in MODE 3, 4, or 5.	B.1	Be in MODE 3, 4, or 5 with the reactor trip breakers open.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify each RCS loop is in operation with variable speed control bypassed.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 Pressurizer

LCO 3.4.5 The pressurizer water level shall be ≤ 92% of span.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Restore pressurizer water level within limit. OR A.2.1 Be in MODE 3 with reactor trip breakers open. AND A.2.2 Be in MODE 4.	6 hours 6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify pressurizer water level ≤ 92% of span.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 Pressurizer Safety Valves

LCO 3.4.6 Two pressurizer safety valves shall be OPERABLE with lift settings ≥ 2460 psig and ≤ 2510 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with RNS isolated or RCS temperature ≥ 275°F.

- NOTE -

The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions.

This exception is allowed for 36 hours following entry into MODE 3, provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with RNS aligned to the RCS and RCS temperature < 275°F.	6 hours 24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify each pressurizer safety valve OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ±1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Operational LEAKAGE

LCO 3.4.7 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE,

b. 0.5 gpm unidentified LEAKAGE,

c. 10 gpm identified LEAKAGE from the RCS,

d. 300 gallons per day total primary to secondary LEAKAGE through both steam generators (SGs),

e. 150 gallons per day primary to secondary LEAKAGE through any one SG, and

f. 500 gallons per day primary to IRWST LEAKAGE through the passive residual heat removal heat exchanger (PRHR HX).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	--- **- NOTE -** Not required to be performed in MODES 3 and 4 until 12 hours of steady state operation. --- Verify RCS Operational LEAKAGE is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.7.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 Minimum RCS Flow

LCO 3.4.8 At least one Reactor Coolant Pump (RCP) shall be in operation with a total flow through the core of at least [10,000] gpm.

- NOTES -

1. All RCPs may be de-energized for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ [275]°F unless the secondary side water temperature of each steam generator (SG) is ≤ [50]°F above each of the RCS cold leg temperatures.

APPLICABILITY: MODES 3, 4, and 5, whenever the reactor trip breakers are open.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. No RCP in operation.	A.1 Isolate all sources of unborated water.	1 hour
	AND	
	A.2 Perform SR 3.1.1.1, (SDM verification).	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify that at least one RCP is in operation at ≥ [25]% rated speed or equivalent.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 RCS Leakage Detection Instrumentation

LCO 3.4.9 The following RCS leakage detection instrumentation shall be OPERABLE:

a. Two containment sump level channels;

b. One containment atmosphere radioactivity monitor (gaseous N13/F18).

APPLICABILITY: MODES 1, 2, 3, and 4.

- NOTES -

1. The N13/F18 containment atmosphere radioactivity monitor is only required to be OPERABLE in MODE 1 with RTP > 20%.

2. Containment sump level measurements cannot be used for leak detection if leakage is prevented from draining to the sump such as by redirection to the IRWST by the containment shell gutter drains.

ACTIONS

- NOTE -

LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required containment sump channel inoperable.	A.1	Verify that the volume input per day to the containment sump does not change (+ or -) more than 10 gallons or 33% of the volume input (whichever is greater). The volume used for comparison will be the value taken during the first day following the entrance into this CONDITION.	Once per 24 hours
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.2	Restore two containment sump channels to OPERABLE status.	14 days
B. Two required containment sump channels inoperable.	B.1	----------------------------------- **- NOTE -** Not required until 12 hours after establishment of steady state operation. -----------------------------------	
		Perform SR 3.4.7.1 (RCS inventory balance).	Once per 24 hours
	<u>AND</u>		
	B.2	Restore one containment sump channel to OPERABLE status.	72 hours
C. Required containment atmosphere radioactivity monitor inoperable.	C.1.1	Analyze grab samples of containment atmosphere.	Once per 24 hours
	<u>OR</u>		
	C.1.2	----------------------------------- **- NOTE -** Not required until 12 hours after establishment of steady state operation. -----------------------------------	
		Perform SR 3.4.7.1.	Once per 24 hours
	<u>AND</u>		
	C.2	Restore containment atmosphere radioactivity monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. All required monitors inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.9.1	Perform a CHANNEL CHECK of required containment atmosphere radioactivity monitor.	12 hours
SR 3.4.9.2	Perform a COT of required containment atmosphere radioactivity monitor.	92 days
SR 3.4.9.3	Perform a CHANNEL CALIBRATION of required containment sump monitor.	24 months
SR 3.4.9.4	Perform a CHANNEL CALIBRATION of required containment atmosphere radioactivity monitor.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 RCS Specific Activity

LCO 3.4.10 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 1.0 μCi/gm.	A.1	------------------------------------ **- NOTE -** LCO 3.0.4 is not applicable. ------------------------------------ Verify DOSE EQUIVALENT I-131 to be ≤ 60 μCi/gm.	Once per 4 hours
	<u>AND</u>		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. DOSE EQUIVALENT XE-133 > 280 μCi/gm.	B.1	Perform SR 3.4.10.2.	4 hours
	<u>AND</u>		
	B.2	Be in MODE 3 with T_{avg} < 500°F.	6 hours
C. Required Action and associated Completion Time of Condition A not met. <u>OR</u> DOSE EQUIVALENT I-131 > 60 μCi/gm.	C.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify reactor coolant DOSE EQUIVALENT XE-133 specific activity ≤ 280 μCi/gm.	7 days
SR 3.4.10.2	-- **- NOTE -** Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 1.0 μCi/gm.	14 days <u>AND</u> Between 2 to 6 hours after a THERMAL POWER change of ≥ 15% of RTP within a 1 hour period
SR 3.4.10.3	-- **- NOTE -** Note required to be performed until 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours. -- Determine DOSE EQUIVALENT XE-133 from a sample taken in MODE 1 after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours.	 184 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Automatic Depressurization System (ADS) – Operating

LCO 3.4.11 The ADS, including 10 flow paths, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One flow path inoperable.	A.1 Restore flow path(s) to OPERABLE status.	72 hours
B. One stage 1 ADS flow path inoperable. AND Either one stage 2 ADS flow path inoperable or one stage 3 ADS flow path inoperable.	B.1 Restore flow path(s) to OPERABLE status.	72 hours
C. Required Action and associated Completion Time not met. OR Requirements of LCO not met for reasons other than Condition A.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	Verify that the motor operated valve in series with each 4th stage ADS valve is fully open.	12 hours
SR 3.4.11.2	Verify that each stage 1, 2, and 3 ADS valve is OPERABLE by stroking them open.	In accordance with the Inservice Testing Program
SR 3.4.11.3	Verify that each stage 4 ADS valve is OPERABLE in accordance with the Inservice Testing Program.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Automatic Depressurization System (ADS) – Shutdown, RCS Intact

LCO 3.4.12 The ADS, including 9 flow paths, shall be OPERABLE.

APPLICABILITY: MODE 5 with RCS pressure boundary intact.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required flow path inoperable.	A.1	Restore flow path(s) to OPERABLE status.	72 hours
B. One required stage 1 ADS flow path inoperable. <u>AND</u> Either one required stage 2 or stage 3 ADS flow path inoperable.	B.1	Restore flow path(s) to OPERABLE status.	72 hours
C. Required Action and associated Completion Time not met. <u>OR</u> Requirements of LCO not met for reasons other than Condition A.	C.1	Initiate action to be in MODE 5, with RCS open and ≥ 20% pressurizer level.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	For flow paths required to be OPERABLE, the SRs of LCO 3.4.11, “Automatic Depressurization System (ADS) – Operating” are applicable.	In accordance with applicable SRs

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 Automatic Depressurization System (ADS) – Shutdown, RCS Open

LCO 3.4.13 ADS stage 1, 2, and 3, flow paths shall be open.
ADS stage 4 with 2 flow paths shall be OPERABLE.

- NOTE -

In MODE 5, the ADS valves may be closed to facilitate RCS vacuum fill operations to establish a pressurizer level ≥ 20%, provided ADS valve OPERABILITY meets LCO 3.4.12, ADS – Shutdown, RCS Intact.

APPLICABILITY: MODE 5 with RCS pressure boundary open or pressurizer level < 20%;
MODE 6 with upper internals in place.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ADS stage 1, 2, or 3 flow path closed.	A.1 Open the affected flow path.	72 hours
	<u>OR</u>	
	A.2 Open an alternative flow path with an equivalent area.	72 hours
B. One required ADS stage 4 flow path closed and inoperable.	B.1 Open an alternative flow path with an equivalent area.	36 hours
	<u>OR</u>	
	B.2 Restore two ADS stage 4 flow paths to OPERABLE status.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time not met while in MODE 5. <u>OR</u> Requirements of LCO not met for reasons other than Conditions A or B while in MODE 5.	C.1	Initiate action to fill the RCS to establish ≥ 20% pressurizer level.	Immediately
	<u>AND</u>		
	C.2	Suspend positive reactivity additions.	Immediately
D. Required Action and associated Completion Time not met while in MODE 6. <u>OR</u> Requirements of LCO not met for reasons other than Conditions A or B while in MODE 6.	D.1	Initiate action to remove the upper internals.	Immediately
	<u>AND</u>		
	D.2	Suspend positive reactivity additions.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	Verify that each ADS stage 1, 2, and 3 valve is in the fully open position.	12 hours
SR 3.4.13.2	For each ADS stage 4 flow path required to be OPERABLE, the following SRs of LCO 3.4.11, “Automatic Depressurization System (ADS) – Operating” are applicable: SR 3.4.11.1 SR 3.4.11.3	In accordance with applicable SRs

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.14 At least one of the following Overpressure Protection Systems shall be OPERABLE, with the accumulators isolated:

a. The Normal Residual Heat Removal System (RNS) suction relief valve, or

b. The RCS depressurized and an RCS vent of ≥ [9.3] square inches.

- NOTE -

When the RCS temperature is ≥ 200°F, a reactor coolant pump (RCP) may not be started if the pressurizer level is ≥ 92%.

APPLICABILITY: MODE 4 when any cold leg temperature is ≤ 275°F,
MODE 5,
MODE 6 when the reactor vessel head is on.

- NOTE -

Accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. An accumulator not isolated when the accumulator pressure is ≥ to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	A.1 Isolate affected accumulator.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1	Increase RCS cold leg temperature to a level acceptable for the existing accumulator pressure allowed in the PTLR.	12 hours
	OR		
	B.2	Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours
C. The RNS suction relief valve inoperable.	C.1	Restore the RNS suction relief valve to OPERABLE status.	12 hours
	OR		
	C.2	Depressurize RCS and establish RCS vent of ≥ [9.3] square inches.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	Verify each accumulator is isolated.	12 hours
SR 3.4.14.2	Verify both RNS suction isolation valves in one RNS suction flow path are open.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.3	------------------------------ **- NOTE -** Only required to be performed when complying with LCO 3.4.14.b. ------------------------------ Verify RCS vent ≥ [9.3] square inches is open.	12 hours for unlocked-open vent <u>AND</u> 31 days for locked-open vent
SR 3.4.14.4	Verify the lift setting of the RNS suction relief valve.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Pressure Isolation Valve (PIV) Integrity

LCO 3.4.15 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, with the RCS not being cooled by the RNS.

ACTIONS

- NOTES -

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Leakage from one or more RCS PIVs not within limit.	A.1	---------------------------------- **- NOTE -** Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.15.1 and be in the reactor coolant pressure boundary or the high pressure portion of the system. ----------------------------------	
		Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	8 hours
	AND		

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.2	Verify a second OPERABLE PIV can meet the leakage limits. This valve is required to be a check valve, or a closed valve, if it isolates a line that penetrates containment.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Verify leakage of each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch valve size up to a maximum of 5 gpm at an RCS pressure ≥ [2215] and ≤ [2255] psig.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 Reactor Vessel Head Vent (RVHV)

LCO 3.4.16 The Reactor Vessel Head Vent shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with the RCS not being cooled by the RNS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One flow path inoperable.	A.1 Restore flow path to OPERABLE status.	72 hours
B. Two flow paths inoperable.	B.1 Restore at least one flow path to OPERABLE status.	6 hours
C. Required Action and associated Completion Time not met. OR Requirements of LCO not met for reasons other than Conditions A or B.	C.1 Be in MODE 3. AND C.2 Be in MODE 4, with the RCS cooling provided by the RNS.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify that each RVHV valve is OPERABLE by stroking it open.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Chemical and Volume Control System (CVS) Makeup Isolation Valves

LCO 3.4.17 Two CVS Makeup Isolation Valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CVS makeup isolation valve inoperable.	A.1 Restore two CVS makeup isolation valves to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met. <u>OR</u> Two CVS makeup isolation valves inoperable.	B.1 ------------------------------------ **- NOTE -** Flow path(s) may be unisolated intermittently under administrative controls. ------------------------------------ Isolate the flow path from the CVS makeup pumps to the Reactor Coolant System by use of at least one closed manual or one closed and de-activated automatic valve.	 1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify two CVS makeup isolation valves are OPERABLE by stroking the valves closed.	In accordance with the Inservice Testing Program
SR 3.4.17.2	Verify closure time of each CVS makeup isolation valve is ≤ 10 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.1 Accumulators

LCO 3.5.1 Both accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODES 3 and 4 with RCS pressure > 1000 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration outside limits.	A.1 Restore boron concentration to within limits.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status.	8 hours if Condition C or E of LCO 3.5.2 has not been entered <u>OR</u> 1 hour if Condition C or E of LCO 3.5.2 has been entered
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Reduce RCS pressure to ≤ 1000 psig.	6 hours 12 hours
D. Two accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	12 hours
SR 3.5.1.2	Verify the borated water volume in each accumulator is ≥ 1667 cu. ft., and ≤ 1732 cu. ft.	12 hours
SR 3.5.1.3	Verify the nitrogen cover gas pressure in each accumulator is ≥ 637 psig and ≤ 769 psig.	12 hours
SR 3.5.1.4	Verify the boron concentration in each accumulator is ≥ 2600 ppm and ≤ 2900 ppm.	31 days <u>AND</u> ------------------------- **- NOTE -** Only required for affected accumulators. ------------------------- Once within 6 hours after each solution volume increase of ≥ 51 cu. ft., 3.0% that is not the result of addition from the in-containment refueling water storage tank
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when pressurizer pressure is ≥ 2000 psig.	31 days
SR 3.5.1.6	Verify system flow performance of each accumulator in accordance with the System Level OPERABILITY Testing Program.	10 years

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.2 Core Makeup Tanks (CMTs) – Operating

LCO 3.5.2 Both CMTs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4 with the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CMT inoperable due to one CMT outlet isolation valve inoperable.	A.1 Restore outlet isolation valve to OPERABLE status.	72 hours
B. One CMT inoperable due to one or more parameters (water temperature, boron concentration) not within limits.	B.1 Restore water temperature or boron concentration to within limits.	72 hours
C. Two CMTs inoperable due to water temperature or boron concentration not within limits.	C.1 Restore water temperature or boron concentration to within limits for one CMT.	8 hours if Condition B of LCO 3.5.1 has not been entered <u>OR</u> 1 hour if Condition B of LCO 3.5.1 has been entered
D. One CMT inoperable due to presence of non-condensible gases in one high point vent.	D.1 Vent noncondensible gases.	24 hours
E. One CMT inoperable for reasons other than Condition A, B, C, or D.	E.1 Restore CMT to OPERABLE status.	8 hours if Condition B of LCO 3.5.1 has not been entered <u>OR</u> 1 hour if Condition B of LCO 3.5.1 has been entered

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, C, D, or E.	F.1 Be in MODE 3. <u>AND</u> F.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the temperature of the borated water in each CMT is < 120°F.	24 hours
SR 3.5.2.2	Verify the borated water volume in each CMT is ≥ 2500 cu. ft.	7 days
SR 3.5.2.3	Verify each CMT inlet isolation valve is fully open.	12 hours
SR 3.5.2.4	Verify the volume of noncondensible gases in each CMT inlet line is ≤ [0.2] ft^3.	24 hours
SR 3.5.2.5	Verify the boron concentration in each CMT is ≥ 3400 ppm, and ≤ 3700 ppm.	7 days
SR 3.5.2.6	Verify each CMT outlet isolation valve is OPERABLE by stroking it open.	In accordance with the Inservice Testing Program
SR 3.5.2.7	Verify system flow performance of each CMT in accordance with the System Level OPERABILITY Testing Program.	10 years

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.3 Core Makeup Tanks (CMTs) – Shutdown, RCS Intact

LCO 3.5.3 One CMT shall be OPERABLE.

APPLICABILITY: MODE 4 with the RCS cooling provided by the Normal Residual Heat Removal System (RNS),
MODE 5 with the RCS pressure boundary intact.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required CMT inoperable due to one outlet isolation valve inoperable.	A.1 Restore required isolation valve to OPERABLE status.	72 hours
B. Required CMT inoperable due to one or more parameters (water temperature, boron concentration) not within limits.	B.1 Restore water temperature or boron concentration to within limits.	72 hours
C. Required CMT inoperable for reasons other than A or B.	C.1 Restore required CMT to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, or C.	D.1 Initiate action to be in MODE 5 with RCS pressure boundary open and ≥ 20% pressurizer level.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	For the CMT required to be OPERABLE, the SRs of Specification 3.5.2, “Core Makeup Tanks (CMTs) – Operating” are applicable.	In accordance with applicable SRs

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.4 Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Operating

LCO 3.5.4 The PRHR HX shall be OPERABLE.

- NOTE -

When any reactor coolant pumps (RCPs) are operating, at least one RCP must be operating in the loop with the PRHR HX, Loop 1.

APPLICABILITY: MODES 1, 2, 3, and 4 with the RCS not being cooled by the Normal Residual Heat Removal System (RNS).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One air operated outlet isolation valve inoperable.	A.1 Restore air operated outlet isolation valve to OPERABLE status.	72 hours
B. One air operated IRWST gutter isolation valve inoperable.	B.1 Restore air operated IRWST gutter isolation valve to OPERABLE status.	72 hours
C. Presence of non-condensible gases in the high point vent.	C.1 Vent noncondensible gases.	24 hours
D. Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4 with the RCS cooling provided by the RNS.	6 hours 24 hours
E. LCO not met for reasons other than A, B, or C.	E.1 Restore PRHR HX to OPERABLE status.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Required Action and associated Completion Time for Condition E not met.	F.1	------------------------------------ **- NOTE -** Prior to initiating actions to change to a lower MODE, verify that redundant means of providing SG feedwater are OPERABLE. If redundant means are not OPERABLE, suspend LCO 3.0.3 and all other LCO Required Actions requiring MODE changes until redundant means are restored to OPERABLE status. ------------------------------------ Be in MODE 3.	6 hours
	<u>AND</u>		
	F.2	------------------------------------ **- NOTE -** Prior to stopping the SG feedwater, verify that redundant means of cooling the RCS to cold shutdown conditions are OPERABLE. If redundant means are not OPERABLE, suspend LCO 3.0.3 and all other LCO Required Actions requiring MODE changes until redundant means are restored to OPERABLE status. ------------------------------------ Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	Verify the outlet manual isolation valve is fully open.	12 hours
SR 3.5.4.2	Verify the inlet motor operated isolation valve is open.	12 hours
SR 3.5.4.3	Verify the volume of noncondensible gases in the PRHR HX inlet line is ≤ [0.4] ft^3.	24 hours
SR 3.5.4.4	Verify that power is removed from the inlet motor operated isolation valve.	31 days
SR 3.5.4.5	Verify both PRHR air operated outlet isolation valves and both IRWST gutter isolation valves are OPERABLE by stroking open the valves.	In accordance with the System Level Inservice Testing Program
SR 3.5.4.6	Verify PRHR HX heat transfer performance in accordance with the System Level OPERABILITY Testing Program.	10 years
SR 3.5.4.7	Verify by visual inspection that the IRWST gutters are not restricted by debris.	24 months

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.5 Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Shutdown, RCS Intact

LCO 3.5.5 The PRHR HX shall be OPERABLE.

- NOTE -

When any reactor coolant pumps (RCPs) are operating, at least one RCP must be operating in the loop with the PRHR HX, Loop 1.

APPLICABILITY: MODE 4 with the RCS cooling provided by the Normal Residual Heat Removal System (RNS),
MODE 5 with the RCS pressure boundary intact and pressurizer level ≥ 20%.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One air operated outlet isolation valve inoperable.	A.1 Restore air operated outlet valve to OPERABLE status.	72 hours
B. One air operated IRWST gutter isolation valve inoperable.	B.1 Restore air operated IRWST gutter isolation valve to OPERABLE status.	72 hours
C. Presence of non-condensible gases in the high point vent.	C.1 Vent noncondensible gases.	24 hours
D. PRHR HX inoperable for reasons other than A, B, or C.	D.1 Restore PRHR HX to OPERABLE status.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, C, or D.	E.1 Initiate action to be in MODE 5 with the RCS pressure boundary open and > 20% pressurizer level.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	The SRs of Specification 3.5.4, "Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Operating" – are applicable.	In accordance with applicable SRs

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.6 In-containment Refueling Water Storage Tank (IRWST) – Operating

LCO 3.5.6 The IRWST, with two injection flow paths and two containment recirculation flow paths, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One IRWST injection line actuation valve flow path inoperable. OR One containment recirculation line actuation valve flow path inoperable.	A.1 Restore the inoperable actuation valve flow path to OPERABLE status.	72 hours
B. IRWST boron concentration not within limits. OR IRWST borated water temperature not within limits. OR IRWST borated water volume < 100% and > 97% of limit.	B.1 Restore IRWST to OPERABLE status.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One motor operated IRWST isolation valve not fully open. <u>OR</u> Power is not removed from one or more motor operated IRWST isolation valves.	C.1	Restore motor operated IRWST isolation valve to fully open condition with power removed from both valves.	1 hour
D. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, or C.	D.1 <u>AND</u> D.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.6.1	Verify the IRWST water temperature is < 120°F.	24 hours
SR 3.5.6.2	Verify the IRWST borated water volume is > [73,900] cu. ft.	24 hours
SR 3.5.6.3	Verify the IRWST boron concentration is ≥ 2600 ppm and ≤ 2900 ppm.	31 days <u>AND</u> Once within 6 hours after each solution volume increase of 15,000 gal

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.6.4	Verify each motor operated IRWST isolation valve is fully open.	12 hours
SR 3.5.6.5	Verify power is removed from each motor operated IRWST isolation valve.	31 days
SR 3.5.6.6	Verify each motor operated containment recirculation isolation valve is fully open.	31 days
SR 3.5.6.7	Verify each IRWST injection and containment recirculation squib valve is OPERABLE in accordance with the Inservice Testing Program.	In accordance with the Inservice Testing Program
SR 3.5.6.8	Verify by visual inspection that the IRWST screens and the containment recirculation screens are not restricted by debris.	24 months
SR 3.5.6.9	Verify IRWST injection and recirculation system flow performance in accordance with the System Level OPERABILITY Testing Program.	10 years

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3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.7 In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 5

LCO 3.5.7 The IRWST, with one injection flow path and one containment recirculation flow path, shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required motor operated containment recirculation isolation valve not fully open.	A.1 Open required motor operated containment recirculation isolation valve.	72 hours
B. IRWST boron concentration not within limits. <u>OR</u> IRWST borated water temperature not within limits. <u>OR</u> IRWST borated water volume < 100% and > 97% of limit.	B.1 Restore IRWST to OPERABLE status.	8 hours
C. Required motor operated IRWST isolation valve not fully open. <u>OR</u> Power is not removed from required motor operated IRWST isolation valve.	C.1 Restore required motor operated IRWST isolation valve to fully open condition with power removed.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, or C.	D.1	Initiate action to be in MODE 5 with the RCS pressure boundary intact and ≥ 20% pressurizer level.	Immediately
	<u>AND</u>		
	D.2	Suspend positive reactivity additions.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.7.1	For the IRWST and flow paths required to be OPERABLE, the SRs of Specification 3.5.6, “In-containment Refueling Water Storage Tank (IRWST) – Operating” are applicable.	In accordance with applicable SRs

3.5 PASSIVE CORE COOLING SYSTEM (PXS)

3.5.8 In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 6

LCO 3.5.8 The IRWST, with one injection flow path and one containment recirculation flow path, shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required motor operated containment recirculation isolation valve not fully open.	A.1 Open required motor operated containment recirculation isolation valve.	72 hours
B. IRWST and refueling cavity boron concentration not within limits. <u>OR</u> IRWST and refueling cavity borated water temperature not within limits. <u>OR</u> IRWST and refueling cavity borated water volume < 100% and > 97% of limit.	B.1 Restore IRWST to OPERABLE status.	8 hours
C. Required motor operated IRWST isolation valve not fully open. <u>OR</u> Power is not removed from required motor operated IRWST isolation valve.	C.1 Restore required motor operated IRWST isolation valve to fully open condition with power removed.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met. OR LCO not met for reasons other than A, B, or C.	D.1 Initiate action to be in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange. AND D.2 Suspend positive reactivity additions.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.8.1	Verify the IRWST and refueling cavity water temperature is < 120°F.	24 hours
SR 3.5.8.2	Verify the IRWST and refueling cavity water total borated water volume is > [73,900] cu. ft.	24 hours
SR 3.5.8.3	Verify the IRWST and refueling cavity boron concentration is ≥ 2600 ppm and ≤ 2900 ppm.	31 days AND Once within 6 hours after each solution volume increase of 15,000 gal
SR 3.5.8.4	For the IRWST and flow paths required to be OPERABLE, the following SRs of Specification 3.5.6, “In-containment Refueling Water Storage Tank (IRWST) – Operating” are applicable: SR 3.5.6.4 SR 3.5.6.6 SR 3.5.6.8 SR 3.5.6.5 SR 3.5.6.7	In accordance with applicable SRs

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage-rate testing except for containment air-lock testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

- NOTES -

1. Entry and exit is permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1, “Containment,” when air lock leakage results in exceeding the overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	A.1 ------------------------------------ **- NOTES -** 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. ------------------------------------	
	Verify the OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.2	Lock the OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>		
	A.3	------------------------------------ **- NOTE -** Air lock doors in high radiation areas may be verified locked closed by administrative means. ------------------------------------	
		Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	B.1	------------------------------------ **- NOTES -** 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ------------------------------------	
		Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	B.2	Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>		
	B.3	------------------------------------ **- NOTE -** Air lock doors in high radiation areas may be verified locked closed by administrative means. ------------------------------------	
		Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>		
	C.2	Verify a door is closed in the affected air lock.	1 hour
	<u>AND</u>		
	C.3	Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	-- **- NOTES -** 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. -- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one door in the air lock can be opened at a time.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

- NOTES -

1. Penetration flow path(s) may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1, “Containment,” when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------------------------- **- NOTE -** Only applicable to penetration flow paths with two containment isolation valves. ------------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. <u>AND</u>	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
	A.2	------------------------------------ **- NOTES -** 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ------------------------------------ Verify the affected penetration flow path is isolated.	 Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment
B. -------------------------------- **- NOTE -** Only applicable to penetration flow paths with two containment isolation valves. -------------------------------- One or more penetration flow paths with two containment isolation valves inoperable.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. -------------------------------- **- NOTE -** Only applicable to penetration flow paths with only one containment isolation valve and a closed system. -------------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	<u>AND</u>		
	C.2	------------------------------------ **- NOTES -** 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ------------------------------------ Verify that the affected penetration flow path is isolated.	Once per 31 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each [16] inch containment purge valve is closed, except when the [16] inch containment purge valves are open for pressure control, ALARA or air quality considerations for personnel containment entry, or for Surveillances which require the valves to be open.	31 days
SR 3.6.3.2	--- **- NOTE -** Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days
SR 3.6.3.3	--- **- NOTE -** Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days
SR 3.6.3.4	Verify the isolation time of each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.5	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ [-0.2] psig and ≤ +1.0 psig.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	12 hours

- Reviewer's Note -

The low pressure limit is not needed for plant locations for which the lowest possible ambient temperature is approximately 20°F.

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 120°F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment average air temperature is within limit.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Passive Containment Cooling System (PCS) – Operating

LCO 3.6.6 The passive containment cooling system shall be OPERABLE, with all three water flow paths OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One passive containment cooling water flow path inoperable.	A.1 Restore flow path to OPERABLE status.	7 days
B. Two passive containment cooling water flow paths inoperable.	B.1 Restore flow paths to OPERABLE status.	72 hours
C. One or more water storage tank parameters (temperature and volume) not within limits.	C.1 Restore water storage tank to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met. OR LCO not met for reasons other than A, B, or C.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify the water storage tank temperature ≥ 40°F and ≤ 120°F.	7 days <u>AND</u> 24 hours when water storage tank temperature is verified ≤ 50°F or ≥ 100°F
SR 3.6.6.2	Verify the water storage tank volume ≥ 756,700 gallons.	7 days
SR 3.6.6.3	Verify each passive containment cooling system, power operated, and automatic valve in each flow path that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.6.6.4	Verify each passive containment cooling system automatic valve in each flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.6.5	Verify the air flow path from the shield building annulus inlet to the exit is unobstructed and, that all air baffle sections are in place.	24 months
SR 3.6.6.6	Verify passive containment cooling system flow and water coverage performance in accordance with the System Level OPERABILITY Testing Program.	At first refueling <u>AND</u> 10 years

3.6 CONTAINMENT SYSTEMS

3.6.7 Passive Containment Cooling System (PCS) – Shutdown

LCO 3.6.7 The passive containment cooling system shall be OPERABLE with all three water flow paths OPERABLE.

APPLICABILITY: MODE 5 with the calculated reactor decay heat > 9.0 MWt,
MODE 6 with the calculated reactor decay heat > 9.0 MWt.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One passive containment cooling water flow path inoperable.	A.1 Restore flow path to OPERABLE status.	7 days
B. Two passive containment cooling water flow paths inoperable.	B.1 Restore flow paths to OPERABLE status.	72 hours
C. One or more water storage tank parameters (temperature and volume) not within limits.	C.1 Restore water storage tank to OPERABLE status.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than A, B, or C.	D.1.1	If in MODE 5, initiate action to be in MODE 5 with the RCS pressure boundary intact and ≥ 20% pressurizer level.	Immediately
	<u>OR</u>		
	D.1.2	If in MODE 6, initiate action to be in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange.	Immediately
	<u>AND</u>		
	D.2	Suspend positive reactivity additions.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	The SRs of Specification 3.6.6, “Passive Containment Cooling System – Operating” are applicable.	In accordance with applicable SRs

3.6 CONTAINMENT SYSTEMS

3.6.8 Containment Penetrations

LCO 3.6.8 The containment penetrations shall be in the following status:

a. The equipment hatches closed and held in place by [four] bolts or, if open, clear of obstructions such that the hatches can be closed prior to steaming into the containment.

b. One door in each air lock closed or, if open, the containment air locks shall be clear of obstructions such that they can be closed prior to steaming into the containment.

c. The containment spare penetrations, if open, shall be clear of obstructions such that the penetrations can be closed prior to steaming into the containment.

d. Each penetration providing direct access from the containment atmosphere to the outside atmosphere either:

   1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or

   2. capable of being closed by an OPERABLE Containment Isolation signal.

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Restore containment penetrations to required status.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met. <u>OR</u> LCO not met for reasons other than Condition A.	B.1.1 If in MODE 5, initiate action to be in MODE 5 with the RCS pressure boundary intact and ≥ 20% pressurizer level. <u>OR</u> B.1.2 If in MODE 6, initiate action to be in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange. <u>AND</u> B.2 Suspend positive reactivity additions.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.8.1	Verify each required containment penetration is in the required status.	7 days
SR 3.6.8.2	-------------------- **- NOTE -** -------------------- Only required to be met for an open equipment hatch. -- Verify that the hardware, tools, equipment and power source necessary to install the equipment hatch are available.	Prior to hatch removal <u>AND</u> 7 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.8.3	--- **- NOTE -** Not required to be met for automatic isolation valve(s) in penetrations closed to comply with LCO 3.6.8.d.1. ---	
	Verify one automatic isolation valve in each open penetration providing direct access from the containment atmosphere to the outside atmosphere actuates to the isolation position on an actual or simulated actuation signal.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.9 pH Adjustment

LCO 3.6.9 The pH adjustment baskets shall contain ≥ [560] ft^3 of trisodium phosphate (TSP).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The volume of trisodium phosphate not within limit.	A.1 Restore volume of trisodium phosphate to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.9.1	Verify that the pH adjustment baskets contain at least [560] ft^3 of TSP (Na_3PO_4-12 H_2O).	24 months
SR 3.6.9.2	Verify that a sample from the pH adjustment baskets provides adequate pH adjustment of the post-accident water.	24 months

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 The MSSVs shall be OPERABLE as specified in Table 3.7.1-1 and Table 3.7.1-2.

APPLICABILITY: MODES 1, 2, 3,
MODE 4 with the RCS not being cooled by the RNS.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required MSSVs inoperable.	A.1	Reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	
	<u>AND</u>		
	A.2	-------------------- **- NOTE -** Only required in MODE 1. --------------------	
		Reduce the Power Range Neutron Flux – High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time not met. OR One or more steam generators with ≥ 3 MSSVs inoperable.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	--- **- NOTE -** Only required to be performed in MODES 1 and 2. --- Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ±1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1 (page 1 of 1)
OPERABLE MSSVs versus Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
5	[82]
4	[65]
3	[48]
2	[31]

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER		LIFT SETTING (psig ± 1%)
STEAM GENERATOR		
#1	#2	
V030A	V030B	1185
V031A	V031B	1191
V032A	V032B	1198
V033A	V033B	1204
V034A	V034B	1211
V035A	V035B	1217

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 The minimum combination of valves required for steam flow isolation shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2, 3, and 4 except when steam flow is isolated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A. Restore valve to OPERABLE status.	8 hours
B. One or more of the turbine stop valves and its associated turbine control valve, turbine bypass valves, or moisture separator reheat supply steam control valves inoperable in MODE 1.	B. Restore valve to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two MSIVs inoperable in MODE 1. <u>OR</u> One MSIV inoperable and one or more of the turbine stop valves and its associated turbine control valve, all turbine bypass valves, or moisture separator reheat supply steam control valves inoperable in MODE 1. <u>OR</u> Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 2.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. -------------------------------- **- NOTE -** Separate Condition entry is allowed for each MSIV. -------------------------------- One or two MSIVs inoperable in MODE 2, 3, or 4. <u>OR</u> One or more of the turbine stop valves and its associated turbine control valve, all turbine bypass valves, or moisture separator reheat supply steam control valves inoperable in MODE 2, 3, or 4.	D.1	Isolate associated steam flow path.	8 hours
	<u>AND</u>		
	D.2	Verify flow path remains closed.	Once per 7 days
E. Required Action and associated Completion Time of Condition D not met.	E.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.2	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	--- **- NOTE -** Only required to be performed prior to entry into MODE 2. --- Verify MSIV closure time ≤ 5 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program
SR 3.7.2.2	--- **- NOTE -** Only required to be performed prior to entry into MODE 2. --- Verify turbine stop, turbine control, turbine bypass, and moisture separator reheat supply steam control valves' closure time ≤ 5 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.3 Main Feedwater Isolation and Control Valves (MFIVs and MFCVs)

LCO 3.7.3 The MFIV and the MFCV for each Steam Generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4 except when the MFIVs or associated MFCV are closed and deactivated.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two MFIVs inoperable.	A.1 Close or isolate the MFIV flow path.	72 hours
	AND	
	A.2 Verify MFIV is closed or isolated.	Once per 7 days
B. One or two MFCVs inoperable.	B.1 Close or isolate the MFCV the flow path.	72 hours
	AND	
	B.2 Verify MFCV is closed or isolated.	Once per 7 days
C. Two valves in the same flow path inoperable.	C.1 Isolate affected flow path.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours
	AND		
	D.3.1	Isolate the affected flow path(s).	36 hours
	OR		
	D.3.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	--- **- NOTE -** Only required to be performed prior to entry into MODE 2. ---	
	Verify the closure time of each MFIV and MFCV is ≤ 5 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.4 Secondary Specific Activity

LCO 3.7.4 The specific activity of the secondary coolant shall be ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify the specific activity of the secondary coolant ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131.	31 days

3.7 PLANT SYSTEMS

3.7.5 Spent Fuel Pool Water Level

LCO 3.7.5 The spent fuel pool water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: At all times.

ACTIONS

- NOTE -

LCOs 3.0.3 and 3.0.8 are not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent fuel pool water level < 23 ft.	A.1 Suspend movement of irradiated fuel assemblies in the spent fuel pool.	Immediately
	AND	
	A.2 Initiate action to restore water level to ≥ 23 ft.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify the spent fuel pool water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

3.7 PLANT SYSTEMS

3.7.6 Main Control Room Habitability System (VES)

LCO 3.7.6 The Main Control Room (MCR) Habitability System shall be OPERABLE.

- NOTE -

The MCR boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, 3, and 4,
During movement of irradiated fuel assemblies.

ACTIONS

- NOTE -

LCO 3.0.8 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One VES valve or damper inoperable.	A.1 Restore VES valve or damper to OPERABLE status.	7 days
B. MCR air temperature not within limit.	B.1 Restore MCR air temperature to within limit.	24 hours
C. Loss of integrity of MCR pressure boundary.	C.1 Restore MCR pressure boundary to OPERABLE status.	24 hours
D. Required Action and associated Completion Time of Conditions A, B, or C not met in MODE 1, 2, 3, or 4.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

ACTIONS (continued)

CONDITION		REQUIRED ACTION		COMPLETION TIME
E.	Required Action and associated Completion Time of Conditions A, B, or C not met during movement of irradiated fuel.	E.1	Suspend movement of irradiated fuel assemblies.	Immediately
F.	VES inoperable in MODE 1, 2, 3, or 4.	F.1	Be in MODE 3.	6 hours
		<u>AND</u>		
		F.2	Be in MODE 4.	12 hours
		<u>AND</u>		
		F.3	Restore VES to OPERABLE status.	36 hours
G.	VES inoperable during movement of irradiated fuel.	G.1	Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify Main Control Room air temperature is ≤ 75°F.	24 hours
SR 3.7.6.2	Verify that the compressed air storage tanks are pressurized to ≥ [3400] psig.	24 hours
SR 3.7.6.3	Verify that each VES air delivery isolation valve is OPERABLE.	In accordance with the Inservice Testing Program
SR 3.7.6.4	Verify that each VES air header manual isolation valve is in an open position.	31 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.6.5	Verify that the air quality of the air storage tanks meets the requirements of Appendix C, Table C-1 of ASHRAE Standard 62.	92 days
SR 3.7.6.6	Verify that all VBS Main Control Room isolation valves are OPERABLE and will close upon receipt of an actual or simulated actuation signal.	24 months
SR 3.7.6.7	Verify that each VES pressure relief isolation valve within the MCR pressure boundary is OPERABLE.	In accordance with the Inservice Testing Program
SR 3.7.6.8	Verify that each VES pressure relief damper is OPERABLE.	24 months
SR 3.7.6.9	Verify that the self-contained pressure regulating valve in each VES air delivery flow path is OPERABLE.	In accordance with the Inservice Testing Program
SR 3.7.6.10	Verify that one VES air delivery flow path maintains a 1/8-inch-water gauge positive pressure in the MCR envelope relative to the adjacent areas at the required air addition flow rate of 65 ± 5 scfm using the safety related compressed air emergency air storage tanks.	24 months

3.7 PLANT SYSTEMS

3.7.7 Startup Feedwater Isolation and Control Valves

LCO 3.7.7 Both Startup Feedwater Isolation Valves and Control Valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4 except when the startup feedwater flow paths are isolated.

ACTIONS

- NOTES -

1. Flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each flow path.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with one inoperable valve.	A.1 Isolate the affected flow path(s).	72 hours
	AND	
	A.2 Verify affected flow path(s) is isolated.	Once per 7 days
B. One flow path with two inoperable valves.	B.1 Isolate the affected flow path.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours
	AND	
	C.3 Isolate the affected flow path(s).	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify both startup feedwater isolation and control valves are OPERABLE.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.8 Main Steam Line Leakage

LCO 3.7.8 Main Steam Line leakage through the pipe walls inside containment shall be limited to 0.5 gpm.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Main Steam Line leakage exceeds operational limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	Verify main steam line leakage into the containment sump ≤ 0.5 gpm.	Per SR 3.4.7.1

3.7 PLANT SYSTEMS

3.7.9 Fuel Storage Pool Makeup Water Sources

LCO 3.7.9 Fuel storage pool makeup water source shall be OPERABLE.

- NOTES -

1. OPERABILITY of the cask washdown pit is required when the calculated spent fuel storage pool decay heat ≥ 4.6 MWt and ≤ 5.4 MWt.

2. OPERABILITY of the passive containment cooling water source is required when the calculated spent fuel storage pool decay heat > 5.4 MWt.

APPLICABILITY: During storage of fuel in the fuel storage pool with a calculated decay heat ≥ 4.6 MWt.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required fuel storage pool makeup water source inoperable.	A.1 ---------------------- **- NOTE -** LCOs 3.0.3 and 3.0.8 are not applicable. ---------------------- Initiate action to restore the required makeup water source to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Verify the passive containment cooling system water storage tank volume is ≥ 400,000 gallons.	7 days
SR 3.7.9.2	Verify the water level in the cask washdown pit is ≥ 13.75 ft.	30 days
SR 3.7.9.3	Verify the spent fuel storage pool makeup isolation valves PCS-PL-V009, PCS-PL-V045, PCS-PL-V051, SFS-PL-V066 and SFS-PL-V068 are OPERABLE in accordance with the Inservice Testing Program.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.10 Steam Generator Isolation Valves

LCO 3.7.10 The steam generator isolation valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with the RCS not being cooled by the RNS.

ACTIONS

- NOTES -

1. Steam generator blowdown flow path(s) may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each flow path.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more PORV flow paths with one SG isolation valve inoperable.	A.1	Isolate the flow path by use of at least one closed and deactivated automatic valve.	72 hours
B. One or more blowdown flow paths with one SG isolation valve inoperable.	B.1	Isolate the flow path by one closed valve.	72 hours
	AND		
	B.2	Verify that the affected SG blowdown flow path is isolated.	Once per 7 days
C. One or more PORV flow paths with two SG isolation valves inoperable.	C.1	Isolate the affected flow path by use of at least one closed and deactivated automatic valve.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more blowdown flow paths with two SG isolation valves inoperable.	D.1	Isolate the flow path by one closed valve.	8 hours
	AND		
	D.2	Verify that the affected SG blowdown flow path is isolated.	Once per 7 days
E. Required Action and associated Completion Time not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 4 with the RCS cooling provided by the RNS.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Verify each steam generator isolation valve (PORV block valves (SGS-PL-V027A & B), PORVs (SGS-PL-V233A & B), and blowdown isolation valves (SGS-PL-V074A & B and SGS-PL-V075A & B)) is OPERABLE by stroking the valve closed.	In accordance with the Inservice Testing Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 DC Sources – Operating

LCO 3.8.1 The Division A, B, C, and D Class 1E DC power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more battery chargers in one division inoperable.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	6 hours
	AND	
	A.2 Verify battery float current ≤ [5] amps.	Once per 24 hours
	AND	
	A.3 Restore battery charger(s) to OPERABLE status.	7 days
B. One or more battery chargers in two divisions inoperable.	B.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	AND	
	B.2 Verify battery float current ≤ [5] amps.	Once per 24 hours
	AND	
	B.3 Restore battery charger(s) to OPERABLE status.	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more batteries in one division inoperable.	C.1 Restore batteries to OPERABLE status.	6 hours
D. One or more batteries in two divisions inoperable.	D.1 Restore batteries to OPERABLE status.	2 hours
E. One DC electrical power subsystem inoperable for reasons other than Condition A or C.	E.1 Restore DC electrical power subsystem to OPERABLE status.	6 hours
F. Two DC electrical power subsystems inoperable for reasons other than B or D.	F.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours
G. Required Action and associated Completion Time not met.	G.1 Be in MODE 3. <u>AND</u> G.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	7 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.2	Verify each battery charger supplies ≥ [400] amps at greater than or equal to the minimum established float voltage for ≥ [8] hours. <u>OR</u> Verify each battery charger can recharge the battery to the fully charged state within [24] hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	24 months
SR 3.8.1.3	-- **- NOTES -** 1. The modified performance discharge test in SR 3.8.7.6 may be performed in lieu of SR 3.8.1.3. 2. This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4 unless the spare battery is connected to replace the battery being tested. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	 24 months

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 DC Sources – Shutdown

LCO 3.8.2 DC electrical power subsystems shall be OPERABLE to support the DC electrical power distribution subsystem(s) required by LCO 3.8.6, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

- NOTE -

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power subsystems inoperable.	A.1 Declare affected required features inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations with a potential for draining the reactor vessel.	Immediately
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.4 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.5 Initiate action to restore required DC electrical power subsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	-------------------- **- NOTE -** -------------------- The following SRs are not required to be performed: SR 3.8.1.2 and SR 3.8.1.3. --	
	For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.2 SR 3.8.1.3	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Inverters – Operating

LCO 3.8.3 The Division A, B, C, and D inverters (Divisions A and D, one each and Divisions B and C two each; six total) shall be OPERABLE.

- NOTES -

One inverter may be disconnected from its associated DC bus for ≤ 72 hours to perform an equalizing charge on its associated battery, providing:

1. The associated instrument and control bus is energized from its Class 1E constant voltage source transformer; and

2. All other AC instrument and control buses are energized from their associated OPERABLE inverters.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One inverter inoperable.	A.1	--- **- NOTE -** Enter applicable Conditions and Required Actions of LCO 3.8.5 “Distribution Systems – Operating” with any instrument and control bus de-energized. --- Restore inverter to OPERABLE status.	24 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify correct inverter voltage, frequency, and alignment to required AC instrument and control buses.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 Inverters – Shutdown

LCO 3.8.4 Inverters shall be OPERABLE to support the onsite Class 1E power distribution subsystems required by LCO 3.8.6, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

- NOTE -

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required inverters inoperable.	A.1	Declare affected required features inoperable.	Immediately
	<u>OR</u>		
	A.2.1	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	A.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>		
	A.2.3	Suspend operations with a potential for draining the reactor vessel.	Immediately
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.4 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.5 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify correct inverter voltage, frequency, and alignments to required AC instrument and control buses.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 Distribution Systems – Operating

LCO 3.8.5 The Division A, B, C, and D AC instrument and control bus and DC electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Division AC instrument and control bus inoperable.	A.1 Restore AC instrument and control bus to OPERABLE status.	6 hours <u>AND</u> 12 hours from discovery of failure to meet the LCO
B. One Division DC electrical power distribution subsystem inoperable.	B.1 Restore DC electrical power distribution subsystem to OPERABLE status.	6 hours <u>AND</u> 12 hours from discovery of failure to meet the LCO
C. Two Divisions AC instrument and control bus inoperable.	C.1 Restore AC instrument and control bus to OPERABLE status.	2 hours <u>AND</u> 16 hours from discovery of failure to meet the LCO.
D. Two Divisions DC electrical power distribution subsystem inoperable.	D.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours <u>AND</u> 16 hours from discovery of failure to meet the LCO.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours
F. Two Divisions with inoperable distribution subsystems that result in a loss of safety function.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	Verify correct breaker and switch alignments and voltage to required DC and AC instrument and control bus electrical power distribution subsystems.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Distribution Systems – Shutdown

LCO 3.8.6 The necessary portions of DC and AC instrument and control bus electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

- NOTE -

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC or AC instrument and control bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required features inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.4 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.5 Initiate actions to restore required DC and AC instrument and control bus electrical power distribution subsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify correct breaker and switch alignments and voltage to required DC and AC instrument and control bus electrical power distribution subsystems.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Battery Parameters

LCO 3.8.7 Battery Parameters for Division A, B, C, and D batteries shall be within limits.

APPLICABILITY: When associated DC electrical power sources are required to be OPERABLE.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more batteries in one division with one or more battery cells float voltage < [2.07] V.	A.1 Perform SR 3.8.1.1.	2 hours
	AND	
	A.2 Perform SR 3.8.7.1.	2 hours
	AND	
	A.3 Restore affected cell voltage ≥ [2.07] V.	24 hours
B. One or more batteries in one division with float current > [5] amps.	B.1 Perform SR 3.8.1.1.	2 hours
	AND	
	B.2 Restore battery float current to ≤ [5] amps.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
------------------------------- **- NOTE -** Required Action C.2 shall be completed if electrolyte level was below the top of plates. -------------------------------		------------------------------------ **- NOTE -** Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. ------------------------------------	
C. One or more batteries in one division with one or more cells electrolyte level less than minimum established design limits.	C.1	Restore electrolyte level to above top of plates.	8 hours
	<u>AND</u>		
	C.2	Verify no evidence of leakage.	12 hours
	<u>AND</u>		
	C.3	Restore electrolyte level to greater than or equal to minimum established design limits.	31 days
D. One or more batteries in one division with pilot cell electrolyte temperature less than minimum established design limits.	D.1	Restore battery pilot cell temperature to greater than or equal to minimum established design limits.	12 hours
E. One or more batteries in two or more divisions with battery parameters not within limits.	E.1	Restore battery parameters for batteries in three divisions to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time not met. <u>OR</u> One or more batteries in one division with one or more battery cells float voltage < [2.07] V and float current > [5] amps.	F.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.7.1	-- **- NOTE -** Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.1.1. -- Verify each battery float current is ≤ [5] amps.	7 days
SR 3.8.7.2	Verify each battery pilot cell voltage is ≥ [2.07] V.	31 days
SR 3.8.7.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	31 days
SR 3.8.7.4	Verify each battery pilot cell temperature is greater than or equal to minimum established design limits.	31 days
SR 3.8.7.5	Verify each battery connected cell voltage is ≥ [2.07] V.	92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.7.6	--- **- NOTE-** This Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---	
	Verify battery capacity is ≥ [80]% of the manufacturer’s rating when subjected to a performance discharge test or a modified performance discharge test.	60 months <u>AND</u> 12 months when battery shows degradation, or has reached [85]% of the expected life with capacity < 100% of manufacturer’s rating <u>AND</u> 24 months when battery has reached [85]% of the expected life with capacity ≥ 100% of manufacturer’s rating

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentration of the Reactor Coolant System (RCS), the fuel transfer canal, and the refueling cavity shall be maintained within the limit specified in COLR.

APPLICABILITY: MODE 6.

- NOTE -

Only applicable to the fuel transfer canal and the refueling cavity when connected to the RCS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend positive reactivity additions.	Immediately
	AND	
	A.3 Initiate actions to restore boron concentration to within limits.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	72 hours

3.9 REFUELING OPERATIONS

3.9.2 Unborated Water Source Flow Paths

LCO 3.9.2 Each unborated water source flow path shall be isolated.

APPLICABILITY: MODE 6.

ACTIONS

- NOTE -

Separate condition entry is allowed for each unborated water source flow path.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------------------------- **- NOTE -** Required Action A.3 must be completed whenever Condition A is entered. -------------------------------- One or more flow paths not isolated.	A.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2 Initiate actions to isolate flow paths.	Immediately
	<u>AND</u>	
	A.3 Perform SR 3.9.1.1, (boron concentration verification).	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify each unborated water source flow path is isolated by at least one valve secured in the closed position.	31 days

3.9 REFUELING OPERATIONS

3.9.3 Nuclear Instrumentation

LCO 3.9.3 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
B. Two required source range neutron flux monitors inoperable.	B.1 Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	AND	
	B.2 Perform SR 3.9.1.1, (Boron Concentration Verification).	Once per 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Perform a CHANNEL CHECK.	12 hours
SR 3.9.3.2	-- **- NOTE-** Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	24 months

3.9 REFUELING OPERATIONS

3.9.4 Refueling Cavity Water Level

LCO 3.9.4 Refueling Cavity Water Level shall be maintained ≥ 23 ft above the top of the reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

- NOTE -

LCO 3.0.8 is not applicable.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1	Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify that refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	24 hours

3.9 REFUELING OPERATIONS

3.9.5 Containment Penetrations

LCO 3.9.5 The containment penetrations shall be in the following status:

a. The equipment hatches closed and held in place by [four] bolts or, if open, the containment air filtration system (VFS) shall be OPERABLE and operating;

b. One door in each air lock closed or, if open, the VFS shall be OPERABLE and operating;

c. The containment spare penetrations closed or, if open, the VFS shall be OPERABLE and operating;

d. Each penetration providing direct access from the containment atmosphere to the outside atmosphere either:

1. Closed by a manual or automatic isolation valve, blind flange, or equivalent, or

2. Capable of being closed by an OPERABLE Containment Isolation signal.

- NOTE -

Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

- NOTE -

LCO 3.0.8 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.5.2	-------------------- **- NOTE-** Not required to be met for containment purge and exhaust valve(s) in penetrations closed to comply with LCO 3.9.4.d.1. -------------------- Verify each required containment purge and exhaust valve actuates to the isolation position on a manual actuation signal.	In accordance with the Inservice Test Program
SR 3.9.5.3	Verify the VFS can maintain a negative pressure ($\leq$ [-0.125] inches water gauge relative to outside atmospheric pressure) in the area enclosed by the containment and alternate barrier.	24 months
SR 3.9.5.4	Operate each VFS train for $\geq$ 10 continuous hours with the heaters operating.	Within 31 days prior to fuel movement or CORE ALTERATIONS

3.9 REFUELING OPERATIONS

3.9.6 Containment Air Filtration System (VFS)

LCO 3.9.6 One VFS exhaust subsystem shall be OPERABLE.

APPLICABILITY: During movement of irradiated fuel assemblies in the fuel building.

ACTIONS

- NOTE -

LCOs 3.0.3 and 3.0.8 are not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required VFS exhaust subsystem inoperable.	A.1 Suspend movement of irradiated fuel assemblies in the fuel building.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Operate each VFS exhaust subsystem for $\geq$ 10 continuous hours with the heaters operating.	Within 31 days prior to fuel movement
SR 3.9.6.2	Verify the VAS fuel handling area subsystem aligns to the VFS exhaust subsystem on an actual or simulated actuation signal.	24 months
SR 3.9.6.3	Verify one VFS exhaust subsystem can maintain a negative pressure ($\leq$ [-0.125] inches water gauge relative to outside atmospheric pressure) in the fuel handling area.	24 months

3.9 REFUELING OPERATIONS

3.9.7 Decay Time

LCO 3.9.7 The reactor shall be subcritical for ≥ 100 hours.

APPLICABILITY: During movement of irradiated fuel in the reactor pressure vessel.

ACTIONS

- NOTE -

LCO 3.0.8 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor subcritical < 100 hours.	A.1 Suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify that the reactor has been subcritical for ≥ 100 hours by verification of the date and time of subcriticality.	Prior to movement of irradiated fuel in the reactor vessel

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4.0 DESIGN FEATURES

4.1 Site

[Not applicable to AP1000 Design Certification. Site specific information to be provided by COL Applicant.]

4.1.1 Site and Exclusion Boundaries

[This information will be provided by the combined license applicant.]

4.1.2 Low Population Zone (LPZ)

[This information will be provided by the combined license applicant.]

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 157 fuel assemblies. Each assembly shall consist of a matrix of fuel rods clad with a zirconium based alloy and containing an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium based alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod and Gray Rod Assemblies

The reactor core shall contain 53 Rod Cluster Control Assemblies (RCCAs), each with 24 rodlets/RCCA. The RCCA absorber material shall be silver indium cadmium as approved by the NRC.

Additionally, there are 16 low worth Gray Rod Cluster Assemblies (GRCAs), with 24 rodlets/GRCA, which, in conjunction with the RCCAs, are used to augment MSHIM load follow operation.

4.0 DESIGN FEATURES

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent.

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water which includes an allowance for uncertainties as described in Section 9.1, "Fuel Storage and Handling."

c. A nominal [10.90] inch center-to-center distance between fuel assemblies placed in the spent fuel storage racks.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent.

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water which includes an allowance for uncertainties as described in Section 9.1, "Fuel Storage and Handling."

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam which includes an allowance for uncertainties as described in Section 9.1, "Fuel Storage and Handling."

d. A nominal [10.90] inch center-to-center distance between fuel assemblies placed in the new fuel storage racks.

4.3.2 Drainage

The spent fuel pool is designed and shall be maintained to prevent inadvertent draining of the pool below a minimum water depth of ≥ 23 ft above the surface of the fuel storage racks.

4.3.3 Capacity

The spent fuel pool is designed and shall be maintained with a storage capacity limited to no more than [616] fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The [Plant Manager] shall be responsible for overall unit operations and shall delegate in writing the succession to this responsibility during his absence.

The [Plant Manager] or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The [Shift Supervisor (SS)] shall be responsible for the control room command function. During any absence of the [SS] from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the [SS] from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the [FSAR/QA Plan];

b. The [Plant Manager] shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operation pressures.

5.2.2 Unit Staff

- REVIEWER'S NOTE -

[Determination of the unit staff positions, numbers, and qualifications are the responsibility of the COL applicant. Input provided in WCAP-14694, Revision 0, for the MCR staff and WCAP-14655, Revision 1, for other than the MCR staff will be used in the determination. Each of the following paragraphs may need to be corrected to specify the plant staffing requirements.]

5.2 Organization

5.2.2 Unit Staff (continued)

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned for each control room from which a reactor is operating in MODE 1, 2, 3, or 4.

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.g for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions (e.g., licensed Senior Reactor Operators (SROs), licensed Reactor Operators (ROs), health physicists, auxiliary operators, and key maintenance personnel).

   The controls shall include guidelines on working hours that ensure adequate shift coverage shall be maintained without routine heavy use of overtime.

   Any deviation from the above guidelines shall be authorized in advance by the plant manager or the plant manager's designee, in accordance with approved administrative procedures, and with documentation of the basis for granting the deviation. Routine deviation from the working hour guidelines shall not be authorized.

   Controls shall be included in the procedures to require a periodic independent review be conducted to ensure that excessive hours have not be assigned.

e. The operations manager or assistant operations manager shall hold an SRO license.

f. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

- REVIEWER'S NOTE -

[Minimum qualifications for members of the unit staff shall be specified by use of an overall qualification statement referencing an ANSI Standard acceptable to the NRC staff or by specifying individual position qualifications. Generally, the first method is preferable; however, the second method is adaptable to those unit staffs requiring special qualification statements because of unique organizational structures.]

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of [Regulatory Guide 1.8, Revision 2, 1987, or more recent revisions, or ANSI Standards acceptable to the NRC staff]. The staff not covered by [Regulatory Guide 1.8] shall meet or exceed the minimum qualifications of [Regulations, Regulatory Guides, or ANSI Standards acceptable to NRC staff].

5.3.2 For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed reactor operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.1, perform the functions described in 10 CFR 50.54(m).

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in [Generic Letter 82-33];

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Reports required by Specification 5.6.2 and Specification 5.6.3.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1. Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   2. A determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.106, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after the approval of the plant manager; and

c. Shall be submitted to the NRC in the form of a complete, legible copy of the changed portion of the ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals

5.5.2 Radioactive Effluent Control Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoints determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public for radioactive materials in liquid effluents released form each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary shall be in accordance with the following:

   1. For noble gases: a dose rate ≤ 500 mrem/yr to the whole body and a dose rate ≤ 3000 mrem/yr to the skin and

5.5 Programs and Manuals

5.5.2 Radioactive Effluent Control Program (continued)

2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: a dose rate ≤ 1500 mrem/yr to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.3 Inservice Testing Program

This program provides control for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda Terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

5.5 Programs and Manuals

5.5.3 Inservice Testing Program (continued)

c. The provisions of SR 3.0.3 are applicable to inservice testing activities;

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.4 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.4.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

5.5.4.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.4-1.

5.5.4.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.4-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.4.3, and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.4.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

2. Tubes in those areas where experience has indicated potential problems.

5.5 Programs and Manuals

5.5.4 Steam Generator (SG) Tube Surveillance Program (continued)

3. A tube inspection (pursuant to Specification 5.5.4.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 5.5.4-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

5.5 Programs and Manuals

5.5.4 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.4.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5.4-2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.4.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.4-2 during the shutdown subsequent to any of the following conditions:

   1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.8.

   2. A seismic occurrence greater than one-third of the Safe Shutdown Earthquake.

   3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

   4. A main steam line or feedwater line break.

d. The provisions of Specification 3.0.2 do not apply for extending the frequency of performing inservice inspections as specified in Specifications 5.5.4.3a and 5.5.4.3b.

5.5 Programs and Manuals

5.5.4 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.4.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of a one-third of the Safe Shutdown Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.4.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

5.5 Programs and Manuals

5.5.4 Steam Generator (SG) Tube Surveillance Program (continued)

9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plugging of all tubes exceeding the plugging limit) required by Table 5.5.4-2.

Table 5.5.4-1 (page 1 of 1)

No. of Steam Generators per Unit	Two
First Inservice Inspection	One*
Second and Subsequent Inservice Inspections	One**

* All steam generators shall be inspected during the first inservice inspection if no preservice inspection was conducted.

** The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. If the condition of the tubes in one steam generator are found to be more severe than in the other steam generator, the SG sampling sequence at the subsequent inspection shall be modified to examine the steam generator with the more severe condition.

Table 5.5.4-2 (page 1 of 1)
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per SG	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this SG	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this SG	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this SG, plug defective tubes and inspect 2S tubes in each other SG Notification to NRC pursuant to 10 CFR 50.73	All other SGs are C-1	None	N/A	N/A
			Some SGs C-2 but no additional SGs are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional SG is C-3	Inspect all tubes in each SG and plug defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

5.5 Programs and Manuals

5.5.5 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.6 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license; or

   2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

5.5 Programs and Manuals

5.5.6 Technical Specifications (TS) Bases Control Program (continued)

d. Proposed changes that meet the criteria of (b) above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.7 Safety Function Determination Program (SFDP)

This program ensure loss of safety function is detected and appropriate action taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the supported system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirement of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system’s Completion Time is not inappropriately extended as a result of multiple support systems inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

5.5 Programs and Manuals

5.5.7 Safety Function Determination Program (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.8 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program, dated September 1995," as modified by approved exceptions.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is [57.8] psig. The containment design pressure is 59 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.10% of primary containment air weight per day.

d. Leakage Rate acceptance criteria are:

   1. Containment leakage rate acceptance criterion is 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 L_a for the Type B and Type C tests and ≤ 0.75 L_a for Type A tests;

   2. Air lock testing acceptance criteria are:

      a) Overall air lock leakage rate is ≤ [0.05] L_a when tested at ≥ P_a,

      b) For each door, leakage rate is ≤ [0.01] L_a when pressurized to ≥ [10] psig.

e. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

f. Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10 CFR 50, Appendix J.

5.5 Programs and Manuals

5.5.9 System Level OPERABILITY Testing Program

The System Level OPERABILITY Testing Program provides requirements for performance tests of passive systems. The System Level Inservice Tests specified in Section 3.9.6 and Table 3.9-17 apply when specified by individual Surveillance Requirements.

a. The provisions of SR 3.0.2 are applicable to the test frequencies specified in Table 3.9.17 for performing system level OPERABILITY testing activities; and

b. The provisions of SR 3.0.3 are applicable to system level OPERABILITY testing activities.

5.5.10 Component Cyclic or Transient Limit

This program provides controls to track the Table 3.9-1A cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.11 Battery Monitoring and Maintenance Program

This Program provides for battery restoration and maintenance, based on [the recommendations of IEEE Standard 450-1995, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications,” or of the battery manufacturer] including the following:

a. Actions to restore battery cells with float voltage < [2.13] V, and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the minimum established design limit.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Occupational Radiation Exposure Report

- NOTE -

A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures > 100 mrem/yr and their associated collective deep dose equivalent (reported in person-rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance, waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket dosimeter, thermoluminescent dosimeter (TLD), electronic dosimeter or film badge measurements. Small exposures totaling < 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total deep dose equivalent received from external sources should be assigned to specific major work functions. The report shall be submitted by April 30 of each year. [The initial report shall be submitted by April 30 of the year following the initial criticality.]

5.6.2 Annual Radiological Environmental Operating Report

- NOTE -

A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements [in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979]. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

- NOTE -

A single submittal may be made for a multiple unit station.

The Radioactive Effluent Release Report covering the operation of the unit in the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

2.1.1, “Reactor Core SLs”
3.1.1, “SHUTDOWN MARGIN (SDM)”
3.1.3, “Moderator Temperature Coefficient”
3.1.5, “Shutdown Bank Insertion Limits”
3.1.6, “Control Bank Insertion Limits”
3.2.1, “Heat Flux Hot Channel Factor”

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (continued)

3.2.2, “Nuclear Enthalpy Rise Hot Channel Factor”
3.2.3, “AXIAL FLUX DIFFERENCE”
3.2.5, “OPDMS-monitored Power Distribution Parameters”
3.3.1, “Reactor Trip System (RTS) Instrumentation”
3.4.1, “RCS Pressure, Temperature, and DNB Limits”
3.9.1, “Boron Concentration”

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology,” July 1985 (Westinghouse Proprietary) and WCAP-9273-NP-A (Non-Proprietary).

   (Methodology for Specifications 3.1.4 - Moderator Temperature Coefficient, 3.1.6 - Shutdown Bank Insertion Limits, 3.1.7 - Control Bank Insertion Limits, 3.2.1 - Heat Flux Hot Channel Factor, 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor, 3.2.3 - AXIAL FLUX DIFFERENCE, and 3.9.1 - Boron Concentration.)

2a. WCAP-8385, “Power Distribution Control and Load Following Procedures - Topical Report,” September 1974 (Westinghouse Proprietary) and WCAP-8403 (Non-Proprietary).

   (Methodology for Specification 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control).)

2b. T. M. Anderson to K. Kniel (Chief of Core Performance Branch, NRC) January 31, 1980 - Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package.

   (Methodology for Specification 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control).)

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch Technical Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981.

   (Methodology for Specification 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control).)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (continued)

3. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification,” February 1994 (Westinghouse Proprietary) and WCAP-10217-A (Non-Proprietary).

   (Methodology for Specifications 3.2.3 - AXIAL FLUX DIFFERENCE (Relaxed Axial Offset Control) and 3.2.1 - Heat Flux Hot Channel Factor (W(Z) surveillance requirements for FQ Methodology).)

4. WCAP-12945-P-A, Volumes 1-5, “Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis,” Revision 2, March 1998 (Westinghouse Proprietary) and WCAP-14747 (Non-Proprietary).

   (Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor.)

5. WCAP-12472-P-A, “BEACON Core Monitoring and Operations Support System,” August 1994, Addendum 1, May 1996 (Westinghouse Proprietary), and Addendum 2, March 2001 (Westinghouse Proprietary) and WCAP-12473-A (Non-Proprietary).

   (Methodology for Specification 3.2.5 - OPDMS - Monitored Power Distribution Parameters.)

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Passive Core Cooling Systems limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

   3.4.3, “RCS Pressure and Temperature (P/T) Limits”
   3.4.15, “Low Temperature Overpressure Protection (LTOP) System”

5.6 Reporting Requirements

5.6.6 RCS PRESSURE AND TEMPERATURE LIMITS REPORT (continued)

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

WCAP-14040-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves." (Limits for LCO 3.4.3 and LCO 3.4.15).

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluency period and for any revision or supplement thereto.

5.6.7 Post Accident Monitoring Report

When a report is required by Condition B of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.8 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging effort.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. This written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 <u>High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation</u>

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

    1. A radiation monitoring device that continuously displays radiation dose rates in the area, or

    2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

    3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

   (i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

   (ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 <u>High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation</u>

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

   1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designees, and

   2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, or personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displaces radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core Safety Limits (SLs)

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not to be exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur, and by requiring that the fuel centerline temperature stays below the melting temperature.

The restriction of this SL prevents overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR or power peaking in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (Zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Protection and Safety Monitoring System (PMS) and steam generator safety valves prevents violation of the reactor core SLs.

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System (RTS) setpoints (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS Flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the PMS and the steam generator safety valves.

The SLs represent a design requirement for establishing the RTS setpoints. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in Section 7.2, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure provided in the COLR shows the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analysis limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNBR correlation.

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

BASES

SAFETY LIMITS (continued)

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, “Reactor Trip System (RTS) Instrumentation.” In MODES 3, 4, 5, and 6, applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the reactor core SLs. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.

2. Section 7.2, “Reactor Trip.”

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, “Reactor Coolant Pressure Boundary,” and GDC 15, “Reactor Coolant System Design” (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, “Reactivity Limits” (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2500 psia (2485 psig). During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases.

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressurizer pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load with loss of feedwater flow, without a direct reactor trip. During the transient, no control actions are assumed except that the

BASES

APPLICABLE SAFETY ANALYSES (continued)

safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressurizer pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressurizer pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. RCS depressurization valves;

b. Steam line relief valves (SG PORVs);

c. Turbine Bypass System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray.

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel, piping, valves, and fittings under the ASME Code, Section III, is 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2733.5 psig.

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 since the reactor vessel closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

SAFETY LIMIT VIOLATIONS

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for abnormal radioactive releases.

BASES

SAFETY LIMIT VIOLATIONS (continued)

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and GDC 28.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ASME Boiler and Pressure Vessel Code, Section XI, Article IWX-5000.
4. 10CFR100.
5. Section 7.2, “Reactor Trip System.”

B 3.0 LIMITING CONDITIONS FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirements for when the LCO is required to be met (i.e. when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification.)

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that the ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case compliance with the Required Actions provides an acceptable level of safety for continued operation.

BASES

LCO 3.0.2 (continued)

Completing the Required Actions is not required when an LCO is met, or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time other conditions could exist which result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met; and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

BASES

LCO 3.0.3 (continued)

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering into LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, “Completion Times.”

A unit shutdown required in accordance with LCO 3.0.3 may be terminated, and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition was initially entered and not from the time LCO 3.0.3 is exited.

LCO 3.0.3 (continued)

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive condition required by LCO 3.0.3. In MODES 5 and 6, LCO 3.0.8 provides actions for Conditions not covered in other Specifications.

Exceptions to 3.0.3 are provided in instances where requiring a unit shutdown in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.5, Spent Fuel Pool Water Level. This Specification has an Applicability of “At all times.” Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.5 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.5 of “Suspend movement of irradiated fuel assemblies in the spent fuel pool” is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It precludes placing the unit in a MODE or other specified condition stated that Applicability (e.g., Applicability desired to be entered) when the following exist:

a. Unit conditions are such that the requirements of the LCO would not be met in the Applicability desired to be entered; and

BASES

LCO 3.0.4 (continued)

b. Continued noncompliance with the LCO requirements, if the Applicability were entered, would result in the unit being required to exit the Applicability desired to be entered to comply with the Required Actions.

Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that results from any unit shutdown.

Exceptions to LCO 3.0.4 are stated in the individual Specifications. These exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time. Exceptions may apply to all the ACTIONS or to a specific Required Action of a Specification.

LCO 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4 or 5, MODE 2 from MODE 3 or 4 or 5, or MODE 1 from MODE 2. Furthermore, LCO 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, 3, or 4. The requirements of LCO 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4 or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or

BASES

LCO 3.0.4 (continued)

SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance of restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of Surveillance Requirements to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required

LCO 3.0.6 (continued)

to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.7, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of

BASES

LCO 3.0.6 (continued)

safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety functions exists are required to be entered.

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the support system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCO 3.1.8 allows specified Technical Specification (TS) requirements to be changed to permit performance of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is

BASES

LCO 3.0.7 (continued)

desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes the ACTIONS that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit.

This Specification delineates the requirements for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.8, 1 hour is allowed to prepare for an orderly plan of action which optimizes plant safety and equipment restoration. The Shutdown Safety Status Trees provide a systematic method to explicitly determine the status of the plant during shutdown conditions, after entering MODE 5. A set of plant parameters is monitored and if any parameter is outside of its defined limits, a transition is made to the Shutdown Emergency Response Guidelines. These guidelines provide preplanned actions for addressing parameters outside defined limits.

Examples of the required end states specified for inoperable passive systems while in MODES 5 and 6 are provided in Table B 3.0-1, Passive Systems Shutdown MODE Matrix. These requirements are specified in the individual Specifications. The required end states specified for passive systems, when the unit is in MODE 5 or 6, are selected to ensure that the initial conditions and system and equipment availabilities minimize the likelihood and consequences of potential shutdown events.

BASES

LCO 3.0.8 (continued)

ACTIONS required in accordance with LCO 3.0.8 may be terminated and LCO 3.0.8 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.8 is exited.

In MODES 5 and 6, LCO 3.0.8 provides actions for Conditions not covered in other Specifications and for multiple concurrent Conditions for which conflicting actions are specified.

As an example of the application of LCO 3.0.8, see column 2 of Table B 3.0-1, Passive Systems Shutdown MODE Matrix, for the core makeup tank. This example assumes that the plant is initially in MODE 5 with the RCS pressure boundary intact. In this plant condition, LCO 3.5.3 requires one core makeup tank to be OPERABLE. The table shows the required end state established by the Required Actions of TS 3.5.3 in the event that the core makeup tank cannot be restored to OPERABLE status.

For this initial plant shutdown condition with no OPERABLE core makeup tanks, four conditions are identified in TS 3.5.3, with associated Required Actions and Completion Times. If Conditions A, B, and C cannot be completed within the required Completion Times, then Condition D requires immediately initiating action to place the plant in MODE 5 with the RCS pressure boundary open, and with pressurizer level greater than 20 percent.

LCO 3.0.8 would apply if actions could not immediately be initiated to open the RCS pressure boundary. In this situation, in parallel with the TS 3.5.3 actions to continue to open the RCS pressure boundary, LCO 3.0.8 requires the operators to take actions to restore one core makeup tank to OPERABLE status, and to monitor the Safety System Shutdown Monitoring Trees.

The Shutdown Status Trees monitor seven key RCS parameters and direct the operators to one of six shutdown ERGs in the event that any of the parameters are outside of allowable limits. The shutdown ERGs

BASES

LCO 3.0.8 (continued)

identify actions to be taken by the operators to satisfy the critical safety functions for the plant in the shutdown condition, using plant equipment available in this shutdown condition. LCO 3.0.8 monitoring would continue to be required until one core makeup tank is restored to OPERABLE status or the Required Actions for Condition D can be satisfied. In this case, once the RCS pressure boundary is open as required by Condition D, LCO 3.0.8 would be exited.

Table B 3.0-1 (page 1 of 1)
Passive Systems Shutdown MODE Matrix

LCO Applicability	Automatic Depressurization System	Core Makeup Tank	Passive RHR	IRWST	Containment	Containment Cooling[(1)]
MODE 5 RCS pressure boundary intact	9 of 10 paths OPERABLE All paths closed LCO 3.4.12	One CMT OPERABLE LCO 3.5.3	System OPERABLE LCO 3.5.5	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6.7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 5 RCS pressure boundary open or pressurizer level < 20%	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.13	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6.7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level			MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 6 Upper internals in place	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.13	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.8	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6.7
Required End State	MODE 6 Upper internals removed			MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full
MODE 6 Upper internals removed	None	None	None	One injection flow path and one recirc-ulation sump flow path OPERABLE LCO 3.5.8	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6.7
Required End State				MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full

(1) Containment cooling via PCS is not required when core decay heat < 9 MWt.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification ensures that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met in accordance with SR 3.0.2 prior to returning equipment to OPERABLE status.

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Actions with a Completion Time that requires the periodic performance of the Required Action on a "once per…" interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per …" basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some remedial action, is

BASES

SR 3.0.2 (continued)

considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed, in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before compliance with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit Conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified unit Conditions or operational situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity. SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

SR 3.0.3 (continued)

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this specification, or within the Completion Time of the ACTIONS restores compliance with SR 3.0.1.

BASES

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or component to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into a MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance, that could not be performed until after entering the LCO Applicability, would have its Frequency specified such that it is not “due” until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a NOTE as not

BASES

SR 3.0.4 (continued)

required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SR's annotation is found in Section 1.4, Frequency.

SR 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, 3, or 4. The requirements of SR 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1) the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shutdown under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to assure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Plant Control System (PLS) can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the PLS, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, “Control Bank Insertion Limits.” When the unit is in the shutdown and refueling modes, the SDM requirements are met by adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analyses (Ref. 2) establish an SDM that ensures that specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram. For MODE 5, the primary safety analysis that relies on the SDM limits is the boron dilution analysis.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departures from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accidents for the SDM requirements are based on a main steam line break (SLB) and inadvertent opening of a steam generator (SG) relief or safety valve, as described in the accident analyses (Ref. 2). The increased steam flow in the main steam system causes an increased energy removal from the affected SG, and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient (MTC), this cooldown causes an increase in core reactivity. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the SLB or opening of an SG relief or safety valve, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and the THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting SLB and inadvertent opening of an SG relief or safety valve transients, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition;

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Rod ejection;

d. Inadvertent operation of Passive Residual Heat Removal Heat Exchanger (PRHR HX).

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting when critical boron concentrations are highest.

The uncontrolled rod withdrawal transient is terminated by a high neutron flux trip. Power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time-dependent redistribution of core power.

The inadvertent actuation of the PRHR HX causes an RCS temperature reduction from an initial injection of relatively cold water and the continued cooling of the RCS by PRHR. In the presence of a negative moderator temperature coefficient, the RCS temperature reduction causes an increase in core reactivity. Safety injection on the low cold leg temperature or low pressurizer pressure signals actuate the core makeup tank (CMT) and bring the plant to a stable condition.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the main control room, SDM is considered an initial condition process variable because it is periodically monitored to provide assurance that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

BASES

LCO (continued)

The SLB and the boron dilution accidents (Ref. 2) are the most limiting analyses that establish the SDM value of the LCO. For SLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100 limits (Ref. 3). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for automatic action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with k_{eff} < 1.0, and in MODES 3, 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, “Boron Concentration.” In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, “Shutdown Bank Insertion Limits,” and LCO 3.1.6, “Control Bank Insertion Limits.”

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a concentrated solution. The operator should begin boration with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration is highest. Assuming that a value of [1.6]% Δk/k must be recovered and a boration flow rate is [100] gpm, it is possible to increase the boron concentration of the RCS by 112 ppm in approximately 29 minutes. If a boron worth of 9 pcm/ppm is assumed, this combination of parameters will increase the SDM by [1.6]% Δk/k. These boration parameters of [100] gpm and [9] ppm represent typical values and are provided for the purpose of offering a specific example.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal Temperature Coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. Chapter 15, “Accident Analysis.”

3. 10 CFR 100.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, “SHUTDOWN MARGIN (SDM)”) in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance since parameters are being maintained relatively stable under steady-state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculation models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and a negative moderator temperature coefficient, the

BASES

BACKGROUND (continued)

excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to compensate reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Certain accident evaluations (Ref. 2) are, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are sensitive to accurate predictions of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analysis are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown

BASES

APPLICABLE SAFETY ANALYSES (continued)

curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOC conditions so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the Conditions of the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This specification does not apply in MODE 3, 4, and 5 because the reactor is shutdown and the reactivity balance is not changing.

BASES

APPLICABILITY (continued)

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, “Boron Concentration”) ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

BASES

ACTIONS (continued)

B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPDs) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPDs following the initial 60 EFPDs after entering MODE 1 is acceptable based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.
2. Chapter 15, “Accident Analysis.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a non-positive MTC over the range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons (burnable absorbers) to yield an MTC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles designed to achieve high burnups that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the Chapter 15 accident and transient analyses (Ref. 2).

If the LCO limits are not met, the plant response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

BASES

BACKGROUND (continued)

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the RCS boron concentration associated with fuel burnup and burnable absorbers.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

Chapter 15 (Ref. 2) contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the least negative value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core heat-up must be evaluated when the MTC is least negative. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is BOC or EOC. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at the limiting time in cycle life. An EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the accident analysis during operation.

Assumptions made in safety analyses require that the MTC be more negative than a given upper limit and less negative than a given lower limit. The MTC is least negative near BOC; this upper bound must not be exceeded. This maximum upper limit occurs at all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The BOC limit and the EOC limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to assure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2, with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In

BASES

APPLICABILITY (continued)

MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents (DBAs) using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the upper MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life, Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be placed in MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC which is less negative than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be placed in a MODE or Condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 4 within 12 hours.

The allowed Completion Time is a reasonable time based on operating experience to reach the required MODE from full power operation in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most limiting MTC LCO. Meeting the limit prior to entering MODE 1 assures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to provide assurance that the LCO limit will be met at EOC when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

a. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOC limit.

c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.
2. Chapter 15, “Accident Analysis.”
3. WCAP 9273-NP-A, “Westinghouse Reload Safety Evaluation Methodology,” July 1985.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (e.g., trippability) of the shutdown and control rods is an initial assumption in all safety analyses which assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, “Reactor Design,” GDC 26, “Reactivity Control System Redundancy and Protection” (Ref. 1), and 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants” (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time but at varying rates (steps per minute) depending on the signal output from the Plant Control System (PLS).

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. The AP1000 design has seven control banks and four shutdown banks.

BASES

BACKGROUND (continued)

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are part of the MSHIM (Mechanical Shim) Control System which utilizes two independently OPERABLE groups of control banks for control of reactivity and axial power distribution.

Certain control rods will be pre-selected for inclusion in the Rapid Power Reduction (RPR) system. The purpose of the RPR is to initiate a rapid decrease in the core power during load rejection transients.

Reactivity control is provided primarily by the M banks. The M Banks consist of several control banks operating with a fixed overlap. The bank worth and overlap are defined so as to minimize the impact on axial offset with control bank maneuvering and still retain the reactivity required to meet the desired load changes.

The axial power distribution control is provided by the AO Bank, a relatively high worth bank.

In order to avoid boron adjustment for load follow operation, gray rods are utilized.

There are 16 gray rod RCCAs in the AP1000, each composed of 24 rodlets mounted on a common RCCA spider. These have been subdivided into what has been termed as MA, MB, MC, and MD Banks with 4 gray rod RCCAs in each.

Each of the MA, MB, MC, and MD Banks has almost the same worth. The primary gray bank function is to provide additional reactivity during the transition periods. During base load operation, two of the gray banks may be fully inserted into the core. Each of the gray banks consists of a relatively low worth bank.

The MA, MB, MC, MD, M1 and M2 Banks function together with a single variable (i.e., criticality or temperature) driving these groups as if they are in one control group.

The control rods are arranged in a radially symmetric pattern so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual control rod position, at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the DRPI will go on half-accuracy. The DRPI System is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment is that:

a. There be no violations of:

   1. Specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 3). With control banks at or above their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely

BASES

APPLICABLE SAFETY ANALYSES (continued)

withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 3).

The Required Actions in this LCO assure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments assure that the assumptions in the safety analysis will remain valid. The requirements on control rod OPERABILITY assure that upon reactor trip, the assumed reactivity will be available and will be inserted. The control rod OPERABILITY requirements (i.e., trippability) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but that do not impact trippability, do not result in rod inoperability.

BASES

LCO (continued)

The requirement to maintain the rod alignment to within plus or minus 12 steps is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and linear heating rates (LHR), or unacceptable SDMs, which may constitute initial conditions inconsistent with the safety analysis.

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are bottomed and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, “SHUTDOWN MARGIN (SDM),” for SDM in MODES 3, 4, and 5 and LCO 3.9.1, “Boron Concentration,” for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate to determine SDM and, if necessary, to initiate boration to restore SDM.

In this situation, SDM verification must include the worth of the untrippable rod as well as a rod of maximum worth.

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

BASES

ACTIONS (continued)

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. With the OPDMS OPERABLE adverse peaking factors resulting from the misalignment can be detected. If the rod can be realigned within the Completion Time of 8 hours adverse burnup shadowing in the location of the misaligned rod can be avoided. With the OPDMS inoperable xenon redistribution can potentially cause adverse peaking factors which may not be detected. However, if the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant and operation may proceed without further restriction.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limit," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified within limit or boration must be initiated to restore SDM within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank M2 to a rod that is misaligned 15 steps from the top of the core could require insertion of the M1 bank to maintain overlap limits.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary to determine the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

BASES

ACTIONS (continued)

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible. A note has been added indicating that Required Actions B.2.4 and B.2.5, F_Q and $F_{\Delta H}$ verification, are only required when the OPDMS is inoperable and therefore unavailable to continuously monitor the core power distribution.

Reduction of power to 75% of RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 3). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Protection and Safety Monitoring System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Online monitoring of core power distribution by the OPDMS, or verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits when the OPDMS is inoperable, ensures that current operation at 75% of RTP with a rod misaligned is not resulting in power distributions which may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Accident (DBA) for the duration of operation under these conditions. The accident analyses presented in Chapter 15 (Ref. 3) that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

BASES

ACTIONS (continued)

C.1

When Required Actions cannot be completed within their Completion Times, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power condition in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM.

Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the CVS makeup pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the rods must be brought to within the alignment limits within 6 hours or the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect that a rod is beginning to deviate from its expected position. The specified Frequency takes into account other rod position information that is continuously available to the operator in the main control room so that during actual rod motion, deviations can immediately be detected.

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after each reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 500°F to simulate a reactor trip under conservative conditions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance is performed during a plant outage due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. Chapter 15, “Accident Analysis.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in the safety analyses which assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, “Reactor Design,” GDC 26, “Reactivity Control System Redundancy and Protection,” GDC 28, “Reactivity Limits” (Ref. 1), and 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors” (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. The AP1000 design has seven control banks and four shutdown banks. See LCO 3.1.4, “Rod Group Alignment Limits,” for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, “Rod Position Indication,” for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Plant Control System (PLS), but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations. Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks

BASES

BACKGROUND (continued)

are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core as allowed by LCO 3.1.6, “Control Bank Insertion Limits.” The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, “SHUTDOWN MARGIN (SDM)”) following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at the rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown bank rod.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or,

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This in conjunction with LCO 3.1.6, “Control Bank Insertion Limits,” ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits with the reactor in MODE 1 and MODE 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6 the shutdown banks are fully inserted in the Core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, “Boron Concentration” ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating that the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2, and A.2

When one or more shutdown banks is not within insertion limits, 2 hours are allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

BASES

ACTIONS (continued)

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

Since the shutdown banks are positioned manually by the main control room operator, a verification of shutdown bank position at a Frequency of 12 hours, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the 12 hours Frequency takes into account other information available in the main control room for the purpose of monitoring the status of shutdown rods.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28.

2. 10 CFR 50.46.

3. Chapter 15, “Accident Analysis.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in the safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, “Reactor Design,” GDC 26, “Reactivity Control System Redundancy and Protection,” GDC 28, “Reactivity Limits” (Ref. 1) and 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors” (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within 1 step of each other. The AP1000 design has seven control banks and four shutdown banks. See LCO 3.1.4, “Rod Group Alignment Limits,” for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, “Rod Position Indication,” for position indication requirements.

The control bank insertion sequence and overlap limits are specified in the COLR. The control banks are required to be at or above the insertion limit lines.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Plant Control System (PLS), but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.1.4, “Rod Group Alignment Limits,” LCO 3.1.5, “Shutdown Bank Insertion Limits,”

BASES

BACKGROUND (continued)

LCO 3.1.6, “Control Bank Insertion Limits,” and LCO 3.2.5, “OPDMS – Monitored Powered Distribution Parameters,” when the OPDMS is OPERABLE, or LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” and LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” when the OPDMS is inoperable, provide limits on control component operation and on monitored process variables which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits and power distribution limits are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits assure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

    1. specified fuel design limits, or

    2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin which assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor, with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worth.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36©(2)(ii) in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions.

Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements are modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2, normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, “SHUTDOWN MARGIN (SDM)”), has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence and overlap limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain outside the insertion limits for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with k_{eff} < 1.0, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable based on operating experience for reaching the required MODE from full power condition in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

Verification of the control banks insertion limits at a Frequency of 12 hours is sufficient to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. 10CFR50, Appendix A, GDC 10, GDC 26, and GDC 28.

2. 10CFR50.46.

3. Chapter 15, “Accident Analysis.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences (AOOs), and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in the safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the RCCA misalignment safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group receive the same signal to move and should, therefore, be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual control rod position, at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is 6 steps. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the DRPI will function at half accuracy with an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the normal indication accuracy of the DRPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, “Shutdown Bank Insertion Limits,” LCO 3.1.6, “Control Bank Insertion Limits”). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, “Rod Group Alignment Limits”). Control rod positions are continuously monitored to provide operators with information that assures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36©(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

BASES

LCO

LCO 3.1.7 specifies that one DRPI System and one Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The DRPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, “Rod Group Alignment Limits”;

b. For the DRPI System there are no failed coils; and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit given in LCO 3.1.4 in position indication for a single control rod ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements provide adequate assurance that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCOs 3.1.4, 3.1.5, and 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods has the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System (RCS).

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

BASES

ACTIONS (continued)

A.1

When one DRPI channel per group fails, the position of the rod can still be determined by use of the On-line Power Distribution Monitoring System (OPDMS). Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Actions of B.1 or B.2 below are required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate to allow continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 2).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3, and B.4

When more than one DRPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Together with the indirect position determination available via incore detectors will minimize the potential for rod misalignment. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition.

Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

The position of the rods may be determined indirectly by use of the incore detectors. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SDM is within the limits provided in the COLR,

BASES

ACTIONS (continued)

provided the nonindicating rods have not been moved. Verification of control rod position once per 8 hours is adequate for allowing continued full power operation for a limited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the DRPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Action of C.1 and C.2 below is required.

<u>C.1 and C.2</u>

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the position was last determined, the Required Actions of A.1 and A.2 or B.1 are still appropriate but must be initiated promptly under Required Action C.1 to begin verifying that these rods are still properly positioned relative to their group positions.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

<u>D.1.1 and D.1.2</u>

With one demand position indicator per bank inoperable, the rod positions can be determined by the DRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

<u>D.2</u>

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits (Ref. 2). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions D.1.1 and D.1.2 or reduce power to ≤ 50% RTP.

BASES

ACTIONS (continued)

E.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the DRPI agrees with the demand position within 12 steps provides assurance that the DRPI is operating correctly. Since the DRPI does not display the actual shutdown rod positions between 18 and 249 steps, only points within the indicated ranges are compared.

This surveillance is performed prior to reactor criticality after each removal of the reactor head, as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13.

2. Chapter 15, “Accident Analysis.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions – MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B, (Ref. 1) requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power and after each refueling. The PHYSICS TEST requirements for reload fuel cycles assure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed (Ref. 4).

PHYSICS TEST procedures are written and approved in accordance with established formats. The procedures include information necessary to permit a detailed execution of the testing required, to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long-term power operation.

BASES

BACKGROUND (continued)

The typical PHYSICS TESTS performed for reload fuel cycles (Ref. 4) in MODE 2 are listed below:

a. Critical Boron Concentration – Control Rods Withdrawn;

b. Control Rod Worth;

c. Isothermal Temperature Coefficient (ITC).

These tests are performed in MODE 2. These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration – Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With rods out, the lead control bank is at or near its fully withdrawn position. HZP is where the core is critical ($k_{eff} = 1.0$), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test should not violate any of the referenced LCOs.

b. The Control Rod Worth Test is used to measure the reactivity worth of selected control banks. This test is performed at HZP and has four alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining control banks. The second method, the Rod Swap Method, measures the worth of a predetermined reference bank using the Boron Exchange Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted into the core. The worth of the selected bank is calculated based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining control banks. The third method, the Boron Endpoint Method, moves the selected control bank over its entire length of travel and while varying the reactor coolant boron concentration to maintain HZP criticality again. The difference in boron concentration is the worth of the selected control bank. This sequence is repeated for the remaining control banks. The fourth method, Dynamic Rod

BASES

BACKGROUND (continued)

Worth Measurement (DRWM), moves each bank, individually, into the core to determine its worth. The bank is dynamically inserted into the core while data is acquired from the excore channel. While the bank is being withdrawn, the data is analyzed to determine the worth of the bank. This is repeated for each control and shutdown bank. Performance of this test will violate LCO 3.1.4, “Rod Group Alignment Limits,” LCO 3.1.5, “Shutdown Bank Insertion Limit,” or LCO 3.1.6, “Control Bank Insertion Limits.”

c. The ITC Test measures the ITC of the reactor. This test is performed at HZP. The method is to vary the RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change and the final ITC is the average of the two calculated ITCs. Performance of this test could violate LCO 3.4.2, “RCS Minimum Temperature for Criticality.”

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology report (Ref. 5). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

Chapter 14 defines requirements for initial testing of the facility, including low power PHYSICS TESTS. Sections 14.2.10.2 and 14.2.10.3 (Ref. 6) summarize the initial criticality and low power tests.

Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1985 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for the LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in:

LCO 3.1.3 “Moderator Temperature Coefficient (MTC),”
LCO 3.1.4 “Rod Group Alignment Limits,”
LCO 3.1.5 “Shutdown Bank Insertion Limit,”

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.1.6 “Control Bank Insertion Limits,” and
LCO 3.4.2 “Minimum Temperature for Criticality,”

are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ [535]°F, and SDM is within the limits provided in the COLR.

PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exception LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

Reference 7 allows special test exceptions (STE) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ [535]°F,

b. SDM is within the limits provided in the COLR, and

c. THERMAL POWER is < 5% RTP.

BASES

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as “During PHYSICS TESTS initiated in MODE 2” to ensure that the 5% RPT maximum power level is not exceeded. Should the THERMAL POWER EXCEED 5% RPT, and consequently the unit enter MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < [535]°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below [535]°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be placed in a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, to reach MODE 3 from MODE 2 HZP conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1 “Reactor Trip System (RTS) Instrumentation.” A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ [535]°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will provide assurance that the initial conditions of the safety analyses are not violated.

SR 3.1.8.3

Verification that the THERMAL POWER is < 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

BASES

SURVEILLANCE REQUIREMENTS (continued)

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

2. 10 CFR 50.59, "Changes, Tests and Experiments."

3. Regulatory Guide 1.68, Revision 2, "Initial Test Programs for Water-Cooled Nuclear Power Plants," August 1978.

4. ANSI/ANS-19.6.1-1997, "Reload Startup Physics Tests for Pressurized Water Reactors," American National Standards Institute, August 22, 1997.

5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

6. Chapter 14, "Initial Testing Program."

7. WCAP-11618, including Addendum 1, April 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.9 Chemical and Volume Control System (CVS) Demineralized Water Isolation Valves

BASES

BACKGROUND

One of the principle functions of the CVS system is to maintain the reactor coolant chemistry conditions by controlling the concentration of boron in the coolant for plant startups, normal dilution to compensate for fuel depletion, and shutdown boration. In the dilute mode of operation, unborated demineralized water may be supplied directly to the reactor coolant system.

Although the CVS is not considered a safety related system, certain functions of the system are considered safety related functions. The appropriate components have been classified and designed as safety related. The safety related functions provided by the CVS include containment isolation of chemical and volume control system lines penetrating containment, termination of inadvertent boron dilution, and preservation of the Reactor Coolant System (RCS) pressure boundary, including isolation of CVS letdown from the RCS.

APPLICABLE SAFETY ANALYSES

One of the initial assumptions in the analysis of an inadvertent boron dilution event (Ref. 1) is the assumption that the increase in core reactivity, created by the dilution event, can be detected by the source range instrumentation. The source range instrumentation will then supply a signal to the demineralized water isolation valves in the CVS causing these valves to close and terminate the boron dilution event. Thus the demineralized water isolation valves are components which function to mitigate an A00.

CVS isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The requirement that at least two demineralized water isolation valves be OPERABLE assures that there will be redundant means available to terminate an inadvertent boron dilution event.

APPLICABILITY

The requirement that at least two demineralized water isolation valves be OPERABLE is applicable in MODES 1, 2, 3, 4, and 5 because a boron dilution event is considered possible in these MODES, and the automatic closure of these valves is assumed in the safety analysis.

BASES

APPLICABILITY (continued)

In MODES 1 and 2, the detection and mitigation of a boron dilution event does not assume the detection of the event by the source range instrumentation. In these MODES, the event would be signalled by an intermediate range trip, a trip on the Power Range Neutron Flux - High (low setpoint nominally at 25% RTP), or Overtemperature delta T. The two demineralized water isolation valves close automatically upon reactor trip.

In MODE 6, a dilution event is precluded by the requirement in LCO 3.9.2 to close, lock and secure at least one valve in each unborated water source flow path.

ACTIONS

A.1

If only one demineralized water isolation valve is OPERABLE, the second valve must be restored to OPERABLE status in 72 hours. The allowed Completion Time assures expeditious action will be taken, and is acceptable because the safety function of automatically isolating the clean water source can be accomplished by the redundant isolation valve.

B.1

If the Required Actions and associated Completion Time of Condition A are not met, or if both CVS demineralized water isolation valves are not OPERABLE (i.e., not able to be closed automatically), then the demineralized water supply flow path to the RCS must be isolated. Isolation can be accomplished by manually isolating the CVS demineralized water isolation valve(s) or by positioning the 3-way blend valve to only take suction from the boric acid tank. Alternatively, the dilution path may be isolated by closing appropriate isolation valve(s) in the flow path(s) from the demineralized water storage tank to the reactor coolant system.

The Action is modified by a Note allowing the flow path to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the main control room. In this way, the flow path can be rapidly isolated when a need for isolation is indicated.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.9.1 Verification that the CVS demineralized water isolation valves are OPERABLE, by stroking each valve closed, demonstrates that the valves can perform their safety related function. The Frequency is in accordance with the Inservice Testing Program.
REFERENCES	1. Chapter 15, “Accident Analysis.”

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (F_Q Methodology)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation with the On-line Power Distribution Monitoring System (OPDMS) inoperable, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

With the OPDMS OPERABLE, peak kw/ft (Z) (which is proportional to $F_Q(Z)$) is measured continuously. With the OPDMS inoperable, $F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

With the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$ with the OPDMS inoperable. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(Z)$ which are present during a nonequilibrium situation such as load following.

To account for these possible variations, the steady state value of $F_Q(Z)$ is adjusted by an elevation dependent factor to account for the calculated worst case transient conditions.

Core monitoring and control under non-equilibrium conditions and the OPDMS inoperable are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

BASES

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed a limit of 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting (i.e., lower than) relative to the $F_Q(Z)$ assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \leq \frac{CFQ}{P} \qquad \text{for } P > 0.5$$

$$F_Q(Z) \leq \frac{CFQ}{0.5} \qquad \text{for } P \leq 0.5$$

where: CFQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

BASES

LCO (continued)

The actual values of CFQ are given in the COLR; however, CFQ is normally a number on the order of [2.60]. For the AP1000, the normalized $F_Q(Z)$ as a function of core height is 1.0.

For RAOC operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F_Q^C(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results the measured value of $F_Q(Z)$, called $F_Q^M(Z)$ is obtained. Then,

$$F_Q^C(Z) = F_Q^M(Z) * F_Q^{MU}(Z)$$

where $F_Q^{MU}(Z)$ is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty. $F_Q^{MU}(Z)$ is provided in the COLR.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z) * W(Z)$$

where W(Z) is a cycle-dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required and if $F_Q^W(Z)$ cannot be maintained within LCO limits, reduction of the AFD limits will also result in a reduction of the core power.

BASES

LCO (continued)

Violating the LCO limits for $F_Q(Z)$ may result in an unanalyzed condition while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

When the OPDMS is inoperable and core power distribution parameters cannot be continuously monitored, it is necessary to determine $F_Q(Z)$ on a periodic basis. Furthermore, the $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% of RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting for fuel manufacturing tolerances and flux map measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require power reductions within 15 minutes of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux – High Trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range

BASES

ACTIONS (continued)

Neutron Flux – High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux – High trip setpoint reductions within 8 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux – High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux – High trip setpoints.

A.3

Reduction in the Overpower ΔT Trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, assures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

BASES

ACTIONS (continued)

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ which can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours restricts the axial flux distribution such that even if a transient occurred, core peaking factors would not be exceeded.

The implicit assumption is that if W(Z) values were recalculated (consistent with the reduced AFD limits), then $F_Q^C(Z)$ times the recalculated W(Z) values would meet the $F_Q(Z)$ limit. Note that complying with this action (of reducing AFD limits) may also result in a power reduction. Hence the need for B.2, B.3, and B.4.

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 8 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

B.3

Reduction in the Overpower ΔT trip setpoints value of K_4 by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

BASES

ACTIONS (continued)

B.4

Verification that $F_Q^W(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the maximum allowable power limit imposed by Required Action B.1 ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition A is exited prior to performing Required Action B.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a MODE or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by two Notes. The first note applies to the situation where the OPDMS is inoperable at the beginning of cycle startup. Note 1 applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% of RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at

BASES

SURVEILLANCE REQUIREMENTS (continued)

which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

The second Note applies to the situation where the OPDMS becomes inoperable while the plant is in MODE 1. Without the continuous monitoring capability of the OPDMS, F_Q limits must be monitored on a periodic basis. The first measurement must be made within 31 days of the most recent date where the OPDMS data has verified peak kw/ft (Z) (and therefore also F_Q) to be within its limit. This is consistent with the 31 day Surveillance Frequency.

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing the measured values of $F_Q^C(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z) * F_Q^{MU}(Z)$. $F_Q^C(Z)$ is then compared to its specified limits.

The limit to which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP assures that the $F_Q^C(Z)$ limit is met when RTP is achieved because Peaking Factors generally decrease as power level is increased.

SURVEILLANCE REQUIREMENTS (continued)

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to assure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 effective full power days (EFPDs) is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with Technical Specifications.

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The limit to which $F_Q^W(Z)$ is compared varies inversely with power.

The W(Z) curve is provided in the COLR for discrete core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0% to 15% inclusive; and

b. Upper core region, from 85% to 100% inclusive.

The top and bottom 15% of the core are excluded from the evaluation because of the difficulty of making a precise measurement in these regions and because of the low probability that these regions would be more limiting than the safety analyses.

This Surveillance has been modified by a Note, which may require that more frequent surveillances be performed. If $F_Q^W(Z)$ is evaluated and found to be within its limit, an evaluation of the expression below is

BASES

SURVEILLANCE REQUIREMENTS (continued)

required to account for any increase to $F_Q^M(Z)$ which could occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent FQ(Z) evaluations show an increase in $F_Q^C(Z)$, it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by a factor of [1.02] or to evaluate $F_Q(Z)$ more frequently, each 7 EFPDs. These alternative requirements will prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% of RTP ensures that the $F_Q(Z)$ limit will be met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

The Surveillance Frequency of 31 EFPDs is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with Technical Specifications, to preclude the occurrence of adverse peaking factors between 31 EFPD Surveillances. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

$F_Q(Z)$ is verified at power increases of at least 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions, to assure that $F_Q(Z)$ will be within its limit at higher power levels.

REFERENCES

1. 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors,” 1974.

2. Regulatory Guide 1.77, Rev. 0, “Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors,” May 1974.

3. 10 CFR 50, Appendix A, GDC 26.

4. WCAP-7308-L-P-A, “Evaluation of Nuclear Hot Channel Factor Uncertainties,” June 1988 (Westinghouse Proprietary) and WCAP-7308-L-A (Non-Proprietary).

5. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification,” February 1994 (Westinghouse Proprietary) and WCAP-10217-A (Non-Proprietary).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F_{\Delta H}^{N}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors assures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F_{\Delta H}^{N}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F_{\Delta H}^{N}$ is a measure of the maximum total power produced in a fuel rod.

$F_{\Delta H}^{N}$ is sensitive to fuel loading patterns, bank insertion and fuel burnup. $F_{\Delta H}^{N}$ typically increases with control bank insertion and typically decreases with fuel burnup.

With the On-line Power Distribution Monitoring System (OPDMS) OPERABLE, $F_{\Delta H}^{N}$ is determined continuously by the OPDMS. When the OPDMS is inoperable, $F_{\Delta H}^{N}$ is not directly measurable but is inferred from a power distribution map obtained with the incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed to determine $F_{\Delta H}^{N}$. This factor is calculated at least every 31 effective full power days (EFPDs). Also, during power operation with the OPDMS inoperable, the global power distribution is monitored by LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” and LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” which are directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio. Transient

BASES

BACKGROUND (continued)

events that may be DNB limited are assumed to begin with a $F^N_{\Delta H}$ that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ prevent core power distributions from occurring which would exceed the following fuel design limits:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), the peak cladding temperature (PCT) must not exceed 2200°F;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when the control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System (RCS) flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNB ratio (DNBR) to the 95/95 DNB criterion. This value provides a high degree of assurance that the hottest fuel rod in the core will not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this

APPLICABLE SAFETY ANALYSES (continued)

variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

The fuel is protected in part by Technical Specifications, which provide assurance that the initial conditions assumed in the safety and accident analyses remain valid. With the OPDMS OPERABLE, peak kw/ft(Z) and $F^N_{\Delta H}$ are directly monitored. Should the OPDMS become inoperable, the following LCOs assure that the conditions assumed for the safety analysis remain valid: LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” LCO 3.1.6, “Control Bank Insertion Limits,” LCO 3.2.2, “Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$),” and LCO 3.2.1, “Heat Flux Hot Channel Factor ($F_Q(Z)$).”

When the OPDMS is not available to measure power distribution parameters continuously, $F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the incore detector system. Measurements are generally taken with the core at, or near, steady-state conditions. Without the OPDMS, core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

BASES

LCO (continued)

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase [0.3]% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

When the OPDMS is inoperable and core power distribution parameters cannot be continuously monitored, it is necessary to monitor $F^N_{\Delta H}(Z)$ on a periodic basis. Furthermore, $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and peak cladding temperature (PCT). Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power-dependent limit.

When the $F^N_{\Delta H}$ limit is exceeded, it is not likely that the DNBR limit would be violated in steady state operation, since events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain outside $F^N_{\Delta H}$ limits for an extended period of time.

BASES

ACTIONS (continued)

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 would nevertheless require another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power were reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 would be performed if power ascension were delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux - High to ≤ 55% RTP in accordance with Required Action A.1.2.2. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those specified in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Time of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may cause an inadvertent reactor trip.

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because

BASES

ACTIONS (continued)

of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence assures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation will proceed within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% of RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note, that states that THERMAL POWER does not have to be reduced prior to performing this action.

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 8 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

When the OPDMS is OPERABLE, the value of $F^N_{\Delta H}$ is directly and continuously monitored. With the OPDMS inoperable, the value of $F^N_{\Delta H}$ is determined by using the incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by a measurement uncertainty factor before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, with the OPDMS inoperable, $F^N_{\Delta H}$ must be determined prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

BASES

SURVEILLANCE REQUIREMENTS (continued)

With the OPDMS inoperable, the 31 EFPDs Frequency is acceptable because the power distribution will change relatively slowly over this amount of fuel burnup. This Frequency is short enough so that the $F_{\Delta H}^{N}$ limit will not be exceeded for any significant period of operation.

REFERENCES

1. Regulatory Guide 1.77, Rev. 0, May 1979.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors.”

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Relaxed Axial Offset Control (RAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core when the On-Line Power Distribution Monitoring System (OPDMS) is inoperable. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing which is a significant factor in axial power distribution control.

RAOC is a calculational procedure which defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to assure that the loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The AFD is monitored on an automatic basis using the computer which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

Although the RAOC defines limits that must be met to satisfy safety analyses, typically, without the OPDMS, an operating scheme, Constant Axial Offset Control (CAOC), is used to control axial power distribution in day-to-day operation (Ref. 1). CAOC requires that the AFD be controlled within a narrow tolerance band around a burnup-dependent target to minimize the variation of axial peaking factors and axial xenon distribution during unit maneuvers.

The CAOC operating space is typically smaller and lies within the RAOC operating space. Control within the CAOC operating space constrains the variation of axial xenon distributions and axial power distributions. RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

BASES

APPLICABLE SAFETY ANALYSES

The AFD is a measure of the axial power distribution skewing SAFETY to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

Three dimensional power distribution calculations are performed to demonstrate that normal operation power shapes are acceptable for the LOCA, the loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

With the OPDMS inoperable, the limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the LOCA. The most important Condition 3 event is the loss of flow accident. The most important Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator through the manual operation of the control banks or automatic motion of control banks. The automatic motion of the control banks is in response to temperature deviations resulting from manual operation of the Chemical and Volume Control System (CVS) to change boron concentration or from power level changes.

Signals are available to the operator from the Protection and Safety Monitoring System (PMS) excore neutron detectors (Ref. 3). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom

BASES

LCO (continued)

excore detectors in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RAOC AFD limits. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.

Violating this LCO on the AFD, with the OPDMS inoperable, could produce unacceptable consequences if a Condition 2, 3 or 4 event occurs while the AFD is outside its specified limits.

APPLICABILITY

The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP where the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis.

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES. With the OPDMS inoperable, it is necessary to monitor AFD via the excore detectors to ensure that it remains within the RAOC limits.

ACTIONS

A.1

Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition where the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

This surveillance verifies that the AFD, as indicated by the PMS excore channel, is within its specified limits. The Surveillance Frequency of 7 days is adequate considering that the AFD is monitored by a computer and any deviation from requirements is alarmed.

BASES

REFERENCES

1. WCAP-8385, “Power Distribution Control and Load Following Procedures,” Westinghouse Electric Corporation, September 1974 (Westinghouse Proprietary) and WCAP-8403 (Non-Proprietary).

2. R.W. Miller et al., “Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification,” WCAP-10216-P-A, June 1983 (Westinghouse Proprietary) and WCAP-10217-A (Non-Proprietary).

3. Chapter 15, “Accident Analysis.”

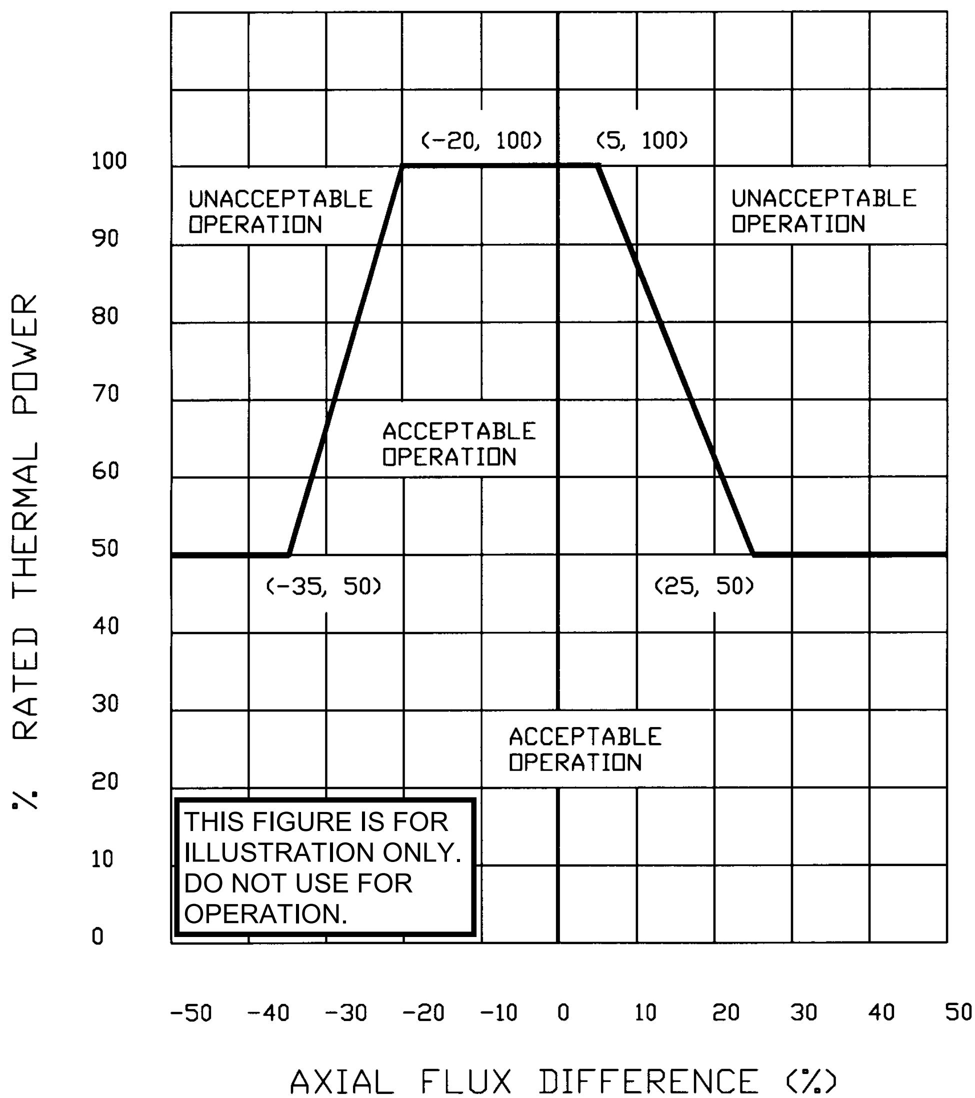

Figure B 3.2.3-1 (page 1 of 1)
AXIAL FLUX DIFFERENCE Limits as a Function
of RATED THERMAL POWER

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

With the OPDMS inoperable, the QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. With the OPDMS OPERABLE, the peak kw/ft(Z) is continuously and directly monitored. With the OPDMS inoperable, LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” and LCO 3.1.6, “Control Rod Insertion Limits,” provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions from occurring which would violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature (PCT) must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least a 95% probability at a 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions from occurring which would exceed the safety analyses limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Should the OPDMS become inoperable, the QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, with the OPDMS inoperable, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, where corrective action is required, provides a margin of protection for both the DNB ratio (DNBR) and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and $F^N_{\Delta H}$ is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to preclude core power distributions from exceeding the design limits. With the OPDMS inoperable, a continuous on-line indication of core peaking factors is not available. Therefore, QPTR must be monitored and the limits on QPTR ensure that peaking factors will be within design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, and the OPDMS inoperable, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

BASES

ACTIONS (continued)

The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require power reduction within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable power level and increasing power up to this revised limit.

A.2

After completion of Required Action A.1, the QPTR alarm may be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are of primary importance in assuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}^N$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction power Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. A Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction power Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limits, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}^N$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}^N$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such

BASES

ACTIONS (continued)

reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors which best characterize the core power distribution. This re-evaluation is required to assure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the QPTR is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours, but is increased slowly,

BASES

ACTIONS (continued)

then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been calibrated to show zero tilt (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are calibrated to show zero tilt and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve the status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR as indicated by the Protection and Safety Monitoring System (PMS) excore channels is within its limits. The Frequency of 7 days takes into account other information and alarms available to the operator in the control room.

For those causes of QPT that occur quickly (a dropped rod), there are other indications of abnormality that prompt a verification of core power tilt.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is ≥ 75% RTP.

With a PMS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts would likely be detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for assuring that any tilt remains within its limits.

For purposes of monitoring the QPTR when one power range channel is inoperable, the incore detectors are used to confirm that the normalized symmetric power distribution is acceptable.

With the OPDMS and one PMS channel inoperable, the surveillance of the incore power distribution on a 12 hour basis is sufficient to maintain peaking factors within their normal limits, especially, considering the other LCOs and ACTIONS required when the OPDMS is out of service.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors.”

2. Regulatory Guide 1.77, Rev. 0, “Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors,” May 1974.

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants,” GDC 26, “Reactivity Control System Redundancy and Capability.”

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.5 OPDMS-Monitored Power Distribution Parameters

BASES

BACKGROUND

The On-line Power Distribution Monitoring System (OPDMS) for the AP1000 is an advanced core monitoring and support package. The OPDMS has the ability to continuously monitor core power distribution parameters.

The purpose of the limits on the OPDMS-monitored power distribution parameters is to provide assurance of fuel integrity during Conditions I (Normal Operation) and II (incidents of Moderate Frequency) events by: (1) not exceeding the minimum departure from boiling ratio (DNBR) in the core, and (2) limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the peak cladding temperature (PCT) limit of 2200°F is not exceeded.

The definition of certain quantities used in these specifications are as follows:

Peak kw/ft(Z)	Peak linear power density (axially dependent) as measured in kw/ft.
$F^N_{\Delta H}$	Ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.
Minimum DNBR	Minimum ratio of the critical heat flux to actual heat flux at any point in the reactor that is allowed in order to assure that certain performance and safety criteria requirements are met over the range of plant conditions.

By continuously monitoring the core and following its actual operation, it is possible to significantly limit the adverse nature of power distribution initial conditions for transients which may occur at any time.

BASES

APPLICABLE SAFETY ANALYSES

The limits on the above parameters preclude core power distributions from occurring which would violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the PCT must not exceed a limit of 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least a 95% probability at a 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

Limits on linear power density or peak kw/ft assure that the peak linear power density assumed as a base condition in the LOCA analyses is not exceeded during normal operation.

Limits on $F_{\Delta H}$ ensure that the LOCA analysis assumptions and assumptions made with respect to the Overtemperature ΔT Setpoint are maintained.

The limit on DNBR ensures that if transients analyzed in the safety analyses initiate from the conditions within the limit allowed by the OPDMS, the DNB criteria will be met.

The OPDMS-monitored power distribution parameters of this LCO satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within these limits. If the LCO limits cannot be maintained within limits, reduction of the core power is required.

Violating the OPDMS-monitored power distribution parameter limits could result in unanalyzed conditions should a design basis event occur while the parameters are outside their specified limits.

BASES

LCO (continued)

Peak kw/ft limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA. The highest calculated linear power densities in the core at specific core elevations are displayed for operator visual verification relative to the COLR values.

The determination of $F^N_{\Delta H}$ identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for DNB. Should $F^N_{\Delta H}$ exceed the limit given in the COLR, the possibility exists for DNBR to exceed the value used as a base condition for the safety analysis.

Two levels of alarms on power distribution parameters are provided to the operator. One serves as a warning before the three parameters (kw/ft(Z), $F^N_{\Delta H}$, DNBR) exceed their values used as a base condition for the safety analysis. The other alarm indicates when the parameters have reached their limits.

APPLICABILITY

The OPDMS-monitored power distribution parameter limits must be maintained in MODE 1 above 50% RTD to preclude core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES, and MODE 1 below 50% RTP, is not required because there is either insufficient stored energy in the fuel or insufficient energy transferred to the reactor coolant to require a limit on the distribution of core power.

Specifically for $F^N_{\Delta H}$, the design bases accidents (DBAs) that are sensitive to $F^N_{\Delta H}$ in other MODES (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

In addition to the alarms discussed in the LCO section above (alarms on OPDMS-monitored power distribution parameters), there is an alarm indicating the potential inoperability of the OPDMS itself.

Should the OPDMS be determined to be inoperable for other than reasons of alarms inoperable, this LCO is no longer applicable and LCOs 3.2.1 through 3.2.4 become applicable.

BASES

ACTIONS

A.1

With any of the OPDMS-monitored power distribution parameters outside of their limits, the assumptions used as most limiting base conditions for the DBA analyses may no longer be valid. The 1 hour operator ACTION requirement to restore the parameter to within limits is consistent with the basis for the anticipated operational occurrences and provides time to assess if there are instrumentation problems. It also allows the possibility to restore the parameter to within limits by rod cluster control assembly (RCCA) motion if this is possible. The OPDMS will continuously monitor these parameters and provide an indication when they are approaching their limits.

B.1

If the OPDMS-monitored power distribution parameters cannot be restored to within their limits within the Completion Time of ACTION A.1, it is likely that the problem is not due to a failure of instrumentation. Most of these parameters can be brought within their respective limits by reducing THERMAL POWER because this will reduce the absolute power density at any location in the core thus providing margin to the limit.

If the parameters cannot be returned to within limits as power is being reduced, THERMAL POWER must be reduced to < 50% RTP where the LCOs are no longer applicable.

A Note has been added to indicate that if the power distribution parameters in violation are returned to within their limits during the power reduction, then power operation may continue at the power level where this occurs. This is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions.

The Completion Time of 4 hours provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain outside the $F^N_{\Delta H}$ limits for an extended period of time.

SURVEILLANCE REQUIREMENTS

With OPDMS operating, the power distribution parameters are continuously computed and displayed, and compared against their limit. Two levels of alarms are provided to the operator. The first alarm provides a warning before these parameters (kw/ft(Z), $F^N_{\Delta H}$, and DNBR) exceed their limits. The second alarm indicates when they actually reach their limits. A third alarm indicates trouble with the OPDMS system.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.5.1

This Surveillance requires the operator to verify that the power distribution parameters are within their limits. This confirmation is a verification in addition to the automated checking performed by the OPDMS system. A 24 hour Surveillance interval provides assurance that the system is functioning properly and that the core limits are met.

With the OPDMS parameter alarms inoperable, an increased Surveillance Frequency is provided to assure that parameters are not approaching the limits. A 12 hour Frequency is adequate to identify changes in these parameters that could lead to their exceeding their limits.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors,” 1974.

2. Regulatory Guide 1.77, Rev. 0, “Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors,” May 1974.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based upon the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Feature Actuation System (ESFAS) in mitigating accidents.

The Protection and Safety Monitoring System (PMS) has been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2750 psia shall not be exceeded.

Operation within the SLs of Specification 2.0, “Safety Limits (SLs),” also maintains the above values and assures that offsite doses are within the acceptance criteria during AOOs.

Design Basis Accidents (DBA) are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that the offsite dose shall be maintained within an acceptable fraction of the limits. Different accident categories are allowed a different fraction of these limits, based on the probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS maintains surveillance on key process variables which are directly related to equipment mechanical limitations, such as pressure, and on variables which directly affect the heat transfer capability of the reactor, such as flow and temperature. Some limits, such as Overtemperature ΔT, are calculated in the protection and safety

BASES

BACKGROUND (continued)

monitoring system cabinets from other parameters when direct measurement of the variable is not possible.

The RTS instrumentation is segmented into four distinct but interconnected modules as identified below:

- Field inputs from process sensors, nuclear instrumentation;
- Protection and Safety Monitoring System Cabinets;
- Voting Logic; and
- Reactor Trip Switchgear Interface.

Field Transmitters and Sensors

Normally, four redundant measurements using four separate sensors are made for each variable used for reactor trip. The use of four channels for protection functions is based on a minimum of two channels being required for a trip or actuation, one channel in test or bypass, and a single failure on the remaining channel. The signal selector algorithm in the Plant Control System (PLS) will function with only three channels. This includes two channels properly functioning and one channel having a single failure. For protection channels providing data to the control system, the fourth channel permits one channel to be in test or bypass. Minimum requirements for protection and control is achieved with only three channels OPERABLE. The fourth channel is provided to increase plant availability, and permits the plant to run for an indefinite time with a single channel out of service. The circuit design is able to withstand both an input failure to the control system, which may then require the protection Function actuation, and a single failure in the other channels providing the protection Function actuation. Again, a single failure will neither cause nor prevent the protection Function actuation. These requirements are described in IEEE-603 (Ref. 5). The actual number of channels required for each plant parameter is specified in Reference 2.

Selected analog measurements are converted to digital form by digital converters within the protection and safety monitoring system cabinets. Signal conditioning may be applied to selected inputs following the conversion to digital form. Following necessary calculations and processing, the measurements are compared against the applicable setpoint for that variable. A partial trip signal for the given parameter is generated if one channel measurement exceeds its predetermined or calculation limit. Processing on all variables for reactor trip is duplicated in each of the four redundant divisions of the protection system. Each

BASES

BACKGROUND (continued)

division sends its partial trip status to each of the other three divisions over isolated multiplexed links. Each division is capable of generating a reactor trip signal if two or more of the redundant channels of a single variable are in the partial trip state.

The reactor trip signal from each division is sent to the corresponding reactor trip actuation division. Each of the four reactor trip actuation divisions consists of two reactor trip circuit breakers. The reactor is tripped when two or more actuation divisions receive a reactor trip signal. This automatic trip demand initiates the following two actions:

1. It de-energizes the undervoltage trip attachment on each reactor trip breaker, and

2. It energizes the shunt trip device on each reactor trip breaker.

Either action causes the breakers to trip. Opening of the appropriate trip breakers removes power to the control rod drive mechanism (CRDM) coils, allowing the rods to fall into the core. This rapid negative reactivity insertion shuts down the reactor.

Protection and Safety Monitoring System Cabinets

The protection and safety monitoring system cabinets contain the necessary equipment to:

- Permit acquisition and analysis of the sensor inputs, including plant process sensors and nuclear instrumentation, required for reactor trip and ESF calculations;

- Perform computation or logic operations on variables based on these inputs;

- Provide trip signals to the reactor trip switchgear and ESF actuation data to the ESF coincidence logic as required;

- Permit manual trip or bypass of each individual reactor trip Function and permit manual actuation or bypass of each individual voted ESF Function;

- Provide data to other systems in the Instrumentation and Control (I&C) architecture;

- Provide separate input circuitry for control Functions that require input from sensors that are also required for protection Functions.

BASES

BACKGROUND (continued)

Each of the four divisions provides signal conditioning, comparable output signals for indications in the main control room, and comparison of measured input signals with established setpoints. The basis of the setpoints are described in References 1, 2, and 3. If the measured value of a unit parameter exceeds the predetermined setpoint, an output is generated which is transmitted to the ESF coincidence logic for logic evaluation.

Within the protection and safety monitoring system redundancy is generally provided for active equipment such as processors and communication hardware. This redundancy is provided to increase plant availability and facilitate surveillance testing. A division or channel is OPERABLE if it is capable of performing its specified safety function(s) and all the required supporting functions or systems are also capable of performing their related support functions. Thus, a division or channel is OPERABLE as long as one set of redundant components within the division or channel is capable of performing its specified safety function(s).

Voting Logic

The voting logic provides a reliable means of opening the reactor trip switchgear in its own division as demanded by the individual protection functions.

Reactor Trip Switchgear Interface

The final stage of the voting logic provides the signal to energize the undervoltage trip attachment on each RTB within the reactor trip switchgear. Loss of the signal de-energizes the undervoltage trip attachments and results in the opening of those reactor trip switchgear. An additional external relay is de-energized with loss of the signal. The normally closed contacts of the relay energize the shunt trip attachments on each switchgear at the same time that the undervoltage trip attachment is de-energized. This diverse trip actuation is performed external to the PMS cabinets. The switchgear interface including the trip attachments and the external relay are within the scope of the PMS. Separate outputs are provided for each switchgear. Testing of the interface allows trip actuation of the breakers by either the undervoltage trip attachment or the shunt trip attachment.

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the trip output is set. Any trip output is considered to be properly adjusted when the “as left”

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value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration accuracy).

The Trip Setpoints used in the trip output are based on the analytical limits stated in Reference 1. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "Westinghouse Setpoint Methodology for Protection Systems" (Refs. 4 and 9). The actual nominal Trip Setpoint entered into the trip output is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the trip output is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Trip Setpoints of Table 3.3.1-1 are the LSSS.

The Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 4, which incorporates all of the known uncertainties applicable for each channel. (Reference 4 is an AP600 document that describes a methodology that is applicable to AP1000. AP1000 has some slight differences in instrument spans as a result of the higher power level.) The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes. Transmitter and signal processing equipment calibration tolerances and drift allowances must be specified in plant calibration procedures, and must be consistent with the values used in the setpoint methodology.

The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against the "as left" data and are shown to be within the setpoint methodology assumptions. The basis

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of the setpoints is described in References 1, 2, 3, and 4. Trending of transmitter calibration is required by Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle."

The protection and safety monitoring system testing features are designed to allow for complete functional testing by using a combination of system self-checking features, functional testing features, and other testing features. Successful functional testing consists of verifying that the capability of the system to perform the safety function has not failed or degraded. For hardware functions this would involve verifying that the hardware components and connections have not failed or degraded. Since software does not degrade, software functional testing involves verifying that the software code has not changed and that the software code is executing. To the extent possible, protection and safety monitoring system functional testing will be accomplished with continuous system self-checking features and the continuous functional testing features.

The protection and safety monitoring system incorporates continuous system self-checking features wherever practical. Self-checking features include on-line diagnostics for the computer system and the hardware and communications tests. These self-checking tests do not interfere with normal system operation.

In addition to the self-checking features, the system includes functional testing features. Functional testing features include continuous functional testing features and manually initiated functional testing features. To the extent practical functional testing features are designed not to interfere with normal system operation.

In addition to the system self-checking features and functional testing features, other test features are included for those parts of the system which are not tested with self-checking features or functional testing features. These test features allow for instruments/sensor checks, calibration verification, response time testing, setpoint verification and component testing. The test features again include a combination of continuous testing features and manual testing features.

All of the testing features are designed so that the duration of the testing is as short as possible. Testing features are designed so that the actual logic is not modified. To prevent unwanted actuation, the testing features are designed with either the capability to bypass a Function during testing and/or limit the number of signals allowed to be placed in test at one time.

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Reactor Trip (RT) Channel

An RT Channel extends from the sensor to the output of the associated reactor trip subsystem in the protection and safety monitoring system cabinets, and includes the sensor (or sensors), the signal conditioning, any associated datalinks, and the associated reactor trip subsystem. For RT Channels containing nuclear instrumentation, the RT Channel also includes the nuclear instrument signal conditioning and the associated Nuclear Instrumentation Signal Processing and Control (NISPAC) subsystem.

Automatic Trip Logic

The Automatic Trip Logic extends from, but does not include, the outputs of the various RT Channels to, but does not include, the reactor trip breakers. Operator bypass of a reactor trip function is performed within the Automatic Trip Logic.

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The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the RTBs are closed.

Each of the analyzed accidents and transients which require reactor trip can be detected by one of more RTS Functions. The accident analysis described in Reference 3 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis were qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the plant. These RTS trip Functions may provide protection for conditions which do not require dynamic transient analysis to demonstrate function performance. These RTS trip Functions may also serve as backups to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of three channels in each instrumentation Function.

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Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the main control room operator can initiate a reactor trip at any time by using either of two reactor trip actuation devices in the main control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It can be used by the reactor operator to shutdown the reactor whenever any parameter is rapidly trending toward its Trip Setpoint. The safety analyses do not take credit for the Manual Reactor Trip.

The LCO requires two Manual Reactor Trip actuation devices be OPERABLE in MODES 1 and 2 and in MODES 3, 4, and 5 with RTBs closed and PLS capable of rod withdrawal. Two independent actuation devices are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown or control rods are withdrawn or the PLS is capable of withdrawing the shutdown or control rods. In MODES 3, 4, and 5, manual initiation of a reactor trip does not have to be OPERABLE if the PLS is not capable of withdrawing the shutdown or control rods. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor because all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function does not have to be OPERABLE.

2. Power Range Neutron Flux

The PMS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The PMS power range detectors provide input to the PLS. Minimum requirements for protection and control is achieved with three channels OPERABLE. The fourth channel is provided to increase plant availability, and permits the plant to run for an

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indefinite time with a single channel in trip or bypass. This Function also satisfies the requirements of IEEE 603 (Ref. 5) with 2/4 logic. This Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. <u>Power Range Neutron Flux – High</u>

The Power Range Neutron Flux – High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion during power operations. Positive reactivity excursions can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires four Power Range Neutron Flux – High channels to be OPERABLE in MODES 1 and 2.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux – High trip must be OPERABLE. This Function will terminate the reactivity excursion and shutdown the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux – High trip does not have to be OPERABLE because the reactor is shutdown and a reactivity excursion in the power range cannot occur. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6. In addition, the PMS power range detectors cannot detect neutron levels in this range.

b. <u>Power Range Neutron Flux – Low</u>

The LCO requirement for the Power Range Neutron Flux – Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions. The Trip Setpoint reflects only steady state instrument uncertainties as this Function does not provide primary protection for any event that results in a harsh environment.

The LCO requires four of the Power Range Neutron Flux – Low channels to be OPERABLE in MODE 1 below the Power Range Neutron Flux P-10 Setpoint and MODE 2.

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In MODE 1, below the Power Range Neutron Flux P-10 setpoint and in MODE 2, the Power Range Neutron Flux – Low trip must be OPERABLE. This Function may be manually blocked by the operator when the respective power range channel is greater than approximately 10% of RTP (P-10 setpoint). This Function is automatically unblocked when the respective power range channel is below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux – High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux – Low trip Function does not have to be OPERABLE because the reactor is shutdown and the PMS power range detectors cannot detect neutron levels generated in MODES 3, 4, 5, and 6. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. <u>Power Range Neutron Flux – High Positive Rate</u>

The Power Range Neutron Flux – High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux which are characteristic of a rod cluster control assembly (RCCA) drive rod housing rupture and the accompanying ejection of the RCCA. This Function compliments the Power Range Neutron Flux – High and Low trip Functions to ensure that the criteria are met for a rod ejection from the power range. The Power Range Neutron Flux Rate trip uses the same channels as discussed for Function 2 above.

The LCO requires four Power Range Neutron Flux – High Positive Rate channels to be OPERABLE. In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the Power Range Neutron Flux – High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux – High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a SDM in the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure

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bolts are detensioned preventing any pressure buildup. In addition, the PMS power range detectors cannot detect neutron levels present in this MODE.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function. The PMS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The safety analyses do not take credit for the Intermediate Range Neutron Flux trip Function. Even though the safety analyses take no credit for the Intermediate Range Neutron Flux trip, the functional capability at the specified Trip Setpoint enhances the overall diversity of the RTS. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any events that result in a harsh environment. This trip can be manually blocked by the main control room operator when above the P-10 setpoint, which is the respective PMS power range channel greater than 10% power, and is automatically unblocked when below the P-10 setpoint, which is the respective PMS power range channel less than 10% power. This Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires four channels of Intermediate Range Neutron Flux to be OPERABLE. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 below the P-10 setpoint, and in MODE 2, when there is a potential for an uncontrolled rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux – High Setpoint trip and the Power Range Neutron Flux – High Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the

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required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the PMS intermediate range detectors cannot detect neutron levels present in this MODE.

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux – Low Setpoint and Intermediate Range Neutron Flux trip Functions. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The PMS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The safety analyses do not take credit for the Source Range Neutron Flux trip Function. Even though the safety analyses take no credit for the Source Range Neutron Flux trip, the functional capability at the specified Trip Setpoint is assumed to be available and the trip is implicitly assumed in the safety analyses.

The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any events that result in a harsh environment. This trip can be manually blocked by the main control room operator when above the P-6 setpoint (Intermediate Range Neutron Flux interlock) and is automatically unblocked when below the P-6 setpoint. The manual block of the trip function also de-energizes the source range detectors. The source range detectors are automatically re-energized when below the P-6 setpoint. The trip is automatically blocked when above the P-10 setpoint (Power Range Neutron Flux interlock). The source range trip is the only RTS automatic protective Function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires four channels of Source Range Neutron Flux to be OPERABLE in MODE 2 below P-6 and in MODE 3, 4, or 5 with RTBs closed and Control Rod Drive System capable of rod withdrawal. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. In MODE 3, 4, or 5 with the RTBs open, the LCO does not require the Source Range Neutron Flux channels for reactor trip Functions to be OPERABLE.

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In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux – Low Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the PMS source range detectors are de-energized and inoperable as described above.

In MODE 3, 4, or 5 with the reactor shutdown, the Source Range Neutron Flux trip Function must also be OPERABLE. If the PLS is capable of rod withdrawal, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal accident. If the PLS is not capable of rod withdrawal, the source range detectors are required to be OPERABLE to provide monitoring of neutron levels and provide protection for events like an inadvertent boron dilution. These Functions are addressed in LCO 3.3.2, “Engineered Safety Feature Actuation System (ESFAS) Instrumentation.” The requirements for the PMS source range detectors in MODE 6 are addressed in LCO 3.9.3, “Nuclear Instrumentation.”

6. <u>Overtemperature ΔT</u>

The Overtemperature ΔT trip Function ensures that protection is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include all combinations of pressure, power, coolant temperature, and axial power distribution, assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function uses each loop ΔT as a measure of reactor power and is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure – the Trip Setpoint is varied to correct for changes in system pressure; and

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- axial power distribution – the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the PMS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower PMS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system. The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. This Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip. No credit is taken in the safety analyses for the turbine runback.

The LCO requires four channels of the Overtemperature ΔT trip Function to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

7. <u>Overpower ΔT</u>

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip function and provides a backup to the Power Range Neutron Flux – High Setpoint trip. The Overpower ΔT

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trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power and is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and
- rate of change of reactor coolant average temperature – including dynamic compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. The Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties as the detectors provide protection for a steam line break and may be in a harsh environment. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback reduces turbine power and reactor power. A reduction in power normally alleviates the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. The Overpower ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to a affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

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8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure – High and – Low trips and the Overtemperature ΔT trip.

a. Pressurizer Pressure – Low

The Pressurizer Pressure – Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure. The Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties as the detectors provide primary protection for an event that results in a harsh environment.

The LCO requires four channels of Pressurizer Pressure – Low to be OPERABLE in MODE 1 above P-10. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure – Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-10 interlock. On decreasing power, this trip Function is automatically blocked below P-10. Below the P-10 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure – High

The Pressurizer Pressure – High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the safety valves to prevent RCS overpressure conditions. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires four channels of the Pressurizer Pressure – High to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

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In MODE 1 or 2, the Pressurizer Pressure – High trip must be OPERABLE to help prevent RCS overpressurization and LCOs, and minimizes challenges to the safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure – High trip Function does not have to be OPERABLE because transients which could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate plant conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

9. Pressurizer Water Level – High 3

The Pressurizer Water Level – High 3 trip Function provides a backup signal for the Pressurizer Pressure – High 3 trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment. The level channels do not actuate the safety valves.

The LCO requires four channels of Pressurizer Water Level – High 3 to be OPERABLE in MODE 1 above P-10. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 when there is a potential for overfilling the pressurizer, the Pressurizer Water Level – High 3 trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-10 interlock. On decreasing power, this trip Function is automatically blocked below P-10. Below the P-10 setpoint, transients which could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate plant conditions and take corrective actions.

10. Reactor Coolant Flow – Low

a. Reactor Coolant Flow – Low (Single Cold Leg)

The Reactor Coolant Flow – Low (Single Cold Leg) trip Function ensures that protection is provided against violating

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the DNBR limit due to low flow in one or more RCS cold legs. Above the P-8 setpoint, a loss of flow in any RCS cold leg will actuate a reactor trip. Each RCS cold leg has four flow detectors to monitor flow. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires four Reactor Coolant Flow – Low channels per cold leg to be OPERABLE in MODE 1 above P-8. Four OPERABLE channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 above the P-8 setpoint, when a loss of flow in one RCS cold leg could result in DNB conditions in the core, the Reactor Coolant Flow – Low (Single Cold Leg) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more cold legs is required to actuate a reactor trip (Function 10.b) because of the lower power level and the greater margin to the design limit DNBR.

b. <u>Reactor Coolant Flow – Low (Two Cold Legs)</u>

The Reactor Coolant Flow – Low (Two Cold Legs) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS cold legs. Above the P-10 setpoint and below the P-8 setpoint, a loss of flow in two or more cold legs will initiate a reactor trip. Each cold leg has four flow detectors to monitor flow. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires four Reactor Coolant Flow – Low channels per cold leg to be OPERABLE in MODE 1 above P-10 and below P-8. Four OPERABLE channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 above the P-10 setpoint and below the P-8 setpoint, the Reactor Coolant Flow – Low (Two Cold Legs) trip must be OPERABLE. Below the P-10 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power

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distributions could occur that would cause a DNB concern at this low power level. Above the P-10 setpoint, the reactor trip on low flow in two or more RCS cold legs is automatically enabled. Above the P-8 setpoint, a loss of flow in any one cold leg will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

11. Reactor Coolant Pump (RCP) Bearing Water Temperature – High

a. RCP Bearing Water Temperature – High (Single Pump)

The RCP Bearing Water Temperature – High (Single Pump) reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS cold leg. Above the P-8 setpoint, high bearing water temperature in any RCP will initiate a reactor trip. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires four RCP Bearing Water Temperature – High channels per RCP to be OPERABLE in MODE 1 above P-8. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS cold leg could result in DNB conditions in the core, the RCP Bearing Water Temperature – High (Single Pump) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more cold legs is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR.

b. RCP Bearing Water Temperature – High (Two Pumps)

The RCP Bearing Water Temperature – High (Two Pumps) reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS cold legs. Above the P-10 setpoint and below the P-8 setpoint, a high bearing water temperature in two or more RCPs will initiate a reactor trip. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

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The LCO requires four RCP Bearing Water Temperature – High channels per RCP to be OPERABLE in MODE 1 above P-10 and below P-8. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 above the P-10 setpoint and below the P-8 setpoint, the RCP Bearing Water Temperature – High (Two Pumps) trip must be OPERABLE. Below the P-10 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-10 setpoint, the reactor trip on loss of flow in two RCS cold legs is automatically enabled. Above the P-8 setpoint, a loss of flow in any one cold leg will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

12. Reactor Coolant Pump Speed – Low

The RCP Speed – Low trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS cold legs. The speed of each RCP is monitored. Above the P-10 setpoint a low speed detected on two or more RCPs will initiate a reactor trip. The Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires four RCP Speed – Low channels to be OPERABLE in MODE 1 above P-10. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 above the P-10 setpoint, the RCP Speed – Low trip must be OPERABLE. Below the P-10 setpoint, all reactor trips on loss of flow are automatically blocked since no power distributions are expected to occur that would cause a DNB concern at this low power level. Above the P-10 setpoint, the reactor trip on loss of flow in two or more RCS cold legs is automatically enabled.

13. Steam Generator Water Level – Low

The SG Water Level – Low trip Function ensures that protection is provided against a loss of heat sink. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low level in any steam

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

generator is indicative of a loss of heat sink for the reactor. The Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties as the detectors provide primary protection for an event that results in a harsh environment. This Function also contributes to the coincidence logic for the ESFAS Function of opening the Passive Residual Heat Removal (PRHR) discharge valves.

The LCO requires four channels of SG Water Level – Low per SG to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level – Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater System (non-safety related). The Main Feedwater System is normally in operation in MODES 1 and 2. PRHR is the safety related backup heat sink for the reactor. During normal startups and shutdowns, the Main and Startup Feedwater Systems (non-safety related) can provide feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level – Low Function does not have to be OPERABLE because the reactor is not operating or even critical.

14. Steam Generator Water Level – High 2

The SG Water Level – High 2 trip Function ensures that protection is provided against excessive feedwater flow by closing the main feedwater control valves, tripping the turbine, and tripping the reactor. While the transmitters (d/p cells) are located inside containment, the events which this function protects against cannot cause severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

The LCO requires four channels of SG Water Level – High 2 per SG to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

In MODES 1 and 2 above the P-11 interlock, the SG Water Level – High 2 trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater System (non-safety related). The Main Feedwater System is only in operation in MODES 1 and 2. In MODE 3, 4, 5, or 6, the SG Water Level – High 2 Function does not

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

have to be OPERABLE because the reactor is not operating or even critical. The P-11 interlock is provided on this Function to permit bypass of the trip Function when the pressure is below P-11. This bypass is necessary to permit rod testing when the steam generators are in wet layup.

15. Safeguards Actuation Signal from Engineered Safety Feature Actuation System

The Safeguards Actuation Signal from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal which initiates the Safeguards Actuation signal. This is a condition of acceptability for the Loss of Coolant Accident (LOCA). However, other transients and accidents take credit for varying levels of ESFAS performance and rely upon rod insertion, except for the most reactive rod which is assumed to be fully withdrawn, to ensure reactor shutdown.

The LCO requires two manual and four automatic divisions of Safeguards Actuation Signal Input from ESFAS to be OPERABLE in MODES 1 and 2. Four automatic divisions are provided to permit one division bypass indefinitely and still ensure no single random failure will disable this trip Function.

A reactor trip is initiated every time a Safeguards Actuation signal is present. Therefore, this trip Function must be OPERABLE in MODES 1 and 2, when the reactor is critical, and must be shutdown in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical.

16. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current plant status. They back up operator actions to ensure protection system Functions are not blocked during plant conditions under which the safety analysis assumes the Functions are OPERABLE. Therefore, the interlock Functions do not need to be OPERABLE when the associated

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

reactor trip Functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when the respective PMS Intermediate Range Neutron Flux channel goes approximately one decade above the minimum channel reading. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-6 interlock allows the manual block of the respective PMS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed.

(2) on decreasing power, the P-6 interlock automatically energizes the PMS source range detectors and enables the PMS Source Range Neutron Flux reactor trip.

(3) on increasing power, the P-6 interlock provides a backup block signal to the source range neutron flux doubling circuit. Normally, this Function is manually blocked by the main control room operator during the reactor startup.

The LCO requires four channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

In MODE 2, when below the P-6 interlock setpoint, the P-6 interlock must be OPERABLE. Above the P-6 interlock setpoint, the PMS Source Range Neutron Flux reactor trip will be blocked; and this Function will no longer be necessary. In MODES 3, 4, 5, and 6, the P-6 interlock does not have to be OPERABLE because the PMS Source Range is providing core protection.

b. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 48% power as determined by the respective PMS power range detector. The P-8 interlock automatically

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

enables the Reactor Coolant Flow – Low (Single Hot Leg) and RCP Bearing Water Temperature – High (Single Pump) reactor trips on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in either RCS hot leg that could result in DNB conditions in the core when greater than approximately 48% power. On decreasing power, the reactor trip on low flow in either hot leg is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS cold leg could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

c. <u>Power Range Neutron Flux, P-10</u>

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power as determined by the respective PMS power-range detector. The LCO requirement for the P-10 interlock ensures that the following functions are performed:

(1) on increasing power, the P-10 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure – Low,
- Pressurizer Water Level – High 3,
- Reactor Coolant Flow – Low (Both Hot Legs),
- RCP Bearing Water Temperature – High (Two Pumps), and
- RCP Speed – Low.

These reactor trips are only required when operating above the P-10 setpoint (approximately 10% power). These reactor trips provide protection against violating the

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

DNBR limit. Below the P-10 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip.

(3) on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux – Low Setpoint reactor trip.

(4) on increasing power, the P-10 interlock automatically provides a backup block signal to the Source Range Neutron Flux reactor trip and also to de-energize the PMS source range detectors.

(5) on decreasing power, the P-10 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure – Low,
- Pressurizer Water Level – High 3,
- Reactor Coolant Flow – Low (Two Cold Legs),
- RCP Bearing Water Temperature – High (Two Pumps), and
- RCP Speed – Low.

(6) on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux – Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

In MODE 1, when the reactor is at power, the Power Range Neutron Flux, P-10 interlock must be OPERABLE. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux – Low Setpoint and Intermediate

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

d. Pressurizer Pressure, P-11

With pressurizer pressure channels less than the P-11 setpoint, the operator can manually block the Steam Generator Narrow Range Water Level – High 2 reactor Trip. This allows rod testing with the steam generators in cold wet layup. With pressurizer pressure channels > P-11 setpoint, the Steam Generator Narrow Range Water Level – High 2 reactor Trip is automatically enabled. The operator can also enable these actuations by use of the respective manual reset.

17. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. There are eight reactor trip breakers with two breakers in each division. The reactor trip circuit breakers are arranged in a two-out-of-four logic configuration, such that the tripping of the two circuit breakers associated with one division does not cause a reactor trip. This circuit breaker arrangement is illustrated in Figure 7.1-7. The LCO requires four divisions of the Reactor Trip Switchgear to be OPERABLE with two trip breakers associated with each required division. This logic is required to meet the safety function assuming a single failure.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs are closed, and the PLS is capable of rod withdrawal.

18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the PLS, or declared inoperable under Function 17 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening the breakers on a valid signal.

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These trip Functions must be OPERABLE in MODES 1 and 2 when the reactor is critical. In MODES 3, 4, and 5, these RTS trip Functions must be OPERABLE when the RTBs are closed, and the PLS is capable of rod withdrawal.

19. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 17 and 18) and Automatic Trip Logic (Function 19) ensures that means are provided to interrupt the power to the CRDMs and allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed.

The automatic trip logic includes the ESF coincidence logic and the voting logic.

The LCO requires four divisions of RTS Automatic Trip Logic to be OPERABLE. Four OPERABLE divisions are provided to ensure that a random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs are closed and the PLS is capable of rod withdrawal.

20. ADS Stages 1, 2 and 3 Actuation Input from Engineered Safety Feature Actuation System

The LCO requirement for this Function provides a reactor trip for any event that may initiate depressurization of the reactor.

The LCO requires four divisions of RTS Automatic Trip Logic to be OPERABLE. Four OPERABLE divisions are provided to ensure that a random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs are closed and the PLS is capable of rod withdrawal.

21. Core Makeup Tank (CMT) Actuation Input from Engineered Safety Feature Actuation System

The LCO requirement for this Function provides a reactor trip for any event that may initiate CMT injection.

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The LCO requires four divisions of RTS Automatic Trip Logic to be OPERABLE. Four OPERABLE divisions are provided to ensure that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODES 1 and 2 when the reactor is critical. In MODE 3, 4, and 5 these RTS trip Functions must be OPERABLE when the RTBs are closed and the PLS is capable of rod withdrawal.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.1-1.

In the event the transmitter, instrument loop, signal processing electronics, or trip output is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection Functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1, and B.2.2

Condition B applies to the Manual Reactor Trip, Manual Safeguards Actuation, Manual ADS Stages 1, 2, and 3 Actuation and Manual Core Makeup Tank Actuation in MODES 1 and 2 and in MODES 3, 4, and 5 with the reactor trip breakers closed and the plant control system capable of rod withdrawal. These Required Actions address inoperability of one manual initiation device of the Manual Reactor Trip Function, Manual

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Safeguards Actuation Function, Manual ADS Stages 1, 2, and 3 Actuation Function and/or Manual Core Makeup Tank Actuation Function. One device consists of an actuation switch and the associated hardware (such as contacts and wiring) up to but not including the eight Reactor Trip Breakers. With one device inoperable, the inoperable device must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE device is adequate to perform the safety function.

If the manual Function(s) cannot be restored to OPERABLE status in the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time) followed by opening the RTBs within 1 additional hour (55 hours total time). The 6 additional hours to reach MODE 3 and the 1 hour to open the RTBs are reasonable, based on operating experience, to reach MODE 3 and open the RTBs from full power operation in an orderly manner and without challenging unit systems. With the RTBs open and the unit in MODE 3, this trip Function is no longer required to be OPERABLE.

C.1 and C.2

Condition C applies to the Manual Reactor Trip in MODES 3, 4, and 5 with the RTBs closed and the PLS capable of rod withdrawal. These Required Actions address inoperability of one manual initiation device of the Manual Reactor Trip Function. One device consists of an actuation switch and the associated hardware (such as contacts and wiring) up to but not including the eight Reactor Trip Breakers. With one device inoperable, the inoperable device must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE device is adequate to perform the safety function.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status in the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, the RTBs must be opened within the next 1 hour. With the RTBs open, this Function is no longer required.

D.1.1, D.1.2, D.1.3, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux – High Function in MODES 1 and 2.

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With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [6] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

In addition to placing the inoperable channel(s) in the bypassed or tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 12 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one or two of the PMS power range detectors inoperable, partial radial power distribution monitoring capability is lost. However, the protective function would still function even with a single failure of one of the two remaining channels.

As an alternative to reducing power, the inoperable channel(s) can be placed in the bypassed or tripped condition within 6 hours and the QPTR monitored every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR compensates for the lost monitoring capability and allows continued plant operation at power levels > 75% RTP. The 12 hour Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if OPDMS and the Power Range Neutron Flux input to QPTR become inoperable. Power distribution limits are normally verified in accordance with LCO 3.2.5, "OPDMS - Monitored Power Distribution Parameters." However, if OPDMS becomes inoperable, then LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," becomes applicable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. If either OPDMS or the channel input to QPTR is OPERABLE, then performance of SR 3.2.4.2 once per 12 hours is not necessary.

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a

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reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

<u>E.1.1, E.1.2, and E.2</u>

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux – Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Power Range Neutron Flux – High Positive Rate;
- Pressurizer Pressure – High;
- SG Water Level – Low; and
- SG Water Level – High 2.

With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [6] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

If the Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

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F.1.1, F.1.2, F.2, and F.3

Condition F applies to the Intermediate Range Neutron Flux trip when above the P-6 setpoint and below the P-10 setpoint. Above the P-6 setpoint and below the P-10 setpoint, the PMS intermediate range detector performs the monitoring functions.

With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [2] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [2] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

As an alternative to placing the channel(s) in bypass or trip if THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 2 hours are allowed to reduce THERMAL POWER below the P-6 setpoint or to increase the THERMAL POWER above the P-10 setpoint. The PMS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the PMS power range detectors perform the monitoring and protective functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment below P-6, and takes into account the redundant capability afforded by the two remaining OPERABLE channels and the low probability of their failure during this period.

G.1 and G.2

Condition G applies to three Intermediate Range Neutron Flux trip channels inoperable in MODE 2 above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the PMS intermediate range detector performs the monitoring Functions. With only one intermediate range channel OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are insufficient

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OPERABLE Intermediate Range Neutron Flux channels to adequately monitor the power rise. The operator must also reduce THERMAL POWER below the P-6 setpoint within 2 hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the PMS Intermediate Range Neutron Flux trip.

H.1

Condition H applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels is inoperable. Below the P-6 setpoint, the PMS source range performs the monitoring and protective functions. At least three of the four PMS intermediate range channels must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. With the unit in this Condition, below P-6, the PMS source range performs the monitoring and protection functions.

I.1

Condition I applies to one or two Source Range Neutron Flux trip channels inoperable when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the PMS source range performs the monitoring and protection functions. With one or two of the four channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only two source range channels OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

J.1

Condition J applies to three inoperable Source Range Neutron Flux channels when in MODE 2, below the P-6 setpoint, and performing a reactor startup, or in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With three source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition and the unit enters Condition T.

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K.1.1, K.1.2, and K.2

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High 3;
- Reactor Coolant Flow – Low (Both Hot Legs);
- RCP Bearing Water Temperature – High (Two Pumps); and
- RCP Speed – Low.

With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [6] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

If Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE. A Completion Time of an additional 6 hours is allowed to reduce power < P-10. Allowance of this time interval takes into consideration the redundant capability provided by the remaining two redundant OPERABLE channels and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

L.1.1, L.1.2, and L.2

Condition L is applicable to the Reactor Coolant Flow – Low (Single Cold Leg) and RCP Bearing Water Temperature – High (Single Pump) reactor trip Functions.

With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [6] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the

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single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

If Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE. A Completion Time of an additional 4 hours is allowed to reduce power < P-8. Allowance of this time interval takes into consideration the redundant capability provided by the remaining two redundant OPERABLE channels and the low probability of occurrence of an event during this period that may require the protection afforded by this Function.

M.1 and M.2

Condition M applies to the Safeguards Actuation signal from ESFAS reactor trip, the RTS Automatic Trip Logic, automatic ADS Stages 1, 2, and 3 actuation, and automatic CMT injection in MODES 1 and 2.

With one or two channels or divisions inoperable, the Required Action is to restore three of the four channels/divisions within 6 hours. Restoring all channels/divisions but one to OPERABLE status ensures that a single failure will neither cause nor prevent the protective function. The 6 hour Completion Time is considered reasonable since the protective function will still function.

If Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE. A Completion Time of an additional 6 hours is allowed to place the unit in MODE 3. The Completion Time is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Allowance of this time interval takes into consideration the redundant capability provided by the remaining two redundant OPERABLE channels/divisions and the low probability of occurrence of an event during this period that may require the protection afforded by this Function.

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ACTIONS (continued)

N.1, N.2.1, N.2.2, and N.3

Condition N applies to the P-6, P-10, and P-11 interlocks. With one or two channels inoperable, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour, or the Functions associated with inoperable interlocks placed in a bypassed or tripped condition within [7] hours, or the unit must be placed in MODE 3 within 13 hours. Verifying the interlock manually accomplishes the interlock condition.

If one interlock channel is inoperable, the associated Function(s) must be placed in a bypass or trip condition within [7] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.)

If two interlock channels are inoperable, one channel of the associated Function(s) must be bypassed and one channel of the associated Function(s) must be tripped. In this state, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [7] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

If placing the associated Functions in bypass or trip is impractical, for instance as the result of other channels in bypass or trip, the Completion Time of an additional 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

O.1, O.2.1, O.2.2, and O.3

Condition O applies to the P-8 interlock. With one or two channels inoperable, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour, or the Functions associated with inoperable interlocks placed in a bypassed or tripped condition within [7] hours, or the unit must be placed in MODE 2 within 13 hours. Verifying the interlock manually accomplishes the interlock condition.

BASES

ACTIONS (continued)

If one interlock channel is inoperable, the associated Function(s) must be placed in a bypass or trip condition within [7] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.)

If two interlock channels are inoperable, one channel of the associated Function(s) must be bypassed and one channel of the associated Function(s) must be tripped. In this state, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [7] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [7].

If placing the associated Functions in bypass or trip is impractical, for instance as the result of other channels in bypass or trip, the Completion Time of an additional 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging plant systems.

<u>P.1, P.2.1, and P.2.2</u>

Condition P applies to the RTBs, and RTB undervoltage and shunt trip mechanisms in MODES 1 and 2, and in MODES 3, 4, and 5 with the RTBs closed and the PLS capable of rod withdrawal. This Condition is primarily associated with mechanical damage that can prevent the RTBs from opening.

With one division inoperable, the reactor trip breakers in the inoperable division must be opened within 8 hours. A division is inoperable, if, within that division, one or both of the RTBs and/or one or both of the trip mechanisms is inoperable.

With one division inoperable (with its RTBs open) and with three OPERABLE divisions remaining, the trip logic becomes one-out-of-three. The one-out-of-three trip logic meets the single failure criterion. (A failure in one of the three remaining divisions will not prevent the protective function.) If, coincident with RTBs inoperable in one division, the automatic trip logic is inoperable in another division, the trip logic becomes one-out-of-two, which meets the single failure criterion.

ACTIONS (continued)

If Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE within an additional 6 hours. This is done by opening all of the RTBs. With the RTBs open, these Functions are no longer required.

Q.1, Q.2.1, and Q.2.2

Condition Q applies to the RTBs in MODES 1 and 2, and in MODES 3, 4, and 5 with the RTBs closed and the PLS capable of rod withdrawal. With two divisions of RTBs and/or RTB Undervoltage and Shunt Trip Mechanisms inoperable, 1 hour is allowed to restore the three of the four divisions to OPERABLE status or the unit must be placed in MODE 3, 4 or 5 and the RTBs opened within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1-hour and 6-hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function. Placing the unit in MODE 3 removes the requirement for this particular Function.

R.1 and R.2

Condition R applies to automatic ADS Stages 1, 2, and 3 Actuation, automatic CMT Actuation and the RTS Automatic Trip Logic in MODES 3, 4, and 5 with the RTBs closed and the PLS capable of rod withdrawal.

With one or two channels/divisions inoperable, three of the four channels/divisions must be restored to OPERABLE status in 48 hours. Restoring all channels but one to OPERABLE ensures that a single failure will neither cause nor prevent the protective function. The 48 hour Completion Time is considered reasonable since the protective function will still function.

If Required Actions described above cannot be met within the specified Completion Times, the unit must be placed in a MODE where this Function is no longer required to be OPERABLE. A Completion Time of an additional 1 hour is allowed to open the RTBs. With RTBs open, these Functions are no longer required.

S.1 and S.2

Condition S applies to one or two inoperable Source Range Neutron Flux channels in MODE 3, 4, or 5 with the RTBs closed and the PLS capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS

BASES

ACTIONS (continued)

source range performs the monitoring and protection functions. With one or two of the source range channels inoperable, 48 hours is allowed to restore three of the four channels to an OPERABLE status. If the channels cannot be returned to an OPERABLE status, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit enters Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 7.

T.1, T.2, and T.3

Condition T applies when the required Source Range Neutron Flux channel is inoperable in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With the required source range channel inoperable, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. In addition to suspension of positive reactivity additions, all valves that could add unborated water to the RCS must be closed within 1 hour as specified in LCO 3.9.2. The isolation of unborated water sources will preclude a boron dilution accident.

Also, the SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM within 1 hour allows sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.11 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified in the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The CHANNEL CALIBRATION and RTCOT are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies. For channels that include dynamic transfer functions, such as, lag, lead/lag, rate/lag, the response time test may be performed with the transfer function set to one, with the resulting measured response time compared to the appropriate Chapter 7 response time (Ref. 2). Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of even something more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment have drifted outside its limit.

The channels to be checked are:

Power Range Neutron Flux
Intermediate Range Neutron Flux
Source Range Neutron Flux
Overtemperature Delta T
Overpower Delta T
Pressurizer Pressure
Pressurizer Water Level
Reactor Coolant Flow – each cold leg
RCP Bearing Water Temperature – each RCP

BASES

SURVEILLANCE REQUIREMENTS (continued)

RCP Speed
SG Narrow Range Level – each SG
RCS Loop T-cold – each cold leg
RCS Loop T-hot – each cold leg

The Frequency is based on operating experience that demonstrates the channel failure is rare. Automated operator aids may be used to facilitate the performance of the CHANNEL CHECK.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance to the nuclear instrumentation channel output every 24 hours. If the calorimetric measurement between 70% and 100% RTP, differs from the nuclear instrument channel output by > 1% RTP, the nuclear instrument channel is not declared inoperable, but must be adjusted. If the nuclear instrument channel output cannot be properly adjusted, the channel is declared inoperable.

Three Notes modify SR 3.3.1.2. The first Note indicates that the nuclear instrument channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the nuclear instrument channel output and the calorimetric measurement between 70% and 100% RTP is > 1% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels the calorimetric data are inaccurate. The third Note is required because, at power levels between 15% and 70% calorimetric uncertainty and control rod insertion create the potential for miscalibration of the nuclear instrumentation channel in cases where the channel is adjusted downward to match the calorimetric power. Therefore, if the calorimetric heat measurement is less than 70% RTP, and if the nuclear instrumentation channel indicated power is lower than the calorimetric measurement by > 1%, then the nuclear instrumentation channel shall be adjusted upward to match the calorimetric measurement. No nuclear instrumentation channel adjustment is required if the nuclear instrumentation channel is higher than the calorimetric measurement (see Westinghouse Technical Bulletin NSD-TB-92-14, Rev. 1.)

The Frequency of every 24 hours is adequate. It is based on plant operating experience, considering instrument reliability and operating history data for instrument drift.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Together these factors demonstrate the change in the absolute difference between nuclear instrumentation and heat balance calculated powers rarely exceeds 1% RTP in any 24 hours period.

In addition, main control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the AXIAL FLUX DIFFERENCE determined using the incore system to the nuclear instrument channel AXIAL FLUX DIFFERENCE every 31 EFPD.

If the absolute difference is ≥ 3% AFD the nuclear instrument channel is still OPERABLE, but must be readjusted. If the nuclear instrument channel cannot be properly readjusted, the channel is declared inoperable. This surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT function.

Two Notes modify SR 3.3.1.3. The first Note indicates that the excore nuclear instrument channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3% AFD. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 20% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 20% RTP. Below 20% RTP, the design of the incore detector system, low core power density, and detector accuracy make use of the incore detectors inadequate for use as a reference standard for comparison to the excore channels.

The Frequency of every 31 EFPD is adequate. It is based on plant operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A Note modifies SR 3.3.1.4. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.5

SR 3.3.1.5 is the performance of a TADOT every 92 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

The Reactor Trip Breaker (RTB) test shall include separate verification of the undervoltage and shunt trip mechanisms. Each RTB in a division shall be tested separately in order to minimize the possibility of an inadvertent trip.

The Frequency of every 92 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data. In addition, the AP1000 design provides additional breakers to enhance reliability.

The SR is modified by a Note to clarify that both breakers in a single division are to be tested during each STAGGERED TEST.

SR 3.3.1.6

SR 3.3.1.6 is the performance of a REACTOR TRIP CHANNEL OPERATIONAL TEST (RTCOT) every [92] days.

A RTCOT is performed on each required channel to provide reasonable assurance that the entire channel will perform the intended Function.

A test subsystem is provided with the protection and safety monitoring system to aid the plant staff in performing the RTCOT. The test subsystem is designed to allow for complete functional testing by using a combination of system self checking features, functional testing features, and other testing features. Successful functional testing consists of verifying that the capability of the system to perform the safety function has not failed or degraded.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For hardware functions this would involve verifying that the hardware components and connections have not failed or degraded. Generally this verification includes a comparison of the outputs from two or more redundant subsystems or channels.

Since software does not degrade, software functional testing involves verifying that the software code has not changed and that the software code is executing.

To the extent possible, protection and safety monitoring system functional testing is accomplished with continuous system self-checking features and the continuous functional testing features. The RTCOT shall include a review of the operation of the test subsystem to verify the completeness and adequacy of the results.

If the RTCOT can not be completed using the built-in test subsystem, either because of failures in the test subsystem or failures in redundant channel hardware used for functional testing, the RTCOT can be performed using portable test equipment.

This test frequency of [92] days is justified based on Reference [7] and the use of continuous diagnostic test features, such as deadman timers, cross-check of redundant channels, memory checks, numeric coprocessor checks, and tests of timers, counters and crystal time bases, which will report a failure within the protection and safety monitoring system cabinets to the operator within 10 minutes of a detectable failure.

SR 3.3.1.6 is modified by a note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.6 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for a time greater than 4 hours, this Surveillance must be performed prior to 4 hours after entry into MODE 3.

During the RTCOT, the protection and safety monitoring system cabinets in the division under test may be placed in bypass.

<u>SR 3.3.1.7</u>

SR 3.3.1.7 is the performance of a RTCOT as described in SR 3.3.1.6, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit

BASES

SURVEILLANCE REQUIREMENTS (continued)

condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 92 days of the Frequencies prior to reactor startup and four hours after reducing power below P-10 and P-6. The Frequency of “prior to startup” ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of “4 hours after reducing power below P-10” (applicable to intermediate and power range low channels) and “4 hours after reducing power below P-6” (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

SR 3.3.1.8

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

Transmitter calibration must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current “as found” values and the previous test “as left” values must be consistent with the transmitter drift allowance used in the setpoint methodology.

The CHANNEL CALIBRATION is assisted by the use of a tester.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The setpoint methodology requires that 30 months drift be used (1.25 times the surveillance calibration interval, 24 months) based on Generic Letter 91-04, “Changes in Technical Specification Surveillance Intervals to Accommodate a 24-month Fuel Cycle.”

SR 3.3.1.8 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 20% RTP. Below 20% RTP, the design of the incore detector system, low core power density, and detector accuracy make use of the incore detectors inadequate for use as a reference standard for comparison to the excore channels. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer’s data. This Surveillance is not required for the power range detectors for entry into MODES 2 and 1, and is not required for the intermediate range detectors for entry into MODE 2, because the plant must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the 24 month Frequency.

SR 3.3.1.10

SR 3.3.1.10 is the performance of a TADOT of the Manual Reactor Trip, and the SI, ADS Actuation, and CMT Injection inputs from the ESF logic. This TADOT is performed every 24 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.11

This SR 3.3.1.11 verifies that the individual channel/division actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response Time testing criteria are included in Reference 2.

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function set to one, with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping test such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements” (Ref. 10), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

Each division response must be verified every 24 months on a STAGGERED TEST BASIS (i.e., all four Protection Channel Sets would be tested after 96 months). Response times cannot be determined during plant operation because equipment operation is required to

BASES

SURVEILLANCE REQUIREMENTS (continued)

measure response times. Experience has shown that these components usually pass this surveillance when performed on a refueling frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR 3.3.1.11 is modified by exempting neutron detectors from response time testing. A Note to the Surveillance indicates that neutron detectors may be excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. Chapter 6.0, “Engineered Safety Features.”

2. Chapter 7.0, “Instrumentation and Controls.”

3. Chapter 15.0, “Accident Analysis.”

4. WCAP-14606, “Westinghouse Setpoint Methodology for Protection Systems,” April 1996 (nonproprietary).

5. Institute of Electrical and Electronic Engineers, IEEE-603-1991, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations,” June 27, 1991.

6. 10 CFR 50.49, “Environmental Qualifications of Electric Equipment Important to Safety for Nuclear Power Plants.”

[7. WCAP-10271-P-A (Proprietary) and WCAP-10272-A (Non-Proprietary), “Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System,” Supplement 2, Revision 1, June 1990.]

8. NRC Generic Letter No. 83-27, Surveillance Intervals in Standard Technical Specifications.

9. ESBU-TB-97-01, Westinghouse Technical Bulletin, “Digital Process Rack Operability Determination Criteria,” May 1, 1997.

10. WCAP-13632-P-A (Proprietary) and WCAP-13787-A (Non-Proprietary), Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” January 1996.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based upon the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into distinct but interconnected modules.

Field Transmitters and Sensors

Normally, four redundant measurements using four separate sensors, are made for each variable used for actuation of ESF. The use of four channels for protection Functions is based on a minimum of two channels being required for a trip or actuation, one channel in test or bypass, and a single failure on the remaining channel. The signal selector in the Plant Control System will function correctly with only three channels. This includes two channels properly functioning and one channel having a single failure. Minimum requirements for protection and control is achieved with three channels OPERABLE. The fourth channel is provided to increase plant availability, and permits the plant to run for an indefinite time with a single channel out of service. The circuit design is able to withstand both an input failure to the control system, which may then require the protection Function actuation, and a single failure in the other channels providing the protection Function actuation. Again, a single failure will neither cause nor prevent the protection Function actuation. These requirements are described in IEEE-603 (Ref. 4). The actual number of channels provided for each plant parameter is specified in Reference 2.

Engineered Safety Features (ESF) Channel

An ESF channel extends from the sensor to the output of the associated ESF subsystem and shall include the sensor (or sensors), the signal conditioning, any associated data links, and the associated ESF subsystem. For ESF channels containing nuclear instrumentation, the ESF channel shall also include the nuclear instrument signal conditioning and the associated Nuclear Instrumentation Signal Processing and Control (NISPAC) subsystem. Any manual ESF controls that are associated with a particular ESF channel are also included in that ESF channel.

BACKGROUND (continued)

Plant Protection Subsystem

The Plant Protection contains the necessary equipment to:

- Permit acquisition and analysis of the sensor inputs, including plant process sensors and nuclear instrumentation, required for reactor trip and ESF calculations;
- Perform computation or logic operations on variables based on these inputs;
- Provide trip signals to the reactor trip switchgear and ESF actuation data to the ESF coincidence logic as required;
- Permit manual trip or bypass of each individual reactor trip Function and permit manual actuation or bypass of each individual voted ESF Function;
- Provide data to other systems in the Instrumentation and Control (I&C) architecture; and
- Provide separate input circuitry for control Functions that require input from sensors that are also required for protection Functions.

Each of the four divisions of plant protection provides signal conditioning, comparable output signals for indications in the main control room, and comparison of measured input signals with established setpoints. The basis of the setpoints are described in References 1, 2, and 3. If the measured value of a unit parameter exceeds the predetermined setpoint, an output is generated which is transmitted to the ESF coincidence logic for logic evaluation.

Within the protection and safety monitoring system, redundancy is generally provided for active equipment such as processors and communication hardware. This redundancy is provided to increase plant availability and facilitate surveillance testing. A division or channel is OPERABLE if it is capable of performing its specified safety function(s) and all the required supporting functions or systems are also capable of performing their related support functions. Thus, a division or channel is OPERABLE as long as one set of redundant components within the division or channel are capable of performing its specified safety function(s).

BACKGROUND (continued)

ESF Coincidence Logic

The ESF coincidence logic contains the necessary equipment to:

- Permit reception of the data supplied by the four divisions of plant protection and perform voting on the trip outputs;
- Perform system level logic using the input data from the plant protection subsystems and transmit the output to the ESF actuation subsystems; and
- Provide redundant hardware capable of providing system level commands to the ESF actuation subsystems.

ESF Actuation Subsystems

The ESF actuation subsystems contain the necessary equipment to:

- Receive automatic system level signals supplied by the ESF coincidence logic;
- Receive and transmit data to/from main control room multiplexers;
- Receive and transmit data to/from other PLCs on the same logic bus;
- Receive status data from component position switches (such as limit switches and torque switches); and
- Perform logic computations on received data, generate logic commands for final actuators (such as START, STOP, OPEN, and CLOSE).

ESF Coincidence Logic and ESF Actuation Subsystem OPERABILITY Background

Each ESF coincidence logic and ESF actuation subsystem has two subsystems that communicate by means of redundant halves of the logic bus. This arrangement is provided to facilitate testing. If one subsystem is removed from service, the remaining subsystem continues to function and the ESF division continues to provide full protection. At least one of these redundant halves is connected to the battery backed portion of the power system. This provides full functionality of the ESF division even when all ac power sources are lost. As long as one battery subsystem within an ESF coincidence logic or ESF actuation subsystem continues to

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BACKGROUND (continued)

operate, the ESF division is unaffected. An ESF division is only affected when all battery backed subsystems within that division's ESF coincidence logic or ESF actuation subsystem are not OPERABLE.

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the trip output is set. Any trip output is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.

The Trip Setpoints used in the trip output are based on the analytical limits stated in Reference 2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "Westinghouse Setpoint Methodology for Protection Systems" (Refs. 9 and 10). (Reference 9 is an AP600 document that describes a methodology that is applicable to AP1000. AP1000 has some slight differences in instrument spans as a result of the higher power level.) The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the trip output is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

The Trip Setpoints and Allowable Values listed in Table 3.3.2-1 are based on the methodology described in Reference 9, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

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Calibration tolerances and drift allowances must be specified in plant calibration procedures, and must be consistent with the values used in the setpoint methodology.

The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against the "as left" data and are shown to be within the setpoint methodology assumptions. The basis of the setpoints is described in References 1, 2, 3, and 9. Trending of transmitter calibration is required by Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle."

The protection and safety monitoring system testing features are designed to allow for complete functional testing by using a combination of system self-checking features, functional testing features, and other testing features. Successful functional testing consists of verifying that the capability of the system to perform the safety function has not failed or degraded. For hardware functions this would involve verifying that the hardware components and connections have not failed or degraded. Since software does not degrade, software functional testing involves verifying that the software code has not changed and that the software code is executing. To the extent possible, protection and safety monitoring system functional testing will be accomplished with continuous system self-checking features and the continuous functional testing features.

The protection and safety monitoring system incorporates continuous system self-checking features wherever practical. Self-checking features include on-line diagnostics for the computer system and the hardware and communications tests. These self-checking tests do not interfere with normal system operation.

In addition to the self-checking features, the system includes functional testing features. Functional testing features include continuous functional testing features and manually initiated functional testing features. To the extent practical functional testing features are designed not to interfere with normal system operation.

In addition to the system self-checking features and functional testing features, other test features are included for those parts of the system which are not tested with self-checking features or functional testing features. These test features allow for instruments/sensor checks,

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calibration verification, response time testing, setpoint verification and component testing. The test features again include a combination of continuous testing features and manual testing features.

All of the testing features are designed so that the duration of the testing is as short as possible. Testing features are designed so that the actual logic is not modified. To prevent unwanted actuation, the testing features are designed with either the capability to bypass a Function during testing and/or limit the number of signals allowed to be placed in test at one time.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure – Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation not specifically credited in the accident safety analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the plant. These Functions may provide protection for conditions which do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO generally requires OPERABILITY of four channels in each instrumentation/logic Function and two devices for each manual initiation Function. The two-out-of-four configurations allow one channel to be bypassed during maintenance or testing without causing an ESFAS initiation. Two manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide plant protection in the event of any of the analyzed accidents. ESFAS protective functions are as follows:

1. Safeguards Actuation

   The Safeguards Actuation signal actuates the alignment of the Core Makeup Tank (CMT) valves for passive injection to the RCS. The Safeguards Actuation signal provides two primary Functions:

   - Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

heat removal and clad integrity, peak clad temperature < 2200°F); and

- Boration to ensure recovery and maintenance of SHUTDOWN MARGIN (k_{eff} < 1.0).

These Functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The Safeguards Actuation signal is also used to initiate other Functions such as:

- Containment Isolation;
- Reactor Trip;
- Turbine Trip;
- Close Main Feedwater Control Valves;
- Trip Main Feedwater Pumps and Closure of Isolation and Crossover Valves; and
- Reactor Coolant Pump Trip.

These other Functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater to limit secondary side mass losses;
- Trip of the reactor coolant pumps to ensure proper CMT actuation;
- Enabling automatic depressurization of the RCS on CMT Level – Low 1 to ensure continued safeguards actuated injection.

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

Manual and automatic initiation of Safeguards Actuation must be OPERABLE in MODES 1, 2, 3, and 4. In these MODES there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Automatic actuation in MODE 4 is provided by the high containment pressure signal.

Manual initiation is required in MODE 5 to support system level initiation. Automatic initiation is not required to be OPERABLE in MODE 5 because parameters are not available to provide automatic actuation, and manual initiation is sufficient to mitigate the consequences of an accident.

These Safeguards Actuation Functions are not required to be OPERABLE in MODE 6 because there is adequate time for the operator to evaluate plant conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of plant systems.

1.a. Manual Initiation

The LCO requires that two manual initiation devices are OPERABLE. The operator can initiate the Safeguards Actuation signal at any time by using either of two switches in the main control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO on Manual Initiation ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each device consists of one switch and the interconnecting wiring to all four divisions. Each manual initiation device actuates all four divisions. This configuration does not allow testing at power.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

1.b. Containment Pressure – High 2

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

The transmitters (d/p cells) and electronics are located inside of containment. Since the transmitters and electronics are located inside of containment, they will experience adverse environmental conditions and the trip setpoint reflects environmental instrument uncertainties. The Containment Pressure – High 2 setpoint has been specified as low as reasonable, without creating potential for spurious trips during normal operations, consistent with the TMI action item (NUREG-0933, Item II.E.4.2) guidance.

The LCO requires four channels of Containment Pressure – High 2 to be OPERABLE in MODES 1, 2, 3, and 4. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

1.c. Pressurizer Pressure – Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer safety valve;
- LOCAs; and
- Steam Generator Tube Rupture (SGTR).

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

The LCO requires four channels of Pressurizer Pressure – Low to be OPERABLE in MODES 1, 2, and 3 (above P-11, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F), to mitigate the consequences of a high energy line rupture inside containment. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic actuation below this pressure is then performed by the Containment Pressure – High 2 signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF Functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

1.d. Steam Line Pressure – Low

Steam Line Pressure – Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

It is possible for the transmitters to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

This Function is anticipatory in nature and has a typical lead/lag ratio of 50/5.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

The LCO requires four channels of Steam Line Pressure – Low to be OPERABLE in MODES 1, 2, and 3 (above P-11, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F). At these conditions, a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. Four channels are provided in each steam line to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern, inside containment SLB will be terminated by automatic actuation via Containment Pressure – High 2, and outside containment SLB will be terminated by the Steam Line Pressure-Negative Rate – High signal for steam line isolation. In MODE 4, 5, or 6, this Function is not needed for accident detection and mitigation because the steam line pressure is below the actuation setpoint. Low steam line pressure in these MODES is not an adequate indication of a feed line or steam line break.

1.e. RCS Cold Leg Temperature (T_{cold}) – Low

This signal provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

The LCO requires four channels of T_{cold} – Low to be OPERABLE in MODES 1 and 2, and in MODE 3 with any main steam isolation valve open and above P-11 when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F. At these conditions, a secondary side break or stuck open valve could result in the rapid cooldown of the primary side. Four channels are provided in each loop to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation because the cold leg temperature is reduced below the actuation setpoint.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

2. Core Makeup Tank (CMT) Actuation

CMT Actuation provides the passive injection of borated water into the RCS. Injection provides RCS makeup water and boration during transients or accidents when the normal makeup supply from the Chemical and Volume Control System (CVS) is lost or insufficient. Two tanks are available to provide passive injection of borated water. CMT injection mitigates the effects of high energy line breaks by adding primary side water to ensure maintenance or recovery of reactor vessel water level following a LOCA, and by borating to ensure recovery or maintenance of SHUTDOWN MARGIN following a steam line break. CMT Valve Actuation is initiated by the Safeguards Actuation signal, Pressurizer Level – Low 2, ADS Stages 1, 2 and 3 Actuation, or manually.

The LCO requires that manual and automatic CMT Valve Actuation be OPERABLE in MODES 1 through 4. Manual and Automatic actuation of the CMT valves is additionally required in MODE 5 with the RCS pressure boundary intact. Actuation of this Function is not required in MODE 5 with the RCS pressure boundary open, or MODE 6 because the CMTs are not required to be OPERABLE in these MODES.

2.a. Manual Initiation

Manual CMT Valve Actuation is accomplished by either of two switches in the main control room. Either switch activates all four divisions.

2.b. Pressurizer Water Level – Low 2

This Function also initiates CMT Valve Actuation from the coincidence of pressurizer level below the Low 2 Setpoint in any two of the four divisions. This function can be manually blocked when the pressurizer water level is below the P-12 Setpoint. This Function is automatically unblocked when the pressurizer water level is above the P-12 Setpoint. The Setpoint reflects both steady state and adverse environmental instrument uncertainties as the detectors provide protection for an event that results in a harsh environment.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

2.c. Safeguards Actuation (Function 1)

CMT Valve Actuation is also initiated by all Functions that initiate the Safeguards Actuation signal. The CMT Valve Actuation Function requirements are the same as the requirements for the Safeguards Actuation Functions, but only apply in MODES 1 through 4, and in MODE 5 with the RCS pressure boundary intact. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1 is referenced for all initiating Functions and requirements.

2.d. ADS Stages 1, 2, and 3 Actuation (Function 9)

The CMTs are actuated on an ADS Stages 1, 2, and 3 actuation. The CMT Actuation Function requirements are the same as the requirements for the ADS Stages 1, 2, and 3 Actuation Function, but only apply in MODES 1 through 4, and in MODE 5 with the RCS pressure boundary intact. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 9 is referenced for all initiating functions and requirements.

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere and selected process systems which penetrate containment from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

Containment Isolation is actuated by the Safeguards Actuation signal, manual actuation of containment cooling, or manually.

Manual and automatic initiation of Containment Isolation must be OPERABLE in MODES 1, 2, 3, and 4, when containment integrity is required. Manual initiation is required in MODE 5 and MODE 6 for closure of open penetrations providing direct access from the containment atmosphere to the outside atmosphere. Manual initiation of this Function in MODES 5 and 6 is not applicable if the direct access lines penetrating containment are isolated. Initiation of containment isolation by manual initiation of passive containment cooling in MODE 5 or 6 with decay heat ≤ 9.0 MWt is not required because OPERABILITY of the passive containment cooling system is not required when air cooling is sufficient. This provides the capability to

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

manually initiate containment isolation during all MODES. Automatic Safeguards Actuation is required in MODE 5 for closure of open penetrations providing direct access from the containment atmosphere to the outside atmosphere. Automatic Safeguards Actuation is not required in MODE 6 because manual initiation is sufficient to mitigate the consequences of an accident in this MODE.

3.a. Manual Initiation

Manual Containment Isolation is accomplished by either of two switches in the main control room. Either switch actuates all four ESFAC divisions.

3.b. Manual Initiation of Passive Containment Cooling (Function 12.a)

Containment Isolation is also initiated by Manual Initiation of Passive Containment Cooling. This is accomplished as described for ESFAS Function 12.a, but are not applicable if the direct access flow paths are isolated.

3.c. Safeguards Actuation (Function 1)

Containment Isolation is also initiated by all Functions that initiate the Safeguards Actuation signal. The Containment Isolation Function requirements are the same as the requirements for the Safeguards Actuation Function, but are not applicable if the direct access flow paths are isolated. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1 is referenced for all initiating functions and requirements.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG at most. For an SLB upstream of the isolation valves, inside or outside of containment, closure of the isolation valves limits the accident to the blowdown from only the affected SG. For a SLB downstream of the isolation valves, closure of the isolation valves terminates the accident as soon as the steam lines depressurize.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

Closure of the turbine stop and control valves and the main steam branch isolation valves is initiated by this Function. Closure of these valves limits the accidental depressurization of the main steam system associated with an inadvertent opening of a single steam dump, relief, safety valve, or a rupture of a main steam line. Closure of these valves also supports a steam generator tube rupture event by isolating the faulted steam generator.

4.a. Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the main control room. There are two switches in the main control room and either switch can initiate action to immediately close all main steam isolation valves (MSIVs). The LCO requires two OPERABLE channels in MODES 1, 2, 3, and 4 with any main steam valve open, when there is sufficient energy in the RCS and SGs to have an SLB or other accident resulting in the release of significant quantities of energy to cause a cooldown of the primary system. In MODES 5 and 6, this Function is not required to be OPERABLE because there is insufficient energy in the secondary side of the unit to cause an accident.

4.b. Containment Pressure – High 2

This Function actuates closure of the MSIVs in the event a SLB inside containment to limit the mass and energy release to containment and limit blowdown to a single SG.

The transmitters and electronics are located inside containment, thus, they will experience harsh environmental conditions and the Trip Setpoint reflects environmental instrument uncertainties.

The Containment Pressure – High 2 setpoint has been specified as low as reasonable, without creating potential for spurious trips during normal operations, consistent with the TMI action item (NUREG-0933, Item II.E.4.2) guidance. The LCO requires four channels of Containment Pressure – High 2 to be OPERABLE in MODES 1, 2, 3, and 4, with any main steam valve open, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

no single random failure will disable this trip Function. There would be a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. In MODES 5 and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure – High 2 setpoint.

4.c. Steam Line Pressure

(1) Steam Line Pressure – Low

Steam Line Pressure – Low provides closure of the MSIVs in the event of an SLB to limit the mass and energy release to containment and limit blowdown to a single SG.

The LCO requires four channels of Steam Line Pressure – Low Function to be OPERABLE in MODES 1, 2, and 3 (above P-11, when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F), with any main steam isolation valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. Four channels are provided in each steam line to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure – High 2, and stuck open valve transients and outside containment steam line breaks will be terminated by the Steam Line Pressure-Negative Rate – High signal for Steam Line Isolation. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

(2) Steam Line Pressure-Negative Rate – High

Steam Line Pressure-Negative Rate – High provides closure of the MSIVs for an SLB, when less than the P-11 setpoint, to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment. When the operator manually

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

blocks the Steam Line Pressure – Low when less than the P-11 setpoint, the Steam Line Pressure-Negative Rate – High signal is automatically enabled.

The LCO requires four channels of Steam Line Pressure-Negative Rate – High to be OPERABLE in MODE 3, with any main steam valve open, when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). Four channels are provided in each steam line to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. In MODES 1 and 2, and in MODE 3 when above the P-11 setpoint with the RCS boron concentration below that necessary to meet the SDM requirements at an RCS temperature of 200°F, this signal is automatically disabled and the Steam Line Pressure – Low signal is automatically enabled.

In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

While the transmitters may experience elevated ambient temperatures due to a steam line break, the Trip Function is on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

4.d. T_{cold} – Low

This Function provides closure of the MSIVs during a SLB or inadvertent opening of a SG relief or a safety valve to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment.

This Function was discussed as Safeguards Actuation Function 1.e.

The LCO requires four channels of T_{cold} – Low to be OPERABLE in MODES 1 and 2, and in MODE 3 above P-11 when the RCS boron concentration is below that necessary to meet the SDM requirements at an RCS temperature of 200°F, with any main steam isolation valve open, when a secondary side break or stuck open valve could result in the rapid

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cooldown of the primary side. Four channels are provided in each loop to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. In MODE 3 below P-11 and in MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation because the cold leg temperature is reduced below the actuation setpoint.

5. Turbine Trip

The primary Function of the Turbine Trip is to prevent damage to the turbine due to water in the steam lines. This Function is necessary in MODES 1 and 2, and 3 above P-11 to mitigate the effects of a large SLB or a large Feedline Break (FLB). Failure to trip the turbine following a SLB or FLB can lead to additional mass and energy being delivered to the steam generators, resulting in excessive cooldown and additional mass and energy release in containment. In MODES 3, 4, 5, and 6, the turbine is not in operation and this function is not required to be OPERABLE.

This Function is actuated by Steam Generator Water Level – High 2, by a Safeguards Actuation signal, or manually. The Reactor Trip Signal also initiates a turbine trip signal whenever a reactor trip (P-4) is generated.

5.a. Manual Main Feedwater Isolation

The Turbine Trip is also initiated by the Manual Main Feedwater Control Valve Isolation Function. The requirements for this Function are the same as the requirements for Manual Main Feedwater Control Valve Isolation (Function 6.a), but only apply in MODES 1 and 2. Therefore, the requirements are not repeated in Table 3.3.2-1, and Function 6.a is referenced for all requirements.

5.b. Steam Generator Narrow Range Water Level – High 2

This signal provides protection against excessive feedwater flow by closing the main feedwater control, isolation and crossover valves, tripping of the main feedwater pumps, and tripping the turbine. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. The transmitters (d/p cells) are located inside containment.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

However, the events which this Function protect against cannot cause severe environment in containment. Therefore, the Setpoint reflects only steady state instrument uncertainties.

5.c. Safeguards Actuation (Function 1)

Turbine Trip is also initiated by all Functions that initiate the Safeguards Actuation signal. The Turbine Trip Function requirements are the same as the requirements for the Safeguards Actuation Function, but only apply in MODES 1 and 2. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1 is referenced for all initiating Functions and requirements. The Safeguards Actuation signal closes all main feedwater control, isolation and crossover valves, trips all main feedwater pumps, and trips the turbine.

5.d. Reactor Trip (Function 18.a)

Turbine Trip is also initiated by all functions that initiate Reactor Trip. The turbine trip function requirements are the same as the requirements for the Reactor Trip Function, but only apply in MODES 1 and 2. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 18.a, P-4 (Reactor Trip), is referenced for all initiating Functions and requirements.

6. Main Feedwater Control Valve Isolation

The primary Function of Main Feedwater Control Valve Isolation is to prevent damage to the turbine due to water in the steam lines and to stop the excessive flow of feedwater into the SGs. This Function is actuated by Steam Generator Narrow Range Water Level – High 2, by a Safeguards Actuation signal, or manually. The Reactor Trip Signal also initiates closure of the main feedwater control valves coincident with a low RCS average temperature (T_{avg}) signal whenever a reactor trip (P-4) is generated.

Closing the Main Feedwater Control Valves on Manual Main Feedwater Isolation, SG Narrow Range Water Level-High 2, or Safeguards Actuation is necessary in MODES 1, 2, and 3 to mitigate the effects of a large SLB or a large FLB. This Function is also required to be OPERABLE in MODES 1 and 2 on T_{avg} Low-1 coincident with Reactor Trip (P-4). Failure to close the main feedwater control valves following a SLB or FLB can lead to

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

additional mass and energy being delivered to the steam generators, resulting in excessive cooldown and additional mass and energy release in containment. Manual main feedwater isolation is required to be OPERABLE in MODE 4 when the main feedwater control valves are open. This Function is not applicable in MODE 4 for valve isolation if the main feedwater line is isolated. Automatic actuation on a Steam Generator Narrow Range Water Level – High 2 is required to be OPERABLE in MODE 4 when the RCS is not being cooled by the RNS. In MODES 5 and 6, the energy in the RCS and the steam generators is low and this function is not required to be OPERABLE.

6.a. Manual Main Feedwater Isolation

Manual Main Feedwater Isolation can be accomplished from the main control room. There are two switches in the main control room and either switch can initiate action in both divisions to close all main and startup feedwater control, isolation and crossover valves, trip all main and startup feedwater pumps, and trip the turbine.

6.b. Steam Generator Narrow Range Water Level – High 2

This signal provides protection against excessive feedwater flow by closing the main feedwater control, isolation and crossover valves, tripping of the Main Feedwater Pumps, and tripping the turbine.

Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. The transmitters (d/p cells) are located inside containment. However, the events which this Function protect against cannot cause severe environment in containment. Therefore, the Setpoint reflects only steady state instrument uncertainties.

6.c. Safeguards Actuation (Function 1)

This Function is also initiated by all Functions that initiate the Safeguards Actuation signal. The Main Feedwater Control Valve Isolation Function requirements are the same as the requirements for the Safeguards Actuation Function, but do not apply in MODE 4 with the flow paths isolated. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead

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Function 1 is referenced for all initiating Functions and requirements. The Safeguards Actuation signal closes all main feedwater control, isolation and crossover valves, trips all main feedwater pumps, and trips the turbine.

6.d. T_{avg} Low-1 Coincident with Reactor Trip (P-4)

This signal provides protection against excessive feedwater flow by closing the main feedwater control valves. This signal results from a coincidence of two of the four divisions of reactor loop average temperature below the Low 1 setpoint coincident with the P-4 permissive. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure that no single random failure will disable this trip Function.

7. Main Feedwater Pump Trip and Valve Isolation

The primary function of the Main Feedwater Pump Trip and Isolation is to prevent damage to the turbine due to water in the steam lines and to stop the excessive flow of feedwater into the SGs. Valve isolation includes closing the main feedwater isolation and crossover valves. Isolation of main feedwater is necessary to prevent an increase in heat removal from the reactor coolant system in the event of a feedwater system malfunction. Addition of excessive feedwater causes an increase in core power by decreasing reactor coolant temperature. This Function is actuated by Steam Generator Water Level – High 2, by a Safeguards Actuation signal, or manually. The Reactor Trip Signal also initiates a turbine trip signal whenever a reactor trip (P-4) is generated.

This Function is necessary in MODES 1, 2, 3, and 4 to mitigate the effects of a large SLB or a large FLB except T_{avg} Low 2 coincident with Reactor Trip (P-4) which is required to be OPERABLE in MODES 1 and 2. Failure to trip the turbine or isolate the main feedwater system following a SLB or FLB can lead to additional mass and energy being delivered to the steam generators, resulting in excessive cooldown and additional mass and energy release in containment. Manual main feedwater isolation is required to be OPERABLE in MODE 4 when the main feedwater isolation valves are open. This Function is not applicable in MODE 4 for valve isolation if the main feedwater line is isolated. Automatic actuation on a Steam Generator Narrow Range Water Level – High 2 is required to be OPERABLE in MODE 4 when the RCS is not being

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

cooled by the RNS. In MODES 5 and 6, the energy in the RCS and the steam generators is low and this Function is not required to be OPERABLE.

7.a. Manual Main Feedwater Isolation

The Main Feedwater Pump Trip and Valve Isolation is also initiated by the Manual Main Feedwater Control Valve Isolation Function. The requirements for this Function are the same as the requirements for Manual Main Feedwater Control Valve Isolation (Function 6.a). Therefore, the requirements are not repeated in Table 3.3.2-1, and Function 6.a is referenced for all requirements.

7.b. Steam Generator Narrow Range Water Level – High 2

This signal provides protection against excessive feedwater flow by closing the main feedwater control, isolation and crossover valves, tripping of the main feedwater pumps, and tripping the turbine. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. The transmitters (d/p cells) are located inside containment. However, the events which this Function protect against cannot cause severe environment in containment. Therefore, the Setpoint reflects only steady state instrument uncertainties.

7.c. Safeguards Actuation (Function 1)

This Function is also initiated by all Functions that initiate the Safeguards Actuation signal. The Main Feedwater Pump Trip and Valve Isolation Function requirements are the same as the requirements for their Safeguards Actuation Function, but do not apply in MODE 4 with the flow paths isolated. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1 is referenced for all initiating Functions and requirements. The Safeguards Actuation signal closes all main feedwater control, isolation and crossover valves, trips all main feedwater pumps, and trips the turbine.

7.d. T_{avg} Low-2 Coincident with Reactor Trip (P-4)

This signal provides protection against excessive feedwater flow by closing the main feedwater isolation and crossover leg valves, and tripping of the main feedwater pumps. This signal

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results from a coincidence of two out of four divisions of reactor loop average temperature below the Low 2 setpoint coincident with the P-4 permissive. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure that no single random failure will disable this trip Function. This Function may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

8. Startup Feedwater Isolation

The primary Function of the Startup Feedwater Isolation is to stop the excessive flow of feedwater into the SGs. This Function is necessary in MODES 1, 2, 3, and 4 to mitigate the effects of a large SLB or a large FLB. Failure to isolate the startup feedwater system following a SLB or FLB can lead to additional mass and energy being delivered to the steam generators, resulting in excessive cooldown and additional mass and energy release in containment.

Startup feedwater isolation must be OPERABLE in MODES 1, 2, 3, and 4 when there is significant mass and energy in the RCS and the steam generators. This Function is not applicable in MODE 4 when the startup feedwater flow paths are isolated. In MODES 5 and 6, the energy in the RCS and the steam generators is low and this Function is not required to be OPERABLE.

8.a. Steam Generator (SG) Narrow Range Water Level – High 2

If steam generator narrow range level reaches the High 2 setpoint in either steam generator, then all startup feedwater control and isolation valves are closed and the startup feedwater pumps are tripped. Four channels are provided in each steam generator to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

8.b. T_{cold} – Low

This Function closes the startup feedwater control and isolation valves and trips the startup feedwater pumps if reactor coolant system cold leg temperature is below the T_{cold} setpoint in any loop. Startup feedwater isolation on this condition may be manually blocked when the pressurizer

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

pressure is below the P-11 setpoint. This function is automatically unblocked when the pressurizer pressure is above the P-11 setpoint with the RCS boron concentration below that necessary to meet the SDM requirements at an RCS temperature of 200°F. Four channels are provided in each loop to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

8.c. Manual Main Feedwater Control Valve Isolation (Function 6.a)

The Startup Feedwater Isolation is also initiated by the Manual Main Feedwater Control Valve Isolation Function. The requirements for this Function are the same as the requirements for the Manual Main Feedwater Control Valve Isolation (Function 6.a). Therefore, the requirements are not repeated in Table 3.3.2-1, and Function 6.a is referenced for all requirements.

9. ADS Stages 1, 2, & 3 Actuation

The Automatic Depressurization System (ADS) provides a sequenced depressurization of the reactor coolant system to allow passive injection from the CMTs, accumulators, and the in-containment refueling water storage tank (IRWST) to mitigate the effects of a LOCA. The depressurization is accomplished in four stages, with the first three stages discharging into the IRWST and the last stage discharging into containment. Each of the first three stages consists of two parallel paths with each path containing an isolation valve and a depressurization valve.

The first stage isolation valves open on any ADS Stages 1, 2, and 3 actuation. The first stage depressurization valves are opened following a preset time delay after the actuation of the isolation valves. The second stage isolation valves are opened following a preset time delay after actuation of the first stage depressurization valves open. The second stage depressurization valves are opened following a preset time delay after the second stage isolation valves are actuated, similar to stage one. Similar to the second stage, the third stage isolation valves are opened following a preset time delay after the actuation of the second stage depressurization valves. The third stage depressurization valves are opened following a preset time delay after the third stage isolation valves are actuated.

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9.a. Manual Initiation

The first stage depressurization valves open on manual actuation. Any ADS Stages 1, 2, and 3 actuation also actuates PRHR and trips all reactor coolant pumps. The operator can initiate an ADS Stages 1, 2, and 3 actuation from the main control room by simultaneously actuating two ADS actuation devices in the same set. There are two sets of two switches each in the main control room. Simultaneously actuating the two devices in either set will actuate ADS Stages 1, 2, and 3. This Function must be OPERABLE in MODES 1, 2, 3, and 4. This Function must also be OPERABLE in MODES 5 and 6 when the required ADS valves are not open, and in MODE 6 with the upper internals in place. The required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS - Shutdown, RCS Intact and LCO 3.4.13, ADS - Shutdown, RCS Open.

9.b. CMT Level – Low 1 Coincident with CMT Actuation

This Function ensures continued passive injection or borated water to the RCS following a small break LOCA. ADS Stages 1, 2 and 3 actuation is initiated when the CMT Level reaches its Low 1 Setpoint coincident with any CMT Actuation signal (Function 2). Four channels are provided in each CMT to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

The ADS Stages 1, 2, and 3 Actuation Function requirements are the same as the requirements discussed in Function 2 (CMT Actuation). Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 2 is referenced for all initiating functions and requirements. This Function must be OPERABLE in MODES 1, 2, 3, and 4.

This Function must also be OPERABLE in MODE 5 with pressurizer level ≥ 20% and the required ADS valves not open. The required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS - Shutdown, RCS Intact and LCO 3.4.13, ADS - Shutdown, RCS Open. In MODE 5, only one CMT is required to be OPERABLE in accordance with LCO 3.5.3, CMTs - Shutdown, RCS Intact; therefore, CMT level channels are only required on an OPERABLE CMT.

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10. ADS Stage 4 Actuation

The ADS provides a sequenced depressurization of the reactor coolant system to allow passive injection from the CMTs, accumulators, and the IRWST to mitigate the effects of a LOCA. The depressurization is accomplished in four stages, with the first three stages discharging into the IRWST and the fourth stage discharging into containment.

The fourth stage of the ADS consists of four parallel paths. Each of these paths consists of a normally open isolation valve and a depressurization valve. The four paths are divided into two groups with two paths in each group. Within each group, one path is designated to be substage A and the second path is designated to be substage B.

The substage A depressurization valves are opened following a preset time delay after the substage A isolation valve confirmatory open signal. The sequence is continued with substage B. A confirmatory open signal is provided to the substage B isolation valves following a preset time delay after the substage A depressurization valve has been opened. The signal to open the substage B depressurization valve is provided following a preset time delay after the substage B isolation valves confirmatory open signal.

10.a. Manual Initiation Coincident with RCS Wide Range Pressure – Low or ADS Stages 1, 2, and 3 Actuation (Function 9)

The fourth stage depressurization valves open on manual actuation. The operator can initiate Stage 4 of ADS from the main control room. There are two sets of two switches each in the main control room. Actuating the two switches in either set will actuate all 4th stage ADS valves. This manual actuation is interlocked to actuate with either the low RCS pressure signal or with the ADS Stages 1, 2, & 3 actuation (Function 9). These interlocks minimize the potential for inadvertent actuation of this Function. This interlock with Function 9 allows manual actuation of this Function if automatic or manual actuation of the ADS Stages 1, 2, & 3 valves fails to depressurize the RCS due to common-mode failure. This consideration is important in PRA modeling to improve the reliability of reducing the RCS pressure following a small LOCA or transient event. This Function must be OPERABLE

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in MODES 1, 2, 3, and 4. This Function must also be OPERABLE in MODES 5 and 6 when the required ADS valves are not open, and in MODE 6 with the upper internals in place. The required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS - Shutdown, RCS Intact and LCO 3.4.13, ADS - Shutdown, RCS Open.

10.b. CMT Level – Low 2 Coincident with RCS Wide Range Pressure – Low

The fourth stage depressurization valves open on CMT Level – Low 2 in two-out-of-four channels in either CMT. Actuation of the fourth stage depressurization valves is interlocked with the third stage depressurization signal such that the fourth stage is not actuated unless the third stage has been previously actuated following a preset time delay. Actuation of the fourth stage ADS valves are further interlocked with a low RCS pressure signal such that the ADS Stage 4 actuation is not actuated unless the RCS pressure is below a predetermined setpoint. Four channels of CMT level are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. This Function must be OPERABLE in MODES 1, 2, 3, and 4. This Function must also be OPERABLE in MODE 5 when the required ADS valves are not open and with the pressurizer level ≥ 20%. The required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS - Shutdown, RCS Intact and LCO 3.4.13, ADS - Shutdown, RCS Open. In MODE 5, only one CMT is required to be OPERABLE in accordance with LCO 3.5.3, CMTs - Shutdown, RCS Intact; therefore, CMT level channels are only required on an OPERABLE CMT.

10.c. Coincident RCS Loop 1 and 2 Hot Leg Level – Low

A signal to automatically open the ADS Stage 4 is also generated when coincident loop 1 and 2 reactor coolant system hot leg level indication decreases below an established setpoint for a duration exceeding an adjustable time delay. This Function is required to be OPERABLE in MODE 4 with the RCS being cooled by the RNS. This Function is also required to be OPERABLE in MODE 5 and in MODE 6 when the required ADS valves are not open. The

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required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS - Shutdown, RCS Intact and LCO 3.4.13, ADS - Shutdown, RCS Open.

11. Reactor Coolant Pump Trip

Reactor Coolant Pump (RCP) Trip allows the passive injection of borated water into the RCS. Injection provides RCS makeup water and boration during transients or accidents when the normal makeup supply from the CVS is lost or insufficient. Two tanks provide passive injection of borated water by gravity when the reactor coolant pumps are tripped. CMT injection mitigates the effects of high energy line breaks by adding primary side water to ensure maintenance or recovery of reactor vessel water level following a LOCA, and by borating to ensure recovery or maintenance of SHUTDOWN MARGIN following a steam line break. RCP trip on high bearing water temperature protects the RCP coast down. RCP trip is actuated by High RCP bearing water temperature ADS Stages 1, 2, and 3 Actuation (Function 9), and CMT actuation.

11.a. ADS Stage 1, 2, and 3 Actuation (Function 9)

The RCPs are tripped any time ADS Stage 1, 2, and 3 actuation is initiated. The RCP trip Function requirements for the ADS Stage 1, 2, and 3 actuation are the same as the requirements for the ADS Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 9 is referenced for all initiating functions and requirements.

11.b. Reactor Coolant Pump Bearing Water Temperature – High

Each affected RCP will be tripped if two-out-of-four sensors on the RCP indicate high bearing water temperature. This Function is required to be OPERABLE in MODES 1 and 2. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

11.c. Manual CMT Actuation (Function 2.a)

RCP trip is also initiated by the manual CMT actuation Function. The RCP trip Function requirements are the same

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as the requirements for the manual CMT actuation Function. Therefore, the requirements are not repeated in Table 3.3.2-1, and Function 2.a is referenced for all requirements.

11.d. Pressurizer Water Level – Low 2

The RCPs are tripped when the pressurizer water level reaches its Low 2 setpoint. This signal results from the coincidence of pressurizer water level below the Low 2 setpoint in any two-of-four divisions. This Function is required to be OPERABLE in MODES 1, 2, 3, and 4. This Function is also required to be OPERABLE in MODE 5 with pressurizer level ≥ 20%, when the RCS is not being cooled by the RNS. This Function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This Function is automatically unblocked when the pressurizer water level is above the P-12 setpoint.

11.e. Safeguards Actuation (Function 1)

This Function is also initiated by all Functions that initiated the Safeguards Actuation signal. The requirements for the reactor trip Functions are the same as the requirements for the Safeguards Actuation Function. Therefore, the requirements are not repeated in Table 3.3.2.1. Instead, Function 1 is referenced for all initiating Functions and requirements.

12. Passive Containment Cooling Actuation

The Passive Containment Cooling System (PCS) transfers heat from the reactor containment to the environment. This Function is necessary to prevent the containment design pressure and temperature from being exceeded following any postulated DBA (such as LOCA or SLB). Heat removal is initiated automatically in response to a Containment Pressure – High 2 signal or manually.

A Passive Containment Cooling Actuation signal initiates water flow by gravity by opening the isolation valves. The water flows onto the containment dome, wetting the outer surface. The path for natural circulation of air along the outside walls of the containment structure is always open.

The LCO requires this Function to be OPERABLE in MODES 1, 2, 3, and 4 when the potential exists for a DBA that could require the

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operation of the Passive Containment Cooling System. In MODES 5 and 6, with decay heat more than 9.0 MWt, manual initiation of the PCS provides containment heat removal. Section B 3.6.7, Applicability, provides the basis for the decay heat limit.

12.a. Manual Initiation

The operator can initiate Containment Cooling at any time from the main control room by actuating either of the two containment cooling actuation switches. There are two switches in the main control room, either of which will actuate containment cooling in all divisions. Manual Initiation of containment cooling also actuates containment isolation.

12.b. Containment Pressure – High 2

This signal provides protection against a LOCA or SLB inside containment. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

The transmitters and electronics are located inside containment, thus, they will experience harsh environmental conditions and the trip setpoint reflects only steady state instrument uncertainties associated with the containment environment. The Containment Pressure – High 2 setpoint has been specified as low as reasonable, without creating potential for spurious trips during normal operations, consistent with the TMI action item (NUREG-0933, Item II.E.4.2) guidance.

13. PRHR Heat Exchanger Actuation

The PRHR Heat Exchanger (HX) provides emergency core decay heat removal when the Startup Feedwater System is not available to provide a heat sink. PRHR is actuated when the discharge valves are opened in response to Steam Generator Narrow Range (NR) Level – Low coincident with Startup Feedwater Flow – Low, Steam Generator Wide Range (WR) Level – Low, ADS Stages 1, 2, and 3 Actuation, CMT Actuation, Pressurizer Water Level – High 3, or Manual Initiation.

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13.a. Manual Initiation

Manual PRHR actuation is accomplished by either of two switches in the main control room. Either switch actuates all four ESFAC Divisions.

This Function is required to be OPERABLE in MODES 1, 2, 3, and 4, and MODE 5 with the RCS pressure boundary intact. This ensures that PRHR can be actuated in the event of a loss of the normal heat removal systems.

13.b. Steam Generator Narrow Range Level – Low Coincident with Startup Feedwater Flow – Low

PRHR is actuated when the Steam Generator Narrow Range Level reaches its low setpoint coincident with an indication of low Startup Feedwater Flow.

The LCO requires four channels per steam generator to be OPERABLE to satisfy the requirements with a two-out-of-four logic. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. The Setpoint reflects both steady state and adverse environmental instrument uncertainties as the detectors provide protection for an event that results in a harsh environment.

Startup Feedwater Flow – Low uses a one-out-of-two logic on each of the two startup feedwater lines. This Function is required to be OPERABLE in MODES 1, 2, and 3 and in MODE 4 when the RCS is not being cooled by the Normal Residual Heat Removal System (RNS). This ensures that PRHR can be actuated in the event of a loss of the normal heat removal systems. In MODE 4 when the RCS is being cooled by the RNS, and in MODES 5 and 6, the SGs are not required to provide the normal RCS heat sink. Therefore, startup feedwater flow is not required, and PRHR actuation on low startup feedwater flow is not required.

13.c. Steam Generator Wide Range Level – Low

PRHR is also actuated when the SG Wide Range Level reaches its Low Setpoint. There are four wide range level channels for each steam generator and a two-out-of-four logic

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is used. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. This Function is required to be OPERABLE in MODES 1, 2, and 3 and in MODE 4 when the RCS is not being cooled by the RNS. This ensures that PRHR can be actuated in the event of a loss of the normal heat removal systems. In MODE 4 when the RCS is being cooled by the RNS, and in MODES 5 and 6, the SGs are not required to provide the normal RCS heat sink. Therefore, SG Wide Range Level is not required, and PRHR actuation on low wide range SG level is not required.

13.d. ADS Stages 1, 2, and 3 Actuation

PRHR is also actuated any time ADS Stages 1, 2, and 3 Actuation is initiated. The PRHR actuation Function requirements for the ADS Stages 1, 2, and 3 actuation are the same as the requirements for the ADS Stages 1, 2, and 3 Actuation Function, but only in MODES 2, 3, and 4, and in MODE 5 with the RCS pressure boundary intact.

13.e. CMT Actuation (Function 2)

PRHR is also actuated by all the Functions that actuate CMT injection. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 2 (CMT Actuation) is referenced for all initiating functions and requirements.

13.f. Pressurizer Water Level – High 3

PRHR is actuated when the pressurizer water level reaches its High 3 setpoint. This signal provides protection against a pressurizer overfill following an inadvertent core makeup tank actuation with consequential loss of offsite power. This Function is automatically unblocked when RCS pressure is above the P-19 setpoint. This Function is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the RCS is not being cooled by the RNS and above the P-19 (RCS pressure) interlock. This Function is not required to be OPERABLE in MODES 5 and 6 because it is not required to mitigate DBA in these MODES.

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14. Steam Generator Blowdown Isolation

The primary Function of the steam generator blowdown isolation is to ensure that sufficient water inventory is present in the steam generators to remove the excess heat being generated until the decay heat has decreased to within the PRHR HX capability.

This Function closes the isolation valves of the Steam Generator Blowdown System in both steam generators when a signal is generated from the PRHR HX Actuation or Steam Generator Narrow Range Water Level – Low. This Function is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the RCS is not being cooled by the RNS. This Function is not required to be OPERABLE in MODE 4 if the steam generator blowdown line is isolated.

14.a. PRHR Heat Exchanger Actuation (Function 13)

Steam Generator Blowdown Isolation is also initiated by all Functions that initiate PRHR actuation. The Steam Generator Blowdown Isolation requirements for these Functions are the same as the requirements for the PRHR Actuation. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 13, PRHR HX Actuation, is referenced for all initiating Functions and requirements.

14.b. Steam Generator Narrow Range Level – Low

The Steam Generator Blowdown isolation is actuated when the Steam Generator Narrow Range Level reaches its Low Setpoint.

The LCO requires four channels per steam generator to be OPERABLE to satisfy the requirements with a two-out-of-four logic. This Function is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the RCS is not being cooled by the RNS. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function. Setpoint reflects both steady state and adverse environmental instrument uncertainties as the detectors provide protection for an event that results in a harsh environment.

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15. Boron Dilution Block

The block of boron dilution is accomplished by closing the CVS suction valves to demineralized water storage tanks, and aligning the boric acid tank to the CVS makeup pumps. This Function is actuated by Source Range Neutron Flux Multiplication, Reactor Trip, and Battery Charger Input Voltage – Low.

15.a. Source Range Neutron Flux Multiplication

A signal to block boron dilution in MODE 2 below the P-6 interlock and MODE 3, 4, or 5 is derived from source range neutron flow increasing at an excessive rate (source range flow multiplication). This Function is not applicable in MODES 4 and 5 if the demineralized water makeup flowpath is isolated. The source range neutron detectors are used for this Function. The LCO requires four divisions to be OPERABLE. There are four divisions and two-out-of-four logic is used. On a coincidence of excessively increasing source range neutron flow in two of the four divisions, demineralized water makeup is isolated to preclude a boron dilution event. In MODE 6, a dilution event is precluded by the requirement in LCO 3.9.2 to close, lock and secure at least one valve in each unborated water source flow path.

15.b. Reactor Trip (Function 18.a)

Demineralized Water Makeup is also isolated by all the Functions that initiate a Reactor Trip. The isolation requirements for these Functions are the same as the requirements for the Reactor Trip Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 18.a, (P-4 Reactor Trip Breakers), is referenced for all initiating Functions and requirements.

15.c. Battery Charger Input Voltage – Low

Block of boron dilution is also actuated from the loss of ac power. A short, preset time delay is provide to prevent actuation upon momentary power fluctuations; however, actuation occurs before ac power is restored by the onsite diesel generators. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. The loss of ac power

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signal is based on the detection of an undervoltage conditions by each of the two sensors connected to two of the four battery chargers. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, and 5. This Function is not applicable in MODES 4 and 5 if the associated flowpath is closed. In MODE 6, a dilution event is precluded by the requirement in LCO 3.9.2 to close, lock and secure at least one valve in each unborated water source flow path.

16. Chemical Volume and Control System Makeup Line Isolation

The CVS makeup line is isolated following certain events to prevent overfilling of the RCS. In addition, this line is isolated on High 2 containment radioactivity to provide containment isolation following an accident. This line is not isolated on a containment isolation signal, to allow the CVS makeup pumps to perform their defense-in-depth functions. However, if very high containment radioactivity exists (above the High 2 setpoint) this line is isolated.

A signal to isolate the CVS is derived from two-out-of-four high steam generator levels on either steam generator, two-out-of-four channels of pressurizer level indicating high or two-out-of-four channels of containment radioactivity indicating high. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure no single random failure will disable this trip Function.

16.a. Steam Generator Narrow Range Water Level – High 2

Four channels of steam generator level are provided for each steam generator. Two-out-of-four channels on either steam generator indicating level greater than the setpoint will close the isolation valves for the CVS. This Function prevents adding makeup water to the RCS during a SGTR. This Function is required to be OPERABLE in MODES 1, 2, 3, and 4 with the RCS not being cooled by the RNS. This Function is not applicable in MODES 3 and 4 if the CVS makeup flowpath is isolated. This Function is not required to be OPERABLE in MODES 5 and 6 because the RCS pressure and temperature are reduced and a steam generator tube rupture event is not credible.

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16.b. Pressurizer Water Level – High 1 Coincident with Safeguards Actuation

Four channels of pressurizer level are provided on the pressurizer. Two-out-of-four channels on indicating level greater than the High 1 setpoint coincident with a Safeguards Actuation signal (Function 1) will close the containment isolation valves for the CVS. This Function prevents the pressurizer level from reaching a level that could lead to water relief through the pressurizer safety valves during some DBAs. This Function is required to be OPERABLE in MODES 1, 2, and 3. This function is not required to be OPERABLE in MODES 4, 5, and 6, because it is not required to mitigate a DBA in these MODES. This Function is not applicable in MODE 3, if the CVS makeup flowpath is isolated.

16.c. Pressurizer Water Level – High 2

A signal to close the CVS isolation valves is generated on Pressurizer Water Level – High 2. This Function results from the coincidence of pressurizer level above the High 2 setpoint in any two of the four divisions. This Function is automatically blocked when the pressurizer pressure is below the P-11 permissive setpoint to permit pressurizer water solid conditions with the plant cold and to permit level makeup during plant cooldowns. This Function is automatically unblocked when RCS pressure is above the P-19 setpoint. This Function is required to be OPERABLE in MODES 1, 2, and 3 and in MODE 4 when the RCS is not being cooled by the RNS. This Function is not required to be OPERABLE in MODE 4 if the CVS makeup flowpath is isolated. This Function is not required to be OPERABLE in MODES 5 and 6 because it is not required to mitigate a DBA in these MODES.

16.d. Containment Radioactivity – High 2

Four channels of Containment Radioactivity – High 2 are required to be OPERABLE in MODES 1, 2, and 3 when the potential exists for a LOCA, to ensure that the radioactivity inside containment is not released to the atmosphere. This Function is not required to be OPERABLE in MODE 3 if the associated flowpath is isolated. This signal results from the coincidence of containment radioactivity above the High 2 Setpoint in any two of the four divisions. These Functions are

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not required to be OPERABLE in MODES 4, 5, and 6 because there is no credible release of radioactivity into the containment in these MODES that would result in a High 2 actuation.

16.e <u>Manual Initiation</u>

Manual Chemical Volume Control System Makeup Isolation is actuated by either of two switches in the main control room. Either switch closes Chemical Volume Control System Makeup valves. The LCO requires two switches to be OPERABLE.

17. <u>Normal Residual Heat Removal System Isolation</u>

The RNS suction line is isolated by closing the containment isolation valves on High 2 containment radioactivity to provide containment isolation following an accident. This line is isolated on a safeguards actuation signal. However, the valves may be reset to permit the RNS pumps to perform their defense-in-depth functions post-accident. Should a high containment radiation signal (above the High 2 setpoint) develop following the containment isolation signal, the RNS valves would re-close. A high containment radiation signal is indicative of a high RCS source term and the valves would re-close to assure offsite doses do not exceed regulatory limits.

17.a. <u>Containment Radioactivity – High 2</u>

A signal to isolate the normal residual heat removal system is generated from the coincidence of containment radioactivity above the High 2 setpoint in two-out-of-four channels. Four channels of Containment Radioactivity – High 2 are required to be OPERABLE in MODES 1, 2, and 3 when the potential exists for a LOCA, to ensure that the radioactivity inside containment is not released to the atmosphere. This Function is not required to be OPERABLE in MODE 3 if the RNS suction line is isolated. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because no DBA that could release radioactivity into the containment is considered credible in these MODES.

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17.b. Safeguards Actuation (Function 1)

This Function is also initiated by all Functions that initiated the Safeguards Actuation signal. The requirements to isolate the normal residual heat removal system are the same as the requirements for the Safeguards Actuation Function. Therefore, the requirements are not repeated in Table 3.3.2.1. Instead, Function 1 is referenced for all initiating Functions and requirements.

17.c Manual Initiation

The operator can initiate RNS isolation at any time from the control room by simultaneously actuating two switches in the same actuation set. Because an inadvertent actuation of RNS isolation could have serious consequences, two switches must be actuated simultaneously to initiate isolation. There are two sets of two switches in the control room. Simultaneously actuating the two switches in either set will isolate the RNS in the same manner as the automatic actuation signal. Two Manual Initiation switches in each set are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function.

18. ESFAS Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions backup manual actions to ensure bypassable Functions are in operation under the conditions assumed in the safety analyses.

18.a. Reactor Trip, P-4

There are eight reactor trip breakers with two breakers in each division. The P-4 interlock is enabled when the breakers in two-out-of-four divisions are open. Additionally, the

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

P-4 interlock is enabled by all Automatic Reactor Trip Actuations. The Functions of the P-4 interlock are:

- Trip the main turbine
- Permit the block of automatic Safeguards Actuation after a predetermined time interval following automatic Safeguards Actuation.
- Block boron dilution
- Isolate main feedwater coincident with low reactor coolant temperature (This function is not assumed in safety analysis therefore, it is not included in the technical specifications.)

The reactor trip breaker position switches that provide input to the P-4 interlock only Function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable Trip Setpoint.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 to trip the main turbine, because the main turbine is not in operation.

The P-4 Function does not have to be OPERABLE in MODE 4 or 5 to block boron dilution, because Function 15.a, Source Range Neutron Flux Multiplication, provides the required block. In MODE 6, the P-4 interlock with the Boron Dilution Block Function is not required, since the unborated water source flow path isolation valves are locked closed in accordance with LCO 3.9.2.

18.b. Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without Safeguards Actuation or main steam line and feedwater isolation. With pressurizer pressure channels less than the P-11 setpoint, the operator can manually block the Pressurizer pressure – Low, Steam Line Pressure – Low, and T_{cold} – Low Safeguards Actuation signals and the Steam Line Pressure – Low and T_{cold} – Low steam line

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

isolation signals. When the Steam Line Pressure – Low is manually blocked, a main steam isolation signal on Steam Line Pressure-Negative Rate – High is enabled. This provides protection for an SLB by closure of the main steam isolation valves. Manual block of feedwater isolation on T_{avg} – Low 1, Low 2, and T_{cold} – Low is also permitted below P-11. With pressurizer pressure channels ≥ P-11 setpoint, the Pressurizer Pressure – Low, Steam Line Pressure – Low, and T_{cold} – Low Safeguards Actuation signals and the Steam Line Pressure Low and T_{cold} – Low steam line isolation signals are automatically enabled. The feedwater isolation signals on T_{cold} – Low, T_{avg} – Low 1 and Low 2 are also automatically enabled above P-11. The operator can also enable these signals by use of the respective manual reset buttons. When the Steam Line Pressure – Low and T_{cold} – Low steam line isolation signals are enabled, the main steam isolation on Steam Line Pressure-Negative Rate – High is disabled. The Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the Safeguards Actuation or main steam or feedwater isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6, because plant pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

18.c. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when the respective NIS intermediate range channel goes approximately one decade above the minimum channel reading. Above the setpoint, the P-6 interlock allows a manual block of the flux multiplication actuation, permitting block of boron dilution. Normally, this Function is blocked by the main control room operator during reactor startup. This Function is required to be OPERABLE in MODE 2.

18.d. Pressurizer Level, P-12

The P-12 interlock is provided to permit midloop operation without core makeup tank actuation, IRWST actuation, reactor coolant pump trip, or purification line isolation. With pressurizer level channels less than the P-12 setpoint, the

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

operator can manually block low pressurizer level signal used for these actuations. Concurrent with blocking CMT actuation on low pressurizer level, IRWST actuation on Low 2 RCS hot leg level is enabled. When the pressurizer level is above the P-12 setpoint, the pressurizer level signal is automatically enabled and a confirmatory open signal is issued to the isolation valves on the CMT cold leg balance lines. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6.

18.e. <u>RCS Pressure, P-19</u>

The P-19 interlock is provided to permit water solid conditions (i.e., when the pressurizer water level is >[92]%) in lower MODES without automatic isolation of the CVS makeup pumps. With RCS pressure below the P-19 setpoint, the operator can manually block CVS isolation on High 2 pressurizer water level. When RCS pressure is above the P-19 setpoint, this Function is automatically unblocked. This Function is required to be OPERABLE IN MODES 1, 2, 3, and 4 with the RCS not being cooled by the RNS. When the RNS is cooled by the RNS, the RNS suction relief valve provides the required overpressure protection (LCO 3.4.14).

19. <u>Containment Air Filtration System Isolation</u>

Some DBAs such as a LOCA may release radioactivity into the containment where the potential would exist for the radioactivity to be released to the atmosphere and exceed the acceptable site dose limits. Isolation of the Containment Air Filtration System provides protection to prevent radioactivity inside containment from being released to the atmosphere.

19.a. <u>Containment Radioactivity – High 1</u>

Three channels of Containment Radioactivity – High 1 are required to be OPERABLE in MODES 1, 2, 3, and 4 with the RCS not being cooled by the RNS, when the potential exists for a LOCA, to protect against radioactivity inside containment being released to the atmosphere. These Functions are not required to be OPERABLE in MODE 4 with the RCS being cooled by the RNS or MODES 5 and 6, because any DBA release of radioactivity into the containment in these MODES would not require containment isolation.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

19.b. Containment Isolation (Function 3)

Containment Air Filtration System Isolation is also initiated by all Functions that initiate Containment Isolation. The Containment Air Filtration System Isolation requirements for these Functions are the same as the requirements for the Containment Isolation. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 3, Containment Isolation, is referenced for initiating Functions and requirements.

20. Main Control Room Isolation and Air Supply Initiation

Isolation of the main control room and initiation of the air supply provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity. This Function is required to be OPERABLE in MODES 1, 2, 3, and 4, and during movement of irradiated fuel because of the potential for a fission product release following a fuel handling accident, or other DBA.

20.a. Control Room Air Supply Radiation – High 2

Two radiation monitors are provided on the main control room air intake. If either monitor exceeds the High 2 setpoint, control room isolation is actuated.

20.b. Battery Charger Input Voltage – Low

Low input voltage to the 1E dc battery chargers will actuate main control room isolation and air supply initiation.

21. Auxiliary Spray and Purification Line Isolation

The CVS maintains the RCS fluid purity and activity level within acceptable limits. The CVS purification line receives flow from the discharge of the RCPs. The CVS also provides auxiliary spray to the pressurizer. To preserve the reactor coolant pressure in the event of a break in the CVS loop piping, the purification line and the auxiliary spray line is isolated on a pressurizer water level Low 1 setpoint. This helps maintain reactor coolant system inventory.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

21.a. Pressurizer Water Level – Low 1

A signal to isolate the purification line and the auxiliary spray line is generated upon the coincidence of pressurizer level below the Low 1 setpoint in any two-out-of-four divisions. This Function is required to be OPERABLE in MODES 1 and 2 to help maintain RCS inventory. In MODES 3, 4, 5, and 6, this Function is not needed for accident detection and mitigation.

21.b. Manual Chemical Volume Control System Makeup Isolation (Function 16.e)

The Auxiliary Spray and Purification Line Isolation is also initiated by the Manual Chemical Volume Control System Makeup Isolation Function. The requirements for this Function are the same as the requirements for Manual Chemical Volume Control System Makeup Isolation (Function 16.e), but only apply in MODES 1 and 2. Therefore, the requirements are not repeated in Table 3.3.2-1, and Function 16.e is referenced for all requirements.

22. IRWST Injection Line Valve Actuation

The PXS provides core cooling by gravity injection and recirculation for decay heat removal following an accident. The IRWST has two injection flow paths. Each injection path includes a normally open motor operated isolation valve and two parallel lines, each isolated by one check valve and one squib valve in series. Manual initiation or automatic actuation on an ADS Stage 4 actuation signal or a coincident RCS Loops 1 and 2 Hot Leg Level-Low will generate a signal to open the IRWST injection line and actuate IRWST injection.

22.a. Manual Initiation

The operator can open IRWST injection line valves at any time from the main control room by actuating two IRWST injection actuation switches in the same actuation set. There are two sets of two switches each in the main control room. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

22.b. ADS Stage 4 Actuation (Function 10)

An open signal will be issued to the IRWST injection isolation valves when an actuation signal is issued to the ADS Stage 4 valves. The requirements for this function are the same as the requirements for the ADS Stage 4 Actuation Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 10 is referenced for all initiating functions and requirements.

22.c. Coincident RCS Loops 1 and 2 Hot Leg Level – Low

A signal to automatically open the IRWST injection line valves is also generated when coincident loops 1 and 2 reactor coolant system hot leg level indication decreases below an established setpoint for a duration exceeding an adjustable time delay. This Function is required to be OPERABLE in MODE 4 with the RCS being cooled by the RNS. This Function is also required to be OPERABLE in MODES 5 and 6.

23. IRWST Containment Recirculation Valve Actuation

The PXS provides core cooling by gravity injection and recirculation for decay heat removal following an accident. The PXS has two containment recirculation flow paths. Each path contains two parallel flow paths, one path is isolated by a motor operated valve in series with a squib valve and one path is isolated by a check valve in series with a squib valve. Manual initiation or automatic actuation on a Safeguards Actuation signal coincident with a Low 3 level signal in the IRWST will open these valves.

23.a. Manual Initiation

The operator can open the containment recirculation valves at any time from the main control room by actuating two containment recirculation actuation switches in the same actuation set. There are two sets of two switches each in the main control room. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6.

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

23.b. ADS Stage 4 Actuation Coincident with IRWST Level – Low 3

A low IRWST level coincident with a ADS Stage 4 Actuation signal will open the containment recirculation valves. Four channels are provided to permit one channel to be in trip or bypass indefinitely and still ensure that no single random failure will disable this trip Function. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6, except when the ADS Stage 4 valves are open or an equivalent relief area is open. The required ADS valves or equivalent relief area are specified in LCO 3.4.12, ADS – Shutdown, RCS Intact and LCO 3.4.13, ADS – Shutdown, RCS Open.

24. Refueling Cavity Isolation

The containment isolation valves in the lines between the refueling cavity and the Spent Fuel Pool Cooling System are isolated on a Low spent fuel pool level.

24.a. Spent Fuel Pool Level – Low

In the event of a leak in the non-safety Spent Fuel Pool Cooling System, closure of the containment isolation valves on low spent fuel pool level in two of three channels will terminate draining of the refueling cavity. Since the transfer canal is open in MODE 6, the spent fuel pool level is the same as the refueling cavity.

Draining of the spent fuel pool, directly, through a leaking Spent Fuel Pool Cooling System is limited by the location of the suction piping, which is near the top of the pool. Therefore, closure of the containment isolation valves between the refueling cavity and the Spent Fuel Pool Cooling System is sufficient to terminate refueling cavity and spent fuel pool leakage through the Spent Fuel Pool Cooling System. This Function is required in MODE 6 to maintain water inventory in the refueling cavity.

25. ESF Logic

This LCO requires four sets of ESF coincidence logic, each set with one battery backed logic group OPERABLE to support automatic actuation. These logic groups are implemented as processor based actuation subsystems. The ESF coincidence logic provides the system level logic interfaces for the divisions.

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

25.a. Coincidence Logic

If one division of battery backed coincidence logic is OPERABLE, an additional single failure will not prevent ESF actuations because three divisions will still be available to provide redundant actuation for all ESF Functions. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6.

26. ESF Actuation

This LCO requires that for each division of ESF actuation, one battery backed logic group be OPERABLE to support both automatic and manual actuation. The ESF actuation subsystems provide the logic and power interfaces for the actuated components.

26.a. Actuation Subsystem

If one battery backed logic group is OPERABLE for the ESF actuation subsystem in all four divisions, an additional single failure will not prevent ESF actuations because ESF actuation subsystems in the other three divisions are still available to provide redundant actuation for ESF Functions. The remaining cabinets in the division with a failed ESF actuation cabinet are still OPERABLE and will provide their ESF Functions. This Function is required to be OPERABLE in MODES 1, 2, 3, 4, 5, and 6.

The ESFAS instrumentation satisfies Criterion 3 of the 10 CFR 50.36(c)(2)(ii).

27. Pressurizer Heater Trip

Pressurizer heaters are automatically tripped upon receipt of a core makeup tank operation signal or a Pressurizer Water Level – High 3 signal. This pressurizer heater trip reduces the potential for steam generator overfill and automatic ADS Stages 1, 2, and 3 actuation for a steam generator tube rupture event. Automatically tripping the pressurizer heaters reduces the pressurizer level swell for certain non-LOCA events such as loss of normal feedwater, inadvertent CMT operation, and CVS malfunction resulting in an increase in RCS inventory. For small break LOCA analysis, tripping the pressurizer heaters supports depressurization of the RCS following actuation of the CMTs.

APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

27.a. CMT Actuation (Function 2)

A signal to trip the pressurizer heaters is generated on a CMT actuation signal. The requirements for this function are the same as the requirements for the CMT Actuation Function, except this function is only required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the RCS is not being cooled by the RNS and above the P-19 (RCS pressure) interlock. Therefore, the requirements are not repeated in Table 3.3.2.1. Instead, Function 2 is referenced for initiating Functions and requirements and SR 3.3.2.9 also applies.

27.b. Pressurizer Water Level – High 3

A signal to trip the pressurizer heaters is generated when the pressurizer water level reaches its High 3 setpoint. This signal provides protection against a pressurizer overfill following an inadvertent core makeup tank actuation with consequential loss of offsite power. This Function is automatically unblocked when RCS pressure is above the P-19 setpoint. This Function is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the RCS is not being cooled by the RNS and above the P-19 (RCS pressure) interlock. This Function is not required to be OPERABLE in MODES 5 and 6 because it is not required to mitigate DBA in these MODES.

28. Chemical and Volume Control System Letdown Isolation

The CVS provides letdown to the liquid radwaste system to maintain the pressurizer level. To help maintain RCS inventory in the event of a LOCA, the CVS letdown line is isolated on a Low 1 hot leg level signal in either of the RCS hot leg loops. This Function is required to be OPERABLE in MODE 4 with the RCS being cooled by the RNS. This Function is also required to be OPERABLE in MODE 5, and in MODE 6 with the water level < 23 feet above the top of the reactor vessel flange.

28.a. Hot Leg Level – Low 1

A signal to isolate the CVS letdown valves is generated upon the occurrence of a Low 1 hot leg level in either of the two RCS hot leg loops. This helps to maintain reactor system inventory in the event of a LOCA. These letdown valves are

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APPLICABLE SAFETY ANALYSES, LCOs, and APPLICABILITY (continued)

also closed by all of the initiating Functions and requirements that generate the Containment Isolation Function in Function 3.

29. SG Power Operated Relief Valve and Block Valve Isolation

The Function of the SG Power Operated Relief Valve and Block Valve Isolation is to ensure that the SG PORV flow paths can be isolated during a SG tube rupture (SGTR) event. The PORV flow paths must be isolated following a SGTR to minimize radiological releases from the ruptured steam generator into the atmosphere. The PORV flow path is assumed to open due to high secondary side pressure, during the SGTR. Dose analyses take credit for subsequent isolation of the PORV flow path by the PORV and/or the block valve which receive a close signal on low steam line pressure. Additionally, the PORV flow path can be isolated manually.

This Function is required to be OPERABLE in MODES 1, 2, 3, and 4 with the RCS cooling not being provided by the Normal Residual Heat Removal System (RNS). In MODE 4 with the RCS cooling being provided by the RNS and in MODES 5 and 6, the steam generators are not being used for RCS cooling and the potential for a SGTR is minimized due to the reduced mass and energy in the RCS and steam generators.

29.a. Manual Initiation

Manual initiation of SG Power Operated Relief Valve and Block Valve Isolation can be accomplished from the control room. There are two switches in the control room and either switch can close the SG PORVs and PORV block valves. The LCO requires two switches to be OPERABLE.

29.b. Steam Line Pressure – Low

Steam Line Pressure – Low provides closure of the PORV flow paths in the event of SGTR in which the PORV(s) open, to limit the radiological releases from the ruptured steam generator into the atmosphere.

This Function is anticipatory in nature and has a typical leading/lag ratio of 50/5.

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The LCO requires four channels of Steam Line Pressure – Low Function to be OPERABLE in MODES 1, 2, 3, and 4 with the RCS cooling not being provided by the RNS. Four channels are provided in each steam line to permit one channel to be in trip or bypass indefinitely and still ensure that no single random failure will disable this Function.

ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this specification may be entered independently for each Function listed on Table 3.3.2-1. The Completion Time(s) of the inoperable equipment of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A second Note has been added to provide clarification that, more than one Condition is listed for each of the Functions in Table 3.3.2-1. If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the second Condition shall be entered.

In the event a channel's Nominal Trip Setpoint is not met, or the transmitter, or the Protection and Safety Monitoring System Division, associated with a specific Function is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the particular protection Function(s) affected. When the Required Channels are specified only on a per steam line, per loop, per SG, basis, then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 in MODES 1 through 4 and LCO 3.0.8 for MODE 5 and 6 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A is applicable to all ESFAS protection Functions. Condition A addresses the situation where one or more channels/divisions for one or more functions are inoperable at the same time. The Required Action is

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to refer to Table 3.3.2-1 and to take the Required Actions for the protection Functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

With one or two channels or divisions inoperable, one affected channel or division must be placed in a bypass or trip condition within [6] hours. If one channel or division is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels or divisions will not prevent the protective function.) If one channel or division is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels or divisions will not prevent the protective function.) If one channel or division is bypassed and one channel or division is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) or division(s) in the bypassed or tripped condition is justified in Reference [6].

C.1

With one channel inoperable, the affected channel must be placed in a bypass condition within [6] hours. The [6] hours allowed to place the inoperable channel in the bypass condition is justified in Reference [6]. If one CVS isolation channel is bypassed, the logic becomes one-out-of-one. A single failure in the remaining channel could cause a spurious CVS isolation. Spurious CVS isolation, while undesirable, would not cause an upset plant condition.

D.1

With one required division inoperable, the affected division must be restored to OPERABLE status within 6 hours.

Condition D applies to one inoperable required division of P-4 Interlock (Function 18.a). With one required division inoperable, the 2 remaining OPERABLE divisions are capable of providing the required interlock function, but without a single failure. The P-4 Interlock is enabled when RTBs in two divisions are detected as open. The status of the other inoperable, non-required P-4 division is not significant, since P-4 divisions can not be tripped or bypassed. In order to provide single failure tolerance, 3 required divisions must be OPERABLE.

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Condition D also applies to one inoperable division of ESF coincidence logic or ESF actuation (Functions 25 and 26). The ESF coincidence logic and ESF actuation divisions are inoperable when their associated battery-backed subsystem is inoperable. With one inoperable division, the 3 remaining OPERABLE divisions are capable of mitigating all DBAs, but without a single failure.

The 6 hours allowed to restore the inoperable division is reasonable based on the capability of the remaining OPERABLE divisions to mitigate all DBAs and the low probability of an event occurring during this interval.

E.1

Condition E is applicable to manual initiation of:

- Safeguards Actuation;
- CMT Actuation;
- Containment Isolation;
- Steam Line Isolation;
- Main Feedwater Control Valve Isolation;
- Main Feedwater Pump Trip and Valve Isolation;
- ADS Stages 1, 2, & 3 Actuation;
- ADS Stage 4 Actuation;
- Passive Containment Cooling Actuation;
- PRHR Heat Exchanger Actuation;
- IRWST Injection Line Valve Actuation;
- IRWST Containment Recirculation Valve Actuation.

This Action addresses the inoperability of the system level manual initiation capability for the ESF Functions listed above. With one switch or switch set inoperable for one or more Functions, the system level manual initiation capability is reduced below that required to meet single failure criterion. Required Action E.1 requires the switch or switch set for

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system level manual initiation to be restored to OPERABLE status within 48 hours. The specified Completion Time is reasonable considering that the remaining switch or switch set is capable of performing the safety function.

F.1, F.2.1, and F.2.2

Condition F is applicable to the Main Control Room (MCR) isolation and air supply initiation function which has only two channels of the initiating process variable. With one channel inoperable, the logic becomes one-out-of-one and is unable to meet single failure criterion. Restoring all channels to OPERABLE status ensures that a single failure will not prevent the protective Function.

Alternatively, radiation monitor(s) which provide equivalent information and control room isolation and air supply initiation manual controls may be verified to be OPERABLE. These provisions for operator action can replace one channel of radiation detection and system actuation. The 72 hour Completion Time is reasonable considering that there is one remaining channel OPERABLE and the low probability of an event occurring during this interval.

G.1

With one switch, switch set, channel, or division inoperable, the system level initiation capability is reduced below that required to meet single failure criterion. Therefore, the required switch, switch set, channel, and division must be returned to OPERABLE status within 72 hours. The specified Completion Time is reasonable considering the remaining switch, switch set, channel, or division is capable of performing manual initiation.

H.1

With one channel inoperable, the inoperable channel must be placed in a trip condition within 6 hours.

Condition H is applicable to the PRHR heat exchangers actuation on SG Narrow Range Water Level Low coincident with Startup Feedwater Flow Low (Function 13.b). With one startup feedwater channel inoperable, the inoperable channel must be placed in a trip condition within 6 hours. If one channel is tripped, the interlock condition is satisfied. Condition H is also applicable to Refueling Cavity Isolation (Function 24.a). With one of the three spent fuel pool level channels

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inoperable, the inoperable channel must be placed in a trip condition within 6 hours. If one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The specified Completion Time is reasonable considering the time required to complete this action.

I.1 and I.2

Condition I applies to IRWST containment recirculation valve actuation on safeguards actuation coincident with IRWST Level Low 3 (Function 23.b). With one or two channels inoperable, one affected channel must be placed in a bypass or trip condition within [6] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is bypassed and one channel is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [6] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [6].

J.1 and J.2

Condition J applies to the P-6, P-11, P-12, and P-19 interlocks. With one or two required channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour, or any Function channels associated with inoperable interlocks placed in a bypassed condition within [7] hours. Verifying the interlock state manually accomplishes the interlock role.

If one interlock channel is inoperable, the associated Function(s) must be placed in a bypass or trip condition within [7] hours. If one channel is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.) If one channel is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels will not prevent the protective function.)

If two interlock channels are inoperable, one channel of the associated Function(s) must be bypassed and one channel of the associated

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Function(s) must be tripped. In this state, the logic becomes one-out-of-two, while still meeting the single failure criterion. The [7] hours allowed to place the inoperable channel(s) in the bypassed or tripped condition is justified in Reference [6].

K.1

LCO 3.08 is applicable while in MODE 5 or 6. Since irradiated fuel assembly movement can occur in MODE 5 or 6, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, the fuel movement is independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

Condition K is applicable to the MCR Isolation and Air Supply Initiation (Function 20), during movement of irradiated fuel assemblies. If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must suspend movement of the irradiated fuel assemblies immediately. The required action suspends activities with potential for releasing radioactivity that might enter the MCR. This action does not preclude the movement of fuel to a safe position.

L.1

If the required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a MODE in which the LCO does not apply. This accomplished by placing the plant in MODE 3 within 6 hours. The allowed time is reasonable, based operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

M.1 and M.2

If the Required Action and associated Completion Time of the first condition listed in Table 3.3.2-1 is not met, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

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N.1 and N.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 4 with the RCS being cooled by the RNS within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

O.1 and O.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

P.1, P.2.1, and P.2.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 cannot be met, the plant must be placed in a condition where the instrumentation Function for valve isolation is no longer needed. This is accomplished by isolating the affected flow path(s) within 24 hours. By isolating the flow path from the demineralized water storage tank to the RCS, the need for automatic isolation is eliminated.

To assure that the flow path remains closed, the flow path shall be isolated by the use of one of the specified means (P.2.1) or the flow path shall be verified to be isolated (P.2.2). A means of isolating the affected flow path(s) includes at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured within 7 days. If one of the P.2.1 specified isolation means is not used, the affected flow path shall be verified to be isolated once per 7 days.

This action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the

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ACTIONS (continued)

valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

Q.1, Q.2.1, and Q.2.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a condition where the instrumentation Function for valve isolation is no longer needed. This is accomplished by isolating the affected flow path by the use of at least one closed manual or closed and deactivated automatic valve within 6 hours.

If the flow path is not isolated within 6 hours the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 within 18 hours.

This action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

R.1, R.2.1.1, R.2.1.2, and R.2.2

If the Required Action and associated Completion Time of the first Condition given in Table 3.3.2-1 is not met the plant must be placed in a condition in which the likelihood and consequences of an event are minimized. This is accomplished by placing the plant in MODE 3 within 6 hours and isolating the affected flow path(s) within 12 hours. To assure that the flow path remains closed, the affected flow path shall be verified to be isolated once per 7 days.

If the flow path is not isolated within 12 hours the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 4 with the RCS cooling provided by the RNS within 30 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

This action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the

ACTIONS (continued)

valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

S.1, S.2.1.1, S.2.1.2, S.2.1.3, and S.2.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a condition in which the likelihood and consequences of an event are minimized. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 4 with the RCS cooling provided by the RNS within 24 hours. Once the plant has been placed in MODE 4 the affected flow path must be isolated within 30 hours. To assure that the flow path remains closed, the affected flow path shall be verified to be isolated once per 7 days.

If the flow path is not isolated within 12 hours, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 5 within 42 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

This action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

T.1.1, T.1.2.1, T.1.2.2, T.2.1, and T.2.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a Condition in which the likelihood and consequences of an event are minimized. This is accomplished by isolating the affected flow path within 6 hours and isolating the affected flow path(s) by the use of at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured within 7 days or verify the affected flow path is isolated once per 7 days.

If the flow path is not isolated within 6 hours the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 5 within 42 hours.

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ACTIONS (continued)

The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

This action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

U.1 and U.2

If the Required Action and the associated Completion Time of the first Condition given in Table 3.3.2-1 is not met, and the required switch or switch set is not restored to OPERABLE status within 48 hours, the plant must be placed in a condition in which the likelihood and consequences of an event are minimized. This is accomplished by placing the plant in MODE 5 within 12 hours. Once in MODE 5, action shall be immediately initiated to open the RCS pressure boundary and establish ≥ 20% pressurizer level. The 12 hour Completion Time is a reasonable time to reach MODE 5 from MODE 4 with RCS cooling provided by the RNS (approximately 350°F) in an orderly manner without challenging plant systems. Opening the RCS pressure boundary assures that cooling water can be injected without ADS operation. Filling the RCS to provide ≥ 20% pressurizer level minimizes the consequences of a loss of decay heat removal event.

V.1, V.2.1, and V.2.2

If the Required Action and the associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met and the required channel(s) is not bypassed within 6 hours, the inoperable channel(s) must be restored within 168 hours. The 168 hour Completion Time is based on the ability of the two remaining OPERABLE channels to provide the protective Function even with a single failure.

If the channel(s) is not restored within the 168 hour Completion Time, the plant shall be placed in a condition in which the likelihood and consequences of an event are minimized. This is accomplished by placing the plant in MODE 5 within 180 hours (the next 12 hours). Once in MODE 5, action shall be initiated to open the RCS pressure boundary and establish ≥ 20% pressurizer level. The 12 hours is a reasonable time

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to reach MODE 5 from MODE 4 with RCS cooling provided by the RNS (approximately 350°F) in an orderly manner without challenging plant systems.

Opening the RCS pressure boundary assures that cooling water can be injected without ADS operation. Filling the RCS to provide ≥ 20% pressurizer level minimizes the consequences of a loss of decay heat removal event.

W.1, W.2, W.3, and W.4

If the Required Action and the associated Completion Time listed in Table 3.3.2-1 is not met while in MODES 5 and 6, the plant must be placed in a MODE in which the likelihood and consequences of an event are minimized. This is accomplished by immediately initiating action to be in MODE 5 with the RCS open and ≥ 20% pressurizer level or to be in MODE 6 with the upper internals removed. The flow path from the demineralized water storage tank to the RCS shall also be isolated by the used of at least one closed and de-activated automatic valve or closed manual valve. These requirements minimize the consequences of the loss of decay heat removal by maximizing RCS inventory and maintaining RCS temperature as low as practical. Additionally, the potential for a criticality event is minimized by isolation of the demineralized water storage tank and by suspension of positive reactivity additions.

X.1, X.2, and X.3

If the Required Action and the associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met while in MODES 5 and 6, the plant must be placed in a MODE in which the likelihood and consequences of an event are minimized. This is accomplished by immediately initiating action to be in MODE 5 with the RCS open and ≥ 20% pressurizer level or to be in MODE 6 with the upper internals removed. These requirements minimize the consequences of the loss of decay heat removal by maximizing RCS inventory and maintaining RCS temperature as low as practical. Additionally, the potential for a criticality event is minimized by suspension of positive reactivity additions.

Y.1, Y.2, Y.3, and Y.4

If the Required Action and the associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met while in MODE 4, with RCS cooling provided by the RNS, MODE 5, or MODE 6, the plant must be placed in a MODE in which the likelihood and consequences of an event

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ACTIONS (continued)

are minimized. If in MODE 4, this is accomplished by placing the plant in MODE 5 within 12 hours. The 12 hours is a reasonable time to reach MODE 5 from MODE 4 with RCS cooling provided by the RNS (approximately 350°F) in an orderly manner without challenging plant systems.

If in MODE 4 or 5, Required Action Y.3 requires initiation of action within 12 hours to close the RCS pressure boundary and establish ≥ 20% pressurizer level. The 12 hour Completion Time allows transition to MODE 5 in accordance with Y.2, if needed, prior to initiating action to open the RCS pressure boundary.

If in MODE 6, Required Action Y.4 requires the plant to be maintained in MODE 6 and initiation of action to establish the reactor cavity water level ≥ 23 feet above the top of the reactor vessel flange.

Required Actions Y.2, Y.3, and Y.4 minimize the consequences of a loss of decay heat removal event by optimizing conditions for RCS cooling in MODE 5 using the PRHR HX or in MODE 6 using IRWST injection. Additionally, maximizing RCS inventory and maintaining RCS temperature as low as practical further minimize the consequences of a loss of decay heat removal event. Closing the RCS pressure boundary in MODE 5 assures that PRHR HX cooling is available. Additionally, the potential for a criticality event is minimized by suspension of positive reactivity additions.

Z.1, Z.2.1, and Z.2.2

If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the plant must be placed in a condition where the instrumentation Function for valve isolation is no longer needed. This is accomplished by isolating the affected flow path by the use of at least one closed manual or closed and deactivated automatic valve within 6 hours.

If the flow path is not isolated within 6 hours, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 with RCS cooling provided by the RNS within 30 hours.

This Action is modified by a Note allowing the flow path(s) to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the

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ACTIONS (continued)

valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

AA.1.1, AA.1.2.1, AA1.2.2, AA.2.1, AA.2.2, and AA.2.3

If the Required Action and associated Completion Time of the first condition listed in Table 3.3.2-1 is not met, the plant must be placed in a condition where the instrumentation Function for valve isolation is no longer needed. This is accomplished by isolating the affected flow path within 24 hours. By isolating the CVS letdown flow path from the RCS, the need for automatic isolation is eliminated.

To assure that the flow path remains closed, the flow path shall be isolated by the use of one of the specified means (AA.1.2.1) or the flow path shall be verified to be isolated (AA.1.2.2). A means of isolating the affected flow path includes at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured, within 7 days. If one of the P.2.1 specified isolation means is not used, the affected flow path shall be verified to be isolated once per 7 days.

This action is modified by a Note allowing the flow path to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way the flow path can be rapidly isolated when a need for flow path isolation is indicated.

If the flow path cannot be isolated in accordance with Required Actions AA.1.1, AA.1.2.1 and AA.1.2.2, the plant must be placed in a MODE in which the likelihood and consequences of an event are minimized. If in MODE 4, this is accomplished by placing the plant in MODE 5 within 12 hours. The 12 hours is a reasonable time to reach MODE 5 from MODE 4 with RCS cooling provided by the RNS (approximately 350°F) in an orderly manner without challenging plant systems.

If in MODE 4 or 5, Required Action AA.2.2 requires initiation of action, within 12 hours, to establish > 20% pressurizer level. The 12 hour Completion Time allows transition to MODE 5 in accordance with AA.2.1, if needed, prior to initiating action to establish the pressurizer level.

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ACTIONS (continued)

If in MODE 6, Required Action AA.2.3 requires the plant to be maintained in MODE 6 and initiation of action to establish the reactor cavity water level ≥ 23 feet above the top of the reactor vessel flange.

Required Actions AA.2.2 and AA.2.3 minimize the consequences of an event by optimizing conditions for RCS cooling in MODE 5 using the PRHR HX or in MODE 6 using IRWST injection.

BB.1 and BB.2

With one channel inoperable, the inoperable channel must be placed in bypass and the hot leg level continuously monitored.

If one channel is placed in bypass, automatic actuation will not occur. Continuous monitoring of the hot leg level provides sufficient information to permit timely operator action to ensure that IRWST injection and ADS Stage 4 actuation can occur, if needed to mitigate events requiring RCS makeup, boration, or core cooling. Operator action to manually initiate IRWST injection and ADS Stage 4 actuation is assumed in the analysis of shutdown events (Reference 11). It is also credited in the shutdown PRA (Reference 12) when automatic actuation is not available.

SURVEILLANCE REQUIREMENTS

The Surveillance Requirements for each ESF Function are identified by the Surveillance Requirements column of Table 3.3.2-1. A Note has been added to the Surveillance Requirement table to clarify that Table 3.3.2-1 determines which Surveillance Requirements apply to which ESF Functions.

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or even something more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the match criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is based on operating experience that demonstrates channel failure is rare. Automated operator aids may be used to facilitate performance of the CHANNEL CHECK.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. This test, in conjunction with the ACTUATION DEVICE TEST, demonstrates that the actuated device responds to a simulated actuation signal. The ESF coincidence logic and ESF actuation subsystems within a division are tested every 92 days on a STAGGERED TEST BASIS.

A test subsystem is provided with the protection and safety monitoring system to aid the plant staff in performing the ACTUATION LOGIC TEST. The test subsystem is designed to allow for complete functional testing by using a combination of system self-checking features, functional testing features, and other testing features. Successful functional testing consists of verifying that the capability of the system to perform the safety function has not failed or degraded.

For hardware functions this would involve verifying that the hardware components and connections have not failed or degraded. Generally this verification includes a comparison of the outputs from two or more redundant subsystems or channels.

Since software does not degrade, software functional testing involves verifying that the software code has not changed and that the software code is executing.

To the extent possible, protection and safety monitoring system functional testing is accomplished with continuous system self-checking features and the continuous functional testing features. The ACTUATION LOGIC TEST shall include a review of the operation of the test subsystem to verify the completeness and adequacy of the results.

If the ACTUATION LOGIC TEST can not be completed using the built-in test subsystem, either because of failures in the test subsystem or failures in redundant channel hardware used for functional testing, the ACTUATION LOGIC TEST can be performed using portable test equipment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of every 92 days on a STAGGERED TEST BASIS provides a complete test of all four divisions once per year. This frequency is adequate based on the inherent high reliability of the solid state devices which comprise this equipment; the additional reliability provided by the redundant subsystems; and the use of continuous diagnostic test features, such as deadman timers, memory checks, numeric coprocessor checks, cross-check of redundant subsystems, and tests of timers, counters, and crystal time basis, which will report a failure within these cabinets to the operator.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a TADOT of the manual actuations, initiations, and blocks for various ESF Functions, the Class 1E battery charger undervoltage inputs, and the reactor trip (P-4) input from the IPCs. This TADOT is performed every 24 months.

The Frequency is based on the known reliability of the ESF Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The setpoints for the Class 1E battery charger undervoltage relays require bench calibration and are verified during CHANNEL CALIBRATION. The other functions have no setpoints associated with them.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a CHANNEL CALIBRATION every 24 months or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor and the IPC.

The Frequency is based on operating experience and consistency with the refueling cycle.

This Surveillance Requirement is modified by a Note. The Note states that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.2.5

SR 3.3.2.5 is the performance of an CHANNEL OPERATIONAL TEST (COT) every [92] days.

SURVEILLANCE REQUIREMENTS (continued)

A COT is performed on each required channel to provide reasonable assurance that the entire channel will perform the intended ESF Function.

A test subsystem is provided with the protection and safety monitoring system to aid the plant staff in performing the COT. The test subsystem is designed to allow for complete functional testing by using a combination of system self-checking features, functional testing features, and other testing features. Successful functional testing consists of verifying that the capability of the system to perform the safety function has not failed or degraded.

For hardware functions this would involve verifying that the hardware components and connections have not failed or degraded. Generally this verification includes a comparison of the outputs from two or more redundant subsystems or channels.

Since software does not degrade, software functional testing involves verifying that the software code has not changed and that the software code is executing.

To the extent possible, protection and safety monitoring system functional testing is accomplished with continuous system self-checking features and the continuous functional testing features. The COT shall include a review of the operation of the test subsystem to verify the completeness and adequacy of the results.

If the COT can not be completed using the built-in test subsystem, either because of failures in the test subsystem or failures in redundant channel hardware used for functional testing, the COT can be performed using portable test equipment.

The [92]-day Frequency is based on Reference 6 and the use of continuous diagnostic test features, such as deadman timers, cross-check of redundant channels, memory checks, numeric coprocessor checks, and tests of timers, counters and crystal time bases, which will report a failure within the integrated protection cabinets to the operator.

During the COT, the protection and safety monitoring system cabinets in the division under test may be placed in bypass.

<u>SR 3.3.2.6</u>

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis.

SURVEILLANCE REQUIREMENTS (continued)

Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment reaches the required functional state (e.g., valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate Chapter 7 (Ref. 2) response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements” (Ref. 11), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

ESF RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. Testing of the devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of an ACTUATION DEVICE TEST. This test, in conjunction with the ACTUATION LOGIC TEST, demonstrates that the actuated device responds to a simulated actuation signal. This Surveillance Requirement is applicable to the equipment which is actuated by the Protection Logic Cabinets except squib valves. The OPERABILITY of the actuated equipment is checked by exercising the equipment on an individual basis.

The Frequency of 24 months is based on the need to perform this surveillance during periods in which the plant is shutdown for refueling to prevent any upsets of plant operation.

This Surveillance Requirement is modified by a Note that states that actuated equipment, that is included in the Inservice Test (IST) Program, is exempt from this surveillance. The IST Program provides for exercising of the safety related valves on a more frequent basis. The results from the IST Program can therefore be used to verify OPERABILITY of the final actuated equipment.

SR 3.3.2.8

SR 3.3.2.8 is the performance of an ACTUATION DEVICE TEST, similar to that performed in SR 3.3.2.7, except this Surveillance Requirement is specifically applicable to squib valves. This test, in conjunction with the ACTUATION LOGIC TEST, demonstrates that the actuated device responds to a simulated actuation signal. The OPERABILITY of the squib valves is checked by performing a continuity check of the circuit from the Protection Logic Cabinets to the squib valve.

The Frequency of 24 months is based on the need to perform this surveillance during periods in which the plant is shutdown for refueling to prevent any additional risks associated with inadvertent operation of the squib valves.

SR 3.3.2.9

SR 3.3.2.9 is the performance of an ACTUATION DEVICE TEST. This test, in conjunction with the ACTUATION LOGIC TEST, demonstrates that the actuated device responds to a simulated actuation signal. This Surveillance Requirement is applicable to the circuit breakers which de-energize the power to the pressurizer heaters upon a pressurizer heater trip. The OPERABILITY of these breakers is checked by opening these breakers using the Plant Control System.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 24 months is based on the need to perform this surveillance during periods in which the plant is shutdown for refueling to prevent any upsets of plant operation. This Frequency is adequate based on the use of multiple circuit breakers to prevent the failure of any single circuit breaker from disabling the function and that all circuit breakers are tested.

REFERENCES

1. Chapter 6, “Engineered Safety Features.”

2. Chapter 7, “Instrumentation and Controls.”

3. Chapter 15, “Accident Analysis.”

4. Institute of Electrical and Electronic Engineers, IEEE-603-1991, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations,” June 27, 1991.

5. 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

[6. WCAP-10271-P-A (Proprietary) and WCAP-10272-A (Non-Proprietary), Supplement 2, Rev. 1, “Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System,” dated June 1990.]

7. 10 CFR 50, Appendix A, “General Design Criteria for Nuclear Power Plants.”

8. NUREG-1218, “Regulatory Analysis for Resolution of USI A-47,” 4/88.

9. WCAP-14606, “Westinghouse Setpoint Methodology for Protection Systems,” April 1996 (nonproprietary).

10. ESBU-TB-97-01, Westinghouse Technical Bulletin, “Digital Process Rack Operability Determination Criteria,” May 1, 1997.

11. WCAP-13632-P-A (Proprietary) and WCAP-13787-A (Non-Proprietary), Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” January 1996.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM Instrumentation is to display unit variables that provide information required by the main control room operators during accident situations. These plant variables provide the necessary information to assess the process of accomplishing or maintaining critical safety functions. The instruments which monitor these variables are designated in accordance with Reference 1.

The OPERABILITY of the PAM Instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

A PAM CHANNEL shall extend from the sensor up to the display device, and shall include the sensor (or sensors), the signal conditioning, any associated datalinks, the display device, any signal gathering or processing subsystems, and any data processing subsystems. Note that for digital PAM CHANNELs, the information may be displayed on multiple display devices. For this case, the PAM CHANNEL shall extend to any available qualified display device.

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category 1 variables. The unit specific implementation of Regulatory Guide 1.97 has not identified any Type A variables, therefore, only Category 1 variables are specified.

APPLICABLE SAFETY ANALYSES

The PAM Instrumentation ensures that the main control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM Instrumentation that is required in accordance with Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for those monitors which provide information required by the control room operators to assess the process of accomplishing or maintaining critical safety functions. This LCO addresses those Regulatory Guide 1.97 instruments which are listed in Table 3.3.3-1.

The OPERABILITY of the PAM Instrumentation ensures there is sufficient information available on selected plant parameters to monitor and assess plant status following an accident. This capability is consistent with the recommendations of Reference 1.

Category 1 non-type A variables are required to meet Regulatory Guide 1.97 Category 1 (Ref. 1) design and qualification requirements for seismic and environmental qualification, single-failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument functions listed in Table 3.3.3-1. Each of these is a Category 1 variable.

1. <u>Intermediate Range Neutron Flux</u>

   Neutron Flux indication is provided to verify reactor shutdown. The neutron flux intermediate range is sufficient to cover the full range of flux that may occur post accident.

   Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

2, 3. <u>Reactor Coolant System (RCS) Wide Range Hot and Cold Leg Temperature</u>

   RCS Hot and Cold Leg Temperatures are provided for verification of core cooling and long-term surveillance. The channels provide indication over a range of [50]°F to [700]°F.

   In addition to this, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the plant conditions necessary to establish natural circulation in the RCS.

BASES

LCO (continued)

4. <u>RCS Pressure</u>

RCS wide range pressure is provided for verification of core cooling and RCS integrity long term surveillance.

5. <u>Pressurizer Pressure and RCS Subcooling Monitor</u>

Pressurizer Pressure is used to determine RCS Subcooling. The RCS Subcooling Monitor is provided for verification of core cooling. Subcooling margin is available when the RCS pressure is greater than the saturation pressure corresponding to the core exit temperature. Inputs to the Subcooling Monitor are pressurizer pressure and RCS hot leg temperature.

6. <u>Containment Water Level</u>

Containment Water Level is used to monitor the containment environment during accident conditions. The containment water level can also provide information to the operators that the various stages of safety injection along with system depressurization are progressing.

7. <u>Containment Pressure</u>

The containment pressure transmitters monitor the containment pressure over the range of [-5] to [10] psig. This provides information on post accident containment pressure and containment integrity.

8. <u>Containment Pressure (Extended Range)</u>

The extended range containment pressure transmitters are instruments that operators use for monitoring the potential for breach of containment, a fission product barrier. The extended range sensors monitor containment pressure over the range of [0] to [240] psig.

9. <u>Containment Area Radiation (High Range)</u>

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

BASES

LCO (continued)

10. Pressurizer Level and Associated Reference Leg Temperature

Pressurizer level is provided to monitor the RCS coolant inventory. During an accident, operation of the safeguards systems can be verified based on coolant inventory indicators.

The reference leg temperature is included in the Technical Specification since it is used to compensate the level signal.

11. In-Containment Refueling Water Storage Tank (IRWST) Water Level

The IRWST provides a long term heat sink for non-LOCA events and is a source of injection flow for LOCA events. When the IRWST is a heat sink, the level will change due to increased volume associated with the temperature increase. When saturation temperature is reached, the IRWST will begin steaming and initially lose mass to the containment atmosphere until condensation occurs on the steel containment shell which is cooled by the passive containment cooling system. The condensate is returned to the IRWST via a gutter.

During a LOCA, the IRWST is available for injection. Depending on the severity of the event, when a fully depressurized RCS has been achieved, the IRWST will inject by gravity flow.

12. Passive Residual Heat Removal (PRHR) Flow and PRHR Outlet Temperature

PRHR Flow is provided to monitor primary system heat removal during accident conditions when the steam generators are not available. PRHR provides primary protection for non-LOCA events when the normal heat sink is lost.

PRHR outlet temperature is provided to monitor primary system heat removal during accident conditions when the steam generators are not available. PRHR provides primary protection for non-LOCA events when the normal heat sink is lost.

13, 14, 15, 16. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

LCO (continued)

An evaluation was made of the minimum number of valid core exit thermocouples necessary for In-Core Cooling (ICC) detection. The evaluation determined the reduced complement of core exit thermocouples necessary to detect initial core recovery and trend the ensuing core heatup. The evaluations account for core nonuniformities including incore effects of the radial decay power distribution and excore effects of condensate runback in the hot legs and nonuniform inlet temperatures. Based on these evaluations, adequate ICC detection is assured with two valid core exit thermocouples per quadrant. Core Exit Temperature is also used for plant stabilization and cooldown monitoring.

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Two thermocouples in each of the two divisions ensure a single failure will not disable the ability to determine the temperature at two locations within a quadrant.

17. Passive Containment Cooling System (PCS) Storage Tank Level and PCS Flow

The PCS must be capable of removing the heat from the containment following a postulated LOCA or steam line break (SLB). The tank level instruments provide indication that sufficient water is available to meet this requirement. The PCS flow instrument provides a diverse indication of the PCS heat removal capability.

18. Remotely Operated Containment Isolation Valve Position

The Remotely Operated Containment Isolation Valve Position is provided for verification of containment OPERABILITY.

19. IRWST to RNS Suction Valve Status

The position of the motor-operated valve in the line from the IRWST to the pump suction header is monitored to verify that the valve is closed following postulated events. The valve must be closed to prevent loss of IRWST inventory into the RNS.

BASES

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables provide the information necessary to assess the process of accomplishing or maintaining critical safety functions following Design Basis Accidents (DBAs). The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, plant conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

The ACTIONS Table has been modified by two Notes.

The first Note excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and low probability of an event requiring these instruments.

The second Note in the ACTIONS clarifies the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that function.

A.1

When one or more Functions have one required channel which is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

The Required Action directs actions to be taken in accordance with Specification 5.6.7 immediately. Each time an inoperable channel has not met Required Action A.1, and the associated Completion Time has expired, Condition B is entered.

BASES

ACTIONS (continued)

C.1

When one or more Functions have two required channels which are inoperable, (two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information.

Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM function will be in a degraded condition should an accident occur.

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3-1. The applicable Condition referenced in the Table is Function dependent.

Each time an inoperable channel has not met any Required Action of Condition C, and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are not met for the Functions in Table 3.3.3-1, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The following SRs apply to each PAM instrumentation function in Table 3.3.3-1:

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days verifies that a gross instrumentation failure has not occurred. A CHANNEL CHECK is a

BASES

SURVEILLANCE REQUIREMENTS (continued)

comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar plant instruments located throughout the plant.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the match criteria, it may be an indication that the sensor or the signal-processing equipment has drifted outside its limit. If the channels are within the match criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

<u>SR 3.3.3.2</u>

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, “Reactor Trip System (RTS) Instrumentation.” RTD and Thermocouple channels are to be calibrated in place using cross-calibration techniques. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

BASES

REFERENCES

1. Regulatory Guide 1.97, Rev. 3, “Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,” U.S. Nuclear Regulatory Commission.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown Workstation (RSW)

BASES

BACKGROUND	The RSW provides the control room operator with sufficient displays and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. Passive residual heat removal (PRHR), the core makeup tanks (CMTs), and the in-containment refueling water storage tank (IRWST) can be used to remove core decay heat. The use of passive safety systems allows extended operation in MODE 4. If the control room becomes inaccessible, the operators can establish control at the RSW and place and maintain the unit in MODE 4 with T_{avg} < 350°F. The unit can be maintained safely in MODE 4 with T_{avg} < 350°F for an extended period of time. The OPERABILITY of the remote shutdown control and display functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 4 with T_{avg} < 350°F should the control room become inaccessible.
APPLICABLE SAFETY ANALYSES	The RSW is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 4 with T_{avg} < 350°F. The criteria governing the design and the specific system requirements of the RSW are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1). Since the passive safety systems alone can establish and maintain safe shutdown conditions for the unit, nonsafety systems are not required for safe shutdown of the unit. Therefore, no credit is taken in the safety analysis for nonsafety systems. The RSW satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The RSW LCO provides the OPERABILITY requirements of the displays and controls necessary to place and maintain the unit in MODE 4 from a location other than the control room. The RSW is OPERABLE if the display instrument and control functions needed to support the RSW are OPERABLE.

BASES

LCO (continued)

The RSW covered by this LCO does not need to be energized to be considered OPERABLE. This LCO is intended to ensure the RSW will be OPERABLE if unit conditions require that the RSW be placed in operation.

APPLICABILITY

The RSW LCO is applicable in MODES 1, 2, and 3 and in MODE 4 with T_{avg} < 350°F. This is required so that the facility can be placed and maintained in MODE 4 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4 with T_{avg} < 350°F or in MODE 5 or 6. In these MODES, the unit is already subcritical and in a condition of reduced Reactor Coolant System (RCS) energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

The Note excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring the RSW and because the equipment can generally be repaired during operation without significant risk of a spurious trip.

A.1

Condition A addresses the situation where the RSW is inoperable. The Required Action is to restore the RSW to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 with T_{avg} < 350°F within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 verifies that each required RSW transfer switch performs the required functions. This ensures that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 4 with T_{avg} < 350°F from the RSW. The 24 month Frequency was developed considering it is prudent that these types of surveillances be performed during a unit outage. However, this surveillance is not required to be performed only during a unit outage. This is due to the unit conditions needed to perform the surveillance and the potential for unplanned transients if the surveillance is performed with the reactor at power. Operating experience demonstrates that RSW transfer switches usually pass the surveillance test when performed on the 24 month Frequency.

SR 3.3.4.2

This Surveillance verifies that the RSW communicates controls and indications with Divisions A, B, C, and D of the PMS. Communication is accomplished by use of separate multiplexers for each division. The operator can select the controls and indications available through each PMS division.

The Frequency is based on the known reliability of the Functions and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.4.3

SR 3.3.4.3 verifies the OPERABILITY of the RSW hardware and software by performing diagnostics to show that operator displays are capable of being called up and displayed to an operator at the RSW. The RSW has several video display units which can be used by the operator. The video display units are identical to that provided in the control room and the operator can display information on the video display units in a manner which is identical to the way the information is displayed in the control room. The operator normally selects an appropriate set of displays based on the particular operational goals being controlled by the operator at the time. Each display consists of static graphical and legend information which is contained within the display processor associated with each video display unit and dynamic data which is updated by the data display system.

The Frequency of 24 months is based on the use of the data display capability in the control room as part of the normal unit operation and the

BASES

SURVEILLANCE REQUIREMENTS (continued)

availability of multiple video display units at the RSW. The Frequency of 24 months is based upon operating experience and consistency with control room hardware and software.

SR 3.3.4.4

SR 3.3.4.4 is the performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT) every 24 months. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the RSW by actuating the RTBs. The Frequency of 24 months was chosen because the RTBs may not be exercised while the facility is at power and is based on operating experience and consistency with the refueling outage.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. Section 7.4.1, “Safe Shutdown.”

B 3.3 INSTRUMENTATION

B 3.3.5 Diverse Actuation System (DAS) Manual Controls

BASES

BACKGROUND

The Diverse Actuation System (DAS) manual controls provide non-Class 1E backup controls in case of common-mode failure of the Protection and Safety Monitoring System (PMS) automatic and manual actuations evaluated in the AP1000 PRA. These DAS manual controls are not credited for mitigating accidents in the DCD Chapter 15 analyses.

The specific DAS controls were selected based on PRA risk importance as discussed in Reference 1. As noted in Reference 1, electrical power for these controls and instrument indications need not be covered by Technical Specifications. The rational is that these controls use the same nonsafety-related power supply used by the plant control system. This power is required to be available to support normal operation of the plant. With offsite power available, there are several sources to provide this power including AC power to non-Class 1E battery chargers, AC power to rectifiers, and non-Class 1E batteries. As a result, with offsite power available it is very likely that power will be available for these DAS controls. If offsite power is not available, then there is still the likelihood that the non-1E batteries or the non-1E diesel generators will be available. Even if these sources are unavailable, the desired actions will occur without operator action for the more probable events. The rods will insert automatically on loss of offsite power. The passive residual heat removal heat exchanger (PRHR HX), core makeup tanks (CMT), passive containment cooling system (PCS), and containment isolation features are initiated by operation of fail-safe, air-operated valves. If all offsite and onsite AC power is lost, the instrument air system will depressurize by the time these functions are needed in the 1-hour time frame.

Instrument readouts are expected to be available even in case of complete failure of the PMS due to common cause failure. These instruments include both DAS and PLS instruments. They are powered by DC sources for 24 or 72 hours following a loss of AC power, as described in DCD Section 8.3.2. As discussed above, it is expected that AC power will be available to power the instruments. Even if the operators have no instrument indications, they are expected to actuate the controls most likely to be needed (PRHR HX, CMT, PCS, and containment isolation). If all AC power fails, then the rods will drop and the air-operated valves will go to their fail-safe positions.

The DAS uses equipment from sensor output to the final actuated device that is diverse from the PMS to automatically initiate a reactor trip, or to manually actuate the identified safety-related equipment. DCD Section 7.7.1.11 (Ref. 2) provides a description of the DAS.

BASES

APPLICABLE SAFETY ANALYSES	The DAS manual controls are required to provide a diverse capability to manually trip the reactor and actuate the specified safety-related equipment, based on risk importance in the AP1000 PRA. The DAS manual controls are not credited for mitigating accidents in the DCD Chapter 15 safety analyses. The AP1000 PRA, Appendix A, provides additional information, including the thermal and hydraulic analyses of success sequences used in the PRA. The DAS manual controls satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The DAS LCO provides the requirements for the OPERABILITY of the DAS manual trip and actuation controls necessary to place the reactor in a shutdown condition and to remove decay heat in the event that the PMS automatic actuation and manual controls are inoperable.
APPLICABILITY	The DAS manual controls are required to be OPERABLE in the MODES specified in Table 3.3.5-1. The manual DAS reactor trip control is required to be OPERABLE in MODES 1 and 2 to mitigate the effects of an ATWS event occurring during power operation. The other manual DAS actuation controls are required to be available in the plant MODES specified, based on the need for operator action to actuate the specified components during events that may occur in these various plant conditions, as identified in the AP1000 PRA.
ACTIONS	<u>A.1</u> Condition A applies when one or more DAS manual controls are inoperable. The Required Action A.1 to restore the inoperable DAS manual control(s) to OPERABLE status within 30 days is reasonable because the DAS is a separate and diverse non-safety backup system for the manual reactor trip and manual safety-related equipment actuation controls. The 30-day Completion Time allows sufficient time to repair an inoperable manual DAS control but ensures the control is repaired to provide backup protection.

BASES

ACTIONS (continued)

B.1 and B.2

Condition B applies when Required Action A cannot be completed for the DAS manual reactor trip control within the required completion time of 30 days.

Required Action B.1 requires SR 3.3.1.5, “Perform TADOT” for the reactor trip breakers, to be performed once per 31 days, instead of once every 92 days. Condition A of Example 1.3-6 illustrates the use of the Completion Time for Required Action B.1. The initial performance of SR 3.3.1.5 on the first division (since it is performed on a STAGGERED TEST BASIS) must be completed within 31 days of entering Condition B. The normal surveillance test frequency requirements for SR 3.3.1.5 must still be satisfied while performing SR 3.3.1.5 for Required Action B.1. The predominant failure requiring the DAS manual reactor trip control is common-mode failure of the reactor trip breakers. This change in surveillance frequency for testing the reactor trip breakers increases the likelihood that a common-mode failure of the reactor trip breakers would be detected while the DAS manual reactor trip control is inoperable. This reduces the likelihood that a diverse manual reactor trip is required. It is not required to perform a TADOT for the manual actuation control. The manual reactor trip control is very simple, highly reliable, and does not use software in the circuitry. Although the DAS manual controls are non-Class 1E, they have been shown to be PRA risk important as discussed in Reference 1. The impact of an inoperable DAS manual control is compensated for by increasing the reactor trip breaker surveillance frequency from once every 92 days to once every 31 days.

Action B.2 requires that the inoperable DAS manual reactor trip control be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

C.1 and C.2

Condition C applies when Required Action A cannot be completed for any DAS manual actuation control (other than reactor trip) within the required completion time of 30 days.

Required Action C.1 requires SR 3.3.2.2, “Perform ACTUATION LOGIC TEST,” to be performed once per 31 days, instead of once every 92 days. Condition A of Example 1.3-6 illustrates the use of the Completion Time for Required Action C.1. The initial performance of SR 3.3.2.2 on the first

BASES

ACTIONS (continued)

division (since it is performed on a STAGGERED TEST BASIS) must be completed within 31 days of entering Condition C. The normal surveillance test frequency requirements for SR 3.3.2.2 must still be satisfied while performing SR 3.3.2.2 for Required Action C.1. The predominant failure requiring the DAS manual actuation control is common-mode failure of the PMS actuation logic software or hardware. This change in surveillance frequency for actuation logic testing increases the likelihood that a common-mode failure of the PMS actuation logic from either cause would be detected while any DAS manual actuation control is inoperable. This reduces the likelihood that a diverse component actuation is required. It is not required to perform a TADOT for the manual actuation control device since the manual actuation control devices are very simple and highly reliable. Although the DAS manual controls are non-Class 1E, they have been shown to be PRA risk important as discussed in Reference 1. The impact of an inoperable DAS manual control is compensated for by increasing the automatic actuation surveillance frequency from once every 92 days to once every 31 days.

Action C.2 requires that the inoperable DAS manual actuation control(s) be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

D.1 and D.2

Condition D is entered if the Required Action associated with Condition B or C is not met within the required Completion Time.

Required Actions D.1 and D.2 ensure that the plant is placed in a condition where the probability and consequences of an event are minimized. The allowed Completion Times are reasonable based on plant operating experience, for reaching the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT of the DAS manual trip and actuation controls for the specified safety-related equipment. This TADOT is performed every 24 months.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency is based on the known reliability of the DAS functions and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of the setpoints from the TADOT. The functions have no setpoints associated with them.

REFERENCES

1. WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," Revision 2, dated August 2003.

2. DCD, Section 7.7.1.11.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within the limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope of operating conditions. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNBR limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. At the beginning of each fuel cycle, precision (calorimetric) flow measurements provide a value for comparison to the limit. The cold leg flow rate channels are normalized to the calorimetric flow measurement for 100% indication and are frequently monitored to determine flow degradation. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown transients initiated within the requirements of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit which could impact these parameters must be assessed for their impact on the DNBR criterion. The transients analyzed include loss of coolant flow events and

BASES

APPLICABLE SAFETY ANALYSES (continued)

dropped or stuck rod events. An assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and the RCS average temperature limit specified in the COLR correspond to analytical limits, with an allowance for steady state fluctuations and measurement errors. The RCS average temperature limit corresponds to the analytical limit with allowance for controller deadband and measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables, pressurizer pressure, RCS average temperature, and RCS total flow rate to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, usually based on [maximum analyzed steam generator tube plugging], is retained in the TS LCO. Operating within these limits will result in meeting DNBR criterion in the event of a DNB limited transient.

RCS total flow rate contains a measurement error based on performing a precision heat balance and using the result to normalize the RCS flow rate indicators.

The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location but have been adjusted for instrument error.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state plant operation in order to ensure DNBR criterion will be met in the event of an unplanned loss of forced coolant flow or other DNB-limiting transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be

BASES

APPLICABILITY (continued)

counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, “Reactor Core SLs.” The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency of pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load

BASES

SURVEILLANCE REQUIREMENTS (continued)

changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 24 months, at the beginning of each fuel cycle, allows the installed RCS flow instrumentation to be normalized and verifies the actual RCS flow is greater than or equal to the minimum required RCS flow rate.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until after 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. Chapter 15, “Accident Analyses.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, “Moderator Temperature Coefficient (MTC).” In the transient and accident analyses, the MTC is assumed to be in a range from zero to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil-ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assume the failure of, or presents a challenge to, the integrity of a fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES (continued)

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality parameter satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, “MODE 2 PHYSICS TEST Exceptions,” permits PHYSICS TESTS to be performed at ≤ 5.0% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.4.2.1</u> RCS loop average temperature is required to be verified at or above [551]°F every 12 hours. The SR to verify RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.
REFERENCES	1. Chapter 15, "Accident Analyses."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 1) requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. An adequate margin to brittle failure must be provided during normal operation, anticipated operational occurrences, and system hydrostatic tests. Reference 1 mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 5).

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the P/T span of the limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 1 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH Testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, “RCS Minimum Temperature for Criticality.”

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. ASME Code, Section XI, Appendix E (Ref. 6) provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 7 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, ISLH testing and criticality; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile (brittle) failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, they are applicable at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, “RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits”; LCO 3.4.2, “RCS Minimum Temperature for Criticality”; and Safety Limit 2.1, “Safety Limits,” also provide operational restrictions for pressure and temperature and

BASES

APPLICABILITY (continued)

maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

The actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures.

A.1 and A.2

Operation outside the P/T limits must be restored to within the limits. The RCPB must be returned to a condition that has been verified by stress analyses. Restoration is in the proper direction to reduce RCPB stress.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with preanalyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6) may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration per Required Action A.1 alone is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS (continued)

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished in 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operate pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 4 within 24 hours, with RCS pressure < 500 psig.

The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power condition in an orderly manner without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to

BASES

ACTIONS (continued)

entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within PTLR limits is required every 30 minutes when RCS P/T conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a NOTE that only requires this surveillance to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2, “RCS Minimum Temperature for Criticality,” contains a more restrictive requirement.

REFERENCES

1. 10 CFR 50, Appendix G, “Fracture Toughness Requirements.”

2. ASME Boiler and Pressure Vessel Code, Section III, Appendix G, “Protection Against Non-Ductile Failure.”

3. ASTM E 185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,” July 1982.

BASES

REFERENCES (continued)

4. 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

5. “Embrittlement of Reactor Vessel Materials,” May 1988.

6. ASME Boiler and Pressure Vessel Code, Section XI, Appendix E, “Evaluation of Unanticipated Operating Events.”

7. WCAP-7924-A, “Basis for Heatup and Cooldown Limit Curves,” April 1975.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs) to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission-product release to the environment; and

e. Removal of the heat generated in the fuel due to fission-product decay following a unit shutdown.

The reactor coolant is circulated through two loops connected in parallel to the reactor vessel, each containing a SG, two reactor coolant pumps (RCPs), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the primary coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

The RCPs must be started using the variable speed controller with the reactor trip breakers open. The controller shall be bypassed prior to closure of the reactor trip breakers.

APPLICABLE SAFETY ANALYSES

MODES 1 and 2

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops and RCPs in service.

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming two RCS loops are initially in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses, where RCP operation is most important are the four pump coastdown, single pump locked rotor, single pump broken shaft or coastdown, and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the two RCS loop operation. For two RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 100% RATED THERMAL POWER (RTP). This is the design overpower condition for two RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 118% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points which result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with both RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

<u>MODES 3, 4, and 5</u>

Whenever the reactor trip breakers are in the closed position and the control rod drive mechanisms (CRDMs) are energized, there is the possibility of an inadvertent rod withdrawal from subcritical, resulting in a power excursion in the area of the withdrawn rod. Such a transient could be caused by a malfunction of the Plant Control System (PLS). In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM. The initial power rise is terminated by doppler broadening in the fuel pins, followed by rod insertion. During this event, if there is not adequate coolant flow along the clad surface of the fuel, there is a potential to exceed the departure from nucleate boiling ratio (DNBR) limit. Therefore, the required coolant flow is an initial condition of a design basis event that presents a challenge to the integrity of a fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, in MODE 3, 4 or 5 with the RTBs in the closed position and the PLS capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires the RCPs to be OPERABLE and in operation to ensure that the accident analysis limits are met.

In MODES 3, 4 and 5 with the RTBs open, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. This is addressed in LCO 3.4.8, “Minimum RCS Flow.”

RCS Loops satisfy Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required in MODES 1 and 2. The requirement that at least four RCPs must be operating in MODES 3, 4 and 5 when the RTBs are closed provides assurance that, in the event of a rod withdrawal accident, there will be adequate flow in the core to avoid exceeding the DNBR limit. Bypass of the RCP variable speed control ensures that the pumps are operating at full flow.

With the RTBs in the open position, the PLS is not capable of rod withdrawal; therefore only a minimum RCS flow of 10,000 gpm is necessary to ensure removal of decay heat from the core in accordance with LCO 3.4.8, Minimum RCS Flow.

Note 1 prohibits startup of a RCP when the reactor trip breakers are closed. This requirement prevents startup of a RCP and the resulting circulation of cold and/or unborated water from an inactive loop into the core, precluding reactivity excursion events which are unanalyzed.

Note 2 requires that the secondary side water temperature of each SG be ≤ [50]°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 275°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 3 permits all RCPS to be de-energized in MODE 3, 4, or 5 for ≤ 1 hour per 8 hour period. The purpose of the NOTE is to permit tests that are designed to validate various accident analysis values. One of these tests is for the validation of the pump coastdown curve, used as input to a number of accident analyses including a loss of flow accident.

BASES

LCO (continued)

This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve may need to be revalidated by conducting the test again.

Another test performed during the startup testing program is the validation of the rod drop times during cold conditions, both with and without flow.

The no-flow tests may be performed in MODE 3, 4, or 5, and require that the pumps be stopped for a short period of time. The Note permits the de-energizing of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should only be performed once, unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests and experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the NOTE is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause natural circulation flow obstruction.

An OPERABLE RCS loop is composed of two OPERABLE RCPs in operation providing forced flow for heat transport and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, Section 5.5.4.

BASES

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, both RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

In MODES 3, 4 and 5, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. For these purposes and because the reactor trip breakers are closed, there is the possibility of an inadvertent rod withdrawal event. Four RCPs are required to be operating in MODES 3, 4 and 5, whenever the reactor trip breakers are closed.

ACTIONS

A.1

If the requirements of the LCO are not met while in MODE 1 or 2, the Required Action is to reduce power and bring the plant to MODE 3 with the reactor trip breakers open. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

Condition A is modified by a Note which requires completion of Required Action A.1 whenever the Condition is entered. This ensures that no attempt is made to restart a pump with the reactor trip breakers closed, thus precluding events which are unanalyzed.

When all four reactor coolant pumps are operating, a loss of a single reactor coolant pump above power level P-8 will result in an automatic reactor trip. When three reactor coolant pumps are operating, a loss of a single reactor coolant pump above power level P-10 will result in an automatic reactor trip.

The Completion Time of 6 hours is reasonable to allow for an orderly transition to MODE 3. The applicable safety analyses described above bound Design Basis Accidents (DBA) initiated with three reactor coolant pumps operating at power levels below P-8, and with two reactor coolant pumps at power levels below P-10.

B.1

If the requirements of the LCO are not met while in MODE 3, 4 or 5, the Required Action is to remain in MODE 3, 4 or 5 and open the reactor trip breakers. This action eliminates the possibility of a rod withdrawal event with one or more pumps not operating and thus minimizing the possibility of violating DNB limits.

BASES

ACTIONS (continued)

Condition B is modified by a Note which requires completion of Required Action B.1 whenever the Condition is entered. This ensures that no attempt is made to restart a pump with the reactor trip breakers closed, thus precluding events which are unanalyzed.

The Completion Time of 1 hour is reasonable to allow for planned opening of the reactor trip breakers, since plant cool-down is not required.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation with the pump variable speed control bypassed. Verification includes flow rate and temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the main control room to monitor RCS loop performance.

REFERENCES

1. Chapter 15, “Accident Analysis.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 Pressurizer

BASES

BACKGROUND	The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients. The normal level and pressure control components addressed by this LCO include the pressurizer water level, the heaters, their controls, and power supplies. Pressurizer safety valves and automatic depressurization valves are addressed by LCO 3.4.6, “Pressurizer Safety Valves,” and LCO 3.4.11, “Automatic Depressurization System (ADS) – Operating,” respectively. The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control. Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure.
APPLICABLE SAFETY ANALYSES	In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. Safety analyses presented in Chapter 15 (Ref. 1) do not take credit for pressurizer heater operation, however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum pressurizer water level limit satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirement for the pressurizer water volume ≤ 92% of span, ensures that an adequate steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions.

If the pressurizer water level is above the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. This is done by restoring the level to within limit, within 6 hours, or by placing the unit in MODE 3 with the reactor trip breakers open within 6 hours, and placing the unit in MODE 4 within 12 hours. This takes the unit out of the applicable MODES and restores the unit to operation within the bounds of the safety analyses.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.5.1 This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess the level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.
REFERENCES	1. Chapter 15, “Accident Analysis.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 Pressurizer Safety Valves

BASES

BACKGROUND

The two pressurizer safety valves provide, in conjunction with the Protection and Safety Monitoring System (PMS), overpressure protection for the RCS. The pressurizer safety valves are totally enclosed, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2733.5 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The minimum relief capacity for each valve, 750,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The pressurizer safety valves discharge into the containment atmosphere. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves.

Overpressure protection is required in MODES 1, 2, 3, 4, 5, and 6 when the reactor vessel head is on; however, in MODE 4 with the RNS aligned, MODE 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.14, “Low Temperature Overpressure Protection (LTOP) System.”

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

The consequences of exceeding the ASME Code, Section III pressure limit (Ref. 1) could include damage to RCS components, increased LEAKAGE, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES

APPLICABLE SAFETY ANALYSES	All accident and safety analyses in Chapter 15 (Ref. 3) that require safety valve actuation assume operation of two pressurizer safety valves to limit increases in the RCS pressure. The overpressure protection analysis (Ref. 2) is also based on operation of the two safety valves. Accidents that could result in overpressurization if not properly terminated include: a. Uncontrolled rod withdrawal from full power; b. Loss of reactor coolant flow; c. Loss of external electrical load; d. Locked rotor; and e. Loss of AC power/loss of normal feedwater Detailed analyses of the above transients are contained in Reference 3. Compliance with this LCO is consistent with the design bases and accident analyses assumptions. Pressurizer Safety Valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The two pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The limit protected by this specification is the Reactor Coolant Pressure Boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.
APPLICABILITY	In MODES 1, 2, and 3, and portions of MODE 4 with the RNS isolated or with the RCS temperature ≥ 275°F, OPERABILITY of two valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included although the listed accidents may not require the safety valves for protection.

BASES

APPLICABILITY (continued)

The LCO is not applicable in MODE 4 with RNS open and in MODE 5, because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODES 3 and 4 with the lift setpoints outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 36 hour exception is based on 18 hour outage time for each of the two valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two pressurizer safety valves are inoperable, the plant must be placed in a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with the RNS aligned to the RCS and RCS temperature < 275°F within 24 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With the RNS aligned to the RCS, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.4.6.1</u> SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested one at a time and in accordance with the requirements of ASME Code Section XI (Ref. 4), which provides the activities and Frequency necessary to satisfy the SRs. No additional requirements are specified. The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the values are reset to ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, NB 7614.3.
2. [WCAP-7769, “Topical Report on Overpressure Protection, October 1971.”]
3. Chapter 15, “Accident Analyses.”
4. ASME Boiler and Pressure Vessel Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core comprise the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of LEAKAGE inside containment is expected from auxiliary systems that cannot be made 100% leaktight. LEAKAGE from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS LEAKAGE detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA. The amount of LEAKAGE can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 300 gpd primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leak contaminates the secondary fluid.

The Chapter 15 (Ref. 3) analyses for the accidents involving secondary side releases assume 150 gpd primary to secondary LEAKAGE in each generator as an initial condition. The design basis radiological consequences resulting from a postulated SLB accident and SGTR are provided in Sections 15.1.5 and 15.6.3 of Chapter 15, respectively.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operation LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets are not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

0.5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air N13/F18 radioactivity monitoring and containment sump level monitoring equipment, can detect within a reasonable time period. This leak rate supports leak before break (LBB) criteria. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

LCO (continued)

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE. Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Both Steam Generators (SGs)

Total primary to secondary LEAKAGE through both SGs amounting to 300 gpd produces acceptable offsite doses in the Steam Line Break (SLB) accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

e. Primary to Secondary LEAKAGE through One SG

The 150 gpd limit from one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line rupture.

The 150 gpd LEAKAGE limit is consistent with guidance provided in Reference 4.

f. Primary to IRWST LEAKAGE through the PRHR Heat Exchanger (HX)

The 500 gpd limit from the PRHR HX is based on the assumption that a single crack leaking this amount would not lead to a PRHR HX tube rupture under the stress condition of an RCS pressure increase event. If leaked through many cracks, the cracks are very small, and the above assumption is conservative. This is conservative because the thickness of the PRHR HX tubes is approximately 60% greater than the thickness of the SG tubes. Furthermore, a PRHR HX tube rupture would result in an isolable leak and would not lead to a direct release of radioactivity to the atmosphere.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and to MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors which tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without ACTIONS challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

Verifying RCS LEAKAGE within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection.

Unidentified LEAKAGE and identified LEAKAGE are determined by performance of a RCS water inventory balance. Primary to secondary

BASES

SURVEILLANCE REQUIREMENTS (continued)

LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The RCS water inventory balance must be met with the reactor at steady state operating conditions. Therefore, a Note is added allowing that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, and with no makeup or letdown.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere N13/F18 radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These LEAKAGE detection systems are specified in LCO 3.4.9, “RCS LEAKAGE Detection Instrumentation.”

The containment atmosphere N13/F18 radioactivity LEAKAGE measurement is valid only for plant power > 20% RTP.

The containment atmosphere N13/F18 radioactivity LEAKAGE measurement during MODE 1 is not valid while containment purge occurs or within 2 hours after the end of containment purge.

The containment sump level change method of detecting leaks during MODES 1, 2, 3, and 4 is not valid while containment purge occurs or within 2 hours after the end of containment purge.

The containment sump level change method of detecting leaks during MODES 1, 2, 3, and 4 is not valid during extremely cold outside ambient conditions when frost is forming in the interior of the containment vessel.

The 72-hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

REFERENCES

1. 10 CFR 50, Appendix A GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. Chapter 15, "Accident Analysis."
4. NEI-97-06 – "Steam Generator Program Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Minimum RCS Flow

BASES

BACKGROUND	The AP1000 RCS consists of the reactor vessel and two heat transfer loops, each containing a steam generator (SG), two reactor coolant pumps (RCPs), a single hot leg and two cold legs for circulating reactor coolant. Loop 1 also contains connections to the pressurizer and passive residual heat removal (PRHR). The primary function of the reactor coolant is removal of decay heat and the transfer of this heat, via the SGs to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid. Within the RCS, coolant loop flow can be provided by the reactor coolant pumps, the Normal Residual Heat Removal System (RNS), and to a lesser degree when in the passive mode of operation, natural circulation.
APPLICABLE SAFETY ANALYSES	An initial condition in the Design Basis Accident (DBA) analysis of a possible Boron Dilution Event (BDE) in MODE 3, 4, or 5 is the assumption of a minimum mixing flow in the RCS. In this scenario, dilute water is inadvertently introduced into the RCS, is uniformly mixed with the primary coolant, and flows to the core. The increase in reactivity is detected by the source range instrumentation which provides a signal to terminate the inadvertent dilution before the available SDM is lost. If there is inadequate mixing in the RCS, the dilute water may stratify in the primary system, and there will be no indication by the source range instrumentation that a dilution event is in progress. When primary flow is finally increased, the dilution event may have progressed to the point that mitigation by the source range instrumentation is too late to prevent the loss of SDM. Thus, a minimum mixing flow in the RCS is a process variable which is an initial condition in a DBA analysis. Minimum RCS Flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The requirement that a minimum RCS flow be maintained provides assurance that in the event of an inadvertent BDE, the diluted water will be properly mixed with the primary system coolant, and the increase in core reactivity will be detected by the source range instrumentation.

BASES

LCO (continued)

NOTE 1 permits all RCPS to be de-energized for ≤ 1 hour per 8 hour period. The purpose of the NOTE is to permit tests that are designed to validate various accident analysis values. One of these tests is for the validation of the pump coastdown curve, used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve may need to be revalidated by conducting the test again.

Another test performed during the startup testing program is the validation of the rod drop times during cold conditions, both with and without flow.

The no-flow tests may be performed in MODE 3, 4, or 5, and require that the pumps be stopped for a short period of time. The Note permits the de-energizing of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should only be performed once, unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests and experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the NOTE is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ [50]°F above each of the RCS cold leg temperatures before the start of

BASES

LCO (continued)

an RCP with any RCS cold leg temperature ≤ 275°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

APPLICABILITY

Minimum RCS flow is required in MODES 3, 4, and 5 with the reactor trip breakers (RTBs) open because an inadvertent BDE is considered possible in these MODES.

In MODES 1 and 2, and in MODES 3, 4, and 5 with the RTBs closed, LCO 3.4.4 requires all four RCPs to be in operation. Thus, in the event of an inadvertent boron dilution, adequate mixing will occur.

A minimum mixing flow is not required in MODE 6 because LCO 3.9.2 requires that all valves used to isolate unborated water sources shall be secured in the closed position. In this situation, an inadvertent BDE is not considered credible.

ACTIONS

A.1

If no RCP is in operation, all sources of unborated water must be isolated within 1 hour. This action assures that no unborated water will be introduced into the RCS when proper mixing cannot be assured. The allowed Completion Time requires that prompt action be taken, and is based on the low probability of a DBA occurring during this time.

A.2

The Requirement to perform SR 3.1.1.1 (SDM verification) within 1 hour assures that if the boron concentration in the RCS has been reduced and not detected by the source range instrumentation, prompt action may be taken to restore the required SDM. The allowed Completion Time is consistent with that required of Action A.1 because the conditions and consequences are the same.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance requires verification every 12 hours that a minimum mixing flow is present in the RCS. A Frequency of 12 hours is adequate considering the low probability of an inadvertent BDE during this time, and the ease of verifying the required RCS flow.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A minimum mixing flow is provided if any of the following conditions are met:

No. of Pumps Operating	% Rated Speed (each pump)
1	25%
2	20%
3	15%
4	10%

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 RCS Leakage Detection Instrumentation

BASES

BACKGROUND	GDC 30 of Appendix A to 10CFR50 (Ref. 1) requires means for detecting, and, to the extent practical, identifying the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting LEAKAGE detection systems. LEAKAGE detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE. Industry practice has shown that water flow changes of 0.5 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE, is instrumented to alarm for increases of 0.5 gpm in the normal flow rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE. Note that the containment sump level instruments are also used to identify leakage from the main steam lines inside containment. Since there is not another method to identify steam line leakage in a short time frame, two sump level sensors are required to be operable. The containment water level sensors (LCO 3.3.3) provide a diverse backup method that can detect a 0.5 gpm leak within 3.5 days. The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity used for leak detection is the decay of N13/F18. The production of N13 and F18 is proportional to the reactor power level. N13 has a short half life and comes to equilibrium quickly. F18 has a longer half life and is the dominant source used for leak detection. Instrument sensitivities for gaseous monitoring are practical for these LEAKAGE detection systems. The Radiation Monitoring System includes monitoring N13/F18 gaseous activities to provide leak detection.
APPLICABLE SAFETY ANALYSES	The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in Chapter 15 (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak occur.

RCS LEAKAGE detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

One method of protecting against large RCS LEAKAGE derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump level monitor, in combination with an N13/F18 gaseous activity monitor, provides an acceptable minimum. Containment sump level monitoring is performed by three redundant, seismically qualified level instruments. The LCO note clarifies that if LEAKAGE is prevented from draining to the sump, its level change measurements made by OPERABLE sump level instruments will not be valid for quantifying the LEAKAGE.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS LEAKAGE detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are lower than those for MODES 1, 2, 3, and 4, the likelihood of LEAKAGE and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

Containment sump level monitoring is a valid method for detecting LEAKAGE in MODES 1, 2, 3, and 4. The containment atmosphere N13/F18 radioactivity LEAKAGE measurement during MODE 1 is valid only for reactor power > 20% RTP. RCS inventory monitoring via the pressurizer level changes is valid in MODES 1, 2, 3, and 4 only when RCS conditions are stable, i.e., temperature is constant, pressure is constant, no makeup and no letdown.

BASES

APPLICABILITY (continued)

The containment sump level change method of detecting leaks during MODES 1, 2, 3, and 4 is not valid while containment purge occurs or within 2 hours after the end of containment purge.

The containment atmosphere N13/F18 radioactivity LEAKAGE measurement during MODE 1 is not valid while containment purge occurs or within 2 hours after the end of containment purge.

The containment sump level change method of detecting leaks during MODES 1, 2, 3, and 4 is not valid during extremely cold outside ambient conditions when frost is forming on the interior of the containment vessel.

ACTIONS

A.1 and A.2

With one of the two required containment sump level channels inoperable, the one remaining operable channel is sufficient for RCS leakage monitoring since the containment radiation provides a method to monitor RCS leakage. However, that is not the case for the steam line leakage monitoring. The remaining operable sump level monitor is adequate as long as it continues to operate properly. Continuing plant operation is expected to result in containment sump level indication increases and in periodic operation of the containment sump pump. Therefore, proper operation of the one remaining sump level sensor is verified by the operators checking the volume input to the sump (as determined by the sump level changes and discharges from the containment) to determine that it does not change significantly. A significant change is considered to be ±10 gallons per day or 33% (whichever is greater) of the volume input for the first 24 hours after this CONDITION is entered. The containment sump level instruments are capable of detecting a volume change of less than 2 gallons. The containment water level sensors also provide a diverse backup that can detect a 0.5 gpm leak within 3.5 days.

Restoration of two sump channels to OPERABLE status is required to regain the function in a Completion Time of 14 days after the monitor's failure. This time is acceptable, considering the frequency and adequacy of the monitoring of the change in integrated sump discharge required by Action A.1.

B.1 and B.2

With two of the two required containment sump level channels inoperable, no other form of sampling can provide the equivalent information;

BASES

ACTIONS (continued)

however, the containment atmosphere N13/F18 radioactivity monitor will provide indications of changes in LEAKAGE. Together with the atmosphere monitor, the periodic surveillance for RCS inventory balance, SR 3.4.7.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect LEAKAGE. A Note is added allowing that SR 3.4.7.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of one sump channel to OPERABLE status is required to regain the function in a Completion Time of 72 hours after the monitor's failure. This time is acceptable, considering the frequency and adequacy of the RCS inventory balance required by Action A.1.

C.1.1, C.1.2, and C.2

With one gaseous N13/F18 containment atmosphere radioactivity-monitoring instrumentation channel inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or RCS inventory balanced, in accordance with SR 3.4.7.1, to provide alternate periodic information.

With a sample obtained and analyzed or an RCS inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the radioactivity monitor.

The 24 hours interval for grab samples or RCS inventory balance provides periodic information that is adequate to detect LEAKAGE. A Note is added allowing that SR 3.4.7.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, and makeup and letdown). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leak detection is available.

Required Action C.1 and Required Action C.2 are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the gaseous N13/F18 containment atmosphere radioactivity monitor channel is inoperable. This allowance is provided because other instrumentation is available to monitor for RCS LEAKAGE.

BASES

ACTIONS (continued)

D.1 and D.2

If a Required Action of Condition A, B or C cannot be met within the required Completion Time, the reactor must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

SR 3.4.9.1 requires the performance of a CHANNEL CHECK of the containment atmosphere N13/F18 radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and risk and is reasonable for detecting off normal conditions.

SR 3.4.9.2

SR 3.4.9.2 requires the performance of a CHANNEL OPERATIONAL TEST (COT) on the atmosphere N13/F18 radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers risks and instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.9.3 and SR 3.4.9.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS Leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. Regulatory Guide 1.45, “Reactor Coolant Pressure Boundary LEAKAGE Detection Systems,” U.S. Nuclear Regulatory Commission.
3. Chapter 15, “Accident Analysis.”

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 RCS Specific Activity

BASES

BACKGROUND

The limits on RCS specific activity ensure that the doses due to postulated accidents are within the doses reported in Chapter 15.

The RCS specific activity LCO limits the allowable concentration of iodines and noble gases in the reactor coolant. The LCO limits are established to be consistent with a fuel defect level of 0.25 percent and to ensure that plant operation remains within the conditions assumed for shielding and Design Basis Accident (DBA) release analyses.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to limit the doses due to postulated accidents to within the values calculated in the radiological consequences analyses (as reported in Chapter 15).

APPLICABLE SAFETY ANALYSES

The LCO limits on the reactor coolant specific activity are a factor in accident analyses that assume a release of primary coolant to the environment either directly as in a Steam Generator Tube Rupture (SGTR) or indirectly by way of LEAKAGE to the secondary coolant system and then to the environment (the Steam Line Break).

The events which incorporate the LCO values for primary coolant specific activity in the radiological consequence analysis include the following:

Steam generator tube rupture (SGTR)
Steam line break (SLB)
Locked RCP rotor
Rod ejection
Small line break outside containment
Loss of coolant accident (LOCA) (early stages)

The limiting event for release of primary coolant activity is the SLB. The SLB dose analysis considers the possibility of a pre-existing iodine spike (in which case the maximum LCO of 60 μCi/gm DOSE EQUIVALENT I-131 is assumed) as well as the more likely initiation of an iodine spike due to the reactor trip and depressurization. In the latter case, the LCO of 1.0 μCi/gm DOSE EQUIVALENT I-131 is assumed at the initiation of the accident, but the primary coolant specific activity is assumed to increase with time due to the elevated iodine appearance rate in the coolant. The reactor coolant noble gas specific activity for both cases is

BASES

APPLICABLE SAFETY ANALYSES (continued)

assumed to be the LCO of 280 μCi/gm DOSE EQUIVALENT XE-133. The safety analysis assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.4, "Secondary Specific Activity."

The LCO limits ensure that, in either case, the doses reported in Chapter 15 remain bounding.

The RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the specific noble gas activity is limited to 280 μCi/gm DOSE EQUIVALENT XE-133. These limits ensure that the doses resulting from a DBA will be within the values reported in Chapter 15. Secondary coolant activities are addressed by LCO 3.7.4, "Secondary Specific Activity."

The SLB and SGTR accident analyses (Refs. 1 and 2) show that the offsite doses are within acceptance limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SLB or SGTR accident, lead to doses that exceed those reported Chapter 15.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 specific activity are necessary to contain the potential consequences of a SGTR to within the calculated site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to verify that DOSE EQUIVALENT I-131 is ≤ 60 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is to continue to provide a trend.

BASES

ACTIONS (continued)

The DOSE EQUIVALENT I-131 must be restored to normal within 48 hours. If the concentration cannot be restored to within the LCO limit in 48 hours, it is assumed that the LCO violation is not the result of normal iodine spiking.

A Note to the Required Action of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1 and B.2

With DOSE EQUIVALENT XE-133 in excess of the allowed limit, an analysis must be performed within 4 hours to determine DOSE EQUIVALENT I-131. The allowed Completion Time of 4 hours is required to obtain and analyze a sample.

The change to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the set points of the main steam safety valves, and prevents venting the SG to the environment in a SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience to reach MODE 3 from full power conditions in an orderly manner, without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is > 60 μCi/gm., the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operation experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SR 3.4.10.1 requires performing a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. This is a quantitative measure of radionuclides with half lives longer than

BASES

SURVEILLANCE REQUIREMENTS (continued)

15 minutes. This Surveillance provides an indication of any increase in the release of noble gas activity from fuel rods containing cladding defects.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The 7 day Frequency considers the unlikelihood of a significant increase in fuel defect level during the time.

SR 3.4.10.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when increased releases of iodine from the fuel (iodine spiking) is apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level. The Frequency, between 2 and 6 hours after a power change of ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failures; samples at other times would provide inaccurate results.

REFERENCES

1. Section 15.1.5, “Steam System Piping Failure.”
2. Section 15.6.3, “Steam Generator Tube Rupture.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Automatic Depressurization System (ADS) – Operating

BASES

BACKGROUND

The ADS is designed to assure that core cooling and injection can be achieved for Design Basis Accidents (DBA). The four stages of ADS valves are sequenced in coordination with the passive core cooling system injection performance characteristics.

The ADS consists of 10 flow paths arranged in four different stages that open sequentially (Ref. 1). Stages 1, 2, and 3 each include 2 flow paths. Each of the stage 1, 2, 3 flow paths has a common inlet header connected to the top of the pressurizer. The outlets of the stage 1, 2, 3 flow paths combine into one of the two common discharge lines to the spargers located in the incontainment refueling water storage tank (IRWST). The first stage valves are 4 inch valves with DC motor operators. The second and third stage valves are 8 inch valves with DC motor operators. An OPERABLE stage 1, 2, or 3 automatic depressurization flow path consists of two OPERABLE normally closed motor operated valves, in series.

Stage 4 includes 4 flow paths. The fourth stage ADS valves are squib valves. The four fourth stage flow paths connect directly to the top of the reactor coolant hot legs and vent directly into the associated steam generator compartment. An OPERABLE stage 4 flow path consists of a open motor operated valve and an OPERABLE closed squib valve. These motor operated valves are not required to be OPERABLE because they are open.

The automatic depressurization valves are designed to open automatically when actuated, and to remain open for the duration of any automatic depressurization event. The valves are actuated sequentially. The stage 1 valves are actuated on a low core makeup tank (CMT) level. Stages 2 and 3 are actuated on the stage 1 signal plus time delays. Stage 4 is actuated on a Low 2 CMT level signal with a minimum time delay after stage 3. Stage 4 is blocked from actuating at normal RCS pressure.

In order to perform a controlled, manual depressurization of the RCS, the valves are opened starting with the first stage. The first stage valves can also be modulated to perform a partial RCS depressurization if required. ADS stage 1, 2, 3 valves may be manually operated under controlled conditions for testing purposes.

BASES

BACKGROUND (continued)

ADS stages 1, 2 and 3 valves are designed to open relatively slowly, from approximately 25 seconds for the first stage valves, to approximately 70 seconds for the second and third stage valves.

The ADS valves are powered by batteries. In the unlikely event that offsite and onsite AC power is lost for an extended period of time, a timer will actuate ADS within 24 hours of the time at which AC power is lost, before battery power has been degraded to the point where the valves cannot be opened.

The number and capacity of the ADS flow paths are selected so that adequate safety injection is provided from the accumulators, IRWST and containment recirculation for the limiting DBA loss of coolant accident (LOCA). For small break LOCAs the limiting single failure is the loss of one fourth stage flow path (Ref. 2). The PRA (Ref. 3) shows that adequate core cooling can be provided with the failure of up to [seven] (all ADS stage 1 to 3 and [one] ADS stage 4) flow paths. The ADS PRA success criteria following a LOCA or non-LOCA with failure of other decay heat removal features is for 3 of 4 ADS stage 4 valves to open. All of the ADS stage 1, 2, 3 valves can fail to open. This ADS capacity is sufficient to support PXS gravity injection and containment recirculation operation.

APPLICABLE SAFETY ANALYSES

For non-LOCA events, use of the ADS is not required and is not anticipated. For these events, injection of borated water into the core from the CMTs may be required for makeup or boration. However, the amount of water necessary will not reduce the level in the CMTs to the point of ADS actuation.

For events which involve a loss of primary coolant inventory, such as a LOCA, the ADS will be actuated, allowing for injection from the accumulators, the IRWST, and the containment recirculation (Ref. 2).

The ADS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The requirement that the 16 ADS valves be OPERABLE ensures that upon actuation, the depressurization of the RCS will proceed smoothly and completely, as assumed in the DBA safety analyses.

For the ADS to be considered OPERABLE, the 16 ADS valves must be closed and OPERABLE (capable of opening on an actuation signal). In addition, the stage 4 motor operated isolation valves must be open. These stage 4 motor operated isolation valves are not required to be OPERABLE because they are maintained open per SR 3.4.11.1.

BASES

APPLICABILITY

In MODES 1, 2, 3 and 4 the ADS must be OPERABLE to mitigate the potential consequences of any event which causes a reduction in the RCS inventory, such as a LOCA.

The requirements for the ADS in MODES 5 and 6 are specified in LCO 3.4.12, "Automatic Depressurization System (ADS) – Shutdown, RCS Intact," and LCO 3.4.13, "Automatic Depressurization System – Shutdown, RCS Open."

ACTIONS

A.1

If any one flow path is determined to be inoperable, the remaining OPERABLE ADS flow paths are adequate to perform the required safety function as long as a single failure does not also occur. A flow path is inoperable if one or two of the ADS valves in the flow path are determined to be inoperable. A Completion Time of 72 hours is reasonable based on the capability of the remaining ADS valves to perform the required safety functions assumed in the safety analyses and the low probability of a DBA during this time period. This Completion Time is the same as is used for two train ECCS systems which are capable of performing their safety function without a single failure.

B.1

If two flow paths, consisting of one stage 1 and either one stage 2 or 3, are determined to be inoperable, the remaining OPERABLE ADS flow paths are adequate to perform the required safety function as long as a single failure does not also occur. A flow path is inoperable if one or two of the ADS valves in the flow path are determined to be inoperable. A Completion Time of 72 hours is reasonable based on the capability of the remaining ADS valves to perform the required safety functions assumed in the safety analyses and the low probability of a DBA during this time period. This Completion Time is the same as is used for two train ECCS systems which are capable of performing their safety function without a single failure.

C.1 and C.2

If the Required Actions and associated Completion Times are not met or the requirements of LCO 3.4.11 are not met for reasons other than Condition A, the plant must be brought to MODE 5 where the probability and consequences on an event are minimized. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Each stage 4 ADS isolation motor operated valve must be verified to be open every 12 hours. Note that these valves receive confirmatory open signals. The Surveillance Frequency is acceptable considering valve position is manually monitored in the control room.

SR 3.4.11.2

This Surveillance requires verification that each ADS stage 1, 2, 3 valve strokes to its fully open position. Note that this surveillance is performed during shutdown conditions.

The Surveillance Frequency for demonstrating valve OPERABILITY references the Inservice Testing Program.

SR 3.4.11.3

This Surveillance requires verification that each ADS stage 4 squib valve is OPERABLE in accordance with the Inservice Testing Program. The Surveillance Frequency for verifying valve OPERABILITY references the Inservice Testing Program.

The squib valves will be tested in accordance with ASME Section XI which specifies valve testing in accordance with the ASME OM Code. The applicable ASME OM Code squib valve requirements are specified in paragraph 4.6, Inservice Tests for Category D Explosively Actuated Valves. The requirements include actuation of a sample of the installed valves each 2 years and periodic replacement of charges.

REFERENCES

1. Section 6.3, “Passive Core Cooling System.”
2. Section 15.6, “Decrease in Reactor Coolant Inventory.”
3. AP1000 Probabilistic Risk Assessment, Appendix A.
4. Section 3.9.6, “Inservice Testing of Pumps and Valves.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Automatic Depressurization System (ADS) – Shutdown, RCS Intact

BASES

BACKGROUND	A description of the ADS is provided in the Bases for LCO 3.4.11, "Automatic Depressurization System (ADS) – Operating."
APPLICABLE SAFETY ANALYSES	For postulated events in MODE 5 with the RCS pressure boundary intact, the primary protection is the Passive Residual Heat Removal Heat Exchanger (PRHR HX). Use of the ADS is not required and is not anticipated. For these events, injection of borated water into the core from the core makeup tanks (CMTs) may be required for makeup or boration. However, the amount of water necessary will not reduce the level in the CMTs to the point of ADS actuation. No LOCAs are postulated during plant operation in MODE 5, however loss of primary coolant through LEAKAGE or inadvertent draining may occur. For such shutdown events occurring in MODE 5 it is anticipated that the ADS will be actuated, allowing injection from the in-containment refueling water storage tank (IRWST) and the containment recirculation if containment flooding occurs (Ref. 2). The ADS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The requirement that 9 ADS flow paths be OPERABLE assures that upon actuation, the depressurization of the RCS will proceed smoothly and completely, as assumed in the DBA safety analyses. An ADS stage 1, 2, or 3 flow path is considered OPERABLE if both valves in the line are closed and OPERABLE (capable of opening on an actuation signal). In addition, an ADS stage 4 flow path is OPERABLE if the motor operated isolation valve is open and the squib valve is closed and OPERABLE (capable of opening on an actuation signal).
APPLICABILITY	In MODE 5 with the reactor coolant pressure boundary (RCPB) intact, 9 flow paths of the ADS must be OPERABLE to mitigate the potential consequences of any event which causes a reduction in the RCS inventory, such as a LOCA.

BASES

APPLICABILITY (continued)

The requirements for the ADS in MODES 1 through 4 are specified in LCO 3.4.11, “Automatic Depressurization System (ADS) – Operating;” and in MODE 5 with the RCS pressure boundary open and MODE 6 in LCO 3.4.13, “Automatic Depressurization System (ADS) – Shutdown, RCS Open.”

ACTIONS

A.1

If any one flow path is determined to be inoperable, the remaining OPERABLE ADS flow paths are adequate to perform the required safety function. A flow path is inoperable if one or two of the ADS valves in the flow path are determined to be inoperable. A Completion Time of 72 hours is acceptable since the OPERABLE ADS paths can mitigate shutdown events without a single failure.

B.1

If two flow paths, consisting of one stage 1 and either one stage 2 or 3, are determined to be inoperable, the remaining OPERABLE ADS flow paths are adequate to perform the required safety function. A flow path is inoperable if one or two of the ADS valves in the flow path are determined to be inoperable. A Completion Time of 72 hours is acceptable since the OPERABLE ADS paths can mitigate shutdown events without a single failure.

C.1

If the Required Actions and associated Completion Times are not met or the requirements of LCO 3.4.12 are not met for reasons other than Condition A, the plant must be placed in a MODE in which this LCO does not apply. Action must be initiated, immediately, to place the plant in MODE 5 with the RCS pressure boundary open and ≥ 20% pressurizer level.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

The LCO 3.4.11 Surveillance Requirements (SR 3.4.11.1) are applicable to the ADS valves required to be OPERABLE. The Frequencies associated with each specified SR are applicable. Refer to the corresponding Bases for LCO 3.4.11 for a discussion of each SR.

BASES

REFERENCES

1. AP1000 Probabilistic Risk Assessment, Appendix A.
2. Section 19E.4, “Safety Analyses and Evaluations.”

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 Automatic Depressurization System (ADS) – Shutdown, RCS Open

BASES

BACKGROUND

A description of the ADS is provided in the Bases for LCO 3.4.11, "Automatic Depressurization System (ADS) – Operating."

APPLICABLE SAFETY ANALYSES

When the plant is shutdown with the RCS depressurized, the core makeup tanks (CMTs) are isolated to prevent CMT injection. Since the ADS is actuated by low CMT level, automatic actuation of the ADS is not available. The required ADS stage 1, 2, and 3 vent paths are opened and two ADS stage 4 flow paths are OPERABLE to ensure that in-containment refueling water storage tank (IRWST) injection and containment recirculation can occur, if needed to mitigate events requiring RCS makeup, boration or core cooling (Ref. 1).

The ADS vent path must be maintained until the upper internals are removed, providing an adequate vent path for IRWST injection.

The ADS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The requirement that ADS stage 1, 2, and 3 flow paths be open, from the pressurizer through the spargers into the IRWST, and that two ADS stage 4 flow paths be OPERABLE assures that sufficient vent area is available to support IRWST injection.

The Note allows closure of the RCS pressure boundary when the pressurizer level is < 20% to facilitate vacuum refill following mid-loop operations to establish a pressurizer water level ≥ 20%. Prior to closure of the ADS valves, compliance with LCO 3.4.12, ADS – Shutdown, RCS Intact, should be verified.

APPLICABILITY

In MODE 5 with the reactor coolant system pressure boundary (RCPB) open or pressurizer level < 20% and in MODE 6 with the upper internals in place, the stage 1, 2, and 3 ADS vent paths must be open and two ADS stage 4 flow paths be OPERABLE.

The requirements for the ADS in MODES 1 through 4 are specified in LCO 3.4.11, "Automatic Depressurization System (ADS) – Operating;" and in MODE 5 with the RCPB intact in LCO 3.4.12, "Automatic Depressurization System (ADS) – Shutdown, RCS Intact."

BASES

ACTIONS

A.1 and A.2

If one required ADS stage 1, 2, or 3 flow path is closed, action must be taken to open the affected path or establish an alternative flow path within 72 hours. In this Condition the remaining open ADS stage 1, 2, and 3 flow paths and the OPERABLE ADS stage 4 flow paths are adequate to perform the required safety function without an additional single failure. The stage 4 valves would have to be opened by the operator in case of an event in this MODE. The required vent area may be restored by opening the affected ADS flow path or an alternate vent path with an equivalent area. Considering that the required function is available in this Condition a Completion Time of 72 hours is acceptable.

B.1 and B.2

If one required ADS stage 4 flow path is closed and inoperable, action must be taken to establish an alternative flow path, or restore at least two stage 4 flow paths to OPERABLE status within 36 hours. In this Condition the remaining open ADS stage 1, 2, and 3 flow paths and the one OPERABLE ADS stage 4 flow path are adequate to perform the required safety function without an additional single failure. The required vent area may be restored by opening an alternate vent path with an equivalent area. Alternatively, two stage 4 flow paths may be restored to OPERABLE status. Therefore a Completion Time of 36 hours is considered acceptable.

C.1 and C.2

If the Required Actions and associated Completion Times are not met or the requirements of LCO 3.4.13 are not met for reasons other than Conditions A or B while in MODE 5, the plant must be placed in a condition which minimizes the potential for requiring ADS venting and IRWST injection. The time to RCS boiling is maximized by increasing RCS inventory to ≥ 20% pressurizer level and maintaining RCS temperature as low as practical.

Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS.

D.1 and D.2

If the Required Actions and associated Completion Times are not met or the requirements of LCO 3.4.13 are not met for reasons other than Conditions A or B while in MODE 6, the plant must be placed in a

BASES

ACTIONS (continued)

condition which precludes the need for the ADS vent paths. Action must be initiated, immediately, to remove the upper internals, providing the required vent path. The time to RCS boiling is maximized by increasing RCS inventory and maintaining RCS temperature as low as practical. Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Each required ADS flow path is verified to be open by verifying that the stage 1, 2, and 3 valves are in their fully open position every 12 hours, as indicated in the control room. This Surveillance Frequency is acceptable based on administrative controls which preclude repositioning the valves.

SR 3.4.13.2

The LCO 3.4.11 Surveillance Requirements (SR 3.4.11.1 and SR 3.4.11.3) are applicable to the stage 4 ADS valves required to be OPERABLE. The Frequencies associated with each specified SR are applicable. Refer to the corresponding Bases for LCO 3.4.11 for a discussion of each SR.

REFERENCES

1. Section 19E.4, “Safety Analyses and Evaluations.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System limits RCS pressure at low temperatures so that the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the limits which set the maximum allowable setpoints for the Normal Residual Heat Removal System (RNS) suction relief valve. LCO 3.4.3 provides the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a maximum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires isolating the accumulators. The pressure relief capacity requires the RNS suction relief valve or a depressurized RCS and an RCS vent of sufficient size. The RNS suction relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

<u>RNS Suction Relief Valve Requirements</u>

During the LTOP MODES, the RNS system is operated for decay heat removal. Therefore, the RNS suction isolation valves are open in the

BASES

BACKGROUND (continued)

piping from the RCS hot legs to the inlet of the RNS system. While these valves are open, the RNS suction relief valve is exposed to the RCS and able to relieve pressure transients in the RCS.

The RNS suction relief valve is a spring loaded, water relief valve with a pressure tolerance and an accumulation limit established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

The RNS suction isolation valves must be open to make the RNS suction relief valves OPERABLE for RCS overpressure mitigation.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it may require removing one or more pressurizer safety valves or manually opening one or more Automatic Depressurization System (ADS) valves. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with the RCS temperature above 275°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. When the RNS is aligned and open to the RCS, overpressure protection is provided by the RNS suction relief valve, or a depressurized RCS and a sufficiently sized open RCS vent.

The actual temperature at which the pressure in the P/T limit curve falls below the suction relief setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RNS suction relief valve, or the depressurized and vented RCS condition.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients. The events listed below were used in the analysis to size the RNS suction relief valve. Therefore, any events with a mass or heat input greater than the listed events cannot be accommodated and must be prevented.

Mass Input

a. Makeup water flow rate to the RCS assuming both CVS makeup pumps are in operation and letdown is isolated.

Heat Input

a. Restart of one reactor coolant pump (RCP) with water in the steam generator secondary side 50°F hotter than the primary side water, and the RCS water solid.

RNS Suction Relief Valve Performance

Since the RNS suction relief valve does not have a variable P/T lift setpoint, the analysis must show that with chosen setpoint, the relief valve will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the minimum of either the P/T limit curve or 110 percent of the design pressure of the normal residual heat removal system. The current analysis shows that up to a temperature of 70°F, the mass input transient is limiting, and above this temperature the heat input transient is limiting.

To prevent the possibility of a heat input transient, and thereby limit the required flow rate of the RNS suction relief valve, an administrative requirement has been imposed that does not allow an RCP to be started with the pressurizer water level above 92% and the RCS temperature above 200°F. Under these imposed conditions, the transient created by the startup of an RCP when the RCS temperature is above 200°F can be accommodated without additional pressure relief.

APPLICABLE SAFETY ANALYSES (continued)

RCS Vent Performance

With the RCS depressurized, a vent size of [9.3] square inches is capable of mitigating a limiting overpressure transient. The area of the vent is equivalent to the area of the inlet pipe to the RNS suction relief valve so the capacity of the vent is greater than the flow possible with either the mass or heat input transient, while maintaining the RCS pressure less than the minimum of either the maximum pressure on the P/T limit curve or 110 percent of the design pressure of the normal residual heat removal system.

The required vent area may be obtained by opening one ADS Stage 2, 3, or 4 flow path.

The RCS vent size will be reevaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the maximum coolant input and minimum pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires all accumulator discharge isolation valves closed and immobilized, when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS temperature allowed in the PTLR.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. One OPERABLE RNS suction relief valve; or

   An RNS suction relief valve is OPERABLE for LTOP when both RNS suction isolation valves in one flow path are open, its setpoint is within limits, and testing has proven its ability to open at this setpoint.

BASES

LCO (continued)

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ [9.3] square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable in MODE 4 when any cold leg temperature is below 275°F, MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 275°F. In MODE 6, the reactor vessel head is off, and overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.6, “Pressurizer Safety Valves,” requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 with the RNS isolated or RCS temperature ≥ 275°F.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure with little or no time for operator action to mitigate the event.

The Applicability is modified by a Note stating that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves.

This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

ACTIONS

A.1, B.1, and B.2

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action B.1 and Required Action B.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS

BASES

ACTIONS (continued)

temperature to > 275°F, the accumulator pressure cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

C.1 and C.2

If the RNS suction relief valve is inoperable and the RCS is not depressurized, there is a potential to overpressurize the RCS and exceed the limits allowed in LCO 3.4.3. The suction relief valve is considered inoperable if the RNS isolation valves have isolated the RNS from the RCS in such a way that the suction relief valve cannot perform its intended safety function, or if the valve itself will not operate to perform its intended safety function.

Under these conditions, Required Actions C.1 or C.2 provide two options, either of which must be accomplished in 12 hours. If the RNS suction relief valve cannot be restored to OPERABLE status, the RCS must be depressurized and vented with a RCS vent which provides a flow area sufficient to mitigate any of the design low temperature overpressure events.

The 12 hour Completion Time represents a reasonable time to repair the relief valve, open the RNS isolation valves or otherwise restore the system to OPERABLE status, or depressurize and vent the RCS, without imposing a lengthy period when the LTOP system is not able to mitigate a low temperature overpressure event.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, the accumulator discharge isolation valves are verified closed and locked out. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the main control room to verify the required status of the equipment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.14.2

The RNS suction relief valve shall be demonstrated OPERABLE by verifying two RNS suction isolation valves in one flow path are open. This Surveillance is only performed if the RNS suction relief valve is being used to satisfy this LCO.

The RNS suction isolation valves are verified to be opened every 12 hours. The Frequency is considered adequate in view of other administrative controls such as valve status indications available to the operator in the control room that verify the RNS suction isolation valves remain open.

SR 3.4.14.3

The RCS vent of ≥ [9.3] square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered “locked” in this context) or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position or a removed pressurizer safety valve or open manway also fits this category).

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.14b.

SR 3.4.14.4

The RNS suction relief valve shall be demonstrated OPERABLE by verifying that two RNS suction isolation valves in one flow path are open and by testing it in accordance with the Inservice Testing Program. (Refer to SR 3.4.14.2 for the RNS suction isolation valve Surveillance.) This Surveillance is only required to be performed if the RNS suction relief valve is being used to meet this LCO. The ASME Code, Section XI (Ref. 5), test per Inservice Testing Program verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

BASES

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix G, “Fracture Toughness Requirements.”
2. Generic Letter 88-11, “NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operation.”
3. ASME Boiler and Pressure Vessel Code, Section III.
4. Section 5.2.2, “Overpressure Protection.”
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Pressure Isolation Valve (PIV) Integrity

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define the RCS pressure boundary as all those pressure containing components such as pressure vessels, piping, pumps, and valves which are connected to the reactor coolant system, up to and including the outermost containment isolation valve in system piping which penetrates primary reactor containment, the second of two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment, and the reactor coolant system safety and relief valves. This includes any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can experience varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The AP1000 PIVs are listed in Chapter 3, Table 3.9-18. The RCS PIV Leakage LCO allows RCS high pressure operation when PIV leakage has been verified.

The purpose of this specification is to prevent overpressure failure or degradation of low pressure portions of connecting systems. The following criteria was used in identifying PIVs for inclusion in the specification. A valve was included in this specification if its failure may result in:

1. Failure of low pressure portions of connected systems, such as a Loss of Coolant Accident (LOCA) outside of containment, which could place the plant in an unanalyzed condition.

2. Degradation of low pressure portions of connected systems, such as damage to a core cooling system, which could degrade a safety related function that mitigates a DBA.

Valves considered for inclusion in this specification are used to isolate the RCS from the following connected systems:

a. Passive Core Cooling System (PXS) Accumulators;

b. Normal Residual Heat Removal System (RNS); and

c. Chemical and Volume Control System (CVS).

BASES

BACKGROUND (continued)

The RNS pressure boundary isolation valves are considered to meet the first criterion for inclusion in this specification. The PXS accumulator check valves were determined to meet the second PIV criteria for inclusion in this specification. It is determined that the CVS PIVs do not meet either criteria for inclusion in this specification.

The PIVs that are addressed by this specification are listed in Chapter 3, Table 3.9-18.

The CVS pressure isolation valves were not included in this specification based on the defined criteria. The justification for excluding the CVS PIVs is discussed in the following paragraph.

The CVS contains four high pressure/low pressure connections with the RCS. Since the portion of the CVS which is located inside reactor containment is designed to full RCS pressure, the high pressure/low pressure interfaces with the RCS are the lines that penetrate the reactor containment. The CVS lines that penetrate containment include the makeup line, the letdown line to the Liquid Radwaste System, the hydrogen supply line, and the demineralizer resin sluice line used to transfer spent resins from the demineralizers to the Solid Radwaste System. These lines each contain two safety related containment isolation valves which are addressed by the Containment Isolation Specification (LCO 3.6.3). In addition to the containment isolation valves in each of the CVS lines that interface with the RCS, there are additional valves in each line that provide diverse isolation capability. Since more restrictive requirements are imposed by LCO 3.6.3, the CVS isolation valves are not included in this LCO.

Since the purpose of this LCO is to verify that the PIVs have not suffered gross failures, the valve leakage test in conjunction with tests specified in the IST program provide an acceptable method of determining valve integrity. The ability of the valves to transition from open to closed provides assurance that the valve can perform its pressure isolation function as required. A small amount leakage through these valves is allowed, provided that the integrity of the valve was demonstrated.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system or the failure of a safety related function to mitigate a DBA.

BASES

APPLICABLE SAFETY ANALYSES	Pressure isolation valve integrity is not considered in any design basis accident analyses. This specification provides for monitoring the condition of the reactor coolant pressure boundary to detect degradation which could lead to accidents or which could impair a connected system's ability to mitigate DBAs. RCS PIV integrity satisfies, Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually small. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. The LCO PIV leakage limit is 0.5 gpm per inch nominal valve size up to a maximum of 5 gpm per valve. This limit is well within the makeup capability of the CVS makeup pumps. This leak rate will not result in the overpressure of a connected low pressure system. Reference 5 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage of the valve. In such cases, the observed leakage rate at lower differential pressures can be assumed to be the leakage at the maximum pressure differential. Verification that the valve leakage diminishes with increasing pressure differential is sufficient to verify that the valve characteristics are such that higher service pressure results in a decrease in overall leakage.
APPLICABILITY	In MODES 1, 2, and 3 and MODE 4, with RCS not being cooled by the RNS, this LCO applies when the RCS is pressurized. In MODE 4, with RNS in operation, and MODES 5 and 6, the RCS pressure is reduced and is not sufficient to overpressurize the connected low pressure systems.
ACTIONS	The ACTIONS are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The pressurization may have affected system OPERABILITY, or isolation of an affected flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

BASES

ACTIONS (continued)

A.1

With one or more PIVs inoperable, the affected flow path(s) must be isolated. Required Action A.1 is modified by a Note that the valves used for isolation must meet the same integrity requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 8 hours. Eight hours provides time to verify IST compliance for the alternate isolation valve and isolate the flow path. The 8 hour Completion Time allows the actions and restricts the operation with inoperable isolation valves.

A.2

Required Action A.2 specifies that a second OPERABLE PIV can be shown to meet the leakage limits within 8 hours. This valve is required to be a check valve, or a closed valve, if it isolates a line that penetrates containment. For the accumulator valves, the normally open accumulator isolation valve is a suitable replacement PIV, but can remain open because leakage into the accumulator is continuously monitored. If leakage into the accumulators increased to the allowable operational leakage limit, then the valve could be used to isolate the accumulators from the RCS.

The 72 hour Completion Time allows the actions and restricts the operation with inoperable isolation valves.

B.1 and B.2

If PIV integrity cannot be restored, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and reduces the potential for a LOCA outside containment.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking

BASES

SURVEILLANCE REQUIREMENTS (continued)

valve. The leakage limit of 0.5 gpm per inch nominal valve size up to a minimum of 5 gpm applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing shall be performed every 24 months, a typical refueling cycle. The 24 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 4) as contained in the Inservice Testing Program and is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 5).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55.
4. 10 CFR 50.55a(g).
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 Reactor Vessel Head Vent (RVHV)

BASES

BACKGROUND

The reactor vessel head vent (RVHV) is designed to assure that long-term operation of the Core Makeup Tanks (CMTs) does not result in overfilling of the pressurizer during Condition II Design Basis Accidents (DBAs). The RVHV can be manually actuated by the operators in the main control room to reduce the pressurizer water level during long-term operation of the CMTs.

The RVHV consists of two parallel flow paths each containing two RVHV isolation valves in series. The RVHV valves are connected to the reactor vessel head via a common line. The outlets of the RVHV flow paths combine into one common discharge line which connects to a single ADS discharge header that discharges to spargers located in the incontainment refueling water storage tank (IRWST). The RVHV valves are 1 inch valves with DC solenoid operators.

The RVHV valves are designed to open when actuated by the operator, and to reclose when actuated by the operator from the main control room.

The number and capacity of the RVHV flow paths are selected so that letdown flow from the RCS is sufficient to prevent pressurizer overfill for events where extended operation of the CMTs causes the pressurizer water level to increase. Although realistic evaluations of the Condition II non-LOCA events does not result in pressurizer overfill, conservative analyses of some of these events can result in pressurizer overfill if no operator actions are assumed.

APPLICABLE SAFETY ANALYSES

For Condition II non-LOCA events, such as inadvertent passive core cooling system operation and chemical and volume control system malfunction, the use of the RVHV may be required to prevent long-term pressurizer overfill (Ref. 1).

For LOCA events, the RVHV is not required.

The RVHV satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The requirement that all four RVHV valves be OPERABLE ensures that upon actuation, the RVHV can reduce the pressurizer water level as assumed in the DBA safety analyses.

BASES

LCO (continued)

For the RVHV to be considered OPERABLE, all four valves must be closed and OPERABLE (capable of opening from the main control room).

APPLICABILITY

In MODES 1, 2, 3, and 4 with the RCS not being cooled by the RNS, the RVHV must be OPERABLE to mitigate the potential consequences of any event which causes an increase in the pressurizer water level that could otherwise result in overfilling of the pressurizer.

In MODE 4, with the RCS being cooled by the RNS, and in MODES 5 and 6, operation of the CMTs or CVS will not result in a pressurizer overfill event.

ACTIONS

A.1

If one or two RVHV valves in a single flow path are determined to be inoperable, the flow path is inoperable. The remaining OPERABLE RVHV flow path is adequate to perform the required safety function. A Completion Time of 72 hours is acceptable since the OPERABLE RVHV paths can mitigate DBAs without a single failure.

B.1

If both flow paths are determined to be inoperable, the RVHV is degraded such that the system is not available for some DBA non-LOCA analyses for which it may be required. A Completion Time of 6 hours is permitted to restore at least one flow path. This Completion Time is acceptable considering that the realistic analysis of these non-LOCA events do not result in pressurizer overfill.

C.1 and C.2

If the Required Actions and associated Completion Times are not met or the requirements of LCO 3.4.16 are not met for reasons other than Conditions A or B, the plant must be brought to MODE 4 where the probability and consequences of an event are minimized. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

The dedicated component level remote manual valve switches in the main control room shall be used to stroke each RVHV valve to demonstrate OPERABILITY of the controls.

This Surveillance requires verification that each RVHV valve strokes to its fully open position. The Surveillance Frequency for demonstrating valve OPERABILITY references the Inservice Testing Program.

REFERENCES

1. Section 15.5, "Increase in Reactor Coolant System Inventory."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Chemical and Volume Control System (CVS) Makeup Isolation Valves

BASES

BACKGROUND

One of the principle functions of the CVS system is to maintain the reactor coolant inventory by providing water makeup for reactor coolant system (RCS) LEAKAGE, shrinkage of the reactor coolant during cooldowns, and RCS boron concentration changes. In the automatic makeup mode of operation, the pressurizer water level starts and stops CVS makeup to the RCS.

Although the CVS is not considered a safety related system, certain isolation functions of the system are considered safety related functions. The appropriate isolation valves have been classified and designed as safety related. One of the safety related functions provided by the CVS is the termination of RCS makeup to prevent overfilling of the pressurizer during non-LOCA transients or to prevent steam generator overfilling during a steam generator tube rupture. The CVS makeup line containment isolation valves provide this RCS makeup isolation function.

APPLICABLE SAFETY ANALYSES

One of the initial assumptions in the analysis of several non-LOCA events and during a steam generator tube rupture accident is that excessive CVS makeup to the RCS may aggravate the consequences of the accident. The need to isolate the CVS makeup to the RCS is detected by the pressurizer level instruments or the steam generator narrow range level instruments. These instruments will supply a signal to the makeup line containment isolation valves in the CVS causing these valves to close and terminate RCS makeup. Thus the CVS makeup isolation valves are components which function to mitigate an accident.

CVS isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The requirement that at least two CVS makeup isolation valves be OPERABLE assures that there will be redundant means available to terminate CVS makeup to the RCS during a non-LOCA event or a steam generator tube rupture accident should that become necessary.

APPLICABILITY

The requirement that at least two CVS makeup isolation valves be OPERABLE is applicable in MODES 1, 2, 3, and 4 with the normal residual heat removal system (RNS) suction to the RCS not open

BASES

APPLICABILITY (continued)

because a pressurizer overfill event or steam generator tube rupture accident is considered possible in these MODES, and the automatic closure of these valves is assumed in the safety analysis.

In the applicable MODES, the need to isolate the CVS makeup to the RCS is detected by the pressurizer level instruments (high 1 setpoint coincident with safeguards actuation or high 2 setpoint) or the steam generator narrow range level instruments (high 2 setpoint).

This isolation function is not required in MODE 4 with the RNS suction open to the RCS or in lower MODES. In such MODES, pressurizer or steam generator overfill is prevented by the RNS suction relief valve.

ACTIONS

A.1

If only one CVS makeup isolation valve is OPERABLE, the second valve must be restored to OPERABLE status in 72 hours. The allowed Completion Time assures expeditious action will be taken, and is acceptable because the safety function of automatically isolating RCS makeup can be accomplished by the redundant isolation valve.

B.1

If the Required Actions and associated Completion Time of Condition A are not met, or if both CVS makeup isolation valves are not OPERABLE (i.e., not able to be closed automatically), then the makeup flow path to the RCS must be isolated. Isolation can be accomplished by manually closing the CVS makeup isolation MOVs or alternatively, manual valve(s) in the makeup line between the makeup pumps and the RCS.

The Action is modified by a Note allowing the flow path to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the main control room. In this way, the flow path can be rapidly isolated when a need for isolation is indicated.

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

Verification that the RCS makeup isolation valves are OPERABLE, by stroking each valve closed, demonstrates that the valves can perform their safety related function. The Frequency is in accordance with the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.17.2

Verification that the RCS makeup isolation valves closure times are less than that assumed in the safety analysis, is performed by measuring the time required for each valve to close. The Frequency is in accordance with the Inservice Testing Program.

REFERENCES

1. Chapter 15, “Accident Analysis.”

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the PXS accumulators are to supply water to the reactor vessel during the blowdown phase of a large-break loss-of-coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, to provide Reactor Coolant System (RCS) makeup for a small-break LOCA, and to provide RCS boration for steam line breaks (Ref. 2).

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The accumulator inventory is available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core.

The accumulators are pressure vessels, partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required for them to perform their function. Internal accumulator pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the static accumulator pressure.

Each accumulator is piped into the reactor vessel via an accumulator line and is isolated from the RCS by two check valves in series.

A normally open motor operated valve is arranged in series with the check valves. Upon initiation of a safeguards actuation signal, the normally open valves receive a confirmatory open signal.

Power lockout and position alarms ensure that the valves meet the requirements of the Institute of Electrical and Electronic Engineers (IEEE) Standard 603-1991 (Ref. 1) for “operating bypasses” and that the accumulators will be available for injection without being subject to a single failure.

BASES

BACKGROUND (continued)

The accumulator size, water volume, and nitrogen cover pressure are selected so that both of the accumulators are sufficient to recover the core cooling before significant clad melting or zirconium water reaction can occur following a large break LOCA. One accumulator is adequate during a small break LOCA where the entire contents of one accumulator can possibly be lost via the pipe break. This accumulator performance is based on design basis accident (DBA) assumptions and models (Ref. 3). The Probabilistic Risk Assessment (PRA) (Ref. 4) shows that one of the two accumulators is sufficient for a large break LOCA caused by spurious ADS actuation and that none of the accumulators are required for small break LOCAs, assuming that at least one core makeup tank (CMT) is available. In addition, both accumulators are required for a large break LOCA caused by the break of a cold leg pipe; the probability of this break has been significantly reduced by incorporation of leak-before-break.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed to be OPERABLE in both the large and small break LOCA analyses at full power (Ref. 3) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

For a small break LOCA, a large range of break sizes and locations were analyzed to verify the adequacy of the design. The cases analyzed include the rupture of one 8 inch direct vessel injection line and several smaller break sizes. Acceptable PXS performance was demonstrated.

For a larger LOCA, including a double ended RCS piping rupture, the PXS can provide a sufficiently large flow rate, assuming both accumulators are OPERABLE, to quickly fill the reactor vessel lower plenum and downcomer. Both accumulators, in conjunction with the CMTs, ensure rapid reflooding of the core. For a large LOCA, both lines are available since an 8 inch line break would be a small LOCA.

Following a non-LOCA event such as a steamline break, the RCS experiences a decrease in temperature and pressure due to an increase in energy removal by the secondary system. The cooldown results in a reduction of the core SHUTDOWN MARGIN with a potential for return to power. During such an event the accumulators provide injection of borated water to assist the CMT’s boration to mitigate the reactivity transient and ensure the core remains shut down.

The accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO establishes the minimum conditions necessary to ensure that sufficient accumulator flow will be available to meet the necessary acceptance criteria established for core cooling by 10 CFR 50.46 (Ref. 5). These conditions are:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium-water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. The core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For an accumulator to be OPERABLE, the isolation valve must be fully open with power removed, and the limits established in the Surveillance Requirements for contained water, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODES 3 and 4 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that adequate injection flow from other sources exists to retain peak clad temperatures below the 10 CFR 50.46 limit of 2200°F.

In MODES 3 and 4 with RCS pressure ≤ 1000 psig, and in MODES 5 and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows the RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

BASES

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, action must be taken to restore the parameter.

Deviations in boron concentration are expected to be slight, considering that the pressure and volume are verified once per 24 hours. For one accumulator, boron concentration not within limits will have an insignificant effect on the ability of the accumulators to perform their safety function. Therefore, a Completion Time of 72 hours is considered to be acceptable.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 8 hours. With one accumulator inoperable, the remaining accumulator is capable of providing the required safety function, except for one low probability event (large cold leg LOCA) discussed in the background section. The effectiveness of one accumulator is demonstrated in analysis performed to justify PRA success criteria (Ref. 4). The analysis contained in this reference shows that for a range of other events including small LOCAs and large hot leg LOCAs that with one accumulator unavailable the core is adequately cooled. The incremental conditional core damage probability with this AOT is more than an order of magnitude less than the value indicated to have a small impact on plant risk (Ref. 7).

The 8 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time is reasonable since the CMTs are required to be available to provide small break LOCA mitigation (i.e., entry into Condition C or E of LCO 3.5.2 has not occurred). The effectiveness of backup CMT injection is demonstrated in analysis performed to justify PRA success criteria (Ref. 3). The analysis contained in this reference shows that for a small LOCA, the injection from one CMT without any accumulator injection supports adequate core cooling. This analysis provides a high confidence that with the unavailability of one accumulator, the core can be cooled following design bases accidents.

The 1 hour Completion Time, in the case with simultaneous entry into Condition C or E of LCO 3.5.2, requires very prompt actions to restore either the accumulator or the CMT to OPERABLE status. This Completion Time is considered reasonable because of the low probability of simultaneously entering these multiple PXS Conditions and the very small likelihood of a LOCA occurring at the same time.

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Action and associated Completion Time of Conditions A or B are not met, the plant must be placed in a MODE or condition in which the LCO does not apply. This is done by placing the plant in MODE 3 within 6 hours and with pressurizer pressure to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures each accumulator isolation valve is fully open, as indicated in the control room, and timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a partially closed valve could result in not meeting DBA analyses assumptions (Ref. 3). A 12 hour Frequency is considered reasonable in view of the other administrative controls which ensure that a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and 3.5.1.3

Verification every 12 hours of the borated water volume and nitrogen cover pressure in each accumulator is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Considering that control room alarms are provided for both parameters these limits are effectively subject to continuous monitoring. The 12 hour Frequency is considered reasonable considering the availability of the control room alarms and the likelihood that, with any deviation which may occur, the accumulators will perform their safety function with slight deviations in these parameters.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days, since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as in-leakage. Sampling the affected accumulator within 6 hours after a 3% volume increase will promptly identify whether the volume change has caused a reduction of boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the in-containment refueling water storage tank (IRWST), because the water contained in the IRWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 6).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the pressurizer pressure is ≥ 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, reduced accumulator capacity might be available for injection following a DBA that required operation of the accumulators. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated isolation valves when pressurizer pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during unit startup or shutdowns.

Should closure of a valve occur, the safeguard actuation signal provided to the valve would open a closed valve, if required.

SR 3.5.1.6

This SR requires performance of a system performance test of each accumulator to verify flow capabilities. The system performance test demonstrates that the accumulator injection line resistance assumed in accident analyses is maintained. Although the likelihood that system performance would degrade with time is low, it is considered prudent to periodically verify system performance. The System Level Operability Testing Program provides specific test requirements and acceptance criteria.

BASES

REFERENCES

1. IEEE Standard 603-1991, “Criteria for Safety Systems for Nuclear Power Generating Stations.”
2. Section 6.3 “Passive Core Cooling System.”
3. Section 15.6 “Decrease in Reactor Coolant Inventory.”
4. AP1000 PRA.
5. 10 CFR 50.46.
6. NUREG-1366, February 1990.
7. Regulatory Guide 1.177, 8/98, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications.”

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.2 Core Makeup Tanks (CMTs) – Operating

BASES

BACKGROUND

Two redundant CMTs provide sufficient borated water to assure Reactor Coolant System (RCS) reactivity and inventory control for all design basis accidents (DBAs), including both loss of coolant accident (LOCA) events and non-LOCA events (Ref. 1).

The CMTs are cylindrical tanks with hemispherical upper and lower heads. They are made of carbon steel and clad on the internal surfaces with stainless steel. They are located in containment at an elevation slightly above the reactor coolant loops. Each tank is full of borated water at > 3400 ppm. During normal operation, the CMTs are maintained at RCS pressure through a normally open pressure balance line from the cold leg.

The outlet line from each CMT is connected to one of two direct vessel injection lines, which provides an injection path for the water supplied by the CMT. The outlet line from each CMT is isolated by parallel, normally closed, fail open valves. Upon receipt of a safeguards actuation signal, these four valves open to align the CMTs to the RCS.

The CMTs will inject to the RCS as inventory is lost and steam or reactor coolant is supplied to the CMT to displace the water that is injected. Steam or reactor coolant is provided to the CMT through the cold leg balance line, depending upon the specific event that has occurred. The inlet line from the cold leg is sized for LOCA events, where the cold legs become voided and higher CMT injection flows are required.

The injection line from each CMT contains a flow tuning orifice that is used to provide a mechanism for the field adjustment of the injection line resistance. The orifice is used to establish the required flow rates for the associated plant conditions assumed in the CMT design. The CMT flow is based on providing injection for a minimum of 20 minutes after CMT actuation.

The CMT size and injection capability are selected to provide adequate RCS boration and safety injection for the limiting DBA. One CMT is adequate for this function during a small break LOCA where one CMT completely spills via the pipe break (Ref. 2). The Probabilistic Risk Assessment (PRA) (Ref. 3) shows that none of the CMTs are required for small LOCAs, assuming that at least one accumulator is available.

BASES

APPLICABLE SAFETY ANALYSES

The CMTs are assumed to be OPERABLE to provide emergency boration and core makeup when the Chemical and Volume Control System (CVS) is inoperable, and to mitigate the consequences of any DBA which requires the safety injection of borated water (Ref. 2).

Following a non-LOCA event such as a steamline break, the RCS experiences a decrease in temperature and pressure due to an increase in energy removal by the secondary system. The cooldown results in a reduction of the core SHUTDOWN MARGIN due to the negative moderator temperature coefficient, with a potential for return to power. The actuation of the CMTs following this event provides injection of borated water to mitigate the reactivity transient and ensure the core remains shut down.

In the case of a steam generator tube rupture (SGTR), CMT injection provides borated water to compensate for RCS LEAKAGE.

In the case of an RCS leak of 10 gallons per minute, the CMTs can delay depressurization for at least 10 hours, providing makeup to the RCS and remain able to provide the borated water to compensate for RCS shrinkage and to assure the RCS boration for a safe shutdown.

In the case of a LOCA, the CMTs provide a relatively large makeup flow rate for approximately 20 minutes, in conjunction with the accumulators to provide the initial core cooling.

CMTs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO establishes the minimum conditions necessary to ensure that sufficient CMT flow will be available to meet the initial conditions assumed in the safety analyses. The volume of each CMT represents 100% of the total injected flow assumed in LOCA analysis. If the injection line from a single CMT to the vessel breaks, no single active failure on the other CMT will prevent the injection of borated water into the vessel. Thus the assumptions of the LOCA analysis will be satisfied.

For non-LOCA analysis, two CMTs are assumed. Note that for non-LOCA analysis, the accident cannot disable a CMT.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4 when the RCS is not being cooled by the Normal Residual Heat Removal System (RNS) the CMTs are required to be OPERABLE to provide borated water for RCS inventory makeup and reactivity control following a design basis event and subsequent cooldown.

The CMT requirements in MODE 5 with the RCS pressure boundary intact are specified in LCO 3.5.3, “Core Makeup Tanks (CMTs) – Shutdown, RCS Intact.”

The CMTs are not required to be OPERABLE while in MODE 5 with the RCS pressure boundary open or in MODE 6 because the RCS is depressurized and borated water can be supplied from the In-containment Refueling Water Storage Tank (IRWST), if needed.

In the unlikely event of a total loss of AC power sources, coupled with an inoperable Passive Residual Heat Removal Heat Exchanger (PRHR HX) (beyond DBA), the CMTs may be used in a feed and bleed sequence to remove heat from the RCS.

ACTIONS

A.1

With one outlet isolation valve inoperable on one CMT, action must be taken to restore the valve. In this Condition, the CMT is capable of performing its safety function, provided a single failure of the remaining parallel isolation valve does not occur. A Completion Time of 72 hours is acceptable for two train ECCS systems which are capable of performing their safety function without a single failure.

B.1

If the water temperature or boron concentration of one CMT is not within limits, it must be returned to within limits within 72 hours. The deviations in these parameters are expected to be slight, considering the frequent surveillances and control room monitors. With the temperature above the limit, the full core cooling capability assumed in the safety analysis may not be available. With the boron concentration not within limits, the ability to maintain subcriticality following a DBA may be degraded. However, because only one of two CMTs is inoperable, and the deviations of these parameters are expected to be slight, it is probable that more than a required amount of boron and cooling capability will be available to meet the conditions assumed in the safety analysis.

BASES

ACTIONS (continued)

Since the CMTs are redundant, safety class components, the 72 hour Completion Time is consistent with the times normally allowed for this type of component.

C.1

With two CMTs inoperable due to water temperature or boron concentration, at least one CMT must be restored to within limits in 8 hours. The deviations in these parameters are expected to be slight, considering the frequent surveillances and control room monitors. A Completion Time of 8 hours is considered reasonable since the CMTs are expected to be capable of performing their safety function with slight deviations in these parameters and the accumulators are required to be available for LOCA mitigation (i.e., entry into Condition B of LCO 3.5.1 has not occurred). The effectiveness of accumulator injection is demonstrated in analysis performed to justify PRA success criteria (Ref. 3). The analysis contained in this reference shows that for a small LOCA, the injection from one accumulator without any CMT injection supports adequate core cooling. This analysis provides a high confidence that with the unavailability of two CMTs due to water temperature or boron concentration deviations, the core can be cooled following design bases accidents.

The 1 hour Completion Time, in the case with simultaneous entry into Condition B of LCO 3.5.1, requires very prompt actions to restore either the CMT or the accumulator to OPERABLE status. This Completion Time is considered reasonable because of the low probability of simultaneously entering these multiple PXS Conditions and the very small likelihood of a LOCA occurring at the same time.

D.1

Excessive amounts of noncondensible gases in a CMT inlet line may interfere with the natural circulation flow (hot water from the RCS through the balance line into the CMT and cold water from the CMT through the direct vessel injection line into the vessel) assumed in the safety analyses for some transients. For CMT injection following a LOCA (steam will enter the CMT through the balance line, displacing the CMT water), gases in the CMT inlet line are not detrimental to the CMT function. The presence of some noncondensible gases does not mean that the CMT natural circulation capability is immediately inoperable, but that gases are collecting and should be vented. The venting of these gases requires containment entry to manually operate the vent valves. A Completion Time of 24 hours is permitted for venting noncondensible gases and is

BASES

ACTIONS (continued)

acceptable, since, for the transients, the natural circulation capability of one CMT is adequate to ensure mitigation assuming less conservative analysis assumptions regarding stuck rods and core characteristics.

E.1

With one CMT inoperable for reasons other than Condition A, B, C, D, operation of the CMT may not be available. Action must be taken to restore the inoperable CMT to OPERABLE status within 8 hours. The remaining CMT is sufficient for DBAs except for LOCA in the OPERABLE CMTs DVI line. The 8 hour Completion Time is based on the required availability of injection from the accumulators (provided that entry into Condition B of LCO 3.5.1 has not occurred) to provide SI injection. The effectiveness of accumulator injection is demonstrated in analysis performed to justify PRA success criteria (Ref. 3). The analysis contained in this reference shows that for a small LOCA, the injection from one accumulator without any CMT supports adequate core cooling. This analysis provides a high confidence that with the unavailability of one CMT, the core can be cooled following design bases accidents.

The 1 hour Completion Time, in the case with simultaneous entry into Condition B of LCO 3.5.1, requires very prompt actions to restore either the CMT or the accumulator to OPERABLE status. This Completion Time is considered reasonable because of the low probability of simultaneously entering these multiple PXS Conditions and the very small likelihood of a LOCA occurring at the same time.

F.1 and F.2

If the Required Action or associated Completion Time of Condition A, B, C, D, or E are not met or the LCO is not met for reasons other than Conditions A through E, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

Verification every 24 hours and 7 days that the temperature and the volume, respectively, of the borated water in each CMT is within limits ensures that when a CMT is needed to inject water into the RCS, the injected water temperature and volume will be within the limits assumed

BASES

SURVEILLANCE REQUIREMENTS (continued)

in the accident analysis. The 24 hour Frequency is adequate, based on the fact that no mechanism exists to rapidly change the temperature of a large tank of water such as a CMT. These parameters are normally monitored in the control room by indication and alarms. Also, there are provisions for monitoring the temperature of the inlet and outlet lines to detect in-leakage which may affect the CMT water temperature.

SR 3.5.2.3

Each CMT inlet isolation valve must be verified to be fully open each 12 hours. Frequent verification is considered to be important, since a CMT can not perform its safety function, if the valve is closed. Control room instrumentation is normally available for this verification.

SR 3.5.2.4

Verification that excessive amounts of noncondensible gases are not present in the inlet line is required every 24 hours. The inlet line of each CMT has a vertical section of pipe which serves as a high point collection point for noncondensible gases. Control room indication of the water level in the high point collection point is available to verify that noncondensible gases have collected to the extent that the water level is depressed below the allowable level. The 24 hour Frequency is based on the expected low rate of gas accumulation and the availability of control room indication.

SR 3.5.2.5

Verification every 7 days that the boron concentration in each CMT is within the required limits ensures that the reactivity control from each CMT, assumed in the safety analysis, will be available as required. The 7 day Frequency is adequate to promptly identify changes which could occur from mechanisms such as in-leakage.

SR 3.5.2.6

Verification that the redundant outlet isolation valves are OPERABLE by stroking the valves open ensures that each CMT will function as designed when these valves are actuated. Prior to opening the outlet isolation valves, the inlet isolation valve should be closed temporarily. Closing the inlet isolation valve ensures that the CMT contents will not be diluted or heated by flow from the RCS. Upon completion of the test, the inlet isolation valves must be opened. The Surveillance Frequency references the inservice testing requirements.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

This SR requires performance of a system performance test of each CMT to verify flow capabilities. The system performance test demonstrates that the CMT injection line resistance assumed in DBA analyses is maintained. Although the likelihood that system performance would degrade with time is low, it is considered prudent to periodically verify system performance. The System Level Operability Testing Program provides specific test requirements and acceptance criteria.

REFERENCES

1. Section 6.3, “Passive Core Cooling System.”
2. Chapter 15, “Accident Analysis.”
3. AP1000 PRA.

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B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.3 Core Makeup Tanks (CMTs) – Shutdown, RCS Intact

BASES

BACKGROUND

A description of the CMTs is provided in the Bases for LCO 3.5.2, "Core Makeup Tanks – Operating."

APPLICABLE SAFETY ANALYSES

When the plant is shutdown with the Reactor Coolant System (RCS) pressure boundary intact, the CMT and Passive Residual Heat Removal (PRHR) are the preferred methods for mitigation of postulated events such as loss of normal decay heat removal capability (either loss of Startup Feedwater or loss of normal residual heat removal system). The CMT and PRHR are preferred because the RCS pressure boundary can remain intact, thus preserving one of the barriers to fission product release. For these events, the PRHR provides the safety related heat removal path. And the CMT maintains RCS inventory control. These events can also be mitigated by In-containment Refueling Water Storage Tank (IRWST) injection; however, the RCS must be depressurized (vented) in order to facilitate IRWST injection.

Since no loss of coolant accidents (LOCAs) are postulated during MODES 5 and 6, the possibility of a break in the direct vessel injection line is not considered. As a result, only one CMT is required to be available to provide core cooling in response to postulated events. The two parallel CMT outlet isolation valves ensure that injection from one CMT occurs in the event of a single active failure.

CMTs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO establishes the minimum conditions necessary to ensure that one CMT will be available for RCS inventory control in the event of the loss of normal decay heat removal capability. The two CMT outlet isolation valves must be OPERABLE to ensure that at least one valve will operate, assuming that the other valve is disabled by a single active failure.

APPLICABILITY

In MODE 4 without steam generator heat removal and in MODE 5 with the RCS pressure boundary intact, one CMT is required to provide borated water to the RCS in the event the nonsafety related chemical and volume control system makeup pumps are not available to provide RCS inventory control.

BASES

APPLICABILITY (continued)

The CMT requirements in MODES 1, 2, 3, and 4 are specified in LCO 3.5.2, "Core Makeup Tanks (CMTs) – Operating."

The CMTs are not required to be OPERABLE while in MODE 5 with the RCS open or in MODE 6 because the RCS is depressurized and borated water can be supplied from the IRWST, if needed.

ACTIONS

A.1

With one outlet isolation valve inoperable action must be taken to restore the valve. In this Condition the CMT is capable of performing its safety function, provided a single failure of the remaining parallel isolation valve does not occur. A Completion Time of 72 hours is consistent with times normally applied to an ECCS system which is capable of performing its safety function without a single failure.

B.1

If the water temperature or boron concentration in the CMT is not within limits, it must be returned to within limits within 72 hours. With the temperature above the limit the makeup capability assumed in the safety analysis may not be available. With the boron concentration not within limits, the ability to maintain subcriticality may be degraded.

Because the mechanisms for significantly altering these parameters in the CMT are limited, it is probable that more than the required amount of boron and cooling capacity will be available to meet the conditions assumed in the safety analysis. Therefore, the 72 hour Completion Time is acceptable.

C.1

With the required CMT inoperable for reasons other than Condition A or B operation of the CMT may not be available. Action must be taken to restore the inoperable CMT to OPERABLE status within 8 hours. LOCAs are not postulated during the MODEs when this LCO is applicable. The only safety function is to provide LEAKAGE makeup in case normal RCS makeup is unavailable. The 8 hour Completion Time is based on the availability of injection from the IRWST to provide RCS makeup. The ability of the IRWST to provide RCS injection is demonstrated by analysis performed to show that IRWST injection together with ADS venting provides adequate core cooling. Such analysis was performed for the loss of RNS cooling during midloop operations. The analysis was performed in support of the AP1000 PRA (Ref. 2).

BASES

ACTIONS (continued)

D.1

If the Required Action or associated Completion Time of Conditions A, B, or C are not met or the LCO is not met for reasons other than Conditions A through C, action must be initiated, immediately, to place the plant in a MODE where this LCO does not apply. Action must be initiated, immediately, to place the plant in MODE 5 with RCS pressure boundary open and ≥ 20% pressurizer level. In this condition, core cooling and RCS makeup are provided by IRWST injection and sump recirculation. Opening of the ADS valves ensures that IRWST injection can occur.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The LCO 3.5.2 Surveillance Requirements (SR 3.5.2.1 through 3.5.2.7) are applicable to the CMT required to be OPERABLE. The Frequencies associated with each specified SR are applicable. Refer to the corresponding Bases for LCO 3.5.2 for a discussion of each SR.

REFERENCES

1. Section 6.3, “Passive Core Cooling System.”

2. AP1000 PRA.

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.4 Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Operating

BASES

BACKGROUND

The normal heat removal mechanism is the steam generators, which are supplied by the startup feedwater system. However, this path utilizes non-safety related components and systems, so its failure must be considered. In the event the steam generators are not available to remove decay heat for any reason, including loss of startup feedwater, the heat removal path is the PRHR HX (Ref. 1).

The principle component of the PRHR HX is a 100% capacity heat exchanger mounted in the In-containment Refueling Water Storage Tank (IRWST). The heat exchanger is connected to the Reactor Coolant System (RCS) by a inlet line from one RCS hot leg, and an outlet line to the associated steam generator cold leg channel head. The inlet line to the passive heat exchanger contains a normally open, motor operated isolation valve. The outlet line is isolated by two parallel, normally closed air operated valves, which fail open on loss of air pressure or control signal. There is a vertical collection point at the top of the common inlet piping high point which serves as a gas collector. It is provided with level detectors that indicate when noncondensible gases have collected in this area. There are provisions to manually vent these gases to the IRWST.

In order to preserve the IRWST water for long term PRHR HX operation, a gutter is provided to collect and return water to the IRWST that has condensed on the inside surface of the containment shell. During normal plant operation any water collected by the gutter is directed to the normal containment sump. During PRHR HX operation, redundant series air operated valves are actuated to block the draining of condensate to the normal sump and to force the condensate into the IRWST. These valves fail closed on loss of air pressure or control signal.

The PRHR HX size and heat removal capability is selected to provide adequate core cooling for the limiting non-LOCA heatup Design Basis Accidents (DBAs) (Ref. 2). The Probability Risk Assessment (PRA) (Ref. 3) shows that PRHR HX is not required assuming that passive feed and bleed is available. Passive feed and bleed uses the Automatic Depressurization System (ADS) for bleed and the CMTs/accumulators/ IRWST for feed.

BASES

APPLICABLE SAFETY ANALYSES

In the event of a non-LOCA DBA during normal operation, the PRHR HX is automatically actuated to provide decay heat removal path in the event the normal path through the steam generators is not available (Ref. 2).

The non-LOCA events which establish the PRHR HX parameters are those involving a decrease in heat removal by the secondary system, such as loss of main feedwater or other failure in the feedwater system. Since the PRHR HX is passive, it will mitigate the consequences of these events with a complete loss of all AC power sources. The PRHR HX actuates when the CMTs are actuated during LOCA events.

The PRHR HX satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the PRHR HX be OPERABLE so that it can respond appropriately to the DBAs which may require its operation. Since this is a passive component, it does not require the actuation of active components such as pumps for its OPERABILITY and will be OPERABLE if the inlet valves are in their normally open position, and the normally closed, fail open outlet valves open on receipt of an actuation signal.

In addition to the appropriate valve configuration, OPERABILITY may be impaired by flow blockage caused by noncondensible gases collecting in the system. Thus the absence of noncondensible gases in the high point is necessary for system OPERABILITY.

The note requires a reactor coolant pump (RCP) to be operating in the loop with the PRHR HX, Loop 1, if any RCPs are operating. If RCPs are only operating in Loop 2 and no RCPs are operating in Loop 1, there is a possibility there may be reverse flow in the PRHR HX.

APPLICABILITY

The PRHR HX must be OPERABLE in MODES 1, 2, 3, and 4 with the RCS not cooled by the Normal Residual Heat Removal System (RNS) if a plant cooldown is required and the normal cooldown path is not available. Under these conditions, the PRHR HX may be actuated to provide core cooling and to mitigate the consequences of a DBA.

The PRHR HX requirements in MODE 4 with RCS cooling provided by the RNS and in MODE 5 with the RCS pressure boundary intact are specified in LCO 3.5.5, “Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Shutdown, RCS Intact.”

The PRHR HX is not capable of natural circulation cooling of the RCS in MODE 5 with the RCS pressure boundary open or in MODE 6.

BASES

ACTIONS

A.1

The outlet line from the PRHR HX is controlled by a pair of normally closed, fail open, air operated valves, arranged in parallel. Thus they are redundant and, if either valve is OPERABLE, the system can function at 100% capacity, assuming other OPERABILITY conditions are met.

If one valve is inoperable, a Completion Time of 72 hours has been allowed to restore the inoperable valve(s) to OPERABLE status. This Completion Time is consistent with the Completion Times specified for other parallel redundant safety related systems.

B.1

With one air operated IRWST gutter isolation valve inoperable, the remaining isolation valve can function to drain the gutter to the IRWST. Action must be taken to restore the inoperable gutter isolation valve to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable based on the capability of the remaining valve to perform 100% of the required safety function assumed in the safety analyses.

C.1

Excessive amounts of noncondensible gases in the PRHR HX inlet line may interfere with the natural circulation flow of reactor coolant through the PRHR HX. The presence of some noncondensible gases does not mean that the PRHR HX is immediately inoperable, but that gases are collecting and should be vented. The venting of these gases requires containment entry to manually operate the appropriate vent valves. A Completion Time of 24 hours is acceptable considering that passive feed and bleed cooling is available to remove heat from the RCS.

D.1 and D.2

If any of the above Required Actions have not been accomplished in the required Completion Time or the LCO is not met for reasons other than Conditions A, B, or C, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4, with the RCS cooled by the RNS, within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

ACTIONS (continued)

E.1

With the LCO not met for reasons other than Condition A, B, or C, the PRHR HX must be restored within 8 hours. The 8 hour Completion Time is based on the availability of passive feed and bleed cooling to provide RCS heat removal. The effectiveness of feed and bleed cooling has been demonstrated in analysis and evaluations performed to justify PRA success criteria (Ref. 3). The analysis contained in this reference shows that for a range of events including loss of main feedwater, SGTR, and small LOCA (as small as 1/2") that feed and bleed cooling provides adequate core cooling.

These analyses and evaluations provide a high confidence that with the unavailability of the PRHR HX the core can be cooled following design bases accidents.

F.1 and F.2

If the PRHR HX is not restored in accordance with Action E.1 within 8 hours, the plant must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 5 within 36 hours.

Action F.1 is modified by a Note which requires that prior to initiating cooldown of the plant to MODE 3, redundant means of providing SG feedwater be verified as OPERABLE. Possible means include main feedwater and startup feedwater pumps. With the PRHR HX and redundant means of feeding the SGs INOPERABLE, the unit is in a seriously degraded condition with no means for conducting a controlled cooldown. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. If redundant means of feeding the SGs are not available, the plant should be maintained in the current MODE until redundant means are restored. LCO 3.0.3 and all other Required Actions shall be suspended until the redundant means are restored, because they could force the unit into a less safe condition.

Action F.2 is modified by a Note which requires that prior to stopping SG feedwater, redundant means of cooling the RCS to cold shutdown conditions must be verified as OPERABLE. One redundant means of cooling the RCS to cold shutdown includes the normal residual heat removal system (RNS) and its necessary support system (both component cooling system pumps and heat exchangers, and both service water system pumps and fans). Without availability of these redundant

BASES

ACTIONS (continued)

cooling means, the unit is in a seriously degraded condition with no means for continuing the controlled cooldown. Until the redundant cooling means are restored, heat removal using SG feedwater should be maintained. LCO 3.0.3 and all other Required Actions shall be suspended until the systems and equipment required for further cooldown are restored, because they could force the unit into a less safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

Verification, using remote indication, that the common outlet manual isolation valve is fully open ensures that the flow path from the heat exchangers to the RCS is available. Misalignment of this valve could render the heat exchanger inoperable. A 12 hour Frequency is reasonable considering that the valve is manually positioned and has control room position indication and alarm.

SR 3.5.4.2

Verification that the motor operated inlet valve is fully open, as indicated in the main control room, ensures timely discovery if the valve is not fully open. The 12 hour Frequency is consistent with the ease of verification, confirmatory open signals, and redundant series valve controls that prevent spurious closure.

SR 3.5.4.3

Verification that excessive amounts of noncondensible gases are not present in the inlet line is required every 24 hours. The inlet line of the PRHR HX has a vertical section of pipe which serves as a high point collection point for noncondensible gases. Control room indication of the water level in this high point collection point is available to verify that noncondensible gases have not collected to the extent that the water level is depressed below the allowable level. The 24 hour Frequency is based on the expected low rate of gas accumulation and the availability of control room indication.

SR 3.5.4.4

Verification is required to confirm that power is removed from the motor operated inlet isolation valve every 31 days. Removal of power from this valve reduces the likelihood that the valve will be inadvertently closed as a result of a fire. The 31 day Frequency is acceptable considering the frequent surveillance of valve position and that the valve has a confirmatory open signal.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.5

Verification that both air operated outlet valves and both IRWST gutter isolation valves are OPERABLE ensures that the PRHR HX will actuate on command, with return flow from the gutter to the IRWST, since all other components of the system are normally in the OPERABLE configuration. Since these valves are redundant, if one valve is inoperable, the system can function at 100% capacity. Verification requires the actual operation of each valve through a full cycle to demonstrate OPERABILITY. The Surveillance Frequency is provided in the Inservice Testing Program.

SR 3.5.4.6

This SR requires performance of a system performance test of the PRHR HX to verify system heat transfer capabilities. The system performance test demonstrates that the PRHR HX heat transfer assumed in accident analyses is maintained. Although the likelihood that system performance would degrade with time is low, it is considered prudent to periodically verify system performance. The System Level Operability Testing Program provides specific test requirements and acceptance criteria.

SR 3.5.4.7

This surveillance requires visual inspection of the IRWST gutters to verify that the return flow to the IRWST will not be restricted by debris. A Frequency of 24 months is adequate, since there are no known sources of debris with which the gutters could become restricted.

REFERENCES

1. Section 6.3, "Passive Core Cooling System."
2. Chapter 15, "Safety Analysis."
3. AP1000 PRA.

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.5 Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Shutdown, RCS Intact

BASES

BACKGROUND

A description of the PRHR HX is provided in the Bases for LCO 3.5.4, “Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Operating.”

APPLICABLE SAFETY ANALYSES

In the event of a loss of normal decay heat removal capability during shutdown with the Reactor Coolant System (RCS) pressure boundary intact, the PRHR HX provides the preferred safety related heat removal path. When required, the PRHR HX is manually actuated and can maintain the RCS < 420°F. Alternatively, the heat removal function can be provided by depressurizing the RCS with the Automatic Depressurization System (ADS) and injection of the In-containment Refueling Water Storage Tank (IRWST) with containment closure capability provided. The PRHR HX is preferred because the RCS pressure boundary remains intact, thus preserving a barrier to fission product release.

The PRHR HX satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires the PRHR HX to be OPERABLE so that it can be placed in service in the event normal decay heat removal capability is lost. Since this a passive component, it does not require the actuation of active components such as pumps for its OPERABILITY and will be OPERABLE if the inlet valves are in their normally open position, and the normally closed, fail open outlet valves open on receipt of an actuation signal.

In addition to the appropriate valve configuration, OPERABILITY may be impaired by flow blockage caused by noncondensible gases collecting in the system. Thus the absence of non-condensible gases in the high point is necessary for system OPERABILITY.

The note requires a reactor coolant pump (RCP) to be operating in the loop with the PRHR HX, Loop 1, if any RCPs are operating. If RCPs are only operating in loop 2 and no RCPs are operating in loop 1, there is a possibility there may be reverse flow in the PRHR HX.

BASES

APPLICABILITY

The PRHR HX must be OPERABLE in MODE 4 with RCS cooling provided by the RNS and in MODE 5 with the RCS pressure boundary intact and pressurizer level ≥ 20% to provide decay heat removal in the event the normal residual heat removal system is not available.

The PRHR HX requirements in MODES 1, 2, 3, and 4 with RCS cooling not provided by the RNS are specified in LCO 3.5.4, "Passive Residual Heat Removal Heat Exchanger (PRHR HX) – Operating."

The PRHR HX is not capable of natural circulation cooling of the RCS in MODE 5 with either the RCS pressure boundary open or with the RCS intact when pressurizer level ≤ 20%, or in MODE 6.

ACTIONS

A.1

The outlet line from the PRHR HX is isolated by a pair of normally closed, fail open, air operated valves, arranged in parallel. They are redundant, and if either valve is OPERABLE the system can function at 100% capacity, assuming other OPERABILITY conditions are met.

Since these valves are redundant, if one valve is inoperable, a Completion Time of 72 hours has been allowed to restore the inoperable valve to OPERABLE status. This Completion Time is consistent with the Completion Times specified for other parallel redundant safety related systems.

B.1

With one air operated IRWST gutter isolation valve inoperable, the remaining isolation valve can function to drain the gutter to the IRWST. Action must be taken to restore the inoperable gutter isolation valve to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable based on the capability of the remaining valve to perform 100% of the required safety function assumed in the safety analyses.

C.1

At the inlet piping high point there is a vertical chamber which serves as a collection point for noncondensible gases. This collection point is provided with detectors which alarm to indicate when gases have collected in this area. The presence of an alarm does not mean that PRHR HX is immediately inoperable, but that gases are collecting and should be vented. A Completion Time of 24 hours is acceptable, considering that passive feed and bleed cooling is available to revise heat from the RCS.

BASES

ACTIONS (continued)

D.1

With the LCO not met for reasons other than Condition A, B, or C, the PRHR HX must be restored within 8 hours. The 8 hour Completion Time is acceptable based on the availability of passive feed and bleed cooling to provide RCS heat removal. The effectiveness of feed and bleed cooling is discussed in the bases for LCO 3.4.4, Action E.1.

E.1

If any of the above Required Actions have not been accomplished in the required Completion Time, or the LCO is not met for reasons other than Conditions A, B, C, or D, action must be initiated, immediately, to be in MODE 5 with the RCS pressure boundary open and pressurizer level $\geq$ 20%. The time to RCS boiling is maximized in the event of loss of normal decay heat removal capability, by maintaining a visible level in the pressurizer. Additionally, in this MODE the RCS must be opened, such that safety related decay heat removal can be immediately initiated by actuation of the IRWST injection valve(s).

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

The LCO 3.5.4 Surveillance Requirements are applicable to the PRHR HX required to be OPERABLE. The Frequencies associated with each specified SR are applicable. Refer to the corresponding Bases for LCO 3.5.4 for a discussion of each SR.

REFERENCES

None.

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.6 In-containment Refueling Water Storage Tank (IRWST) – Operating

BASES

BACKGROUND

The IRWST is a large stainless steel lined tank filled with borated water (Ref. 1). It is located below the operating deck in containment. The tank is designed to meet seismic Category 1 requirements. The floor of the IRWST is elevated above the reactor coolant loop so that borated water can drain by gravity into the Reactor Coolant System (RCS). The IRWST is maintained at ambient containment pressure.

The IRWST has two injection flow paths. The injection paths are connected to the reactor vessel through two direct vessel injection lines which are also used by the accumulators and the core makeup tanks. Each path includes an injection flow path and a containment recirculation flow path. Each injection path includes a normally open motor operated isolation valve and two parallel actuation lines each isolated by one check valve and one squib valve in series.

The IRWST has two containment recirculation flow paths. Each containment recirculation path contains two parallel actuation flow paths, one path is isolated by a normally open motor operated valve in series with a squib valve and one path is isolated by a check valve in series with a squib valve.

During refueling operations, the IRWST is used to flood the refueling cavity. During abnormal events, the IRWST serves as a heat sink for the passive residual heat removal heat exchangers, as a heat sink for the depressurization spargers, and as a source of low head (ambient containment pressure) safety injection during loss of coolant accidents (LOCAs) and loss of decay heat removal in MODE 5 (loops not filled). The IRWST can be cooled by the Normal Residual Heat Removal System (RNS) system.

The IRWST size and injection capability is selected to provide adequate core cooling for the limiting Design Basis Accidents (DBAs) (Ref. 2).

APPLICABLE SAFETY ANALYSES

During non-LOCA events, the IRWST serves as the initial heat sink for the PRHR Heat Exchanger (PRHR HX) if used during reactor cooldown to MODE 4. If RNS is available, it will be actuated in MODE 4 and used to continue the plant cooldown to MODE 5. If RNS is not available, cooldown can continue on PRHR. Continued PRHR HX operation will result in the water in the IRWST heating up to saturation conditions and

BASES

APPLICABLE SAFETY ANALYSES (continued)

boiling. The steam generated in the IRWST enters the containment through the IRWST vents. Most of the steam generated in the IRWST condenses on the inside of the containment vessel and drains back to the IRWST.

For events which involve a loss of primary coolant inventory, such as a large break LOCA, or other events involving automatic depressurization, the IRWST provides low pressure safety injection (Ref. 2). The IRWST drain down time is dependent on several factors, including break size, location, and the return of steam condensate from the passive containment cooling system. During drain down, when the water in the IRWST reaches the Low 5 level, the containment sump will be sufficiently flooded, to initiate containment sump recirculation. This permits continued cooling of the core by recirculation of the spilled water in the containment sumps via the sump recirculation flow paths. In this situation, core cooling can continue indefinitely.

When the plant is in midloop operation, the pressurizer Automatic Depressurization System (ADS) valves are open, and the RNS is used to cool the RCS. The RNS is not a safety related system, so its failure must be considered. In this situation, with the RCS drained and the pressure boundary open, the PRHR HX cannot be used. In such a case, core cooling is provided by gravity injection from the IRWST, venting the RCS through the ADS. Injection from the IRWST provides core cooling until the tank empties and gravity recirculation from the containment starts. With the containment closed, the recirculation can continue indefinitely, with the decay heat generated steam condensing on the containment vessel and draining back into the IRWST.

The IRWST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The IRWST requirements ensure that an adequate supply of borated water is available to act as a heat sink for PRHR and to supply the required volume of borated water as safety injection for core cooling and reactivity control.

To be considered OPERABLE, the IRWST must meet the water volume, boron concentration, and temperature limits defined in the surveillance requirements. The motor operated injection isolation valves must be open with power removed, and the motor operated sump recirculation isolation valves must be open.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a safety related function of the IRWST is to provide a heat sink for PRHR. In MODES 1, 2, 3, 4, and 5, a second safety related function is the low head safety injection of borated water following a LOCA for core cooling and reactivity control. Both of these functions must be available to meet the initial assumptions of the safety analyses. These assumptions require the specified boron concentration, the minimum water volume, and the maximum water temperature.

The requirements for the IRWST in MODES 5 and 6 are specified in LCO 3.5.7, In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 5 and LCO 3.5.8, In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 6.

ACTIONS

A.1

If an IRWST injection line actuation valve flow path or a containment recirculation line actuation valve flow path is inoperable, then the valve actuation flow path must be restored to OPERABLE status within 72 hours. In this condition, three other IRWST injection or containment sump recirculation flow paths are available and can provide 100% of the required flow assuming a break in the direct vessel injection line associated with the other injection train, but with no single failure of the actuation valve flow path in the same injection or sump recirculation flow path. The 72 hour Completion Time is consistent with times normally applied to degraded two train ECCS systems which can provide 100% of the required flow without a single failure.

B.1

If the IRWST water volume, boron concentration, or temperature are not within limits, the core cooling capability from injection or PRHR HX heat transfer and the reactivity benefit of injection assumed in safety analyses may not be available. Due to the large volume of the IRWST, online monitoring of volume and temperature, and frequent surveillances, the deviation of these parameters is expected to be minor. The allowable deviation of the water volume is limited to 3%. This limit prevents a significant change in boron concentration and is consistent with the long-term cooling analysis performed to justify PRA success criteria (Ref. 3), which assumed multiple failures with as many as 3 CMTs/Accum not injecting. This analysis shows that there is significant margin with respect to the water supplies that support containment recirculation operation. The 8-hour Completion Time is acceptable, considering that the IRWST will be fully capable of performing its assumed safety function in response to DBAs with slight deviations in these parameters.

BASES

ACTIONS (continued)

C.1

If the motor operated IRWST isolation valves are not fully open or valve power is not removed, injection flow from the IRWST may be less than assumed in the safety analysis. In this situation, the valves must be restored to fully open with valve power removed in 1 hour. This Completion Time is acceptable based on risk considerations.

D.1 and D.2

If the IRWST cannot be returned to OPERABLE status within the associated Completion Times or the LCO is not met for reasons other than Conditions A, B, or C, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.6.1

The IRWST borated water temperature must be verified every 24 hours to ensure that the temperature is within the limit assumed in the accident analysis. This Frequency is sufficient to identify a temperature change that would approach the limit and has been shown to be acceptable through operating experience.

SR 3.5.6.2

Verification every 24 hours that the IRWST borated water volume is above the required minimum level will ensure that a sufficient initial supply is available for safety injection and floodup volume for recirculation and as the heat sink for PRHR. During shutdown with the refueling cavity flooded with water from the IRWST, this Surveillance requires that the combined volume of borated water in the IRWST and refueling cavity meet the specified limit. Since the IRWST volume is normally stable, and is monitored by redundant main control indication and alarm, a 24 hour Frequency is appropriate.

SR 3.5.6.3

Verification every 31 days that the boron concentration of the IRWST is greater than the required limit, ensures that the reactor will remain subcritical following a LOCA. Since the IRWST volume is large and

BASES

SURVEILLANCE REQUIREMENTS (continued)

normally stable, the 31 day Frequency is acceptable, considering additional verifications are required within 6 hours after each solution volume increase of 15,000 gal. In addition, the relatively frequent surveillance of the IRWST water volume provides assurance that the IRWST boron concentration is not changed.

SR 3.5.6.4

This surveillance requires verification that each motor operated isolation valve is fully open. This surveillance may be performed with available remote position indication instrumentation. The 12 hour Frequency is acceptable, considering the redundant remote indication and alarms and that power is removed from the valve operator.

SR 3.5.6.5

Verification is required to confirm that power is removed from each motor operated IRWST isolation valve each 31 days. Removal of power from these valves reduces the likelihood that the valves will be inadvertently closed. The 31 day Frequency is acceptable considering frequent surveillance of valve position and that the valve has a confirmatory open signal.

SR 3.5.6.6

Each motor operated containment recirculation isolation valve must be verified to be fully open. This valve is required to be open to improve containment recirculation reliability. The 31 day Frequency is acceptable considering the valve has a confirmatory open signal. This surveillance may be performed with available remote position indication instrumentation.

SR 3.5.6.7

This Surveillance requires verification that each IRWST injection and each containment recirculation squib valve is OPERABLE in accordance with the Inservice Testing Program. The Surveillance Frequency for verifying valve OPERABILITY references the Inservice Testing Program.

The squib valves will be tested in accordance with ASME Section XI which specifies valve testing in accordance with the ASME OM Code. The applicable ASME OM Code squib valve requirements are specified in paragraph 4.6, Inservice Tests for Category D Explosively Actuated Valves. The requirements include actuation of a sample of the installed valves each 2 years and periodic replacement of charges.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.6.8

Visual inspection is required each 24 months to verify that the IRWST screens and the containment recirculation screens are not restricted by debris. A Frequency of 24 months is adequate, since there are no known sources of debris with which the gutters could become restricted.

SR 3.5.6.9

This SR requires performance of a system inspection and performance test of the IRWST injection and recirculation flow paths to verify system flow capabilities. The system inspection and performance test demonstrates that the IRWST injection and recirculation capabilities assumed in accident analyses is maintained. Although the likelihood that system performance would degrade with time is low, it is considered prudent to periodically verify system performance. The System Level Operability Testing Program provides specific test requirements and acceptance criteria.

REFERENCES

1. Section 6.3, “Passive Core Cooling.”
2. Section 15.6, “Decrease in Reactor Coolant Inventory.”
3. AP1000 PRA.

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.7 In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 5

BASES

BACKGROUND	A description of the IRWST is provided in LCO 3.5.6, “In-containment Refueling Water Storage Tank – Operating.”
APPLICABLE SAFETY ANALYSES	For postulated shutdown events in MODE 5 with the Reactor Coolant System (RCS) pressure boundary intact, the primary protection is Passive Residual Heat Removal (PRHR), where the IRWST serves as the initial heat sink for the PRHR heat exchanger (PRHR HX). For events in MODE 5 with the RCS pressure boundary open, PRHR is not available and RCS heat removal is provided by IRWST injection and containment sump recirculation. IRWST injection could be required to mitigate some events by providing RCS inventory makeup. No loss of coolant accidents (LOCAs) are postulated during plant operation in MODE 5; therefore, the rupture of the direct vessel injection line (DVI) is not assumed. Since the DVI rupture is not assumed, only one train of IRWST injection and recirculation flow paths is required to mitigation postulated events, assuming a single failure. The IRWST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The IRWST requirements ensure that an adequate supply of borated water is available to act as a heat sink for PRHR and to supply the required volume of borated water as safety injection for core cooling and reactivity control. To be considered OPERABLE, the IRWST must meet the water volume, boron concentration, and temperature limits defined in the Surveillance Requirements, and one path of injection and recirculation must be OPERABLE (the motor operated injection isolation valve must be open with power removed, and the motor operated sump recirculation isolation valves must be open).
APPLICABILITY	In MODE 5 with the RCS pressure boundary intact or with the RCS open with pressurizer level ≥ 20%, the IRWST is an RCS injection source of borated water for core cooling and reactivity control. Additionally, in MODE 5 with the RCS pressure boundary intact, the IRWST provides the heat sink for PRHR.

BASES

APPLICABILITY (continued)

The requirements for the IRWST in MODES 1, 2, 3, and 4 are specified in LCO 3.5.6, In-containment Refueling Water Storage Tank (IRWST) – Operating. The requirements for the IRWST in MODE 6 are specified in LCO 3.5.8, In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 6.

ACTIONS

A.1

If a motor operated containment sump isolation valve in one sump recirculation flow path is not fully open, the valve must be fully opened within 72 hours. The 72 hour Completion Time is consistent with times normally applied to degraded two train ECCS systems which can provide 100% of the required flow without a single failure.

B.1

If the IRWST water volume, boron concentration, or temperature are not within limits, the core cooling capability from injection or PRHR heat transfer and the reactivity benefit of injection assumed in safety analyses may not be available. Due to the large volume of the IRWST, online monitoring of volume and temperature, and frequent surveillances, the deviation of these parameters is expected to be minor. The allowable deviation of the water volume is limited to 3%. This limit prevents a significant change in boron concentration and is consistent with the long-term cooling analysis performed to justify PRA success criteria (Ref. 3), which assumed multiple failures with as many as 3 CMTs/Accum not injecting. This analysis shows that there is significant margin with respect to the water supplies that support containment recirculation operation. The 8-hour Completion Time is acceptable, considering that the IRWST will be fully capable of performing its assumed safety function in response to DBAs with slight deviations in these parameters.

C.1

If the motor operated IRWST isolation valves are not fully open or valve power is not removed, injection flow from the IRWST may be less than assumed in the safety analysis. In this situation, the valves must be restored to fully open with valve power removed in 1 hour. This Completion Time is acceptable based on risk considerations.

D.1 and D.2

If the IRWST cannot be returned to OPERABLE status within the associated Completion Times or the LCO is not met for reasons other than Conditions A, B, or C, the plant must be placed in a condition in which the probability and consequences of an event are minimized to the

BASES

ACTIONS (continued)

extent possible. This is done by immediately initiating action to place the plant in MODE 5 with the RCS intact with ≥ 20% pressurizer level. The time to RCS boiling is maximized by maintaining RCS inventory at ≥ 20% pressurizer level and maintaining RCS temperature as low as practical. With the RCS intact, the availability of the PRHR HX is maintained. Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS.

SURVEILLANCE REQUIREMENTS

SR 3.5.7.1

The LCO 3.5.6 Surveillance Requirements and Frequencies (SR 3.5.6.1 through 3.5.6.7) are applicable to the IRWST and the flow paths required to be OPERABLE. Refer to the corresponding Bases for LCO 3.5.6 for a discussion of each SR.

REFERENCES

None.

B 3.5 PASSIVE CORE COOLING SYSTEM (PXS)

B 3.5.8 In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 6

BASES

BACKGROUND

A description of the IRWST is provided in LCO 3.5.6, “In-containment Refueling Water Storage Tank (IRWST) – Operating.”

APPLICABLE SAFETY ANALYSES

For MODE 6, heat removal is provided by IRWST injection and containment sump recirculation.

IRWST injection could be required to mitigate some events by providing RCS inventory makeup.

One line with redundant, parallel valves is required to accommodate a single failure (to open) of an isolation valve.

The IRWST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The IRWST requirements ensure that an adequate supply of borated water is available to supply the required volume of borated water as safety injection for core cooling and reactivity control.

To be considered OPERABLE, the IRWST in combination with the refueling cavity must meet the water volume, boron concentration, and temperature limits defined in the Surveillance Requirements, and one path of injection and recirculation must be OPERABLE. The motor operated injection isolation valve must be open and power removed, and the motor operated sump recirculation isolation valves must be closed and OPERABLE. Any cavity leakage should be estimated and made up with borated water such that the volume in the IRWST plus the refueling cavity will meet the IRWST volume requirement.

APPLICABILITY

In MODE 6, the IRWST is an RCS injection source of borated water for core cooling and reactivity control.

The requirements for the IRWST in MODES 1, 2, 3, and 4 are specified in LCO 3.5.6, In-containment Refueling Water Storage Tank (IRWST) – Operating. The requirements for the IRWST in MODE 5 are specified in LCO 3.5.7, In-containment Refueling Water Storage Tank (IRWST) – Shutdown, MODE 5.

BASES

ACTIONS

A.1

With one motor operated containment sump isolation valve not fully open, the valve must be fully opened within 72 hours. The 72 hour Completion Time is consistent with times normally applied to degraded two train ECCS systems which can provide 100% of the required flow without a single failure.

B.1

If the IRWST and refueling cavity water volume, boron concentration, or temperature are not within limits, the core cooling capability from injection or PRHR HX heat transfer and the reactivity benefit of injection assumed in safety analyses may not be available. Due to the large volume of the IRWST, online monitoring of volume and temperature, and frequent surveillances, the deviation of these parameters is expected to be minor. The allowable deviation of the water volume is limited to 3%. This limit prevents a significant change in boron concentration and is consistent with the long-term cooling analysis performed to justify PRA success criteria (Ref. 3), which assumed multiple failures with as many as 3 CMTs/Accum not injecting. This analysis shows that there is significant margin with respect to the water supplies that support containment recirculation operation. The 8-hour Completion Time is acceptable, considering that the IRWST will be fully capable of performing its assumed safety function in response to DBAs with slight deviations in these parameters.

C.1

If the motor operated IRWST isolation valves are not fully open or valve power is not removed, injection flow from the IRWST may be less than assumed in the safety analysis. In this situation, the valves must be restored to fully open with valve power removed in 1 hour. This Completion Time is acceptable based on risk considerations.

D.1 and D.2

If the IRWST cannot be returned to OPERABLE status within the associated Completion Times or the LCO is not met for reasons other than Conditions A, B, C, or D, the plant must be placed in a Condition in which the probability and consequences of an event are minimized to the extent possible. In MODE 6, action must be immediately initiated to be in MODE 6 with the cavity water level ≥ 23 feet above the top of the reactor vessel flange.

The time to RCS boiling is maximized by maximizing the RCS inventory and maintaining RCS temperature as low as practical. With the RCS intact, another means of removing decay heat is available (the PRHR HX). Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive

BASES

ACTIONS (continued)

reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS. These Actions place the plant in a condition which maximizes the time to IRWST injection, thus providing time for repairs or application of alternative cooling capabilities.

SURVEILLANCE REQUIREMENTS

SR 3.5.8.1

The IRWST and refueling cavity borated water temperature must be verified every 24 hours to ensure that the temperature is within the limit assumed in accident analysis. This Frequency is sufficient to identify a temperature change that would approach the limit and has been shown to be acceptable through operating experience.

SR 3.5.8.2

Verification every 24 hours that the IRWST and refueling cavity borated water volume is above the required minimum level will ensure that a sufficient initial supply is available for safety injection and floodup volume for recirculation and as the heat sink for PRHR. During shutdown with the refueling cavity flooded with water from the IRWST, this Surveillance requires that the combined volume of borated water in the IRWST and refueling cavity meet the specified limit. Since the IRWST volume is normally stable, and is monitored by redundant main control indication and alarm, a 24 hour Frequency is appropriate.

SR 3.5.8.3

Verification every 31 days that the boron concentration of the IRWST and refueling cavity is greater than the required limit ensures that the reactor will remain subcritical following shutdown events. Since the IRWST volume is large and normally stable, the 31 day Frequency is acceptable, considering additional verifications are required within 6 hours after each solution volume increase of 15,000 gal.

SR 3.5.8.4

LCO 3.5.6 Surveillance Requirements and Frequencies SR 3.5.6.4 through 3.5.6.8 are applicable to the IRWST and the flow paths required to be OPERABLE. Refer to the corresponding Bases for LCO 3.5.6 for a discussion of each SR.

REFERENCES

None.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment is a free standing steel pressure vessel surrounded by a reinforced concrete shield building. The containment vessel, including all its penetrations, is a low-leakage steel vessel designed to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA) such that offsite radiation exposures are maintained within limits. The containment and shield building provide shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment vessel is a vertical cylindrical steel pressure vessel with elliptical upper and lower heads, completely enclosed by a seismic Category I reinforced concrete shield building. A 4.5 foot wide annular space exists between the walls and domes of the steel containment vessel and the concrete shield building to permit inservice inspection and air flow over the steel dome for containment cooling. The containment utilizes the outer concrete building for shielding and a missile barrier, and the inner steel containment for leak tightness and passive containment cooling.

Containment piping penetration assemblies provide for the passage of process, service and sampling pipelines into the containment vessel while maintaining containment integrity. The shield building provides biological shielding and environmental missile protection for the containment vessel and the Nuclear Steam Supply System.

The inner steel containment and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate Surveillance Requirements conform with 10 CFR 50, Appendix J (Ref. 1), as modified by approved exemptions.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

    1. capable of being closed by an OPERABLE automatic containment isolation system, or

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, “Containment Isolation Valves”;

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, “Containment Air Locks”; and

c. All equipment hatches are closed.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rates.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. The DBA analyses assume that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment is designed with an allowable leakage rate of 0.10% of containment air weight of the original content of containment air after a DBA per day (Ref. 3). This leakage rate, used in the evaluation of offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on containment leakage rate testing. L_a is assumed to be 0.10% per day in the safety analysis.

Satisfactory leakage rate test results is a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program Leakage Test. At this time, the applicable leakage limits must be met.

BASES

LCO (continued)

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. The MODES 5 and 6 requirements are specified in LCO 3.6.8, “Containment Penetrations”.

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $< 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.”
2. Chapter 15, “Accident Analysis.”
3. Section 6.2, “Containment Systems.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 feet in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBA that results in the largest release of radioactive material within containment is a loss of coolant accident (LOCA) (Ref. 3). In the analyses of DBAs, it is assumed that containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of containment leakage. The containment is designed with an allowable leakage rate of 0.10% of containment air weight of the original content of containment air per day after a DBA (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a following a DBA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	Each containment air lock forms part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of offsite radiation exposures resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is necessary to support containment OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry and exit from containment.
APPLICABILITY	In MODES 1, 2, 3, and 4 a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES and large inventory of coolant. Therefore, containment air locks are not required to be OPERABLE in MODES 5 and 6 to prevent leakage of radioactive material from containment. However, containment closure capability is required within MODES 5 and 6 as specified in LCO 3.6.8.
ACTIONS	The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair without interrupting containment integrity. If containment entry is required, it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

ACTIONS (continued)

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event that air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, “Containment.”

<u>A.1, A.2, and A.3</u>

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, “Containment,” which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is reasonable based on engineering judgement and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified to be locked closed by administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

The Required Actions are modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the airlock are inoperable. With both doors in the same airlock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of an airlock for entry and exit for 7 days, under administrative controls if both airlocks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specification (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (non-TS-related activities) if the containment is entered, using the inoperable airlock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock door interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same airlock are inoperable. With both doors in the same airlock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the airlock to ensure that only one door is opened at a time (the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to airlock doors located in high radiation areas that allows these doors to be verified locked closed by administrative means. Allowing verification by administrative means is considered acceptable since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position is small.

BASES

ACTIONS (continued)

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance

BASES

SURVEILLANCE REQUIREMENTS (continued)

criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is as required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock door interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at 24 month Frequency. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the airlock.

BASES

REFERENCES	1.	10 CFR 50, Appendix J, Option B "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors, Performance-Based Requirements."
	2.	Section 6.2, "Containment Systems."
	3.	Chapter 15, "Accident Analysis."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Section 6.2 (Ref. 1) identifies parameters which initiate isolation signal generation for containment isolation valves. The containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analysis. Therefore, the OPERABILITY requirements provide assurance that containment function assumed in the safety analysis will be maintained.

<u>Containment Air Filtration System [16-inch] purge valves</u>

The Containment Air Filtration System operates to:

a. Supply outside air into the containment for ventilation and cooling or heating,

b. Reduce the concentration of noble gases within containment prior to and during personnel access, and

c. Equalize internal and external pressures.

BASES

BACKGROUND (continued)

Since the valves used in the Containment Air Filtration System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3 and 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analysis of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 2). In the analyses for each of the accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized.

The DBA dose analysis assumes that, following containment isolation signal generation, the containment purge isolation valves are closed within 10 seconds. The remainder of the automatic isolation valves are assumed closed and the containment leakage is terminated except for the design leakage rate, L_a. Since the containment isolation valves are powered from the 1E division batteries no diesel generator startup time is applied.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the design of the containment purge isolation valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard isolation valves on each line are pneumatically operated, spring closed valves that fail in the closed position and are provided with power via independent sources.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves’ safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

BASES

LCO (continued)

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The valves covered by this LCO are listed along with their associated stroke times in the Section 6.2 (Ref. 1).

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, or blind flanges are in place and closed systems are intact. These passive isolation valves/devices are those listed in Reference 1.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4 a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment isolation valves are not required to be OPERABLE in MODES 5 and 6 to prevent leakage of radioactive material from containment. However, containment closure capability is required in MODES 5 and 6. The requirements for containment isolation valves during MODES 5 and 6 are addressed in LCO 3.6.8, “Containment Penetrations.”

ACTIONS

The ACTIONS are modified by a Note allowing containment penetration flow paths to be unisolated intermittently under administrative control. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

ACTIONS (continued)

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event that the containment isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, or a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration, the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4, and the availability of a second barrier.

For affected penetrations that cannot be restored to OPERABLE status within the 4 hour Completion Time and have been isolated in accordance with Required Action A.1, the affected penetrations must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations that are required to be isolated following an accident and that are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of “once per 31 days for isolation devices outside containment” is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as “prior to entering MODE 4 from MODE 5, if not performed within the previous 92 days,” is based on engineering judgment and is considered reasonable in view of

BASES

ACTIONS (continued)

the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high-radiation areas, and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves once they have been verified to be in the proper position, is small.

<u>B.1</u>

With two containment isolation valves in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2 which remains in effect. This periodic verification is necessary to ensure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

BASES

ACTIONS (continued)

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event that the affected penetration is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Ref. 4. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas, and allows these devices to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered

BASES

ACTIONS (continued)

acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1 and D.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

This SR ensures that the [16 inch] purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the [16 inch] purge valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The [16 inch] purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.2.

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for valves outside containment is relatively easy, the 31 day Frequency is based on

BASES

SURVEILLANCE REQUIREMENTS (continued)

engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency specified as “prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days” is appropriate since these containment isolation valves are operated under administrative control and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation times are specified in Section 6.2.3 (Ref. 1) and Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.3.5

Automatic containment isolation valves close on isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. Section 6.2, “Containment Systems.”

2. Chapter 15, “Accident Analysis.”

3. NUREG-1449, “Shutdown and Low Power Operation at Commercial Nuclear Power Plants in the United States.”

4. Standard Review Plan 6.2.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of transients which result in a negative pressure. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the operating band of conditions used in the containment pressure analyses for the Design Basis Events which result in internal or external pressure loads on the containment vessel. Should operation occur outside these limits, the initial containment pressure would be outside the range used for containment pressure analyses.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients (Ref. 1). The initial pressure condition used in the containment analysis was 15.7 psia (1.0 psig). This resulted in a maximum peak pressure from a LOCA, P_a, of [57.8] psig. The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure results from the SLB. The maximum containment pressure resulting from the SLB, [57.3] psig, does not exceed the containment design pressure, 59 psig. The containment was also designed for an external pressure load equivalent to 2.9 psig. The limiting negative pressure transient is a loss of all AC power sources coincident with extreme cold weather conditions which cool the external surface of the containment vessel. The initial pressure condition used in this analysis was -0.2 psig. This resulted in a minimum pressure inside containment, as illustrated in Reference 1, which is less than the design load. Other external pressure load events evaluated include: Failed fan cooler control Malfunction of containment purge system

BASES

APPLICABLE SAFETY ANALYSES (continued)

Inadvertent Incontainment Refueling Water Storage Tank (IRWST) drain

Inadvertent Passive Containment Cooling System (PCS) actuation

Since the containment external pressure design limits can be met by ensuring compliance with the initial pressure condition, NUREG-1431 LCO 3.6.12, Vacuum Relief System is not applicable to the AP1000 containment.

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following negative pressure transients.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, “Containment,” which requires that containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending of both containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the main control room, including alarms, to alert the operator to an abnormal containment pressure condition.

REFERENCES

1. Section 6.2, “Containment Analysis.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during plant operations. The total amount of energy to be removed from containment by the passive containment cooling system during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment Engineered Safety Feature (ESF) systems, assuming the loss of one Class 1E Engineered Safety Features Actuation Cabinet (ESFAC) Division, which is the worst case single active failure, resulting in one Passive Containment Cooling System flow path being rendered inoperable.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBA for the maximum peak containment air temperature is a LOCA or SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F.

The DBA temperature transients are used to establish the environmental qualification operating envelope for containment. The basis of the containment environmental qualification temperature envelope is to ensure the performance of safety related equipment inside containment (Ref. 2). The containment vessel design temperature is 300°F. The containment vessel temperature remains below 300°F for DBAs. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBAs.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Passive Containment Cooling System (Ref. 1).

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is an SLB or LOCA. The temperature limit is used in the DBA analyses to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is computed to remain within acceptable limits. As a result, the ability of containment to perform its design function is ensured.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

BASES

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within its limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the conservative analysis to variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that the containment average air temperature is within the LCO limit ensures that containment operation remains within the limits assumed for the containment analyses. In order to determine the containment average air temperature, a weighted average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the associated containment atmosphere. The 24 hour Frequency of this Surveillance Requirement is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the main control room, including alarms, to alert the operator to an abnormal containment temperature condition.

REFERENCES

1. Section 6.2, “Containment Systems.”
2. 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Passive Containment Cooling System (PCS) – Operating

BASES

BACKGROUND

The PCS provides containment cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA). The Passive Containment Cooling System is designed to meet the requirements of 10 CFR 50 Appendix A GDC 38 "Containment Heat Removal" and GDC 40 "Testing of Containment Heat Removal Systems" (Ref. 1).

The PCS consists of a 800,000 gal (nominal) cooling water tank, four headered tank discharge lines with flow restricting orifices, and two separate full capacity discharge flow paths to the containment vessel with 3 sets of isolation valves, each capable of meeting the design bases. Algae growth is not expected within the PCCWST; however, to assure water clarity is maintained, a prevailing concentration of hydrogen peroxide is maintained at 50 ppm. The recirculation pumps and heater provide freeze protection for the passive containment cooling water storage tank. However, OPERABILITY of the tank is assured by compliance with the temperature limits specified in SR 3.6.6.1 and not by the recirculation pumps and heater. In addition to the recirculation pumps and heater, the PCS water storage tank temperature can be maintained within limits by the ambient temperature, the large thermal inertia of the tank, or heat from other sources. The PCS valve room temperature must not be below freezing for an extended period to assure the water flow path to the containment shell is available. The isolation valves on each flow path are powered from a separate Division.

Upon actuation of the isolation valves, gravity flow of water from the cooling water tank (contained in the shield building structure above the containment) onto the upper portion of the containment shell reduces the containment pressure and temperature following a DBA. The flow of water to the containment shell surface is initially established to assure that the required short term containment cooling requirements following the postulated worst case LOCA are achieved. As the decay heat from the core becomes less with time, the water flow to the containment shell is reduced in three steps. The change in flow rate is attained without active components in the system and is dependent only on the decreasing water level in the elevated storage tank. In order to ensure the containment surface is adequately and effectively wetted, the water is introduced at the center of the containment dome and flows outward. Weirs are placed on the dome surface to distribute the water and ensure

BACKGROUND (continued)

effective wetting of the dome and vertical sides of the containment shell. The monitoring of the containment surface through the Reliability Assurance Program (RAP) and the Inservice Testing Program assures containment surface does not unacceptably degrade containment heat removal performance. During the initial test program, the containment coverage will be measured at the base of the upper annulus in addition to the coverage at the spring line for the full flow case and a lower flow case with PCS recirculation pumps delivering to the containment shell. These benchmark values at the base of the upper annulus will be used to develop acceptance criteria for technical specifications. Contamination can be removed by PCS actuation and by using coating vendor cleaning procedures.

The path for the natural circulation of air is from the air intakes in the shield building, down the outside of the baffle, up along the containment shell to the top, center exit in the shield building and is always open. The drains in the upper annulus region must be clear to prevent water from blocking the air flow path. Heat is removed from within the containment utilizing the steel containment shell as the heat transfer surface combining conductive heat transfer to the water film, convective heat transfer from the water film to the air, radiative heat transfer from the film to the air baffle, and mass transfer (evaporation) of the water film into the air. As the air heats up and water evaporates into the air, it becomes less dense than the cooler air in the air inlet annulus. This differential causes an increase in the natural circulation of the air upward along the containment surface, with heated air/water vapor exiting the top/center of the shield building. Additional system design details are provided in Reference 3.

The PCS is actuated either automatically, by a containment High-2 pressure signal, or manually. Automatic actuation opens the cooling water tank discharge valves, allowing gravity flow of the cooling water onto the containment shell. The manual containment cooling actuation consists of four momentary controls, if two associated controls are operated simultaneously actuation will occur in all divisions. The discharge continues for at least three days.

The PCS is designed to limit post-accident pressure and temperature in containment to less than the design values. Reduction of containment pressure reduces the release of fission product radioactivity from containment to the environment, in the event of a DBA.

The PCS is an ESF system and is designed to ensure that the heat removal capability required during the post accident period can be attained.

APPLICABLE SAFETY ANALYSES

The Passive Containment Cooling System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF system, assuming the loss of one Class 1E Engineered Safety Features Actuation Cabinet (ESFAC) Division, which is the worst case single active failure and results in one PCS flow path being inoperable.

The analyses and evaluations assume a unit specific power level of 3400 MWt, one passive containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 1.0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Passive Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment cooling system performance for post accident conditions is given in Reference 3. The result of the analysis is that each train can provide 100% of the required peak cooling capacity during the post accident condition.

The modeled Passive Containment Cooling System actuation response time from the containment analysis is based upon a response time associated with exceeding the containment High-2 pressure setpoint to opening of isolation valves.

The Passive Containment Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, one passive containment cooling water flow path is required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). To ensure that this requirement is met, two passive containment cooling water flow paths are provided.

LCO (continued)

Therefore, in the event of an accident, at least one flow path operates, assuming the worst case single active failure occurs. A third PCS flow path is provided for protection against multiple failure scenarios modeled in the PRA. To ensure that these requirements are met, three PCS water flow paths must be OPERABLE.

The PCS includes a cooling water tank, valves, piping, instruments and controls to ensure an OPERABLE flow path capable of delivering water from the cooling water tank upon an actuation signal. An OPERABLE flow path consists of a normally closed valve capable of automatically opening in series with a normally open valve. For the two flow paths containing air-operated valves, it is preferred because of PRA insights that these valves be normally closed.

The PCS cooling water storage tank ensures that an adequate supply of water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA). To be considered OPERABLE, the PCS cooling water storage tank must meet the water volume and temperature limits established in the SRs. To be considered OPERABLE, the air flow path from the shield building annulus inlet to the exit must be unobstructed, with unobstructed upper annulus safety-related drains providing a path for containment cooling water runoff to preclude blockage of the air flow path.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the PCS.

During shutdown the PCS may be required to remove heat from containment. The requirements in MODES 5 and 6 are specified in LCO 3.6.7, Passive Containment Cooling System (PCS) – Shutdown.

ACTIONS

A.1

With one passive containment cooling water flow path inoperable, the affected flow path must be restored within 7 days. In this degraded condition, the remaining flow paths are capable of providing greater than 100% of the heat removal needs after an accident, even considering the worst single failure. The 7 day Completion Time was chosen in light of the remaining heat removal capability and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1

With two passive containment cooling water flow paths inoperable, at least one affected flow path must be restored to OPERABLE status within 72 hours. In this degraded condition, the remaining flow path is capable of providing greater than 100% of the heat removal needs after an accident. The 72 hour Completion Time was chosen in light of the remaining heat removal capability and the low probability of DBA occurring during this period.

C.1

If the cooling water tank is inoperable, it must be restored to OPERABLE status within 8 hours. The tank may be declared inoperable due to low water level or temperature out of limits. The 8 hour Completion Time is reasonable based on the remaining heat removal capability of the system and the availability of cooling water from alternate sources.

D.1 and D.2

If any of the Required Actions and associated Completion Times for Condition A or B are not met, or if the LCO is not met for reasons other than Condition A or B, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time and is reasonable when considering that the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

This surveillance requires verification that the cooling water temperature is within the limits assumed in the accident analyses. The 7-day Frequency is adequate to identify a temperature change that would approach the temperature limits since the tank is large and temperature variations are slow.

The surveillance Frequency is increased to 24 hours in the event that the tank temperature approaches its limits; i.e., once temperature increases

SURVEILLANCE REQUIREMENTS (continued)

either to ≥ 100°F, or decreases to ≤ 50°F. Since the maximum tank temperature variation during the normal surveillance Frequency of 7 days is only about 1°F, the tank temperature cannot exceed its limits before the increased surveillance Frequency takes effect.

SR 3.6.6.2

Verification that the cooling water volume is above the required minimum ensures that a sufficient supply is available for containment cooling. Since the cooling water volume is normally stable and low level is indicated by a main control room alarm, a 7 day Frequency is appropriate and has been shown to be acceptable in similar applications.

SR 3.6.6.3

Verifying the correct alignment of power operated, and automatic valves, excluding check valves, in the Passive Containment Cooling System provides assurance that the proper flow paths exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct positions prior to being secured. This SR does not require any testing or valve manipulation. Rather, it involves verification, through control room instrumentation or a system walkdown, that valves capable of potentially being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single flow path. This Frequency has been shown to be acceptable through operating experience.

SR 3.6.6.4

This SR requires verification that each automatic isolation valve actuates to its correct position upon receipt of an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirmed by operating experience) of the equipment. Operating experience has shown that these components usually pass the Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.5

Periodic inspections of the PCS air flow path from the shield building annulus inlet to the exit ensure that it is unobstructed, the baffle plates are properly installed, and the upper annulus safety-related drains are unobstructed. Although there are no anticipated mechanisms which would cause air flow path or annulus drain obstruction and the effect of a missing air baffle section is small, it is considered prudent to verify this capability every 24 months. Additionally, the 24 month Frequency is based on the desire to perform this Surveillance under conditions that apply during a plant outage, on the need to have access to the locations, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation in similar situations.

SR 3.6.6.6

This SR requires performance of a Passive Containment Cooling System test to verify system flow and water coverage capabilities. The system performance test demonstrates that the containment cooling capability assumed in accident analyses is maintained by verifying the flow rates via each standpipe and measurement of containment wetting coverage. The System Level Operability Testing Program provides specific test requirements and acceptance criteria. Although the likelihood that system performance would degrade with time is low, it is considered prudent to periodically verify system performance. The first refueling and 10 year Frequency is based on the ability of the more frequent surveillances to verify the OPERABILITY of the active components and features which could degrade with time.

REFERENCES

1. 10 CFR 50, Appendix A, “General Design Criteria for Nuclear Power Plants.”

2. 10 CFR 50, Appendix K, “ECCS Evaluation Models.”

3. Chapter 6.2, “Containment Systems.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Passive Containment Cooling System (PCS) – Shutdown

BASES

BACKGROUND	A description of the PCS is provided in the Bases for LCO 3.6.6, “Passive Containment Cooling System – Operating.”
APPLICABLE SAFETY ANALYSES	The PCS limits the temperature and pressure that could be experienced during shutdown following a loss of decay heat removal. For shutdown events, the Reactor Coolant System (RCS) sensible and decay heat removal requirements are reduced as compared to heat removal requirements for MODE 1, 2, 3, or 4 events. Therefore, the shutdown containment heat removal requirements are bounded by analyses of MODES 1, 2, 3, and 4 events. A discussion of MODES 1, 2, 3, and 4 DBAs is provided in the Bases for LCO 3.6.6, “Passive Containment Cooling System (PCS) – Operating.” The PCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	For postulated shutdown events, one passive containment cooling water flow path is required to provide the required containment heat removal capability (Ref. 1). To ensure that this requirement is met, two passive containment cooling water flow paths are provided. Therefore, in the event of an accident, at least one flow path operates, assuming the worst case single active failure occurs. A third PCS flow path is provided for protection against multiple failure scenarios modeled in the PRA. To ensure that these requirements are met, three PCS water flow paths must be OPERABLE. The PCS includes a cooling water tank, valves, piping, instruments and controls to ensure an OPERABLE flow path capable of delivering water from the cooling water tank upon an actuation signal. The PCS cooling water storage tank ensures that an adequate supply of water is available to cool and depressurize the containment in the event of a loss of decay heat removal. To be considered OPERABLE, the PCS cooling water storage tank must meet the water volume and temperature limits established in the SRs. To be considered OPERABLE, the air flow path from the shield building annulus inlet to the exit must be unobstructed, with unobstructed upper annulus safety-related drains providing a path for containment cooling water runoff to preclude blockage of the air flow path.

BASES

APPLICABILITY

OPERABILITY of the PCS is required in either MODE 5 or 6 with the calculated reactor decay heat greater than 9 MWt for heat removal in the event of a loss of nonsafety decay heat removal capabilities.

With the decay heat less than 9 MWt, the decay heat can be easily removed from containment with air cooling alone. Confirmation of decay heat levels may be determined consistent with the assumptions and analysis basis of ANS 1979 plus 2 sigma or via an energy balance of the reactor coolant system.

The PCS requirements in MODES 1, 2, 3, and 4 are specified in LCO 3.6.6, “Passive Containment Cooling System (PCS) – Operating.”

ACTIONS

A.1

With one passive containment cooling water flow path inoperable, the affected flow path must be restored within 7 days. In this degraded condition, the remaining flow paths are capable of providing greater than 100% of the heat removal needs after an accident, even considering the worst single failure. The 7 day Completion Time was chosen in light of the remaining heat removal capability and the low probability of a DBA occurring during this period.

B.1

With two passive containment cooling water flow paths inoperable, at least one affected flow path must be restored to OPERABLE status within 72 hours. In this degraded condition, the remaining flow path is capable of providing greater than 100% of the heat removal needs after an accident. The 72 hour Completion Time was chosen in light of the remaining heat removal capability and the low probability of an event occurring during this period.

C.1

If the cooling water tank is inoperable, it must be restored to OPERABLE status within 8 hours. The tank may be declared inoperable due to low water volume or temperature out of limits. The 8 hour Completion Time is reasonable based on the remaining heat removal capability of the system and the availability of cooling water from alternate sources.

D.1.1, D.1.2, and D.2

Action must be initiated if any of the Required Actions and associated Completion Times for Condition A or B are not met, or if the LCO is not met for reasons other than Condition A or B. If in MODE 5 with the RCS

BASES

ACTIONS (continued)

pressure boundary open and/or pressurizer level < 20%, action must be initiated, immediately, to increase the RCS level to a pressurizer level ≥ 20% and to close the RCS so that the PRHR HX operation is available. If in MODE 6, action must be initiated, immediately, to increase the refueling cavity water level ≥ 23 feet above the top of the reactor vessel flange. In both cases, the time to RCS boiling is maximized by maximizing the RCS inventory and maintaining RCS temperature as low as practical. Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS.

These Actions place the plant in a condition which maximize the time to actuation of the Passive Containment Cooling System, thus providing time for repairs or application of alternative cooling capabilities.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

The LCO 3.6.6 Surveillance Requirements (SR 3.6.6.1 through 3.6.6.6) are applicable. The Frequencies associated with each specified SR are applicable. Refer to the corresponding Bases for LCO 3.6.6 for a discussion of each SR.

REFERENCES

1. Section 6.2, “Containment Systems.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Containment Penetrations

BASES

BACKGROUND

Containment closure capability is required during shutdown operations when there is fuel inside containment. Containment closure is required to maintain within containment the cooling water inventory. Due to the large volume of the IRWST and the reduced sensible heat during shutdown, the loss of some of the water inventory can be accepted. Further, accident analyses have shown that containment closure capability is <u>not</u> required to meet offsite dose requirements. Therefore, containment does not need to be leak tight as required for MODES 1 through 4.

In MODES 5 and 6, the LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no requirement for containment leak tightness, compliance with the Appendix J leakage criteria and tests are not required.

In MODES 5 and 6, there is no potential for steam release into the containment immediately following a accident. Pressurization of the containment could only occur after heatup of the IRWST due to PRHR HX operation (MODE 5 with RCS intact) or after heatup of the RCS with direct venting to the containment (MODE 5 with reduced RCS inventory or MODE 6 with the refueling cavity not fully flooded) or after heatup of the RCS and refueling cavity (MODE 6 with refueling cavity fully flooded). The time from loss of normal cooling until steam release to the containment for four representative sets of plant conditions is shown in Figure B 3.6.8-1 as a function of time after shutdown. Because local manual action may be required to achieve containment closure it is assumed that the containment hatches, air locks and penetrations must be closed prior to steaming into containment.

Figure B 3.6.8-1 provides allowable closure times for four representative sets of plant conditions. The time to steaming is dependent on various plant parameters (RCS temperature, IRWST temperature, etc.) and plant configuration (RCS Pressure Boundary Intact, RCS Open, etc.). Therefore, the actual representation of the time to steaming may be different than that provided in Figure B 3.6.8-1. In determining the minimum time to steaming, conservative assumptions regarding core decay heat, RCS configuration, and initial RCS inventory are used to minimize the calculated time to steaming. The curves are based on the core decay heat prior to refueling so that closure times are longer following the core reload.

BACKGROUND (continued)

As presented in Tables 54-1 and 54-4 of Reference 2, the most risk significant events during shutdown are events that lead to a loss of RNS cooling. Of these, the limiting events that lead to steaming to containment are the loss of shutdown cooling events, specifically:

- Loss of decay heat removal during drained conditions due to a failure of component cooling water or service water system;
- Loss-of-offsite power during drained conditions; and
- Loss of decay heat removal during drained conditions due to failure of the normal residual heat removal system.

These events are further discussed in Section 19.59.5 of Reference 1. Time to steaming is dependent on the postulated RCS configuration (intact versus open), and is based on the response of the plant considering features such as the operation of the 4th stage ADS valves if necessary, status of the upper internals, status of refueling cavity, etc. Conservative assumptions regarding these features are made in the determination of the minimum time to steaming. The time assumed in the PRA to close the penetrations before steaming to containment included 15 minutes for the diagnosis and decision-making time, in addition to the time required to physically complete the closure action.

The risk of overdraining the RCS has been significantly reduced in the AP1000 due to the automatic protection features associated with the hot leg level instruments which isolate letdown on low hot leg water level. Overdraining the RCS is no longer a significant contributor to core damage, as shown in Table 54-4 of Reference 2.

The assumptions used in determining the required closure time for the various containment openings should be conservative, and should be consistent with the plant operating procedures, staffing levels, and status of the containment openings. The evaluation should consider the ability to close the containment for the limiting loss of shutdown cooling event, and considering the possibility of a station blackout. In determining if containment can be closed within the time permitted to containment closure specified in Figure B 3.6.8 -1, the time to close containment penetrations must include both the diagnosis and decision-making time and the time required to physically complete the closure action.

Containment should be closed during the initial mid-loop period for a refueling since the time permitted to containment closure is shorter than the time to diagnose and make a decision that closure is needed

BASES

BACKGROUND (continued)

following an event. The need to close containment for the mid-loop period following a refueling must be evaluated since decay heat varies with the time after shutdown and the impact of the partial core replacement with new fuel. It is expected that containment will be closed for activities where drain-down is planned, such as the RCS drain-down from no-load pressurizer level for the initial mid-loop period during a refueling. Containment is not expected to be closed for minor, unplanned RCS volume transients, such as a short-term inventory where the pressurizer level may be reduced, but not emptied, and where recovery actions are within the time to containment closure.

The containment equipment hatches, which are part of the containment pressure boundary, provide a means for moving large equipment and components into and out of containment. If closed, the equipment hatch must be held in place by at least [four] bolts. Good engineering practice dictates that bolts required by this LCO be approximately equally spaced. Alternatively, if open, each equipment hatch can be installed using a dedicated set of hardware, tools and equipment. A self-contained power source is provided to drive each hoist while lowering the hatch into position. Large equipment and components may be moved through the hatches as long as they can be removed and the hatch closed prior to steaming into the containment.

Reviewers Note: The design of the equipment hatch is such that the [four] bolts would only be needed to support the hatch in place and provide adequate strength to support the hatch dead weight and associated loads. The hatch is installed on the inside containment and is held in place against a matching flange surface with mating bolt pattern by the bolts. Once the dead weight is supported, any pressure (greater than atmospheric) within containment will serve to exert closure force on the hatch toward the mating flange surface serving to reduce stresses on bolts. Therefore the determination of the number of bolts is limited to the quantity required to support the hatch itself and not related to any potential containment pressure.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, “Containment Air Locks.” Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for

BACKGROUND (continued)

extended periods when frequent containment entry is necessary. Temporary equipment connections (e.g., power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment.

Containment spare penetrations which also provide a part of the containment boundary provide for temporary support services (electrical, I&C, air, and water supplies) during MODES 5 and 6. Each penetration is flanged and normally closed. During periods of plant shutdown, temporary support systems may be routed through the penetrations; temporary equipment connections (e.g., power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment. The spare penetrations must be closed or, if open, capable of closure prior to steaming to containment.

Containment penetrations, including purge system flow paths, that provide direct access from containment atmosphere to outside atmosphere must be isolated or capable of being isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary barrier for the containment penetrations. The equivalent isolation barrier must be capable of maintaining containment isolation at the containment design pressure of 59 psig (Ref. 1).

APPLICABLE SAFETY ANALYSES

For postulated shutdown events in MODES 5 and 6, RCS heat removal is provided by either passive residual heat removal (PRHR) or IRWST injection and containment sump recirculation. To support RCS heat removal, containment closure is required to limit the loss of the cooling water inventory from containment (Ref. 1).

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the loss of cooling water inventory in containment to assure continued coolant inventory by limiting the potential escape paths for water released within containment. Penetrations closed in accordance with these requirements are not required to be leak tight.

BASES

LCO (continued)

The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed or capable of being closed prior to steaming into the containment. The equipment hatches may be open; however, the hatches shall be clear of obstructions such that capability to close the hatch within the indicated time period is maintained. The hardware, tools, equipment and power sources necessary to install the hatches shall be available when the hatch is open. Both doors in each containment air lock may be open; however, the air locks shall be clear of obstructions such that the capability to close at least one door within the indicated time period is maintained. Alternatively, one door in an air lock may be closed. Containment spare penetrations may be open; however, the penetrations shall be capable of being closed within the indicated time period. Direct access penetrations shall be closed by at least one manual or automatic isolation valve, blind flange or equivalent, or capable of being closed by at least one valve actuated by a containment isolation signal. If direct access penetrations are open, OPERABILITY of the containment isolation instrumentation is required for the open penetrations by LCO 3.3.2, Function 3.a, Containment Isolation, Manual Initiation. An OPERABLE Containment Isolation Function includes LCO 3.3.2, Function 19.b, Containment Air Filtration System Isolation, Containment Isolation. Figure B 3.6.8-1 provides the acceptable required closure times for various representative MODES and conditions.

APPLICABILITY

The containment penetration requirements are applicable during conditions for which the primary safety related core cooling and boration capabilities are provided by IRWST or injection or PRHR – MODES 5 and 6. The capability to close containment is required to ensure that the cooling water inventory is not lost in the event of an accident.

In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1.

ACTIONS

A.1

If the containment equipment hatches, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the containment isolation function not capable of actuation when automatic isolation valves are open, the penetration(s) must be restored to the required status within 1 hour.

ACTIONS (continued)

B.1.1, B.1.2, and B.2

If Required Action A.1 is not completed within 1 hour or the LCO is not met for reasons other than Condition A, action must be taken to minimize the probability and consequences of an accident.

In MODE 5, action must be initiated, immediately, to be in MODE 5 with a pressurizer level ≥ 20% and to close the RCS so that the PRHR HX operation is available. In MODE 6, action must be initiated, immediately, to be in MODE 6 with the refueling cavity water level ≥ 23 feet above the top of the reactor vessel flange. The time to RCS steaming to containment is maximized by maximizing RCS inventory, and allowing PRHR HX operation. Additionally, action to suspend positive reactivity additions is required to ensure that the SDM is maintained. Sources of positive reactivity addition include boron dilution, withdrawal of reactivity control assemblies, and excessive cooling of the RCS.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal. Open containment spare penetrations shall be verified capable of being closed prior to steaming to containment by removal of obstructions and installation of the flange or by other closure means which will limit loss of the cooling water inventory from containment.

The Surveillance is performed every 7 days. The Surveillance interval is selected to ensure that the required penetration status is maintained during shutdown inspections, testing, and maintenance.

SR 3.6.8.2

Each of the two equipment hatches is provided with a set of hardware, tools, equipment, and self-contained power source for moving the hatch from its storage location and installing it in the opening. The required set of hardware and tools shall be visually inspected to ensure that they can perform the required functions. The equipment and power source shall

BASES

SURVEILLANCE REQUIREMENTS (continued)

be inspected and/or operated as necessary to verify that the hatch can be installed. The power source shall be verified as containing sufficient energy to install the hatch from the storage location.

The 7 day Frequency is adequate considering that the hardware, tools, equipment, and power sources are dedicated to the associated equipment hatch and not used for any other functions.

The SR is modified by a Note which only requires that the surveillance be met for an open equipment hatch. If the equipment hatch is installed in position, then the availability of the means to install the hatch is not required.

SR 3.6.8.3

This Surveillance demonstrates that at least one valve in each open penetration actuates to its isolation position on manual initiation or on an actual or simulated containment isolation signal. The 24 month Frequency maintains consistency with other similar valve testing requirements. The OPERABILITY requirements for the Containment Isolation function are specified in LCO 3.3.2.

The SR is modified by a Note stating that this Surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability.

REFERENCES

1. DCD Chapter 19.
2. AP1000 Probabilistic Risk Assessment.

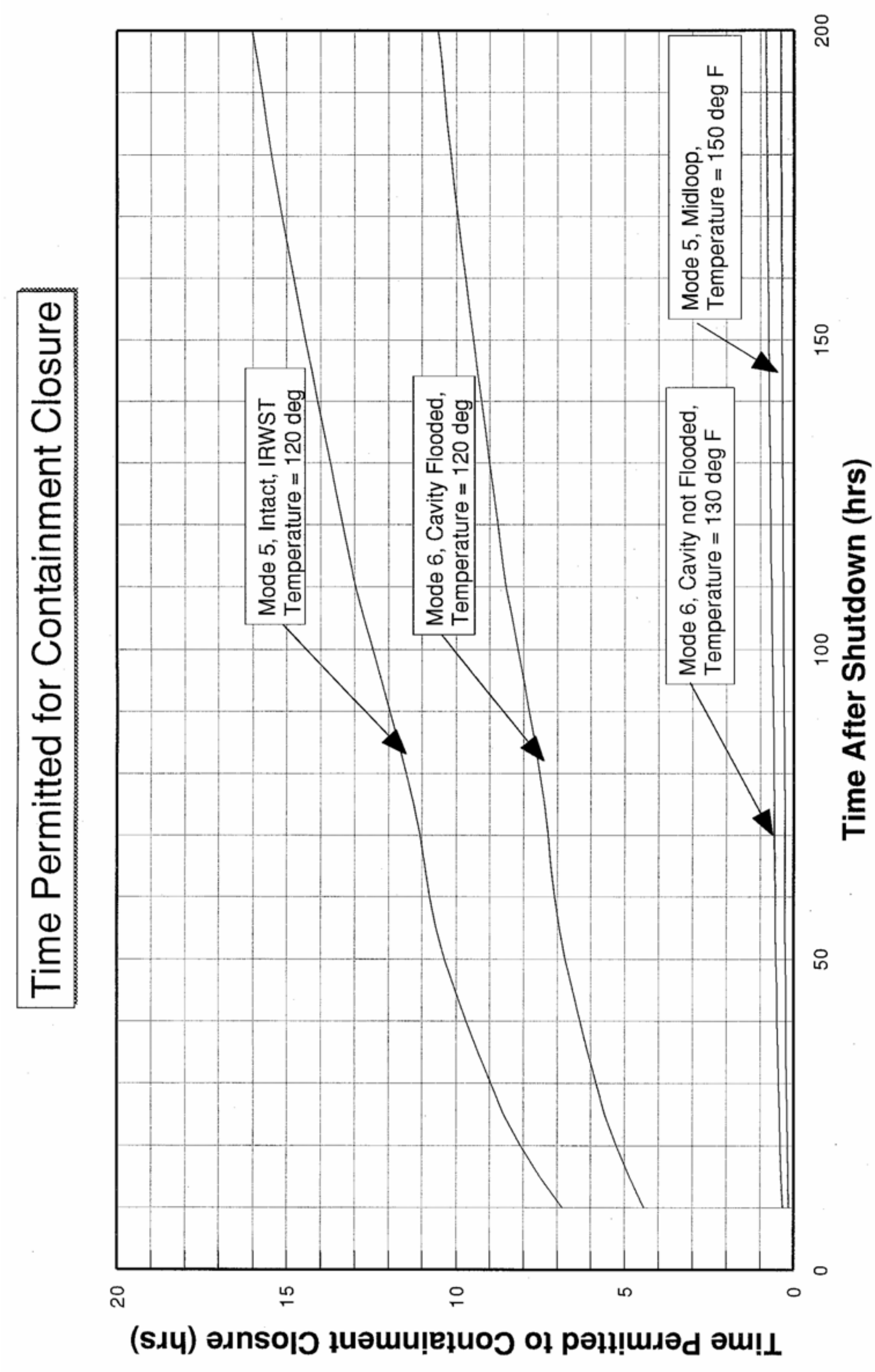

Figure B 3.6.8-1 (page 1 of 1)
Time Prior to Coolant Inventory Boiling

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 pH Adjustment

BASES

BACKGROUND

The Passive Core Cooling System (PXS) includes two pH adjustment baskets which provide adjustment of the pH of the water in the containment following an accident where the containment floods.

Following an accident with a large release of radioactivity, the containment pH is automatically adjusted to greater than or equal to 7.0, to enhance iodine retention in the containment water. Chemical addition is necessary to counter the affects of the boric acid contained in the safety injection supplies and acids produced in the post-LOCA environment (nitric acid from the irradiation of water and air and hydrochloric acid from irradiation and pyrolysis of electric cable insulation). The desired pH values significantly reduce formation of elemental iodine in the containment water, which reduces the production of organic iodine and the total airborne iodine in the containment. This pH adjustment is also provided to prevent stress corrosion cracking of safety related containment components during long-term cooling.

Dodecahydrate trisodium phosphate (TSP) contained in baskets provides a passive means of pH control for such accidents. The baskets are made of stainless steel with a mesh front that readily permits contact with water. These baskets are located inside containment at an elevation that is below the minimum floodup level. The baskets are placed at least a foot above the floor to reduce the chance that water spills will dissolve the TSP. Natural recirculation of water inside the containment, following a LOCA, is driven by the core decay heat and provides mixing to achieve a uniform pH. The dodecahydrate form of TSP (Na_3PO_4-$12H_2O$) is initially loaded into the baskets because it is hydrated and will undergo less physical and chemical change than would anhydrous TSP as a result of the humidity inside containment. (Refs. 1 and 2)

APPLICABLE SAFETY ANALYSES

In the event of a Design Basis Accident (DBA), iodine may be released from the fuel to containment. To limit this iodine release from containment, the pH of the water in the containment sump is adjusted by the addition of TSP. Adjusting the sump water to neutral or alkaline pH ($pH \geq 7.0$) will augment the retention of the iodine, and thus reduce the iodine available to leak to the environment.

pH adjustment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The requirement to maintain the pH adjustment baskets with ≥ [560] ft^3 of TSP assures that for DBA releases of iodine into containment, the pH of the containment sump will be adjusted to enhance the retention of the iodine.

A required volume is specified instead of mass because it is not feasible to weigh the TSP in the containment. The minimum required volume is based on the manufactured density of TSP. This is conservative because the density of TSP may increase after installation due to compaction.

APPLICABILITY

In MODES 1, 2, 3, and 4 a DBA could cause release of radioactive iodine to containment requiring pH adjustment. The pH adjustment baskets assist in reducing the airborne iodine fission product inventory available for release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, pH adjustment is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

If the TSP volume in the baskets is not within limits, the iodine retention may be less than that assumed in the accident analysis for the limiting DBA. Due to the very low probability that the volume of TSP may change, the variations are expected to be minor such that the required capability is substantially available. The 72 hour Completion Time for restoration to within limits is consistent with times applied to minor degradations of ECCS parameters.

B.1 and B.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

The minimum amount of TSP is [560] ft^3. A volume is specified since it is not feasible to weigh the TSP contained in the pH adjustment baskets. This volume is based on providing sufficient TSP to buffer the post accident containment water to a minimum pH of 7.0. Additionally, the TSP volume is based on treating the maximum volume of post accident water ([918,600] gallons) containing the maximum amount of boron ([3009] ppm) as well as other sources of acid. The minimum required mass of TSP is [27,540] pounds.

The minimum required volume of TSP is based on this minimum required mass of TSP, the minimum density of TSP plus margin to account for degradation of TSP during plant operation. The minimum TSP density is based on the manufactured density, since the density may increase and the volume decrease, during plant operation, due to agglomeration from humidity inside the containment. The minimum required TSP volume also has about 10% margin to account for degradation of TSP during plant operation.

The periodic verification is required every 24 months, since access to the TSP baskets is only feasible during outages, and normal fuel cycles are scheduled for 24 months. Operating experience has shown this Surveillance Frequency acceptable due to the margin in the volume of TSP placed in the containment building.

SR 3.6.9.2

Testing must be performed to ensure the solubility and buffering ability of the TSP after exposure to the containment environment. A representative sample of [2.36] grams of TSP from one of the baskets in containment is submerged in ≥ 1 liter of water at a boron concentration of [3009] ppm and at the standard temperature of 25 ± 5°C. Without agitation, the solution pH should be raised to ≥ 7.0 within 4 hours.

The minimum required amount of TSP is sufficient to buffer the maximum amount of boron [3009] ppm, the maximum amount of other acids, and the maximum amount of water [918,600] gallons that can exist in the containment following an accident and achieve a minimum pH of 7.0.

Agitation of the test solution is prohibited, since an adequate standard for the agitation intensity cannot be specified. The test time of 4 hours is necessary to allow time for the dissolved TSP to naturally diffuse through the sample solution. In the post LOCA sump area, rapid mixing would occur due to liquid flow, significantly decreasing the actual amount of time

BASES

SURVEILLANCE REQUIREMENTS (continued)

before the required pH is achieved. This would ensure compliance with the Standard Review Plan requirement of a pH ≥ 7.0 by the onset of recirculation after a LOCA.

REFERENCES

1. Section 6.3.2.1.4, “Containment pH Control.”
2. Section 6.3.2.2.4, “pH Adjustment Baskets.”
3. Section 15.6.5.3.1, “Identification of Cause and Accident Description.”

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Six MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in Reference 1. The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, as shown in Table 3.7.1-2 of the specification, so that only the needed valves actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open the valves following a turbine-reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operating occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, are those characterized as decreased heat removal events, which are presented in Section 15.2 (Ref. 3). Of these, the full power turbine trip without turbine bypass is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

The safety analysis demonstrates that the transient response for turbine trip without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. One turbine trip analysis is performed assuming primary system pressure control via operation of the pressurizer spray. This analysis demonstrates that the DNB design basis is met. Another analysis is performed assuming no primary system pressure control, but crediting reactor trip on high pressurizer pressure and operation of the pressurizer safety valves. This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the atmospheric or condenser steam dump valves. The DCD Section [15.4.2] safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The DCD safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization may be determined by system transient analyses or conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by lowering the Power Range Neutron Flux-High setpoint to an appropriate value.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The accident analysis requires six MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% of RTP. A MSSV will be considered inoperable if it fails to open in the event of a pressure excursion in excess of the setpoint. The LCO requires that six MSSVs be OPERABLE in compliance with Reference 2. Operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements). These limitations are according to Table 3.7.1-1 of the specification and Required Action A.1.

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings specified in Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB or Main Steam System integrity.

APPLICABILITY

In MODE 1 at or above 67% RTP, six MSSVs per steam generator are required to be OPERABLE. Below 67% RTP in MODE 1, 2, 3, or 4 (without the normal residual heat removal system in service), only four MSSVs per steam generator are required to be OPERABLE.

In MODES 4 (with the normal residual heat removal system in service) and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized. There is no requirement for the MSSVs to be OPERABLE in these MODES.

BASES

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1 and A.2

With one or more MSSVs inoperable, reduce power so that the available MSSV relieving capacity meets Reference 2 requirements for the applicable THERMAL POWER.

Operation with less than all six MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator. For example, if two MSSVs are inoperable in one steam generator, the relief capacity of that steam generator is reduced by approximately 33%. To offset this reduction in relief capacity, energy transfer to that steam generator must be similarly reduced by at least 33%. This is accomplished by reducing THERMAL POWER by at least 33%, which conservatively limits the energy transfer to both steam generators to approximately 67% of total capacity, consistent with the relief capacity of the most limiting steam generator.

For each steam generator, at a specified pressure, the fractional relief capacity (FRC) of each MSSV is determined as follows:

$$FRC = \frac{A}{B}$$

where:

A = the relief capacity of the MSSV; and

B = the total relief capacity of all the MSSVs of the steam generator

The FRC is the relief capacity necessary to address operation with reduced THERMAL POWER.

The reduced THERMAL POWER levels in the LCO, prevent operation at power levels greater than the relief capacity of the remaining MSSVs. The reduced THERMAL POWER is determined as follows:

$$RP = [1 - (N_1 \times FRC_1 + N_2 \times FRC_2 + N_3 \times FRC_3 + N_4 \times FRC_4 + N_5 \times FRC_5 + N_6 \times FRC_6)] \times 100\%$$

ACTIONS (continued)

where:

RP = Reduced THERMAL POWER for the most limiting steam generator expressed as a percent of RTP;

N_1, N_2, N_3, N_4, N_5, N_6 represent the status of MSSV 1, 2, 3, 4, 5, and 6, respectively,

= 0 if the MSSV is OPERABLE,
= 1 if the MSSV is inoperable;

FRC_1, FRC_2, FRC_3, FRC_4, FRC_5, FRC_6 = the relief capacity of MSSV 1, 2, 3, 4, 5, and 6 respectively, as defined above.

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status within the associated Completion Time, or if one or more steam generators have less than two MSSVs OPERABLE, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, with RCS cooling provided by the RNS, within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 4), requires that safety and relief valve tests be performed in accordance with ASME OM Code (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Set pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The ANSI/ASME standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ±3% setpoint tolerance

for OPERABILITY; however, the valves are reset to ±1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. Chapter 10, “Steam and Power Conversion Systems Description.”
2. ASME Boiler and Pressure Vessel Code, Section III, Article NC-7000, “Overpressure Protection,” Class 2 Components.
3. Section 15.2, “Decreased Heat Removal by Secondary System.”
4. ASME Boiler and Pressure Vessel Code, Section XI, Article IV-3500, “Inservice Test: Category C Valves.”
5. ASME OM Code-1995 and Addenda through the 1996 Addenda, “Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices in Light Water Reactor Power Plants.”

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

Each main steamline has one safety related MSIV to isolate steam flow from the secondary side of the steam generators following a high energy line break. MSIV closure terminates flow from the unaffected (intact) steam generator.

One MSIV is located in each main steam line outside containment. The MSIVs are downstream from the main steam safety valves (MSSVs). Downstream from the MSIVs, main steam enters the high pressure turbine through four stop valves and four governing control valves. Closing the MSIVs isolates each steam generator from the other and isolates the turbine bypass system, and other steam supplies from the steam generator.

The MSIVs, turbine stop and control valves, turbine bypass valves, and moisture separator reheat supply steam control valves close on a main steam isolation signal generated by either low steam line pressure, high containment pressure, Low T_{cold}, or high negative steam pressure rate. The MSIVs fail closed on loss of control air or actuation signal from either of two 1E power divisions.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the Section 10.3 (Ref. 1). Descriptions for the turbine bypass valves, and moisture separator reheat supply steam control valve are found in the Section 10.4 (Ref. 6).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the Section 6.2 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the Section 15.1 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

Design basis events of concern for containment analysis are SLB inside containment with the failure of the associated MSIV to close, or a main feedline break with the associated failure of a feedline isolation or control

APPLICABLE SAFETY ANALYSES (continued)

valve to close. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the MSIV to close, the additional mass and energy in the steam headers, downstream from the other MSIV, contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Core Makeup Tanks (CMTs).

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes consideration of scenarios with offsite power available, and with a loss of offsite power. With offsite power available, the reactor coolant pumps continue to circulate coolant for a longer period through the steam generators, maximizing the Reactor Coolant System cooldown. The reactor protection system includes a safety related signal that initiates the coastdown of the reactor coolant pumps early in the large SLB transient. Therefore, there is very little difference in the predicted departure from nucleate boiling ratio between cases with and without offsite power. Significant single failures considered include failure of an MSIV to close.

The non-safety related turbine stop or control valves, in combination with the turbine bypass, and moisture separator reheat supply steam control valves, are assumed as a backup to isolate the steam flow path given a single failure of an MSIV. The safety analyses do not differentiate between the availability of the turbine stop valve or its series control valve. Either the turbine stop valves or its associated turbine control valve are required by this LCO to be OPERABLE. These valves, along with the turbine bypass, and moisture separator reheat supply steam control valves are considered as alternate downstream valves.

The MSIVs serve a safety related function and remain open during power operation. These valves operate under the following situations:

a. High energy line break inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from both steam generators until the unaffected loop MSIV closes. After

BASES

APPLICABLE SAFETY ANALYSES (continued)

MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIV in the unaffected loop. Closure of the MSIV isolates the break from the unaffected steam generator.

b. A break outside of containment, and upstream or downstream from the MSIVs, is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs or alternate downstream valves isolates the break, and limits the blowdown to a single steam generator.

c. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator to minimize radiological releases.

d. The MSIVs are also utilized during other events such as a feedwater line break; however, these events are less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs and the alternate downstream valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Following an SLB and main steam isolation signal, the analyses assume continued steam loss through the steamline condensate drain lines, turbine gland seal system, and the main steam to auxiliary steam header which supplies the auxiliary steam line to the deaerator. Since these valves are not assumed for steam isolation, they do not satisfy the 10 CFR 50.36(c)(2)(ii) criteria.

LCO

This LCO requires that one MSIV in each of the two steam lines be OPERABLE. The MSIVs are considered OPERABLE when their isolation times are within limits, and they close on an isolation actuation signal.

This LCO requires that four turbine stop valves or their associated turbine control valve, six turbine bypass valves, and four moisture separator reheat supply steam control valve be OPERABLE. A valve is considered OPERABLE when its isolation time is within the safety analysis isolation time limit of 5 seconds and it closes on an MSIV actuation signal. The

LCO (continued)

turbine bypass valves are alternatively considered OPERABLE when closed and administratively maintained closed with automatic actuation blocked as appropriate.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 limits or the NRC staff approved licensing basis.

This LCO provides assurance that the design and performance of the alternate downstream valves are compatible with the accident conditions for which they are called upon to function (Ref. 5).

APPLICABILITY

The MSIVs, turbine stop or associated turbine control valves, turbine bypass valves, and moisture separator reheat supply steam control valves must be OPERABLE in MODE 1 and MODES 2, 3, and 4, except when steam flow is isolated when there is significant mass and energy in the RCS and steam generators. Therefore, these valves must be OPERABLE or closed. When these valves are closed, they are already performing their required function.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs and alternate downstream valves are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

<u>A.1</u>

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the valves can be made with the plant hot. The 8 hour Completion Time is reasonable considering the low probability of an accident occurring during this time period that would require a closure of these valves. With a single MSIV inoperable, the safety function, isolation of the steam flow path, is provided by the OPERABLE alternate downstream valves, but cannot accommodate a single failure. The assumptions and criteria of the accident analyses are preserved by the ability to automatically isolate the steam flow path.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a

BASES

ACTIONS (continued)

closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides a positive means for containment isolation.

B.1

With any number of the turbine stop valves and the associated turbine control valve, turbine bypass, or moisture separator reheat supply steam control valves inoperable in MODE 1, action must be taken to restore OPERABLE status within 72 hours. Some repairs to the valves can be made with the plant hot. The 72 hour Completion Time is reasonable considering the low probability of an accident occurring during this time period that would require a closure of these valves. With the backup isolation valves inoperable, the safety function, isolation of the steam flow path, is provided by the remaining OPERABLE valves, but cannot accommodate a single failure. The assumptions and criteria of the accident analyses are preserved by the ability to automatically isolate the steam flow path.

C.1

With two MSIVs inoperable in MODE 1 or one MSIV and an alternate downstream valve inoperable or if the valves cannot be restored to OPERABLE status in accordance with Required Action A.1 or B.1, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition D would be entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 in an orderly manner and without challenging unit systems.

D.1 and D.2

Condition D is modified by a Note indicating that a separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2, 3, and 4, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition A, and conservative considering the reduced energy in the steam generators in MODES 2, 3, and 4.

BASES

ACTIONS (continued)

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time but were closed, these inoperable valves must be verified to be continually closed on a periodic basis. This is necessary to ensure that the assumptions in the safety analyses remain valid. The 7 day Completion Time is based on engineering judgment, and is considered reasonable in view of MSIV status indications available in the control room and other administrative controls which ensure that these valves will continue to be closed.

E.1 and E.2

If the MSIVs cannot be restored to OPERABLE status or closed within the associated Completion Times of Condition D, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 with normal residual heat removal system in service within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5.0 seconds, on an actual or simulated actuation signal. The MSIV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. As the MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 7), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies that the turbine stop, turbine control, turbine bypass, and moisture separator reheat supply steam control valves' closure time is ≤ 5.0 seconds, on an actual or simulated actuation signal. These alternate downstream isolation valves must meet the MSIV isolation time assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The alternate downstream valves should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. As the alternate downstream valves are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 7), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. Section 10.3, "Main Steam System."
2. Section 6.2.1, "Containment Functional Design."
3. Section 15.1, "Increase in Heat Removal by Secondary System."
4. Section 10.2, "Turbine Generator."
5. NUREG-138, Issue 1, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director NRR to NRR Staff."
6. Section 10.4, "Other Features of Steam and Power Conversion Systems."
7. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation and Control Valves (MFIVs and MFCVs)

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break. The safety related function of the MFCVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following a high energy line break. Closure of the MFIVs or MFCVs terminates flow to the steam generators, terminating the event for feedwater line breaks occurring upstream of the MFIVs or MFCVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs or MFCVs, effectively terminates the addition of main feedwater to an affected steam generator, limiting the mass and energy release for steam or feedwater line breaks inside containment, and reducing the cooldown effects for steam line breaks (SLBs).

The MFIVs or MFCVs isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of startup feedwater (SFW) to the intact loops of the steam generator.

One MFIV and one MFCV are located on each MFW line, outside but close to containment. The MFIVs and MFCVs are located in the MFW line and are independent of the delivery of the MFW or SFW via the SFW line which is separately connected and isolated from the steam generator. This configuration permits MFW or SFW to be supplied to the steam generators following MFIV or MFCV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases following either an SLB or FWLB.

The MFIVs and MFCVs close on receipt of engineered safeguards feedwater isolation signal generated from any of the following conditions:

- Automatic or manual safeguards actuation “S” signal
- High steam generator level
- Low-2 T_{avg} signal coincident with reactor trip (P-4)
- Manual actuation

BASES

BACKGROUND (continued)

Additionally, the MFIVs close automatically on a Low-1 T_{avg} coincident with reactor trip (P-4). Each valve may be actuated manually. In addition to the MFIVs and the MFCVs, a check valve is available outside containment to isolate the feedwater line penetrating containment. In the event of feedwater line depressurization due to pump trip on line break, the check valve provides rapid backup isolation of the steam generators limiting the inventory loss. A description of the MFIVs and MFCVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs and MFCVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large Feedwater Line Break (FWLB). Closure of the MFIVs (or MFCVs) may also be relied on to mitigate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level – High 2 signal.

Failure of an MFIV (or MFCV), to close following an SLB or FWLB, can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

The MFIVs and MFCVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFIVs and the MFCVs will isolate the main feedwater system.

This LCO requires that the one isolation valve and one control valve on each feedwater line be OPERABLE. These valves are considered OPERABLE when their isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A main feedwater isolation signal on high steam generator level is relied on to terminate an excess feedwater flow event, and therefore failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIVs and MFCVs must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and the steam generators. This ensures that, in the event of a high energy line

APPLICABILITY (continued)

break, a single failure cannot result in the blowdown of more than one steam generator. In MODE 1, 2, 3, or 4, these valves are required to be OPERABLE to limit the amount of available fluid that could be added to the containment in the case of a secondary system pipe break inside containment. When the valves are closed and deactivated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 5 and 6 steam generator energy is low. Therefore, the MFIVs and the MFCVs are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate condition entry is allowed for each valve.

A.1, A.2, B.1, and B.2

With one or two MFIVs, or one or two MFCVs inoperable, close or isolate inoperable affected flow path in 72 hours. When these flow paths are isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves, and the low probability of an event that would require isolation of the main feedwater flow paths occurring during this period.

For inoperable MFIVs and MFCVs valves that cannot be restored to OPERABLE status within the specified Completion Time but are closed or isolated, the flow paths must be verified on a periodic basis to be closed or isolated. This is necessary to ensure that the assumptions in the safety analyses remain valid. The 7 day Completion Time is reasonable based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

C.1

With two inoperable valves in the same flow path there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, one valve in the affected flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the situation in which at least one valve in the affected flow path is performing the required safety function. The 8 hour Completion Time is a reasonable amount of time to complete the actions required to close the MFIV, or

BASES

ACTIONS (continued)

MFCV, which includes performing a controlled plant shutdown. The Completion Time is reasonable based on operating experience to reach MODE 2 with the MFIV or MFCV closed, from full-power conditions in an orderly manner and without challenging plant systems.

D.1, D.2, and D.3

If the MFIVs and MFCVs cannot be restored to OPERABLE status, or closed, or isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, in MODE 4 with the normal residual heat removal system in service within 24 hours, and the affected flow path isolated within 36 hours or in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFIV and MFCV is ≤ 5.0 seconds, on an actual or simulated actuation signal. The MFIV and MFCV isolation times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. This is consistent with the ASME Code, Section XI (Ref. 2), quarterly stroke requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

The test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. Section 10.4.7, “Condensate and Feedwater System.”

2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.4 Secondary Specific Activity

BASES

BACKGROUND	Activity in the secondary coolant results from steam generator tube LEAKAGE from the Reactor Coolant System (RCS). Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant. While fission products present in the primary coolant, as well as activated corrosion products, enter the secondary coolant system due to the primary to secondary LEAKAGE, only the iodines are of a significant concern relative to airborne release of activity in the event of an accident or abnormal occurrence (radioactive noble gases that enter the secondary side are not retained in the coolant but are released to the environment via the condenser air removal system throughout normal operation). The limit on secondary coolant radioactive iodines minimizes releases to the environment due to anticipated operational occurrences or postulated accidents.
APPLICABLE SAFETY ANALYSES	The accident analysis of the main steam line break (SLB) as discussed in Chapter 15 (Ref. 1) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.1 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of a postulated SLB are within the acceptance criteria in SRP Section 15.0.1, and within the exposure guideline values of 10 CFR Part 50.34. Secondary specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	As indicated in the Applicable Safety Analyses, the specific activity limit of the secondary coolant is required to be ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131 to maintain the validity of the analyses reported in Chapter 15 (Ref. 1). Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

BASES

APPLICABILITY	In MODES 1, 2, 3, and 4 the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere. In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.
ACTIONS	<u>A.1 and A.2</u> DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.4.1</u> This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or leakage. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.
REFERENCES	1. Chapter 15, “Accident Analyses.”

B 3.7 PLANT SYSTEMS

B 3.7.5 Spent Fuel Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel pool meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are at their maximum capacity. The water also provides shielding during the movement of spent fuel, and a large capacity heat sink in the event the spent fuel pool cooling system is inoperable. A general description of the spent fuel pool design is given in Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling System is given in Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in Section 15.7.4 (Ref. 3).
APPLICABLE SAFETY ANALYSES	The minimum water level in the spent fuel pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 4). The design basis radiological consequences resulting from a postulated fuel handling accident are within the dose values provided in Section 15.7.4 (Ref. 3). According to Reference 3 there is 23 ft of water between the damaged fuel bundle and the fuel pool surface during a fuel handling accident. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle. This slight reduction in water depth does not adversely affect the margin of conservatism associated with the assumed pool scrubbing factor of 500 for elemental iodine. In addition to mitigation of the effects of a fuel handling accident, the required minimum water level in the spent fuel pool provides a large capacity heat sink for spent fuel pool cooling in the event the spent fuel pool cooling system is inoperable. The Spent Fuel Pool Water Level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The spent fuel pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident

BASES

LCO (continued)

analysis (Ref. 3) and loss of spent fuel pool cooling. As such, it is the minimum required for fuel storage and movement within the spent fuel pool.

APPLICABILITY

This LCO applies at all times since the loss of spent fuel pool cooling is not MODE dependent.

ACTIONS

LCO 3.0.3 is applicable while in MODE 1, 2, 3, or 4. Since spent fuel pool cooling requirements apply at all times, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. Spent fuel pool cooling requirements are independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

LCO 3.0.8 is applicable while in MODE 5 or 6. Since spent fuel pool cooling requirements apply at all times, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. Spent fuel pool cooling requirements are independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

<u>A.1</u>

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel pool water level is lower than the required level, the movement of irradiated fuel assemblies shall be suspended. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 4, 5, or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2 and 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

<u>A.2</u>

If the water level in the spent fuel pool is < 23 ft, the heat capacity of the spent fuel pool will be less than that assumed in the event of a loss of spent fuel pool cooling. In this case, action must be initiated within 1 hour

BASES

ACTIONS (continued)

to restore the water level in the spent fuel pool to ≥ 23 ft above the top of the irradiated fuel assemblies. Initiation of this action requires that the action be continued until a water level of ≥ 23 ft is attained.

The Completion Time of 1 hour assures prompt action to compensate for a degraded condition.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies sufficient spent fuel pool water is available in the event of a fuel handling accident or loss of spent fuel pool cooling. The water level in the spent fuel pool must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the spent fuel pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.4.1.

REFERENCES

1. Section 9.1.2, “Spent Fuel Storage.”

2. Section 9.1.3, “Spent Fuel Pool Cooling System.”

3. Section 15.7.4, “Fuel Handling Accident.”

4. Regulatory Guide 1.183 Rev. 0, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Control Room Emergency Habitability System (VES)

BASES

BACKGROUND

The Main Control Room Habitability System (VES) provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity. The system is designed to operate following a Design Basis Accident (DBA) which requires protection from the release of radioactivity. In these events, the Nuclear Island Non-Radioactive Ventilation System (VBS) would continue to function if AC power is available. If AC power is lost or a High-2 main control room (MCR) radiation signal is received, the VES is actuated. The major functions of the VES are: 1) to provide forced ventilation to deliver an adequate supply of breathable air (Ref. 4) for the MCR occupants; 2) to provide forced ventilation to maintain the MCR at a 1/8 inch water gauge positive pressure with respect to the surrounding areas; and 3) to limit the temperature increase of the MCR equipment and facilities that must remain functional during an accident, via the heat absorption of passive heat sinks.

The VES consists of compressed air storage tanks, two air delivery flow paths, associated valves, piping, and instrumentation. The tanks contain enough breathable air to supply the required air flow to the MCR for at least 72 hours. The VES system is designed to maintain CO_2 concentration less than 0.5% for up to 11 MCR occupants.

Sufficient thermal mass exists in the surrounding concrete structure (including walls, ceiling and floors) to absorb the heat generated inside the MCR, which is initially at or below 75°F. Heat sources inside the MCR include operator workstations, emergency lighting and occupants. Sufficient insulation is provided surrounding the MCR pressure boundary to preserve the minimum required thermal capacity of the heat sink. The insulation also limits the heat gain from the adjoining areas following the loss of VBS cooling.

In the unlikely event that power to the VBS is unavailable for more than 72 hours, MCR envelope habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR envelope.

The compressed air storage tanks are initially pressurized to 3400 psig. During operation of the VES, a self contained pressure regulating valve maintains a constant downstream pressure regardless of the upstream pressure. An orifice downstream of the regulating valve is used to control the air flow rate into the MCR. The MCR is maintained at a 1/8 inch water gauge positive pressure to minimize the infiltration of airborne contaminants from the surrounding areas.

APPLICABLE SAFETY ANALYSES

The compressed air storage tanks are sized such that the set of tanks has a combined capacity that provides at least 72 hours of VES operation.

Operation of the VES is automatically initiated by either of two safety related signals: 1) undervoltage to Class 1E battery charger, or 2) high-2 particulate or iodine radioactivity.

In the event of a loss of all AC power, the VES functions to provide ventilation, pressurization, and cooling of the MCR pressure boundary.

In the event of a high level of gaseous radioactivity outside of the MCR, the VBS continues to operate to provide pressurization and filtration functions. The MCR air supply downstream of the filtration units is monitored by a safety related radiation detector. Upon an undervoltage to Class 1E battery charger or high-2 particulate or iodine radioactivity setpoint, a safety related signal is generated to isolate the MCR from the VBS and to initiate air flow from the VES storage tanks. Isolation of the VBS consists of closing safety related valves in the supply and exhaust ducts that penetrate the MCR pressure boundary. VES air flow is initiated by a safety related signal which opens the isolation valves in the VES supply lines.

The VES functions to mitigate a DBA or transient that either assumes the failure of or challenges the integrity of the fission product barrier.

The VES satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The VES limits the MCR temperature rise and maintains the MCR at a positive pressure relative to the surrounding environment.

Two air delivery flow paths are required to be OPERABLE to ensure that at least one is available, assuming a single failure.

The VES is considered OPERABLE when the individual components necessary to deliver a supply of breathable air to the MCR are OPERABLE. This includes components listed in SR 3.7.6.2 through 3.7.6.8. In addition, the MCR pressure boundary must be maintained, including the integrity of the walls, floors, ceilings, electrical and mechanical penetrations, and access doors.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

LCO (continued)

The LCO is modified by a Note allowing the control room boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated.

APPLICABILITY

The VES is required to be OPERABLE in MODES 1, 2, 3, and 4 and during movement of irradiated fuel because of the potential for a fission product release following a DBA.

The VES is not required to be OPERABLE in MODES 5 and 6 when irradiated fuel is not being moved because accidents resulting in fission product release are not postulated.

ACTIONS

LCO 3.0.8 is applicable while in MODE 5 or 6. Since irradiated fuel assembly movement can occur in MODE 5 or 6, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, the fuel movement is independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

A.1

When a VES valve or damper is inoperable, action is required to restore the component to OPERABLE status. A Completion Time of 7 days is permitted to restore the valve or damper to OPERABLE status before action must be taken to reduce power. The Completion Time of 7 days is based on engineering judgment, considering the low probability of an accident that would result in a significant radiation release from the fuel, the low probability of not containing the radiation, and that the remaining components can provide the required capability.

B.1

When the main control room air temperature is outside the acceptable range during VBS operation, action is required to restore it to an acceptable range. A Completion Time of 24 hours is permitted based

BASES

ACTIONS (continued)

upon the availability of temperature indication in the MCR. It is judged to be a sufficient amount of time allotted to correct the deficiency in the nonsafety ventilation system before shutting down.

C.1

If the MCR pressure boundary is damaged or otherwise degraded, action is required to restore the integrity of the pressure boundary and restore it to OPERABLE status within 24 hours. A Completion Time of 24 hours is permitted based upon operating experience. It is judged to be a sufficient amount of time allotted to correct the deficiency in the pressure boundary.

D.1 and D.2

In MODE 1, 2, 3, or 4 if Conditions A, B, or C cannot be restored to OPERABLE status within the required Completion Time, the plant must be placed in a MODE that minimizes accident risk. This is done by entering MODE 3 within 6 hours and MODE 5 within 36 hours.

E.1

During movement of irradiated fuel assemblies, if the Required Action A.1, B.1, or C.1 cannot be completed within the required Completion Time, the movement of fuel must be suspended. Performance of Required Action E.1 shall not preclude completion of actions to establish a safe condition.

F.1, F.2, and F.3

If the VES is inoperable in MODE 1, 2, 3, or 4, the VES may not be capable of performing the intended function, and the plant must be brought to MODE 4, where the probability and consequences of an event are minimized, and the VES must be restored to OPERABLE status within 36 hours. This is accomplished by placing the plant in MODE 3 within 6 hours and in MODE 4 within 12 hours.

G.1

During movement of irradiated fuel assemblies with the VES inoperable, the Required Action is to immediately suspend activities that present a potential for releasing radioactivity that might enter the MCR. This places the plant in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

The MCR air temperature is checked at a frequency of 24 hours to verify that the VBS is performing as required to maintain the initial condition temperature assumed in the safety analysis, and to ensure that the MCR temperature will not exceed the required conditions after loss of VBS cooling. The surveillance limit of 75°F is the initial heat sink temperature assumed in the VES thermal analysis. The 24 hour Frequency is acceptable based on the availability of temperature indication in the MCR.

SR 3.7.6.2

Verification every 24 hours that compressed air storage tanks are pressurized to ≥ [3400] psig is sufficient to ensure that there will be an adequate supply of breathable air to maintain MCR habitability for a period of 72 hours. The Frequency of 24 hours is based on the availability of pressure indication in the MCR.

SR 3.7.6.3

VES air delivery isolation valves are required to be verified as OPERABLE. The Frequency required is in accordance with the Inservice Testing Program.

SR 3.7.6.4

VES air header isolation valves are required to be verified open at 31 day intervals. This SR is designed to ensure that the pathways for supplying breathable air to the MCR are available should loss of VBS occur. These valves should be closed only during required testing or maintenance of downstream components, or to preclude complete depressurization of the system should the VES isolation valves in the air delivery line open inadvertently or begin to leak.

SR 3.7.6.5

Verification that the air quality of the air storage tanks meets the requirements of Appendix C, Table C-1 of ASHRAE Standard 62 is required every 92 days. If air has not been added to the air storage tanks since the previous verification, verification may be accomplished by confirmation of the acceptability of the previous surveillance results along with examination of the documented record of air makeup. The purpose of ASHRAE Standard 62 states: “This standard specifies minimum ventilation rates and indoor air quality that will be acceptable to human occupants and are intended to minimize the potential for adverse health

SURVEILLANCE REQUIREMENTS (continued)

effects." Verification of the initial air quality (in combination with the other surveillances) ensures that breathable air is available for 11 MCR occupants for at least 72 hours.

SR 3.7.6.6

Verification that all VBS isolation valves are OPERABLE and will actuate upon demand is required every 24 months to ensure that the MCR can be isolated upon loss of VBS operation.

SR 3.7.6.7

Verification that each VES pressure relief isolation valve within the MCR pressure boundary is OPERABLE is required in accordance with the Inservice Testing Program. The SR is used in combination with SR 3.7.6.7 to ensure that adequate vent area is available to mitigate MCR overpressurization.

SR 3.7.6.8

Verification that the VES pressure relief damper is OPERABLE is required at 24 month intervals. The SR is used in combination with SR 3.7.6.6 to ensure that adequate vent area is available to mitigate MCR overpressurization.

SR 3.7.6.9

Verification of the OPERABILITY of the self-contained pressure regulating valve in each VES air delivery flow path is required in accordance with the Inservice Testing Program. This is done to ensure that a sufficient supply of air is provided as required, and that uncontrolled air flow into the MCR will not occur.

SR 3.7.6.10

Per Reference 1, a functional test is required to establish that one VES air delivery flow path, using the safety related compressed air storage tanks, pressurizes the MCR envelope to at least a positive 1/8 inch water gauge pressure relative to the surrounding spaces at the required air addition flow rate of 65 ± 5 scfm (Ref. 3). The test need not last 72 hours, only long enough to demonstrate the ability to achieve the required differential pressure. The MCR envelope leakage rate must be within the design capacity of the VES to pressurize the MCR for 72 hours. One air

BASES

SURVEILLANCE REQUIREMENTS (continued)

delivery flow path is tested on an alternating basis. The system performance test demonstrates that the MCR pressurization assumed in dose analysis is maintained.

REFERENCES

1. Section 6.4, "Main Control Room Habitability Systems."

2. Section 9.4.1, "Nuclear Island Non-Radioactive Ventilation System."

3. SECY-95-132, "Policy and Technical Issues Associated With The Regulatory Treatment of Non-Safety Systems (RTNSS) In Passive Plant Designs (SECY-94-084)," May 22, 1995.

4. ASHRAE Standard 62-1989, "Ventilation for Acceptable Indoor Air Quality."

5. Regulatory Guide 1.78, "Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," Revision 1, December 2001.

B 3.7 PLANT SYSTEMS

B 3.7.7 Startup Feedwater Isolation and Control Valves

BASES

BACKGROUND

The startup feedwater system supplies feedwater to the steam generators during plant startup, hot standby and cooldown, and in the event of main feedwater unavailability.

The startup feedwater system serves no safety related function and has no safety related design basis, except to isolate feedwater in the event of a feedwater, steam line break, a steam generator tube rupture or other secondary side event.

The startup feedwater system consists of a flow path to each of the steam generators. Each flow path consists of two series startup feedwater valves to provide feedwater control for low feedwater demand conditions. Feedwater can be supplied to the startup feedwater line via either the main or startup feedwater pumps. The feedwater is delivered directly to the SG independent of the main feedwater line. Each startup feedwater line contains one control valve and one isolation valve (Ref. 1).

APPLICABLE SAFETY ANALYSES

The basis for the requirement to isolate the startup feedwater system is established by the analysis for large Steam Line Break (SLB) inside containment. It is also based on the analysis for a large Feedline Break (FLB) and a steam generator tube rupture.

Failure to isolate the startup feedwater system following a SLB or FLB can lead to additional mass and energy being delivered to the steam generators, resulting in excessive cooldown and additional mass and energy release in containment. Failure to isolate the startup feedwater following a steam generator tube rupture may result in overfilling the steam generator.

Low T_{cold} or high steam generator level signals close the startup feedwater control and isolation valves and trips the startup feedwater pumps.

The startup feedwater isolation and control valves are components which actuate to mitigate a Design Basis Accident, and as such meet Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO ensures that the startup feedwater isolation and control valves will actuate on command, following a SLB, FLB or SGTR, and isolate startup feedwater flow to the steam generators.

The startup feedwater isolation and control valves are considered OPERABLE when they automatically close on an isolation actuation signal, and their isolation times are within the required limits.

APPLICABILITY

The startup feedwater isolation and control valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and the steam generators. In MODES 1, 2, 3 and 4, the startup feedwater isolation and control valves are required to be OPERABLE in order to limit the amount of mass and energy that could be added to containment in the event of a SLB or FLB and prevent steam generator overfill in the event of an SGTR. When the valves are closed, they are already performing their safety function.

In MODES 5 and 6, the energy in the steam generators is low, and isolation of the startup feedwater system is not required.

ACTIONS

The ACTIONS are modified by a Note allowing flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the flow paths can be rapidly isolated.

The second Note allows separate Condition entry for each flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable flow path.

<u>A.1 and A.2</u>

With only one isolation or control valve OPERABLE in one or more flow paths, there is no redundant capability to isolate the flow paths. In this case, both an isolation and a control valve in each flow path must be restored to OPERABLE status with 72 hours, or the flow path must be isolated. A Completion Time of 72 hours is acceptable since, with one valve in a flow path inoperable, there is a second valve available in the flow path to isolate the line.

BASES

ACTIONS (continued)

If the inoperable valve in the flow path can not be restored to OPERABLE status, then the flow path must be isolated within a Completion Time of 72 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure.

For flow paths isolated in accordance with Required Action A.2.1, the affected flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that flow paths required to be isolated following an accident will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown, that the isolation devices are in the correct position. The Completion Time of “once per 7 days” is appropriate considering the fact that the devices are operated under administrative controls, valve status indications in the main control room and the probability of their misalignment is low.

B.1

With both the isolation and control valves inoperable in one flow path, the affected flow path must be restored to OPERABLE status or isolated within a Completion Time of 8 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure.

C.1, C.2, and C.3

If the isolation and control valves cannot be restored to OPERABLE status, closed, or isolated within the associated Completion Times, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in least MODE 3 within 6 hours, and in MODE 4 with RCS cooling provided by the normal residual heat removal system within 24 hours, and the affected flow path isolated within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.7.7.1</u> This surveillance requires verification in accordance with the Inservice Testing Program to assure that both startup feedwater isolation and control valves are OPERABLE. The Surveillance Frequency is provided in the Inservice Testing Program.
REFERENCES	1. Section 10.4.9, “Startup Feedwater System.”

B 3.7 PLANT SYSTEMS

B 3.7.8 Main Steam Line Leakage

BASES

BACKGROUND	A limit on leakage from the main steam line inside containment is required to limit system operation in the presence of excessive leakage. Leakage is limited to an amount which would not compromise safety consistent with the Leak-Before-Break (LBB) analysis discussed in Chapter 3 (Ref. 1). This leakage limit ensures appropriate action can be taken before the integrity of the lines is impaired. LBB is an argument which allows elimination of design for dynamic load effects of postulated pipe breaks. The fundamental premise of LBB is that the materials used in nuclear plant piping are strong enough that even a large throughwall crack leaking well in excess of rates detectable by present leak detection systems would remain stable, and would not result in a double-ended guillotine break under maximum loading conditions. The benefit of LBB is the elimination of pipe whip restraints, jet impingement effects, subcompartment pressurization, and internal system blowdown loads. As described in Section 3.6 (Ref. 1), LBB has been applied to the main steam line pipe runs inside containment. Hence, the potential safety significance of secondary side leaks inside containment requires detection and monitoring of leakage inside containment. This LCO protects the main steam lines inside containment against degradation, and helps assure that serious leaks will not develop. The consequences of violating this LCO include the possibility of further degradation of the main steam lines, which may lead to pipe break.
APPLICABLE SAFETY ANALYSES	The safety significance of plant leakage inside containment varies depending on its source, rate, and duration. Therefore, detection and monitoring of plant leakage inside containment are necessary. This is accomplished via the instrumentation required by LCO 3.4.9, “RCS Leakage Detection Instrumentation,” and the RCS water inventory balance (SR 3.4.7.1). Subtracting RCS leakage as well as any other identified non-RCS leakage into the containment area from the total plant leakage inside containment provides qualitative information to the operators regarding possible main steam line leakage. This allows the operators to take corrective action should leakage occur which is detrimental to the safety of the facility and/or the public.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Although the main steam line leakage limit is not required by the 10 CFR 50.36(c)(2)(ii) criteria, this specification has been included in Technical Specifications in accordance with NRC direction (Ref. 2).

LCO

Main steam line leakage is defined as leakage inside containment in any portion of the two (2) main steam line pipe walls. Up to 0.5 gpm of leakage is allowable because it is below the leak rate for LBB analyzed cases of a main steam line crack twice as long as a crack leaking at ten (10) times the detectable leak rate under normal operating load conditions. Violation of this LCO could result in continued degradation of the main steam line.

APPLICABILITY

Because of elevated main steam system temperatures and pressures, the potential for main steam line leakage is greatest in MODES 1, 2, 3, and 4.

In MODES 5 and 6, a main steam line leakage limit is not provided because the main steam system pressure is far lower, resulting in lower stresses and a reduced potential for leakage. In addition, the steam generators are not the primary method of RCS heat removal in MODES 5 and 6.

ACTIONS

A.1 and A.2

With main steam line leakage in excess of the LCO limit, the unit must be brought to lower pressure conditions to reduce the severity of the leakage and its potential consequences. The reactor must be placed in MODE 3 with 6 hours and MODE 5 within 36 hours. This action reduces the main steam line pressure and leakage, and also reduces the factors which tend to degrade the main steam lines. The Completion Time of 6 hours to reach MODE 3 from full power without challenging plant systems is reasonable based on operating experience. Similarly, the Completion Time of 36 hours to reach MODE 5 without challenging plant systems is also reasonable based on operating experience. In MODE 5, the pressure stresses acting on the main steam line are much lower, and further deterioration of the main steam line is less likely.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.8.1 Verifying that main steam line leakage is within the LCO limit assures the integrity of those lines inside containment is maintained. An early warning of main steam line leakage is provided by the automatic system which monitor the containment sump level. Main steam line leakage would appear as unidentified leakage inside containment via this system, and can only be positively identified by inspection. However, by performance of an RCS water inventory balance (SR 3.4.7.1) and evaluation of the cooling and chilled water systems inside containment, determination of whether the main steam line is a potential source of unidentified leakage inside containment is possible.
REFERENCES	1. Section 3.6, “Protection Against the Dynamic Effects Associated with the Postulated Rupture of Piping.” 2. NRC letter, Diane T. Jackson to Westinghouse (Nicholas J. Liparulo), dated September 5, 1996, “Staff Update to Draft Safety Evaluation Report (DSER) Open Items (OIs) Regarding the Westinghouse AP600 Advanced Reactor Design,” Open Item #365.

B 3.7 PLANT SYSTEMS

B 3.7.9 Fuel Storage Pool Makeup Water Sources

BASES

BACKGROUND

The spent fuel storage pool is normally cooled by the nonsafety spent fuel pool cooling system. In the event the normal cooling system is unavailable, the spent fuel storage pool can be cooled by the normal residual heat removal system. Alternatively, the spent fuel storage pool contains sufficient water inventory for decay heat removal by boiling. To support extended periods of loss of normal pool cooling, makeup water is required to provide additional cooling by boiling. Both safety and non-safety makeup water sources are available on-site.

Two safety-related, gravity fed sources of makeup water are provided to the spent fuel storage pool. These makeup water sources contain sufficient water to maintain spent fuel storage pool cooling for 72 hours. The containment cooling system water storage tank provides makeup water when pool decay heat is > 5.4 MWt and the decay heat in the reactor is less than 9.0 MWt. The cask washdown pit provides makeup water when decay heat in the pool is ≥ 4.6 MWt and ≤ 5.4 MWt. Additional on-site makeup water sources are available to provide fuel pool cooling between 3 and 7 days.

The containment cooling system water storage tank is isolated by two normally closed valves. The normally closed valves will be opened only to provide emergency makeup to the spent fuel storage pool. A third downstream valve permits the operator to regulate addition of water to the spent fuel storage pool as required to maintain the cooling water inventory.

Once decay heat in the fuel pool is reduced to below 4.6 MWt, the spent fuel storage pool water inventory is sufficient, without makeup, to maintain spent fuel storage pool for 72 hours. When the spent fuel storage pool decay heat load is reduced below 4.6 MWt, the cask washdown pit may be drained and returned to use for shipping cask cleaning operations.

A general description of the fuel storage pool design is given in Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in Section 9.1.3 (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES

In the event the normal spent fuel storage pool cooling system is unavailable, the spent fuel cooling is provided by the heat capacity of the water in the pool. The worst case decay heat load (decay heat > 5.4 MWt) is produced by an emergency full core off-load following a refueling plus ten years of spent fuel. For this case the spent fuel storage pool inventory provided by the water over the stored fuel and below the pump suction connection is capable of cooling the spent fuel storage pool without boiling for at least 2.5 hours, following a loss of normal spent fuel storage pool cooling. After boiling starts, makeup water may be required to replace water lost by boiling and is available, without offsite support, via the passive containment cooling water storage tank.

The requirements of LCO 3.6.6, “Passive Containment Cooling System – Operating,” are applicable in MODES 1, 2, 3, and 4 and LCO 3.6.7, “Passive Containment Cooling System – Shutdown,” are applicable in MODES 5 and 6 with decay heat > 9.0 MWt. LCOs 3.6.6 and 3.6.7 require availability of the containment cooling water tank for containment heat removal. Below 9.0 MWt decay heat, containment air cooling is adequate. Since there are no design conditions which result in both reactor decay heat > 9.0 MWt and spent fuel storage pool decay heat > 5.4 MWt, the applicability for LCOs 3.6.6/3.6.7 and for LCO 3.7.9 are mutually exclusive.

Since none of the Chapter 15 Design Basis Accident analyses assume availability of the containment cooling water tank or the cask washdown pit for spent fuel storage pool makeup, the fuel storage pool makeup water sources specification does not satisfy any of the 10 CFR 50.36(c)(2)(ii) criteria. This LCO is included in accordance with NRC guidance provided in an NRC letter (Reference 3).

LCO

The fuel storage pool makeup water sources, the cask washdown pit, and the containment cooling water tank are required to contain 13.75 ft and 400,000 gallons of water, respectively. An OPERABLE flow path from the required makeup source assures spent fuel cooling for at least 72 hours. Several additional makeup sources are available, including the ground level containment cooling ancillary water storage tank. These makeup sources assure spent fuel cooling for at least 7 days.

Note 1 specifies that either the cask washdown pit or the passive containment cooling water storage tank is required to be OPERABLE when the spent fuel storage pool decay heat ≥ 4.6 MWt and ≤ 5.4 MWt. Note 2 specifies that the passive containment cooling water storage tank source is required to be OPERABLE when the spent fuel storage pool decay heat is > 5.4 MWt, which is normal following a full core off load. The larger makeup source is necessary for the higher decay heat load.

BASES

LCO (continued)

When a portion of the fuel is returned to the reactor vessel in preparation for startup, the pool decay heat is reduced to ≤ 5.4 MWt and makeup from the cask washdown pit is sufficient.

APPLICABILITY

This LCO applies during storage of fuel in the fuel storage pool with a calculated decay heat ≥ 4.6 MWt. With decay heat < 4.6 MWt, the assumed spent fuel storage pool water inventory (i.e., level below the pump suction connection to the pool) provides for 3 days of cooling without makeup.

ACTIONS

LCO 3.0.3 is applicable while in MODE 1, 2, 3, or 4. Since spent fuel pool cooling requirements apply at all times, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. Spent fuel pool cooling requirements are independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

LCO 3.0.8 is applicable while in MODE 5 or 6. Since spent fuel pool cooling requirements apply at all times, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. Spent fuel pool cooling requirements are independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

A.1

If the passive containment cooling water storage tank (with decay heat > 5.4 MWt) and/or the cask washdown pit (with decay heat ≥ 4.6 and ≤ 5.4 MWt) is inoperable, Action must be initiated immediately to restore the makeup source or its associated flow path to OPERABLE status.

Additionally, in order to provide the maximum cooling capability, the spent fuel pool should be filled to its maximum level. Nonsafety related makeup sources can be used to fill the pool. This action is not specified in the specification, since the benefit of adding approximately 6 inches of water to the pool is less than a 5% improvement in cooling capability.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies sufficient passive containment cooling system water storage tank volume is available in the event of a loss of spent fuel cooling.

The 7 day Frequency is appropriate because the volume in the passive containment cooling system water storage tank is normally stable and water level changes are controlled by plant procedures.

SR 3.7.9.2

This SR verifies sufficient cask washdown pit water volume is available in the event of a loss of spent fuel cooling. The 13.75 ft level specified provides makeup water for stored fuel with decay heat ≥ 4.6 and ≤ 5.4 MWt.

The 30 day Frequency is appropriate because the cask washdown pit has only one drain line which is isolated by series manual valves which are only operated in accordance with plant procedures, thus providing assurance that inadvertent level reduction is not likely.

SR 3.7.9.3

This SR requires verification of the OPERABILITY of the manual makeup water source isolation valves in accordance with the requirements and Frequency specified in the Inservice Testing Program. Manual valves PCS-PL-V009, PCS-PL-V045, PCS-PL-V051, isolate the makeup flow path from the passive containment cooling system water storage tank. Manual valves SFS-PL-V066 and SFS-PL-V068 isolate the makeup flow path from the cask washdown pit.

REFERENCES

1. Section 9.1.2, “Spent Fuel Storage.”

2. Section 9.1.3, “Spent Fuel Pool Cooling System.”

3. NRC letter, William C. Huffman to Westinghouse Electric Corporation, “Summary of Telephone Conference with Westinghouse to Discuss Proposed Design Changes to the AP600 Main Control Room Habitability System,” dated September 11, 1997.

B 3.7 PLANT SYSTEMS

B 3.7.10 Steam Generator Isolation Valves

BASES

BACKGROUND	The steam generator isolation valves consist of the power operated relief valve (PORV) block valves (SGS-PL-V027A & B), PORVs (SGS-PL-V233A & B), and blowdown isolation valves (SGS-PL-V074A & B and SGS-PL-V075A & B). The PORV flow paths must be isolated following a Steam Generator Tube Rupture (SGTR) to minimize radiological releases. The blowdown flow path must be isolated following Loss of Feedwater and Feedwater Line Break events to retain the steam generator water inventory for Reactor Coolant System (RCS) heat removal. A PORV is installed in a 6 inch branch line off of the main steam line piping from each steam generator, to provide for controlled removal of reactor decay heat during normal reactor cooldown when the main steam isolation valves are closed or the turbine bypass system is not available. A normally-open block valve is provided in each PORV line to provide backup isolation capability. Both the PORV and the block valve receive a Protection and Safety Monitoring System (PMS) isolation signal on low steam line pressure. The block valve is also a containment isolation valve. The blowdown line from each steam generator is provided with two series isolation valves, both located outside, but close to, containment. The blowdown valves receive a PMS isolation signal on low SG level and on PRHR actuation. The first blowdown isolation valve outside of containment is also a containment isolation valve. The steam generator PORVs and the blowdown isolation valves fail closed on loss of control or actuation power. The steam generator PORV block valves fail as-is on loss of control or actuation power. The steam generator isolation valves may also be actuated manually. Descriptions of the PORVs and SG blowdown isolation are found in Section 10.3.2.2.3 and Section 10.4.8 (Refs. 1 & 2).
APPLICABLE SAFETY ANALYSES	The PORV flow paths must be isolated following an SGTR to minimize radiological releases from the ruptured steam generator into the atmosphere. The PORV flow path is assumed to open due to high secondary side pressure, during the SGTR. Dose analyses take credit for subsequent isolation of the PORV flow path by the PORV and/or the block valve which receive a close signal on low steam line pressure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The blowdown flow path on each SG must be isolated following Loss of Feedwater and Feedwater Line Break events to retain the steam generator water inventory for use in Reactor Coolant System (RCS) heat removal via the SGs. RCS heat removal for these events is, primarily, provided by the Passive Residual Heat Removal Heat Exchanger (PRHR HX); however, the SG heat removal is assumed. The SG blowdown isolation valves receive an isolation signal on low SG level or PRHR actuation. These events take credit for steam generator heat removal using the water inventory retained after blowdown isolation. If the blowdown line were not isolated, much of the inventory would drain from the SG rather than cool the RCS.

The steam generator isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the steam generator isolation valves consisting of the PORV, PORV block valve, and blowdown isolation valves on each steam generator to be OPERABLE. These isolation valves are considered OPERABLE when the valves are capable of closing on a PMS actuation signal.

This LCO provides assurance that the PORV and PORV block valve will perform their design safety function to mitigate the consequences of an SGTR that could result in offsite exposures.

Additionally, this LCO provides assurance that the steam generator blowdown isolation valves will perform their design safety function to mitigate the consequences of Loss of Feedwater and Feedwater Line Break events by retaining the steam generator water inventory for Reactor Coolant System (RCS) heat removal.

APPLICABILITY

The steam generator isolation valves must be OPERABLE in MODES 1, 2, and 3, and in MODE 4 with the RCS cooling not being provided by the Normal Residual Heat Removal System (RNS).

In MODE 4 with the RCS cooling being provided by the RNS and in MODES 5 and 6, the steam generators are not needed for RCS cooling and the potential for an SGTR or Loss of Feedwater and Feedwater Line Break events is minimized due to the reduced mass and energy in the RCS and steam generators.

ACTIONS

The ACTIONS are modified by a Note allowing the blowdown isolation flow paths to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the flow path can be rapidly isolated when a need for blowdown isolation is indicated.

The second Note allows separate Condition entry for each steam generator isolation flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable flow path.

A.1

With one valve in one or more PORV flow paths inoperable, action must be taken to isolate the flow path with a closed and deactivated valve. The valve must be deactivated to assure that the flow path will not be opened by a high pressure signal during the course of an SGTR event. This action places the flow path in a condition which assures the safety function is performed. A Completion Time of 72 hours is based on the availability of one OPERABLE PORV flow path isolation valve which is fully capable of performing the required isolation function.

B.1 and B.2

With one valve in one or more blowdown flow paths inoperable, action must be taken to isolate the flow path with a closed valve. This action places the flow path in a condition which assures the safety function is performed. A Completion Time of 72 hours to isolate the flow path is based on the availability of one OPERABLE blowdown flow path isolation valve which is fully capable of performing the required isolation function.

Since the blowdown isolation valve is not deactivated, periodic verification is required to assure that the flow path remains isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of status indications available in the control room, and other administrative controls, to ensure that the valve remains in the closed position.

C.1

With both valves in one or more PORV flow paths inoperable, action must be taken to isolate the flow path with a closed and deactivated valve. The valve must be deactivated to assure that the flow path will not be opened by a high pressure signal during the course of an SGTR event. This

BASES

ACTIONS (continued)

action places the flow path in a condition which assures the safety function is performed. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the SG isolation valves. The incremental conditional core damage probability with this AOT is more than an order of magnitude less than the value indicated to have a small impact on plant risk in Reference 6.

D.1 and D.2

With two valves in one or more blowdown flow paths inoperable, action must be taken to isolate the flow path with a closed valve. This action places the flow path in a condition which assures the safety function is performed. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the SG isolation valves. The incremental conditional core damage probability with this AOT is more than an order of magnitude less than the value indicated to have a small impact on plant risk in Reference 3.

Since the blowdown isolation valve is not deactivated, periodic verification is required to assure that the flow path remains isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of status indications available in the control room, and other administrative controls, to ensure that the valve remains in the closed position.

E.1 and E.2

If the SG isolation valves cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 with the RCS cooling provided by the RNS within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

The function of the SG isolation valves (PORV block valves (SGS-PL-V027A & B), PORVs (SGS-PL-V233A & B) and blowdown isolation valves (SGS-PL-V074A & B and SGS-PL-V075A & B)) is to isolate the steam generators in the event of SGTR, Loss of Feedwater or Feedwater Line Break. Stroking the valves closed demonstrates their capability to perform the isolation function. The Frequency for this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. Section 10.3.2.2.3, “Power-Operated Atmospheric Relief Valves.”
2. Section 10.4.8, “Steam Generator Blowdown System.”
3. Regulatory Guide 1.177, 8/98, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 DC Sources – Operating

BASES

BACKGROUND

The Class 1E DC and UPS System (IDS) provides electrical power for safety related and vital control instrumentation loads, including monitoring and main control room emergency lighting. It also provides power for safe shutdown when all the onsite and offsite AC power sources are lost and cannot be recovered for 72 hours. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the Class 1E DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The Class 1E DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of four independent safety related Class 1E DC electrical power subsystems (Division A, B, C, and D). Divisions A and D each consist of one 24 hour battery bank, one battery charger, and the associated control equipment and interconnecting cable. Divisions B and C each consist of two battery banks (one 24 hour and one 72 hour), two battery chargers, and the associated control equipment and interconnecting cabling. The loads on the battery banks (including those on the associated inverters) are grouped according to their role in response to a Design Basis Accident (DBA). Loads which are a one time or limited duration load (engineered safeguards features (ESF) actuation cabinets and reactor trip function) required within the first 24 hours following an accident are connected to the “24 hour” battery bank. Loads which are continuous or required beyond the first 24 hours following an accident (emergency lighting, post accident monitoring, and Qualified Data Processing System) are connected to the “72 hour” battery bank. There are a total of six battery banks. A battery bank consists of two batteries connected in parallel. Each battery consist of 60 cells connected in series. Divisions A and D each have one 4800 ampere hour battery bank and Divisions B and C each have two 4800 ampere hour battery banks.

Additionally, there is one installed spare battery bank and one installed spare battery charger, which provide backup service in the event that one of the battery banks and/or one of the preferred battery chargers is out of service. The spare battery bank and charger are Class 1E and have the same rating as the primary components. If the spare battery bank with the charger is substituted for one of the preferred battery banks or chargers, then the requirements of independence and redundancy between subsystems are maintained and the division is OPERABLE.

BASES

BACKGROUND (continued)

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

Each battery bank provides power to an inverter, which in turn powers an AC instrumentation and control bus. The AC instrumentation and control bus loads are connected to inverters according to the battery bank type, 24 hour or 72 hour.

The Class 1E DC power distribution system is described in more detail in Bases for LCO 3.8.5, “Distribution System – Operating,” and LCO 3.8.6, “Distribution System – Shutdown.”

Each battery has adequate storage capacity to carry the required load for the required duration as discussed in Reference 4.

Each 125 VDC battery bank, including the spare battery bank, is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a separate subsystem. There is no sharing between separate Class 1E subsystems such as batteries, battery chargers, or distribution panels.

The batteries for each Class 1E electrical power subsystem are based on 125% of required capacity. The voltage limit is 2.13 V per cell, which corresponds to a total minimum voltage output of 128 V per battery discussed in Reference 4. The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 5).

Each electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the Chapter 6 (Ref. 6) and Chapter 15, (Ref. 7), assume that engineered safety features are OPERABLE. The Class 1E DC electrical power system provides 125 volts power for safety related and vital control instrumentation loads

BASES

APPLICABLE SAFETY ANALYSES (continued)

including monitoring and main control room emergency lighting during all MODES of operation. It also provides power for safe shutdown when all the onsite and offsite AC power sources are lost.

The OPERABILITY of the Class 1E DC sources is consistent with the initial assumptions of the accident analyses. This includes maintaining at least three of the four divisions of DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite and onsite AC power sources; and

b. A worst case single failure.

The DC Sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Class 1E DC electrical power subsystems are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of Class 1E DC electrical power from one division does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE Class 1E DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es). The spare battery and/or charger may be used by one subsystem for OPERABILITY.

APPLICABILITY

The Class 1E DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

Class 1E DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.2, “DC Sources – Shutdown.”

BASES

ACTIONS

A.1, A.2, and A.3

Condition A represents one division with one or two battery chargers inoperable (e.g., the voltage limit of SR 3.8.1.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 6 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

Because of the passive system design and the use of fail-safe components, the remaining Class 1E DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate most DBAs following a subsequent worst case single failure. The 6 hour Completion Time is reasonable based on engineering judgement balancing the risks of operation without one DC subsystem against the risks of a forced shutdown. Additionally, the Completion Time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown; and, if necessary, prepare and effect an orderly and safe shutdown.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 6 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

BASES

ACTIONS (continued)

If the charger is operating in the current limit mode after 6 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to [5] amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 24 hour period the battery float current is not less than or equal to [5] amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1, B.2, and B.3

Condition B represents two divisions with one or more battery chargers inoperable (e.g., the voltage limit of SR 3.8.1.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action B.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to the charger inoperability.

ACTIONS (continued)

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action B.2).

Required Action B.2 requires that the battery float current be verified as less than or equal to [5] amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 24 hour period the battery float current is not less than or equal to [5] amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action B.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

<u>C.1</u>

Condition C represents one division with one or more batteries inoperable. With one or more batteries inoperable, the DC bus is being supplied by the OPERABLE battery chargers. Any event that results in a loss of the AC bus supporting the battery chargers will also result in loss of DC to that train.

BASES

ACTIONS (continued)

Because of the passive system design and the use of fail-safe components, the remaining Class 1E DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate most DBAs following a subsequent worst case single failure. The 6 hour Completion Time is reasonable based on engineering judgement balancing the risks of operation without one DC subsystem against the risks of a forced shutdown. Additionally, the Completion Time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown; and, if necessary, prepare and effect an orderly and safe shutdown.

The installed spare battery bank and charger may be used to restore an inoperable Class 1E DC electrical power subsystem; however, all applicable Surveillances must be met by the spare equipment used, prior to declaring the subsystem OPERABLE.

D.1

Condition D represents two divisions with one or more batteries inoperable. With one or more batteries inoperable, the DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in loss of DC to that train. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than [2.07] V, etc.) are identified in Specifications 3.8.1, 3.8.2, and 3.8.7 together with additional specific completion times.

The installed spare battery bank and charger may be used to restore an inoperable Class 1E DC electrical power subsystem; however, all applicable Surveillances must be met by the spare equipment used, prior to declaring the subsystem OPERABLE.

E.1

If one of the Class 1E DC electrical power subsystems is inoperable, the remaining Class 1E DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate all design basis accidents, based on conservative analysis.

Because of the passive system design and the use of fail-safe components, the remaining Class 1E DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate most DBAs

BASES

ACTIONS (continued)

following a subsequent worst case single failure. The 6 hour Completion Time is reasonable based on engineering judgement balancing the risks of operation without one DC subsystem against the risks of a forced shutdown. Additionally, the Completion Time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown; and, if necessary, prepare and effect an orderly and safe shutdown.

The 6 hour Completion Time is also consistent with the time specified for restoration of one (of four) Protection and Safety Monitoring System (PMS) (LCO 3.3.2, ESFAS Instrumentation). Depending on the nature of the DC electrical power subsystem inoperability, one supported division of instrumentation could be considered inoperable. Inoperability of a PMS Division is similar to loss of one DC electrical power subsystem. In both cases, actuation of the safety functions associated with one of the four subsystems/divisions may no longer be available.

F.1

Condition F represents two subsystems with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected distribution subsystems. The 2 hour limit is consistent with the allowed time for two inoperable DC distribution subsystems.

If two of the required DC electrical power subsystems are inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the two remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate all but the very worst case events. Since a subsequent worst case single failure would, however, result in the loss of the third subsystem, leaving only one subsystem with limited capacity to mitigate events, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 11) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

BASES

ACTIONS (continued)

G.1 and G.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers which support ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8).

SR 3.8.1.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying [400] amps at the minimum established float voltage for [24] hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the

SURVEILLANCE REQUIREMENTS (continued)

charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least [2] hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, an the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ [2] amps.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

<u>SR 3.8.1.3</u>

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the Class 1E DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed with intervals between tests not to exceed 24 months. This Surveillance may be performed during any plant condition with the spare battery and charger providing power to the bus.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity,

BASES

SURVEILLANCE REQUIREMENTS (continued)

the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems if the spare battery is not connected. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," U.S. Nuclear Regulatory Commission, March 10, 1971.

BASES

REFERENCES (continued)

3. IEEE-308 1991, “IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations,” Institute of Electrical and Electronic Engineers.

4. Section 8.3.2, “Class 1E DC Power Systems.”

5. IEEE-485 1997, “IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications,” Institute of Electrical and Electronic Engineers, June 1983.

6. Chapter 6, “Engineered Safety Features.”

7. Chapter 15, “Accident Analyses.”

8. IEEE-450 1995, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications,” Institute of Electrical and Electronic Engineers, June 1986.

9. Regulatory Guide 1.32, “Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, February 1977.

10. Regulatory Guide 1.129 Revision 1, “Maintenance Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, February 1978.

11. Regulatory Guide 1.93, “Availability of Electric Power Sources,” U.S. Nuclear Regulatory Commission, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 DC Sources – Shutdown

BASES

BACKGROUND

A description of the Class 1E DC power sources is provided in the Bases for LCO 3.8.1, “DC Sources – Operating.”

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume engineered safety features are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystem is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems’ OPERABILITY.

The OPERABILITY of the minimum Class 1E DC power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate Class 1E DC power sources are provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES [1, 2, 3, and 4] have no specific analyses in MODES [5 and 6] because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal

BASES

APPLICABLE SAFETY ANALYSES (continued)

consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The Class 1E DC Sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Class 1E DC electrical power subsystems are required to be OPERABLE to support required trains of Class 1E Distribution System divisions required to be OPERABLE by LCO 3.8.6. This ensures the availability of sufficient Class 1E DC power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, inadvertent reactor vessel draindown).

As described in the previous section, “Applicable Safety Analyses,” in the event of an accident during shutdown, the Technical Specifications are designed to maintain the plant in such a condition that, even with a single failure, the plant will not be in immediate difficulty.

BASES

APPLICABILITY

The Class 1E DC power sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features needed to mitigate a fuel-handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The Class 1E DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1, “DC Sources – Operating.”

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

<u>A.1 and A.2</u>

With one or more of the required (per LCO 3.8.6, “Distribution Systems – Shutdown”) Class 1E DC power subsystems inoperable, the remaining subsystems may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS, fuel movement, and/or operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO ACTIONS. In many instances this option would likely involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity

BASES

ACTIONS (continued)

additions that could result in failure to meet the minimum SDM or boron concentration limit) to assure continued safe operation. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary Class 1E DC electrical power to the unit safety systems.

The installed spare battery bank and charger may be used to restore an inoperable Class 1E DC power subsystem; however, all applicable surveillances must be met by the spare equipment used, prior to declaring the subsystem OPERABLE.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required Class 1E DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires performance of all Surveillances required by SR 3.8.1.1 through SR 3.8.1.8. Therefore, see the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. Chapter 6, “Engineered Safety Features.”

2. Chapter 15, “Accident Analysis.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Inverters – Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the Class 1E AC instrument and control buses because of the stability and reliability they achieve. Divisions A and D, each consist of one Class 1E inverter. Divisions B and C, each consist of two inverters. The function of the inverter is to convert Class 1E DC electrical power to AC electrical power, thus providing an uninterruptible power source for the instrumentation and controls for the Protection and Safety Monitoring System (PMS). The inverters are powered from the Class 1E 125 V battery sources (Ref. 1).

Under normal operation, a Class 1E inverter supplies power to the Class 1E AC instrument and control bus. If the inverter is inoperable or the Class 1E 125 VDC input to the inverter is unavailable, the Class 1E AC instrument and control bus is powered from the backup source associated with the same division via a static transfer switch featuring a make-before-break contact arrangement. In addition, a manual mechanical bypass switch is used to provide a backup power source to the Class 1E AC instrument and control bus when the inverter is removed from service. The backup source is a Class 1E regulating 480-208/120 volt transformer providing a regulated output to the Class 1E AC instrument and control bus through a static transfer switch and a manual bypass switch.

In addition to powering safety loads, the Class 1E AC power sources are used for emergency lighting in the main control room and remote shutdown workstation. When a normal AC power source for emergency lighting is lost, the loads are automatically transferred to a Class 1E AC power source. Specific details on inverters and their operating characteristics are found in Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) transient analyses in Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume engineered safety features are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the PMS instrumentation and controls so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (Containment Systems).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining at least three of the four Divisions of AC instrument and control buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite and onsite AC power source; and

b. A worst case single failure.

Inverters are a part of distribution systems, and as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the PMS instrumentation and controls is maintained. The six inverters ensure an uninterruptible supply of AC electrical power to the six Class 1E AC instrument and control buses even if all AC power sources are de-energized.

OPERABLE inverters require that the Class 1E AC instrument and control bus be powered by the inverter with output voltage and frequency within tolerances, and the power input to the inverter from a 125 VDC station battery.

This LCO is modified by a Note that allows one inverter to be disconnected from its associated Class 1E DC bus for ≤ 72 hours, if the associated Class 1E AC instrument and control bus is powered from its Class 1E regulating transformer during the period and all other inverters are OPERABLE. This allows an equalizing charge to be placed on one battery bank. If the inverter was not disconnected, the resulting voltage condition might damage the inverter. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 72 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected Class 1E AC instrument and control bus while taking into consideration the time required to perform an equalizing charge on the battery bank.

BASES

LCO (continued)

The intent of this Note is to limit the number of inverters that may be disconnected. Only the inverter associated with the single battery bank undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.4, "Inverters – Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated Class 1E AC instrument and control bus is automatically energized from its regulating transformer. A manual switch is also provided which can be used if the static transfer switch does not properly function.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.5, "Distribution System – Operating." This ensures that the vital bus is re-energized within 12 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour time limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument and control bus is powered from its regulating transformer, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC instrument and control buses is the preferred source for powering instrumentation trip setpoint devices.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to MODE 5 where the probability and consequences on an event are minimized. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This Surveillance verifies that the inverters are functioning properly with all required switches and circuit breakers closed and Class 1E AC instrument and control buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the PMS instrumentation connected to the Class 1E AC instrument and control buses. The 7 day Frequency takes into account the effectiveness of the voltage and frequency instruments, the redundant capability of the inverters, and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. Section 8.3.2.1.1.2, “Class 1E Uninterruptible Power Supplies.”

2. Chapter 6, “Engineered Safety Features.”

3. Chapter 15, “Accident Analyses.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 Inverters – Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for Specification 3.8.3, “Inverters – Operating.”

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume engineered safety features are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Protection and Monitoring System Engineered Safety Feature Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems’ OPERABILITY.

The OPERABILITY of the minimum inverters to each Class 1E AC instrument and control bus during MODES 5 and 6, ensures that (Refs. 1 and 2):

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal

BASES

APPLICABLE SAFETY ANALYSES (continued)

consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The Class 1E UPS inverters are part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or postulated DBA. The battery powered inverters provide an uninterruptible supply of AC electrical power to the Class 1E AC instrument and control buses, even if the normal power supply from the 480 VAC is deenergized. OPERABILITY of the inverters requires that the Class 1E instrument and control buses be powered by the inverter with output voltage and frequency within tolerances, and the power input to the inverter from a 125 VDC station battery. This ensures the availability of sufficient inverter power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (fuel handling accidents, inadvertent reactor vessel draindown).

BASES

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Class 1E UPS inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.3, “Inverters – Operating.”

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1 and A.2

If one or more required (per LCO 3.8.6, Distribution Systems – Shutdown) inverters are inoperable, the remaining OPERABLE inverters may be capable of supporting required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowance of the option to declare required features inoperable with associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs’ Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). Suspending positive reactivity additions that could result in

BASES

ACTIONS (continued)

failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a regulating transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and Class 1E AC instrument and control buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the Class 1E AC instrument and control buses. The 7 day Frequency takes into account the effectiveness of the voltage and frequency instruments, the redundant capability of the inverters, and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. Chapter 6, “Engineered Safety Features.”
2. Chapter 15, “Accident Analysis.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 Distribution Systems – Operating

BASES

BACKGROUND

The onsite Class 1E and DC and UPS electrical power distribution system is divided by division into four independent AC and DC electrical power distribution subsystems (Divisions A, B, C, and D).

The Class 1E AC distribution Divisions A and D each consists of one 208/120 V bus. The Class 1E AC distribution Divisions B and C each consists of two 208/120 V buses. The buses are normally powered from separate inverters which are connected to the respective Division Class 1E battery banks. The backup source provided for each Division for the Class 1E AC instrument and control buses is a Class 1E regulating transformer providing regulated output to the Class 1E AC instrument and control buses through a static transfer switch and a manual bypass switch. Power to the transformer is provided by the nonsafety related Main AC Power System. Additional description of this system may be found in the Bases for Specification 3.8.3, “Inverters – Operating.”

The Class 1E DC distribution Divisions A and D each consists of one 125 VDC bus. The Class 1E DC distribution Divisions B and C each consists of two 125 VDC buses. The buses for the four Divisions are normally powered from their associated Division battery chargers. The backup source for each Class 1E DC bus is its associated Class 1E battery bank. Additionally, there is one installed spare Class 1E battery bank and one installed spare Class 1E battery charger, which can provide backup power to a Class 1E DC bus in the event that one of the battery banks or one of the chargers is out of service. Additional description of this system may be found in the Bases for Specification 3.8.1, “DC Sources Operating.”

The list of all required distribution buses is presented in Table B 3.8.5-1 and shown in Section 8.3.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume engineered safety features (ESFs) are OPERABLE. The Class 1E AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the ESFs so that the fuel, Reactor Coolant System (RCS) and containment design limits are not exceeded.

BASES

APPLICABLE SAFETY ANALYSES (continued)

These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (Containment Systems).

The OPERABILITY of the Class 1E AC and DC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least three of the four Divisions of Class 1E AC and DC power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite and onsite AC power sources; and

b. A worst case single failure.

The Class 1E AC and DC electrical power distribution system satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.5-1 ensure the availability of Class 1E AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division A, B, C, and D Class 1E AC and DC electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Division A, B, C, and D AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of the ESFs is not defeated. Three of the four Class 1E AC and DC power distribution subsystems are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any subsystem or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE Class 1E DC electric power distribution subsystems require the associated buses, motor control centers, and electrical circuits to be energized to their proper voltage from either the associated battery bank or charger. The spare battery bank and/or chargers may be used by one subsystem for OPERABILITY. OPERABLE Class 1E AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages and frequencies from the associated inverter or regulating transformer.

BASES

APPLICABILITY

The Class 1E AC and DC electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The Class 1E AC and DC electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for Specification 3.8.6, “Class 1E Distribution Systems – Shutdown.”

ACTIONS

A.1

With one division of the Class 1E AC instrument and control bus inoperable the remaining Class 1E AC instrument and control buses have the capacity to support a safe shutdown and to mitigate all DBAs, based on conservative analysis.

Because of the passive system design and the use of fail-safe components, the remaining Class 1E AC instrument and control buses have the capacity to support a safe shutdown and to mitigate most design basis accidents following a subsequent worst case single failure. The 6 hour Completion Time is reasonable based on engineering judgement balancing the risks of operation without one AC instrument and control bus against the risks of a forced shutdown. Additionally, the Completion Time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown; and, if necessary, prepare and effect an orderly and safe shutdown.

This 6 hour limit is shorter than Completion Times allowed for most supported systems which would be without power. Taking exception to LCO 3.0.2 for components without adequate DC Power, which would have Required Action Completion Times shorter than 6 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

BASES

ACTIONS (continued)

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 6 hour Completion Time takes into account the importance to safety of restoring the Class 1E AC instrument and control bus to OPERABLE status, the passive design of the ESF systems, the redundant capability afforded by the other OPERABLE Class 1E AC instrument and control buses, and the low probability of a DBA occurring during this period which requires more than two OPERABLE AC instrument and control buses.

The 6 hour Completion Time is also consistent with the time specified for restoration of one (of four) Protection and Safety Monitoring System division (LCO 3.3.2, ESFAS Instrumentation). Depending on the nature of the AC instrument and control inoperability, one supported division of instrumentation could be considered inoperable. Inoperability of a PMS division is similar to loss of one division AC instrument and control bus. In both cases, actuation of the safety functions associated with one of the four subsystems/divisions may no longer be available.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 6 hours. This could lead to a total of 12 hours, since initial failure of the LCO, to restore the AC instrument and control distribution system. At this time, a DC circuit could again become inoperable, and AC instrument and control distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal “time zero” for beginning the allowed outage time “clock.” This will result in establishing the “time zero” at the time the LCO was initially not met, instead of the time Condition A was entered. The 12 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

BASES

ACTIONS (continued)

B.1

With one Division of the Class 1E DC electrical power distribution subsystem inoperable, the remaining Divisions have the capacity to support a safe shutdown and to mitigate all DBAs, based on conservative analysis.

Because of the passive system design and the use of fail-safe components, the remaining Divisions have the capacity to support a safe shutdown and to mitigate most design basis accidents following a subsequent worst case single failure. The 6 hour Completion Time is reasonable based on engineering judgement balancing the risks of operation without one Division against the risks of a forced shutdown. Additionally, the completion time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown; and, if necessary, prepare and effect an orderly and safe shutdown.

The 6 hour Completion Time is also consistent with the time specified for restoration of one (of four) Protection and Safety Monitoring System division (LCO 3.3.2, ESFAS Instrumentation). Depending on the nature of the DC electrical power distribution subsystem inoperability, one supported division of instrumentation could be considered inoperable. Inoperability of a PMS division is similar to loss of one DC electrical power distribution subsystem. In both cases, actuation of the safety functions associated with one of the four subsystems/divisions may no longer be available.

This 6 hour limit is shorter than Completion Times allowed for most supported systems which would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 6 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions to restore power to the affected division; and

ACTIONS (continued)

c. The potential for an event in conjunction with a single failure of a redundant component.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC instrument and control bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 6 hours. This could lead to a total of 6 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal “time zero” for beginning the allowed outage time “clock.” This will result in establishing the “time zero” at the time the LCO was initially not met, instead of the time Condition B was entered. The 12 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With two divisions of AC instrument and control buses inoperable, the remaining OPERABLE buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required divisions of AC instrument and control buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated [inverter via inverted DC, inverter using internal AC source, or Class 1E constant voltage transformer].

Condition C represents two divisions of AC instrument and control vital buses without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptable power. It is, therefore, imperative that the operator’s attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining buses and restoring power to the affected buses.

BASES

ACTIONS (continued)

This 2 hour time limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate AC instrument and control power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, which would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue);

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC instrument and control buses to OPERABLE status, the redundant capability afforded by the other OPERABLE buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action C.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, a DC bus is inoperable and subsequently returned to OPERABLE, the LCO may already have been not met for up to 12 hours. This could lead to a total of 14 hours, since initial failure of the LCO, to restore the bus distribution system. At this time, a DC train could again become inoperable, and AC bus distribution restored to OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal “time zero” for beginning the allowed outage time “clock.” This will result in establishing the “time zero” at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

ACTIONS (continued)

D.1

With two divisions of DC electrical power distribution subsystems inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the [required] DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition D represents two subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining divisions and restoring power to the affected divisions.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected divisions; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

BASES

ACTIONS (continued)

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition D is entered while, for instance, an AC instrument and control bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 12 hours. This could lead to a total of 14 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored to OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

E.1 and E.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to MODE 5 where the probability and consequences on an event are minimized. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With two Divisions with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

This Surveillance verifies that the Class 1E AC and DC electrical power distribution subsystems are functioning properly, with the required circuit breakers and switches properly aligned. The verification of proper voltage availability on the buses ensures that the required voltage is

BASES

SURVEILLANCE REQUIREMENTS (continued)

readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the Class 1E AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. Section 8.3.2, “DC Power Systems.”
2. Chapter 6, “Engineering Safety Features.”
3. Chapter 15, “Accident Analyses.”

Table B 3.8.5-1 (page 1 of 1)
Class 1E AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	DIVISION A*	DIVISION B*	DIVISION C*	DIVISION D*
DC Buses	125 Vdc	IDSA-DS-1	IDSB-DS-1 IDSB-DS-2	IDSC-DS-1 IDSC-DS-2	IDSD-DS-1
DC Distribution Panels	125 Vdc	IDSA-DD-1 IDSA-DK-1	IDSB-DD-1 IDSB-DK-1	IDSC-DD-1 IDSC-DK-1	IDSD-DD-1 IDSD-DK-1
AC Instrumentation and Control Buses	120 Vac	IDSA-EA-1	IDSB-EA-1 IDSB-EA-3	IDSC-EA-1 IDSC-EA-3	IDSD-EA-1

* Each Division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Distribution Systems – Shutdown

BASES

BACKGROUND

A description of the Class 1E AC instrument and control bus and Class 1E DC electrical power distribution system is provided in the Bases for Specification 3.8.5, “Distribution System – Operating.”

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume engineered safety features are OPERABLE. The Class 1E AC and DC electrical power sources and associated power distribution systems are designed to provide sufficient capacity, redundancy, and reliability to ensure the availability of necessary power to the ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the minimum Class 1E AC and DC electrical power sources and associated power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The Class 1E AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components—all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

BASES

LCO (continued)

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The Class 1E AC and DC electrical power distribution subsystems are required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The Class 1E AC and DC electrical power distribution subsystem requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.5, “Distribution Systems – Operating.”

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

<u>A.1 and A.2</u>

If one or more required Class 1E DC or Class 1E AC instrument and control bus electrical power distribution subsystems are inoperable, the remaining OPERABLE divisions may be capable of supporting required features to allow continuation of CORE ALTERATIONS, fuel movement, and/or operations with a potential for draining the reactor vessel. By

BASES

ACTIONS (continued)

allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions will be implemented in accordance with the affected equipment LCO Required Actions. In many instances this would likely involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions will minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This Surveillance verifies that the Class 1E AC and DC electrical power distribution subsystems are functioning properly, with the required circuit breakers and switches properly aligned. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system

BASES

SURVEILLANCE REQUIREMENTS (continued)

loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. Chapter 6, "Engineered Safety Features."
2. Chapter 15, "Accident Analysis."
3. Section 8.3.2, "DC Power Systems."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Battery Parameters

BASES

BACKGROUND	LCO 3.8.7, Battery Parameters, delineates the limits on electrolyte temperature, level, float voltage and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.1, “DC Sources – Operating,” and LCO 3.8.2, “DC Sources – Shutdown.” In addition to the limitations of this Specification, the [licensee controlled program] also implements a program specified in Specification 5.5.11 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, “IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications” (Ref. 3).
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 1), and Chapter 15 (Ref. 2), assume engineered safety features are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for safety related and vital control instrumentation loads including monitoring and main control room emergency lighting during all MODES of operation. It also provides power for safe shutdown when all the onsite and offsite AC power sources are lost. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least three of the four Divisions of DC sources OPERABLE during accident conditions, in the event of: a. An assumed loss of all offsite and onsite AC power sources; and b. A worst case single failure. Battery parameters satisfy the Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with

BASES

LCO (continued)

limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the [licensee controlled program] is conducted as specified in Specification 5.5.11.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.1, and LCO 3.8.2.

ACTIONS

A.1, A.2, and A.3

With one or more cells in one or more batteries in one Division < [2.07] V, the battery cell is degraded. Within 2 hours verification of the required battery charger, OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.1.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.7.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < [2.07] V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify “perform,” a failure of SR 3.8.1.1 or SR 3.8.7.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.7.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1 and B.2

One or more batteries in one Division with float > [2] amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addresses charger inoperability. If the

BASES

ACTIONS (continued)

charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within [12] hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than [2.07] V, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than [2.07] V there is good assurance that, within [12] hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within [12] hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than [2.07] V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and [12] hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.1.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

C.1, C.2, and C.3

With one or more batteries in one Division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to

BASES

ACTIONS (continued)

perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.11, Battery Monitoring and Maintenance Program). They are modified by a note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.11.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the batteries may have to be declared inoperable and the affected cells replaced.

<u>D.1</u>

With one or more batteries in one Division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

<u>E.1</u>

With one or more batteries in two or more Divisions with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits in three Divisions within 2 hours.

BASES

ACTIONS (continued)

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one Division with one or more battery cells float voltage less than [2.07] V and float current greater than [2] amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 3). The 7 day Frequency is consistent with IEEE-450 (Ref. 3).

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.1.1. When this float voltage is not maintained the Required Actions of LCO 3.8.1 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of [2] amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.7.2 and SR 3.8.7.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to [130.5] V at the battery terminals, or [2.25] Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than [2.07] Vpc, are addressed in Specification 5.5.11. SRs 3.8.7.2 and 3.8.7.5 require verification that the cell float voltages are equal to or greater than the short term absolute

SURVEILLANCE REQUIREMENTS (continued)

minimum voltage of [2.07] V. The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450 (Ref. 3).

SR 3.8.7.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 3).

SR 3.8.7.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., [40]°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provided the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 3).

SR 3.8.7.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.7.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.1.3.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery’s ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a

BASES

SURVEILLANCE REQUIREMENTS (continued)

one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 3) and IEEE-485 (Ref. 4). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this [80]% limit.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's ratings. Degradation is indicated, according to IEEE-450 (Ref. 3), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ [10%] below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown

BASES

SURVEILLANCE REQUIREMENTS (continued)

and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

REFERENCES

1. Chapter 6, “Engineered Safety Features.”

2. Chapter 15, “Accident Analyses.”

3. IEEE-450 1995, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications.”

4. IEEE-485-1983, June 1983.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentration of the Reactor Coolant System (RCS), the refueling cavity, and the transfer tube during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by procedures.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled down and depressurized, the vessel head is unbolted and slowly removed. The refueling cavity and the fuel transfer canal are then flooded with borated water from the In-containment Refueling Water Storage Tank (IRWST) by the use of the Spent Fuel Pool Cooling System (SFS).

During refueling, the water volumes in the RCS, the fuel transfer canal and the refueling cavity are contiguous. However, the soluble boron concentration is not necessarily the same in each volume. If additions of boron are required during refueling, the Chemical and Volume Control System (CVS) provides the borated makeup.

The pumping action of the Normal Residual Heat Removal System (RNS) in the RCS, the SFS pumps in the spent fuel pool and refueling cavity, and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the fuel transfer canal. The RNS is in operation during refueling to provide forced circulation in the RCS, while the SFS is in operation to cool and purify the spent fuel pool and refueling cavity. Their operation assists in maintaining the boron concentration in the RCS, the refueling cavity, and fuel transfer canal above the COLR limit.

BASES

APPLICABLE SAFETY ANALYSES

The boron concentration limit, specified in the COLR, is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% Δk/k margin of safety is established during refueling.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling cavity and the transfer tube while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a k_{eff} of ≤ 0.95. Above MODE 6, LCO 3.1.1, “SHUTDOWN MARGIN (SDM)” ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the plant in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling cavity, or the fuel transfer canal is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude completion of actions to establish a safe condition, including moving a component to a safe position.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

BASES

ACTIONS (continued)

In determining the required combination of boration flow rate and concentration, no unique design basis accident (DBA) must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator shall begin boration with the best source available for plant operations.

Once boration is initiated, it must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR verifies that the coolant boron concentration in the RCS, the refueling cavity and the fuel transfer canal is within the COLR limit. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is a sufficient interval to verify the boron concentration. The surveillance interval is based on operating experience, isolation of unborated water sources in accordance with LCO 3.9.2, and the availability of the source range neutron flux monitors required by LCO 3.9.3.

REFERENCES

1. Chapter 15, “Accident Analysis.”

2. NS-57.2, ANSI/ANS-57.2-1983, Section 6.4.2.2.3, American Nuclear Society, American National Standard, “Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Plants,” 1983.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Flow Paths

BASES

BACKGROUND	During MODE 6 operation, all flow paths for reactor makeup water sources containing unborated water which are connected to the Reactor Coolant System (RCS) must be closed to prevent an unplanned dilution of the reactor coolant. At least one isolation valve in each flow path must be secured in the closed position. The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition, made by reducing the boron concentration, is inappropriate during MODE 6, isolation of all unborated water sources prevents an unplanned boron dilution event.
APPLICABLE SAFETY ANALYSES	The possibility of an unplanned boron dilution event (Ref. 1) in MODE 6 is precluded by adherence to this LCO which requires that potential dilution sources be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portions of the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required in MODE 6. The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that flow paths to the RCS from unborated water sources be isolated to prevent unplanned boron dilution during MODE 6 and, thus, avoid a reduction in SHUTDOWN MARGIN.
APPLICABILITY	In MODE 6, this LCO is applicable to prevent an unplanned boron dilution event by ensuring isolation of all sources of unborated water to the RCS. In MODES 1 through 5, the requirements of LCO 3.1.9, “Chemical and Volume Control System (CVS) Demineralized Water Isolation Valves,” apply.

BASES

ACTIONS

The ACTIONS Table has been modified by a Note which allows separate Condition entry for each unborated water source flow path.

A.1

Continuation of CORE ALTERATIONS is contingent upon maintaining the plant in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS must be suspended immediately. The Completion Time of “Immediately” shall not preclude completion of actions to establish a safe condition, including movement of a component to a safe location.

Condition A has been modified by a Note to require that Required Action A.3 must be completed whenever Condition A is entered.

A.2

Preventing unplanned dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valves secured closed. Securing the valves in the closed position verifies that the valves cannot be inadvertently opened. The Completion Time of “Immediately” requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

A.3

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to verify that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution flow paths. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that all unborated water source flow paths are isolated, precluding a dilution. The boron concentration is checked every 31 days during MODE 6 under SR 3.9.1.1. This surveillance demonstrates that the valves are closed through a system

BASES

SURVEILLANCE REQUIREMENTS (continued)

walkdown. The 31 day Frequency is based on engineering judgement and is considered reasonable in view of other administrative controls that will verify that the valve opening is an unlikely possibility.

REFERENCES

1. Chapter 15, “Accident Analyses.”
2. NUREG-0800, Standard Review Plan, Section 15.4.6, “Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the RCS.”

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND	The source range neutron flux monitors are used to monitor the core reactivity during refueling operations. The source range neutron flux monitors are part of the Protection and Safety Monitoring System (PMS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux ($1x10^{+6}$ cps) with a 5% instrument accuracy. The detectors also provide continuous visual and audible indication in the main control room and an audible alarm in the main control room and containment building.
APPLICABLE SAFETY ANALYSES	Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as those associated with an improperly loaded fuel assembly. During initial fuel loading, or when otherwise required, temporary neutron detectors may be used to provide additional reactivity monitoring (Ref. 2). The potential for an uncontrolled boron dilution accident is eliminated by isolating all unborated water sources as required by LCO 3.9.2 (Ref. 1). The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires two source range neutron flux monitors to be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity.
APPLICABILITY	In MODE 6, the source range neutron flux monitors are required to be OPERABLE to determine possible changes in core reactivity. There are no other direct means available to monitor the core reactivity conditions. In MODES 2, 3, 4, and 5, the source range detectors and associated circuitry are also required to be OPERABLE by LCO 3.3.1, “Reactor Trip System Instrumentation.”

BASES

ACTIONS

A.1 and A.2

Redundancy has been lost if only one source range neutron flux monitor is OPERABLE. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of actions to establish a safe condition.

B.1

If no source range neutron flux monitors are OPERABLE, actions to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, actions shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

If no source range neutron flux monitors are OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are discontinued, the core reactivity condition is stabilized and no changes are permitted until the source range neutron flux monitors are restored to OPERABLE status. This stable condition is confirmed by performing SR 3.9.1.1 to verify that the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration. The Frequency of once per 12 hours ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable considering the low probability of a change in core reactivity during this time period.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is the comparison of the indicated parameter values monitored by each of these instruments. It is based on the assumption that the two indication channels should be consistent for the existing core conditions. Changes in core geometry due to fuel loading can result in significant differences between the source range channels, however each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified for these same instruments in LCO 3.3.1, “Reactor Trip System Instrumentation.”

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consisting of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed during the refueling outage.

REFERENCES

1. Chapter 15, "Accident Analysis."
2. Section 14.2.6.1, "Initial Fuel Loading."

B 3.9 REFUELING OPERATIONS

B 3.9.4 Refueling Cavity Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in containment, refueling cavity, refueling canal, fuel transfer canal, and spent fuel pool to retain iodine fission product activity in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to within the values reported in Chapter 15.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the water level in the refueling cavity and the refueling canal is an initial condition design parameter in the analysis of a fuel-handling accident in containment, as postulated by Regulatory Guide 1.183 (Ref. 1). The fuel handling accident analysis inside containment is described in Reference 2. This analysis assumes a minimum water level of 23 feet. Refueling Cavity Water Level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within the values calculated in Reference 2.
APPLICABILITY	Refueling Cavity Water Level is applicable when moving irradiated fuel assemblies in containment. The LCO minimizes the possibility of radioactive release due to a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not being moved in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.5, “Spent Fuel Pool Water Level.”

BASES

ACTIONS	LCO 3.0.8 is applicable while in MODE 5 or 6. Since irradiated fuel assembly movement can occur in MODE 5 or 6, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, the fuel movement is independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily. <u>A.1</u> With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement to safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.4 1</u> Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2). The Frequency of 24 hours is based on engineering judgement and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions which make significant unplanned level changes unlikely.
REFERENCES	1. Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.” 2. Section 15.7.4, “Fuel Handling Accident.”

B 3.9 REFUELING OPERATIONS

B 3.9.5 Containment Penetrations

BASES

BACKGROUND

During movement of irradiated fuel assemblies within containment, potential releases of fission product radioactivity within containment are monitored and filtered or are restricted from escaping to the environment when the LCO requirements are met. Monitoring of potential releases of radiation is performed in accordance with Administrative Controls Section 5.5.2, “Radioactive Effluent Control Program.” In MODES 1, 2, 3, and 4, containment OPERABILITY is addressed in LCO 3.6.1, “Containment.” In MODES 5 and 6, closure capability of containment penetrations is addressed in LCO 3.6.8, “Containment Penetrations.” Since there is no potential for containment pressurization due to a fuel handling accident, the Appendix J leakage criteria and tests are not required in MODES 5 and 6.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained within the requirements of 10 CFR 50.34. For a fuel handling accident, the AP1000 dose analysis does not rely on containment closure to meet the offsite radiation exposure limits. This LCO is provided as an additional level of defense against the possibility of a fission product release from a fuel handling accident.

The containment equipment hatches, which are part of the containment pressure boundary, provide a means for moving large equipment and components into and out of containment. During movement of irradiated fuel assemblies within containment, an equipment hatch is considered closed if the hatch cover is held in place by at least [four] bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

If the equipment hatch is open, an alternative barrier between the containment atmosphere and the outside atmosphere shall be in place. Each containment equipment hatch opens into a staging area in the auxiliary building. These staging areas contain doors that open to the radiologically controlled areas of the annex building. The annex building contains a door that opens to the outside atmosphere. The alternate barrier may consist of the staging area in the auxiliary building, or may consist of the staging areas in the auxiliary building and the radiologically controlled areas in the annex building provided the doors from the annex building to the outside atmosphere are closed. The alternate barrier may

BASES

BACKGROUND (continued)

also consist of a temporary equipment hatch cover that provides equivalent isolation capability. The alternate boundary prevents the airborne fission products from being readily released to the atmosphere if the equipment hatches were open during a fuel handling accident.

If an equipment hatch is open during movement of irradiated fuel assemblies within containment, the containment air filtration system (VFS) shall be OPERABLE, and at least one exhaust fan shall be operating to provide for monitoring of air-borne radioactivity. This system services the containment, and upon detection of high radiation, also services the fuel handling area, the auxiliary building (including the staging areas), and the annex building. If high airborne radioactivity is detected in the area enclosed by the alternate barrier, the radiologically controlled area ventilation system (VAS) supply and exhaust duct isolation dampers automatically close to isolate the affected area from the outside environment, and the VAS exhaust is automatically aligned to the VFS exhaust subsystem. The operation of the VFS exhaust fans provides the system with the ability for monitoring of radioactivity releases from containment following a fuel handling accident and, if operating, will provide filtration of the containment atmosphere.

If a personnel air lock or spare containment penetration is open during movement of irradiated fuel assemblies within containment, then the containment air filtration system (VFS) shall be OPERABLE and operating to monitor for the release of radioactivity and to provide filtration of the air inside containment. These penetrations open into the auxiliary building. Upon detection of high radiation in the exhaust air from the auxiliary building, VFS will provide filtered exhaust of these areas. Considering that these penetrations open into the auxiliary building and not directly to the atmosphere, and that the VFS is in operation, an alternate barrier to the release of radioactivity directly to the environment is provided.

APPLICABLE SAFETY ANALYSES

For the AP1000, there are no safety analyses that require containment closure during movement of irradiated fuel assemblies within containment, other than those discussed in LCO 3.6.8. Fuel handling accidents, analyzed in Reference 1, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.4, “Refueling Cavity Water Level,” ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the

APPLICABLE SAFETY ANALYSES (continued)

guideline values specified in 10 CFR 50.34. Standard Review Plan, Section 15.0.1 (Reference 2), defines the dose acceptance limit to be 25% of the limiting dose guideline values.

This specification is included as defense-in-depth.

LCO

This LCO provides defense-in-depth against the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. This LCO requires that if an equipment hatch, personnel air lock, or spare containment penetration is open during movement of irradiated fuel assemblies within containment, then the containment air filtration system (VFS) shall be OPERABLE and operating to monitor for the release of radioactivity and to provide filtration of the air inside containment.

The VFS is OPERABLE when:

a. One VFS exhaust fan is operating; the associated HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and air circulation can be maintained;

b. An alternative barrier between the containment atmosphere and the outside atmosphere is in place. The alternate barrier may consist of the staging area in the auxiliary building, or may consist of the staging areas in the auxiliary building and the radiologically controlled areas in the annex building provided the doors from the annex building to the outside atmosphere are closed.

   Doors in the alternate barrier which are normally closed may be opened for short periods of time for ingress and egress. The alternate barrier may also consist of a temporary equipment hatch cover that provides equivalent isolation capability.

APPLICABILITY

The containment penetration requirements are applicable during movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Containment closure capability in MODES 5 and 6 are addressed by LCO 3.6.8.

BASES

ACTIONS

LCO 3.0.8 is applicable while in MODE 5 or 6. Since irradiated fuel assembly movement can occur in MODE 5 or 6, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, the fuel movement is independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

A.1

The required status for the containment equipment hatch, air locks or spare penetration is either closed, or open with the VFS OPERABLE and operating. The required status for the containment penetrations that provide direct access from the containment atmosphere to the outside atmosphere is either closed by a manual or automatic isolation valve, blind flange or equivalent, or capable of being closed by an OPERABLE Containment Isolation Signal. If the containment equipment hatch or air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.5 1

This Surveillance verifies that each of the containment penetrations required to be in its closed position is in that position or the VFS is OPERABLE and operating. For the VFS to be considered OPERABLE, this surveillance also requires that an alternate barrier is in place.

SR 3.9.5.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. The Frequency is in accordance with the Inservice Testing Program.

The SR is modified by a Note stating that this Surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.5.3

This SR verifies the ability of the VFS to maintain a negative pressure (≤ [-0.125] inches water gauge relative to outside atmospheric pressure) in the containment and the portions of the auxiliary and/or annex building that comprise the envelope defined as the alternate barrier. This surveillance is performed with the VFS in containment operating. Doors in the alternate barrier which are normally closed may be opened for ingress and egress. The portion of the VAS which services the area enclosed by the alternate barrier is aligned to the VFS exhaust subsystem, and the VAS auxiliary/annex building supply fans and VFS containment purge supply fans not operating. The Frequency of 24 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 3).

SR 3.9.5.4

The VFS should be checked periodically to ensure that it functions properly. As the operating conditions on this system are not severe, testing each train within 31 days prior to fuel movement provides an adequate check on this system. Operation of the heater dries out any moisture accumulated in the charcoal from humidity in the ambient air.

REFERENCES

1. Section 15.7.4, “Fuel Handling Accident.”
2. NUREG-0800, Section 15.0.1, Rev. 0.
3. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Containment Air Filtration System (VFS)

BASES

BACKGROUND

The radiologically controlled area ventilation system (VAS) serves the fuel handling area of the auxiliary building, and the radiologically controlled portions of the auxiliary and annex buildings, except for the health physics and hot machine shop areas which are provided with a separate ventilation system (VHS). If high airborne radioactivity is detected in the exhaust air from the fuel handling area, the auxiliary building, or the annex buildings, the VAS supply and exhaust duct isolation dampers automatically close to isolate the affected area from the outside environment and the containment air filtration exhaust subsystem starts. The VFS exhaust subsystem prevents exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at ≤ [-0.125] inches water gauge pressure relative to the outside atmosphere. Monitoring of potential releases of radiation is performed in accordance with Administrative Controls Section 5.5.2, “Radioactive Effluent Control Program.”

For a fuel handling accident, the AP1000 dose analysis does not rely on the OPERABILITY of the VAS or VFS exhaust subsystem to meet the offsite radiation exposure limits. This LCO is provided as an additional level of defense-in-depth against the possibility of a fission product release from a fuel handling accident in the fuel building. The plant vent radiation detectors monitor effluents discharged from the plant vent to the environment.

Each VFS exhaust subsystem includes one 100 percent capacity exhaust air filtration unit, and the associated exhaust fan, heater and ductwork.

The filtration units are connected to a ducted system with isolation dampers to provide HEPA filtration and charcoal adsorption of exhaust air from the containment, fuel handling area, radiologically controlled areas of the auxiliary and annex buildings. A gaseous radiation monitor is located downstream of the exhaust air filtration units to provide an alarm if abnormal gaseous releases are detected. The plant vent exhaust flow is monitored for gaseous, particulate and iodine releases to the environment. During conditions of abnormal airborne radioactivity in the fuel handling area, auxiliary and/or annex buildings, the VFS exhaust subsystem provides filtered exhaust to minimize unfiltered offsite releases.

BACKGROUND (continued)

The VAS is described in Reference 1 and the VFS is described in Reference 2.

APPLICABLE SAFETY ANALYSES

The VFS is not required to mitigate the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident. The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged. The DBA analysis of the fuel handling accident does not assume that the VFS provides a filtered exhaust, and its operation would reduce the consequences of the fuel handling accident.

This specification is included for defense-in-depth.

LCO

One VFS exhaust subsystem is required to be OPERABLE to reduce the consequences of a fuel handling accident by filtering the fuel building atmosphere.

A VFS exhaust subsystem is considered OPERABLE when its associated:

a. Exhaust fan is capable of operating;

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function;

c. The associated heater and ductwork are capable of operating.

APPLICABILITY

During movement of irradiated fuel in the fuel handling area, one VFS exhaust subsystem is OPERABLE to alleviate the potential consequences of a fuel handling accident.

ACTIONS

LCO 3.0.3 is applicable while in MODE 1, 2, 3, or 4. Since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

LCO 3.0.8 is applicable while in MODE 5 or 6. Since irradiated fuel assembly movement can occur in MODE 5 or 6, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, the fuel movement is independent of shutdown reactor operations. Entering LCO 3.0.8 while in MODE 5 or 6 would require the optimization of plant safety, unnecessarily.

A.1

When the required VFS exhaust subsystem is inoperable during movement of irradiated fuel assemblies in the fuel building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the fuel building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Each VFS exhaust subsystem should be checked 31 days prior to fuel movement in the fuel handling area to ensure that it functions properly. As the operating conditions on this subsystem are not severe, testing each subsystem within one month prior to fuel movement provides an adequate check on this system. Operation of the heater dries out any moisture accumulated in the charcoal from humidity in the ambient air.

SR 3.9.6.2

This SR verifies that the VAS fuel handling area subsystem aligns to the VFS and that the VFS exhaust subsystem starts and operates on an actual or simulated actuation signal. During the post-accident mode of operation, the VAS fuel handling area subsystem aligns to the VFS filtered exhaust subsystem. The 24 month Frequency is consistent with Reference 4.

SR 3.9.6.3

This SR verifies the integrity of the fuel handling area of the auxiliary building enclosure. The ability of the VAS and VFS to maintain negative pressure (≤ [-0.125] inches water gauge relative to outside atmospheric pressure) in the fuel handling area of the auxiliary building is periodically tested to verify proper function of the VAS and VFS exhaust subsystem. During this surveillance, the VAS fuel handling area subsystem is aligned

BASES

SURVEILLANCE REQUIREMENTS (continued)

to the operating VFS exhaust subsystem. The fan for the VAS fuel handling area subsystem is off. In this configuration, the VFS exhaust subsystem is designed to maintain a negative pressure in the fuel handling area of the auxiliary building (≤ [-0.125] inches water gauge relative to outside atmospheric pressure), to prevent unfiltered and unmonitored leakage. Doors may be opened for short periods of time to allow ingress and egress. During this surveillance, the VAS may be servicing the remaining portions of the auxiliary and annex buildings. The Frequency of 24 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 5).

REFERENCES

1. Section 9.4.3, “Radiologically Controlled Area Ventilation System.”
2. Section 9.4.7, “Containment Air Filtration System.”
3. Section 15.7.4, “Fuel Handling Accident.”
4. Regulatory Guide 1.140 (Rev. 2).
5. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Decay Time

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment or in the fuel handling area inside the auxiliary building requires allowing at least 100 hours for radioactive decay time before fuel assembly handling can be initiated. During fuel handling, this ensures that sufficient radioactive decay has occurred in the event of a fuel handling accident (Refs. 1 and 2). Sufficient radioactive decay of short-lived fission products would have occurred to limit offsite doses from the accident to within the values reported in Chapter 15.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the radioactivity decay time is an initial condition design parameter in the analysis of a fuel-handling accident inside containment or in the fuel handling area inside the auxiliary building, as postulated by Regulatory Guide 1.183 (Ref. 1). The fuel handling accident analysis inside containment or in the fuel handling area inside the auxiliary building is described in Reference 2. This analysis assumes a minimum radioactive decay time of 100 hours. Radioactive decay time satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum radioactive decay time of 100 hours is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment or in the fuel handling area inside the auxiliary building are within the values calculated in Reference 2.
APPLICABILITY	Radioactive decay time is applicable when moving irradiated fuel assemblies in containment or in the fuel handling area inside the auxiliary building. The LCO minimizes the possibility of radioactive release due to a fuel handling accident that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not being moved, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are also covered by LCO 3.7.11, “Fuel Storage Pool Water Level.”

BASES

ACTIONS

LCO 3.0.8 is applicable while in MODE 5 or 6. Since movement of irradiated fuel assemblies with less than 100 hours of decay time can occur in MODE 6 after removing the reactor vessel head following the reactor shutdown, the ACTIONS have been modified by a Note stating that LCO 3.0.8 is not applicable. If moving irradiated fuel assemblies while in MODE 6, the fuel movement is independent of shutdown reactor operations since the reactor is already shutdown. Entering LCO 3.0.8 while in MODE 6 would not specify any action.

A.1

With a decay time of less than 100 hours, all operations involving movement of irradiated fuel assemblies within containment or in the fuel handling area inside the auxiliary building shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement to safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

Verification that the reactor has been subcritical for at least 100 hours prior to movement of irradiated fuel in the reactor pressure vessel to the refueling cavity in containment or to the fuel handling area inside the auxiliary building ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Specifying radioactive decay time limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident (Ref. 2).

REFERENCES

1. Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”

2. Section 15.7.4, “Fuel Handling Accident.”

16.2 Design Reliability Assurance Program

See subsection 17.4 for information on the AP1000 Design Reliability Assurance Program (D-RAP).

16.3 Investment Protection

16.3.1 Investment Protection Short-Term Availability Controls

The importance of nonsafety-related systems, structures and components in the AP1000 has been evaluated. The evaluation uses PRA insights to identify systems, structures and components that are important in protecting the utilities investment and for preventing and mitigating severe accidents. To provide reasonable assurance that these systems, structures and components are operable during anticipated events short-term availability controls are provided. These investment protection systems, structures and components are also included in the D-RAP/O-RAP (refer to Subsection 17.4), which provides confidence that availability and reliability are designed into the plant and that availability and reliability are maintained throughout plant life through the maintenance rule. Technical Specifications are not required for these systems, structures and components because they do not meet the selection criteria applied to the AP1000 (refer to subsection 16.1.1).

Table 16.3-1 lists nonsafety-related systems, structures and components that have investment protection short-term availability controls. This table also lists the number of trains that should be operable and the plant operating MODES when they should be operable. Table 16.3-2 contains the investment protection short-term availability controls. These short-term availability controls define:

– Equipment that should be operable
– Operational MODES when the equipment should be operable
– Testing and inspections that should be used to demonstrate the equipment's operability
– Operational MODES that should be used for planned maintenance operations
– Remedial actions that should be taken if the equipment is not operable

Tables 16.3-1 and 16.3-2 contain defined terms that appear in capitalized type. These terms are defined below.

ACTIONS—shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.

CHANNEL CALIBRATION—shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an in-place qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION shall include an in-place cross calibration that compares the other sensing elements with the recently installed sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.

CHANNEL CHECK—shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

CHANNEL OPERATIONAL TEST (COT)—shall be the injection of a simulated or TEST (COT) actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustment as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.

MODE—shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified below with fuel in the reactor vessel.

OPERABLE-OPERABILITY—system, subsystem, train, component, or device is OPERABLE or has OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

16.3.2 Combined License Information

Combined License applicants referencing the AP1000 will develop a procedure to control the operability of investment protection systems, structures and components in accordance with Table 16.3-2.

MODES

MODES	TITLE	REACTIVITY CONDITION (K_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	> 420
4	Safe Shutdown[b]	< 0.99	NA	$420 \geq T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.
(b) All reactor vessel head closure bolts fully tensioned.
(c) One or more reactor vessel head closure bolts less than fully tensioned.

Table 16.3-1

LIST OF INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

Systems, Structures, Components	Number Trains (a)	MODES Operation (b)
1.0 Instrumentation Systems		
1.1 DAS ATWS Mitigation	2	1
1.2 DAS ESF Actuation	2	1,2,3,4,5,6 (3)
2.0 Plant Systems		
2.1 RNS	1	1,2,3
2.2 RNS - RCS Open	2	5,6 (2,3)
2.3 CCS - RCS Open	2	5,6 (2,3)
2.4 SWS - RCS Open	2	5,6 (2,3)
2.5 PCS Water Makeup - Long Term Shutdown	1	1,2,3,4,5,6
2.6 MCR Cooling - Long Term Shutdown	1	1,2,3,4,5,6
2.7 I&C Room Cooling - Long Term Shutdown	1	1,2,3,4,5,6
2.8 Hydrogen Ignitors	1	1,2,5,6 (2,3)
3.0 Electrical Power Systems		
3.1 AC Power Supplies	1	1,2,3,4,5
3.2 AC Power Supplies - RCS Open	2 (1)	5,6 (2,3)
3.3 AC Power Supplies - Long Term Shutdown	1	1,2,3,4,5,6
3.4 Non Class 1E DC and UPS System (EDS)	2	1,2,3,4,5,6 (3)

Alpha Notes:

(a) Refers to the number of trains covered by the availability controls.
(b) Refers to the MODES of plant operation where the availability controls apply.

Notes:

(1) 2 of 3 AC power supplies (2 standby diesel generators and 1 offsite power supply).
(2) MODE 5 with RCS open.
(3) MODE 6 with upper internals in place or cavity level less than full.

Table 16.3-2

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

1.0 Instrumentation Systems

1.1 Diverse Actuation System (DAS) ATWS Mitigation

OPERABILITY: DAS ATWS mitigation function listed in Table 1.1-1 should be operable

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DAS ATWS Function with one or more required channels inoperable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore required channels to operable status.	14 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	1.1.1	Perform CHANNEL CHECK on each required channel.	30 hours
SR	1.1.2	Perform CHANNEL OPERATIONAL TEST on each required channel.	92 days
SR	1.1.3	Perform CHANNEL CALIBRATION on each required channel.	24 months
SR	1.1.4	Verify that the MG set field breakers open on demand.	24 months

Table 1.1-1, DAS ATWS Functions

DAS Function	Initiating Signal	Number Installed	Channels Required	Setpoint
Rod Drive MG Set Trip, Turbine Trip and PRHR HX Actuation	SG Wide Range Level	2 per SG	1 per SG	> [55,000 lb]

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

1.0 Instrumentation Systems

1.1 DAS ATWS Mitigation

BASES:

The DAS ATWS mitigation function of reactor trip, turbine trip and passive residual heat removal heat exchanger (PRHR HX) actuation should be available to provide ATWS mitigation capability. This function is important based on 10 CFR 50.62 (ATWS Rule) and because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to actuate.

The DAS uses a 2 out of 2 logic to actuate automatic functions. When a required channel is unavailable the automatic DAS function is unavailable. DCD subsection 7.7.1.11 provides additional information. The DAS channels listed in Table 1.1-1 should be available.

Automated operator aids may be used to facilitate performance of the CHANNEL CHECK. An automated tester may be used to facilitate performance of the CHANNEL OPERATIONAL TEST.

The DAS ATWS mitigation function should be available during MODE 1 when ATWS is a limiting event. Planned maintenance affecting this DAS function should be performed MODES 3, 4, 5, 6; these MODES are selected because the reactor is tripped in these MODES and ATWS can not occur.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

1.0 Instrumentation Systems

1.2 DAS Engineering Safeguards Features Actuation (ESFA)

OPERABILITY: DAS ESFA functions listed in Table 1.2-1 should be operable

APPLICABILITY: MODE 1, 2, 3, 4, 5,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DAS ESFA Functions with one or more required channels inoperable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore required channels to operable status.	14 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	1.2.1	Perform CHANNEL CHECK on each required CHANNEL.	30 hours
SR	1.2.2	Perform CHANNEL OPERATIONAL TEST on each required CHANNEL.	92 days
SR	1.2.3	Perform CHANNEL CALIBRATION on each required CHANNEL.	24 months

Table 1.2-1, DAS ESFA Functions

DAS Function	Initiating Signal	Number Installed	Channels Required	Setpoint
PRHR HX Actuation	SG Wide Level or	2 per SG	1 per SG	> [55,000 lb]
	HL Temp	1 per HL	1 per HL	< [625]F
CMT Actuation and RCP trip	Pzr Level	2	2	> [7]%
Passive Cont. Cooling and Selected Cont. Isolation Actuation	Cont. Temp	2	2	< [200]F

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

1.0 Instrumentation Systems

1.2 DAS ESFA

BASES:

The DAS ESFA functions listed in Table 1.2-1 should be available to provide accident mitigation capability. This function is important because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to actuate.

The DAS uses a 2 out of 2 logic to actuate automatic functions. When a required channel is unavailable the automatic DAS function is unavailable. DCD subsection 7.7.1.11 provides additional information. The DAS channels listed in Table 1.2-1 should be available.

Automated operator aids may be used to facilitate performance of the CHANNEL CHECK. An automated tester may be used to facilitate performance of the CHANNEL OPERATIONAL TEST.

The DAS ESFA mitigation functions should be available during MODES 1, 2, 3, 4, 5, 6 when accident mitigation is beneficial to the PRA results. The DAS ESFA should be available in MODE 6 with upper internals in place or cavity level less than full. Planned maintenance affecting these DAS functions should be performed in MODE 6 when the refueling cavity is full; this MODE is selected because requiring DAS ESFA are not anticipated in this MODE.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.1 Normal Residual Heat Removal System (RNS)

OPERABILITY: One train of RNS injection should be operable

APPLICABILITY: MODE 1, 2, 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required train not operable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore one train to operable status	14 days
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 2.1.1 Verify that one RNS pump develops a differential head of [330] feet on recirculation flow	92 days
SR 2.1.2 Verify that the following valves stroke open RNS V011 RNS Discharge Cont. Isolation RNS V022 RNS Suction Header Cont. Isolation RNS V023 RNS Suction from IRWST Isolation RNS V055 RNS Suction from Cask Loading Pit	92 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.1 RNS

BASES:

The RNS injection function provides a nonsafety-related means of injecting IRWST water into the RCS following ADS actuations. The RNS injection function is important because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

One train of RNS injection includes one RNS pump and the line from the cask loading pit (CLP) to the RCS. One valve in the line between the CLP and the RCS is normally closed and needs to be opened to allow injection. Later on, the RNS suction is switched from the CLP to the IRWST. Two valves in the IRWST line are normally closed and must be opened to allow recirculation. This equipment does not normally operate during MODES 1, 2, 3. DCD subsection 5.4.7 contains additional information on the RNS.

The RNS injection function should be available during MODES 1, 2, 3 because decay heat is higher and the need for ADS is greater.

Planned maintenance on redundant RNS SSCs should be performed during MODES 1, 2, 3. Such maintenance should be performed on an RNS SSC not required to be available. The bases for this recommendation is that the RNS is more risk important during shutdown MODES when it is normally operating than during other MODES when it only provides a backup to PXS injection.

Planned maintenance on non-redundant RNS valves (such as V011, V022, V023, V055) should be performed to minimize the impact on their RNS injection and their containment isolation capability. Non-pressure boundary maintenance should be performed during MODE 5 with a visible pressurizer level or MODE 6 with the refueling cavity full. In these MODES, these valves need to be open but they do not need to be able to close. Containment closure which is required in these MODES can be satisfied by one normally open operable valve. Pressure boundary maintenance can not be performed during MODES when the RNS is used to cool the core, therefore such maintenance should be performed during MODES 1, 2, 3. Since these valves are also containment isolation valves, maintenance that renders the valves inoperable requires that the containment isolation valve located in series with the inoperable valve has to closed and de-activated. The bases for this recommendation is that the RNS is more risk important during shutdown MODES when it is normally operating than during other MODES when it only provides a backup to PXS injection. In addition, it is not possible to perform pressure boundary maintenance of these valves during RNS operation.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.2 Normal Residual Heat Removal System (RNS) - RCS Open

OPERABILITY: Both RNS pumps should be operable for RCS cooling

APPLICABILITY: MODE 5 with RCS pressure boundary open,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump not operable.	A.1 Initiate actions to increase the water inventory above the core. AND A.2 Remove plant from applicable MODES	12 hours 72 hours
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE. AND B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 day 1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	2.2.1	Verify that one RNS pump is in operation and that each RNS pump operating individually circulates reactor coolant at a flow > [900] gpm OR Verify that both RNS pumps are in operation and circulating reactor coolant at a flow > [1800] gpm	Within 1 day prior to entering the MODES of applicability

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.2 RNS - RCS Open

BASES:

The RNS cooling function provides a nonsafety-related means to normally cool the RCS during shutdown operations (MODES 4, 5, 6). This RNS cooling function is important during conditions when the RCS pressure boundary is open and the refueling cavity is not flooded because it reduces the probability of an initiating event due to loss of RNS cooling and because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The RCS is considered open when its pressure boundary is not intact. The RCS is also considered open if there is no visible level in the pressurizer. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The RNS cooling of the RCS involves the RNS suction line from the RCS HL, the two RNS pumps and the RNS discharge line returning to the RCS through the DVI lines. The valves located in these lines should be open prior to the plant entering reduced inventory conditions. One of the RNS pumps has to be operating; the other pump may be operating or may be in standby. Standby includes the capability of being able to be placed into operation from the main control room. DCD subsection 5.4.7 contains additional information on the RNS.

Both RNS pumps should be available during the MODES of applicability when the loss of RNS cooling is risk important. If both RNS pumps are not available, the plant should not enter these conditions. If the plant has entered reduced inventory conditions, then the plant should take action to restore full system operation or leave the MODES of applicability. If the plant has not restored full system operation or left the MODES of applicability within 12 hours, then actions need to be initiated to increase the RCS water level to either 20% pressurizer level or to a full refueling cavity.

Planned maintenance affecting this RNS cooling function should be performed in MODES 1, 2, 3 when the RNS is not normally operating. The bases for this recommendation is that the RNS is more risk important during shutdown MODES, especially during the MODES of applicability conditions than during other MODES when it only provides a backup to PXS injection.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.3 Component Cooling Water System (CCS) - RCS Open

OPERABILITY: Both CCS pumps should be operable for RNS cooling

APPLICABILITY: MODE 5 with RCS pressure boundary open,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump not operable.	A.1 Initiate actions to increase the water inventory above the core.	12 hours
	AND	
	A.2 Remove plant from applicable MODES.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	2.3.1	Verify that one CCS pump is in operation and each CCS pump operating individually provides a CCS flow through one RNS heat exchanger > [2820] gpm OR Verify that both CCS pumps are in operation and the CCS flow through each RNS heat exchanger is > [2820] gpm	Within 1 day prior to entering the MODES of applicability

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.3 CCS - RCS Open

BASES:

The CCS cooling of the RNS HXs provides a nonsafety-related means to normally cool the RCS during shutdown operations (MODES 4, 5, 6). This RNS cooling function is important because it reduces the probability of an initiating event due to loss of RNS cooling and because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The RCS is considered open when its pressure boundary is not intact. The RCS is also considered open if there is no visible level in the pressurizer. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The CCS cooling of the RNS involves two CCS pumps and HXs and the CCS line to the RNS HXs. The valves around the CCS pumps and HXs and in the lines to the RNS HXs should be open prior to the plant entering these conditions. One of the CCS pumps and its HX has to be operating. One of the lines to a RNS HX also has to be open. The other CCS pump and HX may be operating or may be in standby. Standby includes the capability of being able to be placed into operation from the main control room. DCD subsection 9.2.2 contains additional information on the CCS.

Both CCS pumps should be available during the MODES of applicability when the loss of RNS cooling is risk important. If both CCS pumps are not available, the plant should not enter these conditions. If the plant has entered these conditions, then the plant should take action to restore both CCS pumps or to leave these conditions. If the plant has not restored full system operation or left the MODES of applicability within 12 hours, then actions need to be initiated to increase the RCS water level to either 20% pressurizer level or to a full refueling cavity.

Planned maintenance affecting this CCS cooling function should be performed in MODES 1, 2, 3 when the CCS is not supporting RNS operation. The bases for this recommendation is that the CCS is more risk important during shutdown MODES, especially during the MODES of applicability conditions than during other MODES.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.4 Service Water System (SWS) - RCS Open

OPERABILITY: Both SWS pumps and cooling tower fans should be operable for CCS cooling

APPLICABILITY: MODE 5 with RCS pressure boundary open,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump or fan not operable.	A.1 Initiate actions to increase the water inventory above the core.	12 hours
	AND	
	A.2 Remove plant from applicable MODES.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	2.4.1	Verify that one SWS pump is operating and that each SWS pump operating individually provides a SWS flow > [8600] gpm	Within 1 day prior to entering the MODES of applicability
SR	2.4.2	Operate each cooling tower fan for > 15 min	Within 1 day prior to entering the MODES of applicability

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.4 SWS - RCS Open

BASES:

The SWS cooling of the CCS HXs provides a nonsafety-related means to normally cool the RNS HX which cool the RCS during shutdown operations (MODES 4, 5, 6). This RNS cooling function is important because it reduces the probability of an initiating event due to loss of RNS cooling and because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The RCS is considered open when its pressure boundary is not intact. The RCS is also considered open if there is no visible level in the pressurizer. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The SWS cooling of the CCS HXs involves two SWS pumps and cooling tower fans and the SWS line to the RNS HXs. The valves in the SWS lines should be open prior to the plant entering these conditions. One of the SWS pumps and its cooling tower fan has to be operating. The other SWS pump and cooling tower fan may be operating or may be in standby. Standby includes the capability of being able to be placed into operation from the main control room. DCD subsection 9.2.1 contains additional information on the CCS.

Both SWS pumps and cooling tower fans should be available during the MODES of applicability when the loss of RNS cooling is risk important. If both SWS pumps and cooling tower fans are not available, the plant should not enter these conditions. If the plant has entered these conditions, then the plant should take action to restore both SWS pumps / fans or to leave these conditions. If the plant has not restored full system operation or left the MODES of applicability within 12 hours, then actions need to be initiated to increase the RCS water level to either 20% pressurizer level or to a full refueling cavity.

Planned maintenance affecting this SWS cooling function should be performed in MODES when the SWS is not supporting RNS operation, ie during MODES 1, 2, 3. The bases for this recommendation is that the SWS is more risk important during shutdown MODES, especially during the MODES of applicability conditions than during other MODES.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.5 Passive Containment System Water Storage Tank (PCCWST) and Spent Fuel Pool Makeup - Long Term Shutdown

OPERABILITY: Long term makeup to the PCCWST and the Spent Fuel Pool should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5, 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Water volume in PCS ancillary tank less than limit.	A.1 Notify [chief nuclear officer] or [on-call alternate]. AND A.2 Restore volume to within limits	72 hours 14 days
B. One required PCS recirculation pump not operable.	B.1 Notify [chief nuclear officer] or [on-call alternate]. AND B.2 Restore pump to operable status	72 hours 14 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

C. Required Action and associated Completion Time of Condition A, B not met.	C.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE. AND C.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 day 1 month

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 2.5.1 Verify water volume in the PCS ancillary tank is > [580,000] gal.	31 days
SR 2.5.2 Record that the required PCS recirculation pump provides recirculation of the PCCWST at > [100] gpm.	92 days
SR 2.5.3 Verify that each PCS recirculation pump transfers > [100] gpm from the PCS ancillary tank to the PCCWST. During this test, each PCS recirculation pump will be powered from a ancillary diesel.	10 years

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.5 PCCWST and Spent Fuel Pool Makeup - Long Term Shutdown

BASES:

The PCS recirculation pumps provide long-term shutdown support by transferring water from the PCS ancillary tank to the PCCWST and the spent fuel pool. The specified PCS ancillary water tank volume is sufficient to maintain PCS and Spent Fuel Pool cooling during the 3 to 7 day time period following an accident. After 7 days, water brought in from offsite allows the PCCWST to continue to provide PCS cooling and makeup to the spent fuel pit. This PCCWST makeup function is important because it supports long-term shutdown operation. A minimum availability of 90% is assumed for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The PCCWST makeup function involves the use of one PCS recirculation pump, the PCS ancillary tank and the line connecting the PCS ancillary tank with the PCCWST and spent fuel pool. One PCS recirculation pump normally operates to recirculate the PCCWST. DCD subsections 6.2.2 and 9.1.3 contain additional information on the PCCWST and spent fuel pool makeup function.

The PCCWST makeup function should be available during MODES of operation when PCS and spent fuel pool cooling is required; one PCS recirculation pump and PCS ancillary tank should be available during all MODES.

Planned maintenance should be performed on the redundant pump (ie the pump not required to be available). Planned maintenance affecting the PCS ancillary tank that requires less than 72 hours to perform can be performed in any MODE of operation. Planned maintenance requiring more than 72 hours should be performed in MODES 5 or 6 when the calculated core decay heat is < 9 MWt. The bases for this recommendation is that the long-term PCS makeup is not required in this condition, and in most cases, the PCCWST can provide the required makeup to the spent fuel pool.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.6 Main Control Room (MCR) Cooling - Long Term Shutdown

OPERABILITY: Long term cooling of the MCR should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5, 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required MCR ancillary fans not operable.	A.1 Notify [chief nuclear officer] or [on-call alternate]. AND A.2 Restore one fan to operable status	72 hours 14 days
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE. AND B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 day 1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 2.6.1 Operate required MCR ancillary fan for > 15 min	92 days
SR 2.6.2 Verify that each MCR ancillary fan can provide a flow of air into the MCR for >15 min. During this test, the MCR ancillary fans will be powered from the ancillary diesels.	10 years

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.6 MCR Cooling - Long Term Shutdown

BASES:

The MCR ancillary fans provide long term shutdown support by cooling the main control room. For the first three days after an accident the emergency HVAC system (VES) together with the passive heat sinks in the MCR provide cooling of the MCR. After 3 days, the MCR ancillary fans can be used to circulate ambient air through the MCR to provide cooling. The long term MCR cooling function should be available during all MODES of operation. This long term MCR cooling function is important because it supports long-term shutdown operation. A minimum availability of 90% is assumed for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The long term MCR cooling function involves the use of a MCR ancillary fan. During SR 2.6.1 the fan will be run to verify that it operates without providing flow to the MCR. During SR 2.6.2 each fan will be connected to the MCR and operated such that they provide flow to the MCR. DCD subsection 9.4.1 contains additional information on the long term MCR cooling function.

One MCR ancillary fan should be available during all MODES of plant operation. Planned maintenance should not be performed on the required MCR ancillary fan during a required MODE of operation; planned maintenance should be performed on the redundant MCR ancillary fan (ie the fan not required to be available) during MODES 3 or 4, MODE 5 with a visible pressurizer level or MODE 6 with the refueling cavity full; these MODES are selected because the reactor is tripped in these MODES and the risk of core damage is low.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.7 I&C Room Cooling - Long Term Shutdown

OPERABILITY: Long term cooling of I&C rooms B & C should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5, 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required I&C room ancillary fan not operable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore one fan to operable status	14 days
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	2.7.1	Operate required I&C room ancillary fan for > 15 min	92 days
SR	2.7.2	Verify that each I&C room ancillary fan can provide a flow of air into an I&C room for >15 min. During this test, the I&C room ancillary fans will be powered from an ancillary diesel.	10 years

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.7 I&C Room Cooling - Long Term Shutdown

BASES:

The I&C room ancillary fans provide long term shutdown support by cooling I&C rooms B & C which contain post accident instrument processing equipment. For the first three days after an accident the passive heat sinks in the I&C rooms provide cooling. After 3 days, the I&C room ancillary fans can be used to circulate ambient air through the I&C room to provide cooling. The long term I&C room cooling function should be available during all MODES of operation. This long term I&C room cooling function is important because it supports long-term shutdown operation. A minimum availability of 90% is assumed for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The long term I&C room cooling function involves the use of two I&C room ancillary fans; each fan is associated with one I&C room (B or C). During SR 2.6.1 the required fan will be run to verify that it operates without providing flow to the I&C room. During SR 2.6.2 each fan will be connected to its associated I&C room and operated such that flow is provided to the I&C room. DCD subsection 9.4.1 contains additional information on the long term I&C room cooling function.

One I&C room ancillary fan should be available during all MODES of plant operation. Planned maintenance should not be performed on the required I&C room ancillary fan during a required MODE of operation; planned maintenance should be performed on the redundant I&C room ancillary fan.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.8 Hydrogen Ignitors

OPERABILITY: Hydrogen ignitors should be operable in accordance with Table 2.8-1

APPLICABILITY: MODE 1, 2,
MODE 5 with RCS pressure boundary open,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required hydrogen ignitor inoperable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore required ignitors to operable status.	14 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	2.8.1	Energize each required hydrogen ignitor and verify the surface temperature is > [1700]°F.	Each refueling outage

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

Table 2.8-1, Hydrogen Ignitors

Location	Hydrogen Ignitors Group 1	Group 2	Number Available (1)
- Reactor Cavity	(2)	(2)	na
- Loop Compartment 01	12,13	11,14	3 of 4
- Loop Compartment 02	5,8	6,7	3 of 4
- Pressurizer Compartment	49,60	50,59	3 of 4
- Tunnel connecting Loop Compartments	1,3,31	2,4,30	5 of 6
- Southeast Valve Room & Southeast Accumulator Room	21	20	2 of 2
- East Valve Room, Northeast Accumulator Room, & Northeast Valve Room	18	17,19	(3)
- North CVS Equipment Room	34	33	2 of 2
- Lower Compartment Area (CMT and Valve Area)	22,27,28,29,31, 32	23,24,25,26,30	10 of 11
- IRWST	9,35,37	10,36,38	5 of 6
- IRWST inlet	16	15	2 of 2
- Refueling Cavity	55,58	56,57	3 of 4
- Upper Compartment			
- Lower Region	39,42,43,44,47	40,41,45,46,47	9 of 10
- Mid Region	51,54	52,53	2 of 4
- Upper Region	61,63	62,64	2 of 4

Notes:

(1) In each location, the minimum number of ignitors that should be available are defined in this column.

(2) Ignitors in this location are shared with other locations.

(3) Ignitor 18 and either 17 or 19 should be available.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

2.0 Plant Systems

2.8 Hydrogen Ignitors

BASES:

The hydrogen ignitors should be available to provide the capability of burning hydrogen generated during severe accidents in order to prevent failure of the containment due to hydrogen detonation. These hydrogen ignitors are required by 10 CFR 50.34 to limit the buildup of hydrogen to less than 10% assuming that 100% of the active zircaloy fuel cladding is oxidized.

This function is also important because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The ignitors are distributed in the containment to limit the buildup of hydrogen in local areas. Two groups of ignitors are provided in each area; one of which is sufficient to limit the buildup of hydrogen. When an ignitor is energized, the ignitor surface heats up to ≥[1700]°F. This temperature is sufficient to ignite hydrogen in the vicinity of the ignitor when the lower flammability limit is reached. DCD subsection 6.2.4 provides additional information.

The hydrogen ignitor function should be available during MODES 1 and 2 when core decay heat is high and during MODE 5 when the RCS pressure boundary is open and in MODE 6 when the refueling cavity is not full. Planned maintenance should be performed on hydrogen ignitors when they are not required to meet this availability control. Table 2.8-1 indicates the minimum number of hydrogen ignitors that should be available.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.1 AC Power Supplies

OPERABILITY: One standby diesel generator should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel volume in one required standby diesel fuel tank less than limit.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore volume to within limits	14 days
B. One required fuel transfer pump or standby diesel generator not operable.	B.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	B.2 Restore pump and diesel generator to operable status	14 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

C. Required Action and associated Completion Time not met.	C.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability and schedule for restoration to OPERABLE. AND C.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 day 1 month

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.1 Verify that the fuel oil volume in the required standby diesel generator fuel tank is > [50,000] gal.	31 days
SR 3.1.2 Record that the required fuel oil transfer pump provides a recirculation flow of > [8] gpm.	92 days
SR 3.1.3 Verify that the required standby diesel generator starts and operates at > [4000] kw for > 1 hour. This test may utilize diesel engine prelube prior to starting and a warmup period prior to loading.	92 days
SR 3.1.4 Verify that each standby diesel generator starts and operates at > [4000] kw for > 24 hours. This test may utilize diesel engine prelube prior to starting and a warmup period prior to loading. Both diesel generators will be operated at the same time during this test.	10 years

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.1 AC Power Supplies

BASES:

AC power is required to power the RNS and to provide a nonsafety-related means of supplying power to the safety-related PMS for actuation and post accident monitoring. The RNS provides a nonsafety-related means to inject water into the RCS following ADS actuations in MODES 1,2,3,4 (when steam generators cool the RCS). This AC power supply function is important because it adds margin to the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

Two standby diesel generators are provided. Each standby diesel generator has its own fuel oil transfer pump and fuel oil tank. The volume of fuel oil required is that volume that is above the connection to the fuel oil transfer pump. DCD subsection 8.3.1 contains additional information.

This AC power supply function should be available during MODES 1,2,3,4,5 when RNS injection and PMS actuation are more risk important. Planned maintenance should not be performed on required AC power supply SSCs during a required MODE of operation; planned maintenance should be performed on redundant AC power supply SSCs during MODES 1, 2, 3 when the RNS is not normally in operation. The bases for this recommendation is that the AC power is more risk important during shutdown MODES, especially when the RCS is open as defined in availability control 2.2, than during other MODES.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.2 AC Power Supplies - RCS Open

OPERABILITY: Two AC power supplies should be operable to support RNS operation

APPLICABILITY: MODE 5 with RCS pressure boundary open,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required AC power supply not operable.	A.1 Initiate actions to increase the water inventory above the core.	12 hours
	AND	
	A.2 Remove plant from applicable MODES	72 hours
B. Required Action and associated Completion Time not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1	Verify that the required number of AC power supplies are operable	Within 1 day prior to entering the MODES of applicability

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.2 AC Power Supplies - RCS Open

BASES:

AC power is required to power the RNS and its required support systems (CCS & SWS); the RNS provides a nonsafety-related means to normally cool the RCS during shutdown operations. This RNS cooling function is important when the RCS pressure boundary is open and the refueling cavity is not flooded because it reduces the probability of an initiating event due to loss of RNS cooling during these conditions and because it provides margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The RCS is considered open when its pressure boundary is not intact. The RCS is also considered open if there is no visible level in the pressurizer. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

Two AC power supplies, one offsite and one onsite supply, should be available as follows:

a) Offsite power through the transmission switchyard and either the main step-up transformer / unit auxiliary transformer or the reserve auxiliary transformer supply from the transmission switchyard, and

b) Onsite power from one of the two standby diesel generators.

DCD subsection 8.3.1 contains additional information on the standby diesel generators. DCD Section 8.2 contains information on the offsite AC power supply.

One offsite and one onsite AC power supply should be available during the MODES of applicability when the loss of RNS cooling is important. If both of these AC power supplies are not available, the plant should not enter these conditions. If the plant has already entered these conditions, then the plant should take action to restore this AC power supply function or to leave these conditions. If the plant has not restored full system operation or left the MODES of applicability within 12 hours, then actions need to be initiated to increase the RCS water level to either 20% pressurizer level or to a full refueling cavity.

Planned maintenance should not be performed on required AC power supply SSCs. Planned maintenance affecting the standby diesel generators should be performed in MODES 1, 2, 3 when the RNS is not normally in operation. Planned maintenance of the other AC power supply should be performed in

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

MODES 2, 3, or MODE 6 with the refueling cavity full. The bases for this recommendation is that the AC power is more risk important during shutdown MODES, especially during the MODES of applicability conditions than during other MODES.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.3 AC Power Supplies - Long Term Shutdown

OPERABILITY: One ancillary diesel generator should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5, 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel volume in ancillary diesel fuel tank less than limit.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore volume to within limits	14 days
B. One required ancillary diesel generator not operable.	B.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	B.2 Restore one diesel generator to operable status	14 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

C. Required Action and associated Completion Time not met.	C.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE.	1 day
	AND	
	C.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.3.1 Verify fuel volume in the ancillary fuel tank is >[600] gal	31 days
SR 3.3.2 Verify that the required diesel generator starts and operates for >1 hour connected to a test load > [35] kw. This test may utilize diesel engine warmup period prior to loading.	92 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SR	3.3.3	Verify that each diesel generator starts and operates for 4 hours while providing power to the regulating transformer, an ancillary control room fan, an ancillary I&C room fan and a passive containment cooling water storage tank recirculation pump that it will power in a long term post accident condition. Test loads will be applied to the output of the regulating transformers that represent the loads required for post-accident monitoring and control room lighting. This test may utilize diesel engine warmup prior to loading. Both diesel generators will be operated at the same time during this test.	10 years

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.3 AC Power Supplies - Long Term Shutdown

BASES:

The ancillary diesel generators provide long term power supplies for post accident monitoring, MCR and I&C room cooling, PCS and spent fuel water makeup. For the first three days after an accident the 1E batteries provide power for post accident monitoring. Passive heat sinks provide cooling of the MCR and the I&C rooms. The initial water supply in the PCCWST provides for at least 3 days of PCS cooling. The initial water volume in the spent fuel pit normally provides for 7 days of spent fuel cooling; in some shutdown events the PCCWST is used to supplement the spent fuel pit. A minimum availability of 90% is assumed for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

After 3 days, ancillary diesel generators can be used to power the MCR and I&C room ancillary fans, the PCS recirculation pumps and MCR lighting. In this time frame, the PCCWST provides water makeup to both the PCS and the spent fuel pit. An ancillary generator should be available during all MODES of operation. This long term AC power supply function is important because it supports long-term shutdown operation.

The long-term AC power supply function involves the use of two ancillary diesel generators and an ancillary diesel generator fuel oil storage tank. The specified ancillary fuel oil storage tank volume is based on operation of both ancillary diesel-generators for 4 days. DCD subsection 8.3.1 contains additional information on the long-term AC power supply function.

One ancillary diesel generator and the ancillary diesel generator fuel oil storage tank should be available during all MODES of plant operation. Planned maintenance should not be performed on the required ancillary diesel generator during a required MODE of operation; planned maintenance should be performed on the redundant ancillary diesel generator. Planned maintenance affecting the ancillary diesel fuel tank that requires less than 72 hours to perform can be performed in any MODE of operation. Planned maintenance requiring more than 72 hours should be performed in MODE 6 with the refueling cavity full. The basis for this recommendation is that core decay heat is low and the risk of core damage is low in these MODES, the inventory of the refueling cavity results in slow response of the plant to accidents.

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.4 Non Class 1E DC and UPS System (EDS)

OPERABILITY: Power for DAS automatic actuation functions listed in 1.1 and 1.2 should be operable

APPLICABILITY: MODES 1, 2, 3, 4, 5,
MODE 6 with upper internals in place or cavity level less than full

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Power to DAS Function inoperable.	A.1 Notify [chief nuclear officer] or [on-call alternate].	72 hours
	AND	
	A.2 Restore power supply to DAS to operable status	14 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Submit report to [chief nuclear officer] or [on-call alternate] detailing interim compensatory measures, cause for inoperability, and schedule for restoration to OPERABLE	1 day
	AND	
	B.2 Document in plant records the justification for the actions taken to restore the function to OPERABLE.	1 month

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR	3.4.1	Verify power supply voltage at each DAS cabinet is 120 volts $\pm$ 5%	92 days

Table 16.3-2 (Cont.)

INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

3.0 Electrical Power Systems

3.4 Non Class 1E DC and UPS System (EDS)

BASES:

The EDS function of providing power to DAS to support ATWS mitigation is important based on 10 CFR 50.62 (ATWS Rule) and to support ESFA is important based on providing margin in the PRA sensitivity performed assuming no credit for nonsafety-related SSCs to mitigate at-power and shutdown events. The margin provided in the PRA study assumes a minimum availability of 90% for this function during the MODES of applicability, considering both maintenance unavailability and failures to operate.

The DAS uses a 2 out of 2 logic to actuate automatic functions. EDS power must be available to the DAS sensors, DAS actuation, and the devices which control the actuated components. Power may be provided by EDS to DAS by non-1E batteries through non-1E inverters. Other means of providing power to DAS include the spare battery through a non-1E inverter or non-1E regulating transformers.

The EDS support of the DAS ATWS mitigation function is required during MODE 1 when ATWS is a limiting event and during MODES 1, 2, 3, 4, 5, 6 when ESFA is important. The DAS ESFA is required in MODE 6 with upper internals in place or cavity level less than full. Planned maintenance should not be performed on a required EDS SSC during a required MODE of operation; planned maintenance should be performed on redundant supplies of EDS power.

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CHAPTER 17

QUALITY ASSURANCE

17.1 Quality Assurance During the Design and Construction Phases

See Section 17.5.

17.2 Quality Assurance During the Operations Phase

See Section 17.5.

17.3 Quality Assurance During Design, Procurement, Fabrication, Inspection, and/or Testing of Nuclear Power Plant Items

This section outlines the quality assurance program applicable to the design, procurement, fabrication, inspection, and/or testing of items and services for the AP1000 Project. The design for AP1000 is based upon employing the design of AP600 to the maximum extent possible. As a result, a continuous quality program spanning AP600 design as well as AP1000 design has been used. Westinghouse has and will continue to maintain a quality assurance program meeting the requirements of 10 CFR 50 Appendix B for the AP1000 program that will be applicable to the design, procurement, fabrication, inspection, and/or testing activities.

Effective March 31, 1996, activities affecting the quality of items and services for the AP600 Project during design, procurement, fabrication, inspection, and/or testing were being performed in accordance with the quality plan described in "Westinghouse Electric Corporation – Energy Systems Business Unit, Quality Management System," (Reference 1). The Quality Management System (QMS) has been maintained as the Quality Plan for the AP1000 program and subsequent revisions have been submitted to and accepted by the NRC as meeting the requirements of 10 CFR 50 Appendix B.

Prior to introduction of the QMS as the quality plan applicable to the AP1000 project, activities on the AP600/AP1000 program were performed in accordance with topical report WCAP 8370 (References 2 and 3), Westinghouse Energy Systems Business Unit/Power Generation Business Unit Quality Assurance Plan. WCAP 8370 was subsequently superceded by the Westinghouse QMS to describe the quality assurance plan and Westinghouse commitments to meet the requirements of 10 CFR 50 Appendix B.

The current Westinghouse quality plan for work being performed on the AP1000 is the Westinghouse Electric Company Quality Management System (QMS) (Reference 9). The referenced revision of the QMS was accepted by the NRC as meeting the requirements of 10 CFR 50, Appendix B, on September 13, 2002.

A project-specific quality plan was issued to supplement the quality management system document and the topical reports for design activities affecting the quality of structures, systems, and components for the AP600 project (Reference 4). This plan addresses the NQA-1-1989 edition through NQA-1b-1991 addenda and is applicable to work performed for the AP1000 design.

Quality Assurance requirements for systems, structures, and components will be graded based on the safety classification as indicated in Section 3.2. Safety-related systems are classified as Equipment Classes A, B and C, and will meet the requirements of 10 CFR 50, Appendix B. For systems, structures, and components included in the regulatory treatment of nonsafety systems (RTNSS), the quality requirements are identified in Table 17-1. See Section 16.3 for systems that should be considered for designation of systems and components included in the regulatory treatment of nonsafety systems.

While Westinghouse retains the overall responsibility for the AP1000 design, portions of the design are developed by external organizations. Each organization maintains a quality assurance program that meets the NQA-1 criteria that apply to its work scope. In accordance with the QMS, Westinghouse performs an initial evaluation of these programs and monitors their continued effective implementation through audits, surveillance, and evaluation of the performance of external organizations.

17.4 Design Reliability Assurance Program

This subsection presents the AP1000 Design Reliability Assurance Program (D-RAP).

17.4.1 Introduction

The AP1000 D-RAP is implemented as an integral part of the AP1000 design process to provide confidence that reliability is designed into the plant and that the important reliability assumptions made as part of the AP1000 probabilistic risk assessment (PRA) (Reference 5) will remain valid throughout plant life. The PRA quantifies plant response to a spectrum of initiating events to demonstrate the low probability of core damage and resultant risk to the public. PRA input includes specific values for the reliability of the various structures, systems, and components (SSCs) in the plant that are used to respond to postulated initiating events.

The D-RAP, as shown in Figure 17.4-1, is implemented in three phases. The first phase, the Design Certification phase, defines the overall structure of the AP1000 D-RAP, and implements those aspects of the program which are applicable to the design process. During this phase, risk-significant SSCs are identified for inclusion in the program using probabilistic, deterministic, and other methods. Phase II, the post-design certification process, develops component maintenance recommendations for the plant’s operations and maintenance activities for the identified SSCs. The third phase is the site-specific phase, which introduces the plant’s site-specific SSCs to the D-RAP process. Phase I is performed by the designer. Phases II and III are the responsibility of the Combined License applicant.

Finally, Figure 17.4-1 shows the Operational Reliability Assurance Process (O-RAP). This phase, which is implemented by the Combined License applicant, provides confidence that the operations and maintenance activities performed by the operating plant support should maintain the reliability assumptions made in the plant PRA.

17.4.2 Scope

The D-RAP includes a design evaluation of the AP1000 and identifies the aspects of plant operation, maintenance, and performance monitoring pertinent to risk-significant SSCs. In

addition to the PRA, deterministic tools, industry sources, and expert opinion are used to identify and prioritize those risk-significant SSCs.

17.4.3 Design Considerations

As part of the design process, risk-significant components are evaluated to determine their dominant failure modes and the effects associated with those failure modes. For most components, a substantial operating history is available which defines the significant failure modes and their likely causes.

The identification and prioritization of the various possible failure modes for each component lead to suggestions for failure prevention or mitigation. This information is provided as input to the Combined License applicant's O-RAP.

The design reflects the reliability values assumed in the design and PRA as part of procurement specifications. When an alternative design is proposed to improve performance in either area, the revised design is first reviewed to provide confidence that the current assumptions in the other areas are not violated. When a potential conflict exists between safety goals and other goals, safety goals take precedence.

17.4.4 Relationship to Other Administrative Programs

The D-RAP manifests itself in other administrative and operational programs. The technical specifications provide surveillance and testing frequencies for certain risk-significant SSCs, providing confidence that the reliability values assumed for them in the PRA will be maintained during plant operations. Risk-significant systems that provide defense-in-depth or result in significant improvement in the PRA evaluations are included in the scope of the D-RAP.

The O-RAP can be implemented through the plant's existing programs for maintenance or quality assurance. For example, the plant's implementation of the Maintenance Rule, 10 CFR 50.65, can provide coverage of the SSCs that would be included in O-RAP. The Combined License applicant will be responsible for the submittal of an O-RAP to the NRC. The NRC will review this process as part of the plant's maintenance program, Quality Assurance program, or other existing program.

17.4.5 The AP1000 Design Organization

The AP1000 organization of Section 1.4 formulates and implements the AP1000 D-RAP.

The AP1000 management staff is responsible for the AP1000 design and licensing.

The AP1000 staff coordinates the program activities, including those performed within Westinghouse as well as work completed by the architect-engineers and other supporting organizations listed in Section 1.4.

The AP1000 staff is responsible for development of Phase I of the D-RAP and the design, analyses, and risk and reliability engineering required to support development of the program. Westinghouse is responsible for the safety analyses, the reliability analyses, and the PRA.

The reliability analyses are performed using common databases from Westinghouse and from industry sources such as INPO and EPRI.

The Risk and Reliability organization is responsible for developing the D-RAP and has direct access to the AP1000 staff. Risk and Reliability is responsible for keeping the AP1000 staff cognizant of the D-RAP risk-significant items, program needs, and status. Risk and Reliability participates in the design change control process for the purpose of providing D-RAP-related inputs to the design process. Additionally, a cognizant representative of Risk and Reliability is present at design reviews. Through these interfaces, Risk and Reliability can identify interfaces between the performance of risk-significant SSCs and the reliability assumptions in the PRA. Meetings between Risk and Reliability and the designer are then held to manage interface issues.

17.4.6 Objective

The objective of the D-RAP is to design reliability into the plant and to maintain the AP1000 reliability consistent with the NRC-established PRA safety goals.

The following goals have been established for the D-RAP:

- Provide reasonable assurance that
  - The AP1000 is designed, procured, constructed, maintained and operated in a manner consistent with the assumptions and risk insights in the AP1000 PRA for these risk-significant SSCs
  - The risk-significant SSCs do not degrade to an unacceptable level during plant operations
  - The frequency of transients that challenge the AP1000 risk-significant SSCs are minimized
  - The risk-significant SSCs function reliably when they are challenged
- Provide a mechanism for establishing baseline reliability values for risk-significant SSCs identified by the risk determination methods used to implement the Maintenance Rule (10 CFR 50.65) and consistent with PRA reliability and availability design basis assumptions used for the AP1000 design
- Provide a mechanism for establishing baseline reliability values for SSCs consistent with the defense-in-depth functions to minimize challenges to the safety-related systems
- Generate design and operational information to be used by a Combined License applicant for ongoing plant reliability assurance activities

Development of maintenance assessments and recommendations for the D-RAP (Phase II) and the site-specific portion of the D-RAP (Phase III) is the responsibility of the Combined License applicant.

The Combined License applicant is responsible for submitting its maintenance recommendations (Phase II) and site-specific (Phase III) D-RAP organization description to the NRC.

The goal of the Combined License applicant's O-RAP is to maintain reliability consistent with overall safety goals and to maintain the capability to perform safety-related functions. Individual component reliability values are expected to change throughout the course of plant life because of aging and changes in suppliers and technology. Changes in individual component reliability values are acceptable as long as overall plant safety performance is maintained within the NRC-established PRA safety goals and the deterministic licensing design bases.

17.4.7 D-RAP, Phase I

Phase I, the definition portion of the D-RAP, includes the initial identification of SSCs to be included in the program, implementation of the aspects applicable to design efforts, and definition of the scope, requirements, and implementation options to be included in the later phases.

17.4.7.1 SSCs Identification and Prioritization

The initial task of the D-RAP is identification of risk-significant SSCs to be included within the scope of the program. As shown in Figure 17.4-1, the AP1000 PRA is used to identify those SSCs, consistent with the criteria of Reference 7 for risk achievement worth (RAW), risk reduction worth (RRW), and Fussel-Vesely Worth (FVW). Note that, although Reference 7 was developed for AP600, it is directly applicable to AP1000. The review of light water reactor industry experience and industry notices (such as licensee event reports) supports the process. An expert panel is also employed in the selection process.

PRA-based measurements provide information that contributes to the identification and prioritization of SSCs. A component's RAW is the factor by which the plant's core damage frequency increases if the component reliability is assigned the value 0.0. Components with risk achievement worth values of 2 or greater are considered for inclusion in the D-RAP.

RRW is used in the selection process. A component's risk reduction worth is the amount by which the plant's core damage frequency decreases if the component's reliability is assigned the value 1.0. A threshold measure of 1.005 or greater is used as the cutoff. Components with RRW of 1.005 or greater are considered for inclusion in the D-RAP.

FVW is also used in the screening process. This is a measure of an event's contribution to the overall plant core damage frequency. Components with Fussel-Vesely worth of 0.5 percent or greater are considered for inclusion in the D-RAP.

Deterministic considerations are also instrumental in identifying risk-significant SSCs. The deterministic identification of risk-significant SSCs encompasses the following guidelines and considerations:

- ATWS rule (10 CFR 50.62)
- Loss of all ac power (10 CFR 50.63)
- Post-72-hour actions

- Containment performance
- Adverse interactions with the AP1000 safety-related systems
- Seismic considerations

Nonsafety-related systems identified as risk-significant are considered in the scope of the D-RAP:

- Diverse actuation system
- Non-Class 1E dc and uninterruptible power supply system
- Offsite power, main ac power, and onsite standby power systems
- Normal residual heat removal system
- Component cooling water system
- Service water system

Finally, risk-significant SSCs are selected using industry experience, regulations, and engineering judgment.

17.4.7.1.1 Level 1 PRA and Shutdown Analysis

The Level 1 PRA evaluates accident sequences from initiating events and failures of safety functions to core damage events. The probability of core damage and the identification of dominant contributors to that state are also determined in this analysis.

A low-power and shutdown assessment is conducted to address concerns about risk of operations during shutdown conditions. It encompasses operation when the reactor is in a subcritical state or is in a transition between subcriticality and power operation up to 5 percent of rated power. It consists of a Level 1 PRA and an evaluation of release frequencies and magnitudes.

Included in the D-RAP are events that meet the threshold risk achievement worth, risk reduction worth, or Fussel-Vesely worth values defined in subsection 17.4.7.1.

17.4.7.1.2 Level 2 Analysis

The Level 2 analysis predicts the plant response to severe accidents and offsite fission product releases. Specifically, the analysis includes the following sections:

- Evaluating severe accident phenomena and fission product source terms
- Modeling the containment event tree
- Analyzing hydrogen burn, mixing, and igniter placement
- Modeling the AP1000 utilizing the MAAP4 code

Equipment used in the prevention of severe accidents and severe post-accident boundary conditions is credited in the Level 1 and Level 2 PRA analyses. An example of this preventive equipment is the reactor coolant system automatic depressurization system (ADS). Successful depressurization leads to core cooling, and in the event that injection fails, results in a low pressure core damage sequence that has fewer uncertainties and can be more easily mitigated than high pressure core damage.

The containment event tree used in the AP1000 Level 2 PRA examines the operation of equipment which mitigates the threat to the containment from severe accident phenomena. The systems credited for the mitigation of large fission product releases are containment isolation, passive containment cooling water (PCS), and operator action to flood the cavity by opening the recirculation valves and energizing the hydrogen igniters.

17.4.7.1.3 External Event Analyses

These analyses consider the events whose cause is external to all the systems associated with normal and emergency operations situations. They include the following:

- Internal flood
- Seismic margins analysis
- External events evaluations (such as high winds and tornados, external floods, and transportation accidents)
- Fire

The internal flood analysis identifies, analyzes, and quantifies the core damage risk contribution as a result of internal flooding during at-power and shutdown conditions. The analysis models potential flood vulnerabilities in conjunction with random failures modeled as part of the internal events PRA.

The seismic margins analysis identifies potential vulnerabilities and demonstrates seismic margin beyond the safe shutdown earthquake. The capacity of those components required to bring the plant to a safe, stable shutdown is evaluated.

17.4.7.1.4 Expert Panel

Meetings were held among Systems Engineering, PRA, and Reliability Engineering to perform the final selection of SSCs that should be included in the D-RAP. As shown in Figure 17.4-1, industry-wide information sources and engineering judgment were employed in considering the addition of SSCs to the D-RAP.

17.4.7.1.5 SSCs to be Included in D-RAP

Table 17.4-1 lists the non-site-specific SSCs included in the D-RAP. In Figure 17.4-1, this list is denoted as "Risk-significant items (non-site-specific)." For each item listed in the "SSC" column, there is a corresponding "Rationale" given. Items whose values exceed the thresholds for RAW or RRW are included and noted as such. Other SSCs are included based upon their significance to Level 2 analysis, external event analyses, or seismic margin analysis. Additional items are included based upon an expert panel review. The "Insights and Assumptions" column provides additional insights into the selection process.

The use of Fussel-Vesely worth resulted in no SSC selections.

17.4.7.2 D-RAP, Phase II

During Phase II of the D-RAP, maintenance assessments and recommendations are developed to enhance the reliability of the plant risk-significant components. These activities are shown in Figure 17.4-1 as "Recommended Plant Maintenance Monitoring Activities." The recommendations can take the form of monitoring activities or preventive, predictive or corrective maintenance, and are dependent upon the types of failure modes that a component may experience. These modes are generally determined by a failure modes, effects and criticality analysis. The maintenance recommendations address the most significant failure modes of the component.

17.4.7.2.1 Information Available to Combined License Applicant

To support the Combined License applicant's D-RAP Phases II and III and O-RAP, the following information is provided:

- The list of risk-significant SSCs identified during the design phase (Table 17.4-1)
- The PRA assumptions for component unavailability and failure data (Chapter 32 of the AP1000 PRA [Reference 5])
- The analyses performed for components identified as major contributors to total risk, with the dominant failure modes identified and prioritized. (Chapter 50 of the AP1000 PRA [Reference 5] identifies major contributors to total risk, and Chapters 8 to 28 of the AP1000 PRA describes the analyses of the respective systems and associated components in Table 17.4-1.) The suggested means for prevention or mitigation of these failure modes forms the basis for the plant surveillance, testing, and maintenance programs.

17.4.7.3 D-RAP, Phase III

Site-specific activities of the D-RAP are the responsibility of the Combined License applicant. Figure 17.4-1 shows these activities in the Phase III area of the figure. At this stage, the D-RAP package is modified or appended based on considerations specific to the site.

The COL applicant will need to establish PRA importance measures, the expert panel process, and other deterministic methods to determine the site-specific list of SSCs under the scope of RAP.

The Combined License applicant would benefit from using the Phase I and II processes as a guide during this phase of the program. It is the responsibility of the Combined License applicant to ensure its Expert Panel is composed of personnel knowledgeable in the systems, operations, and maintenance of a plant, and that these personnel should have the breadth of experience necessary to perform the site-specific SSC selections and evaluations for the RAP.

17.4.7.4 D-RAP Implementation

The following is an example of a system that was reviewed and modified under the D-RAP, Phase I. The design and analytical results presented here are intended as an example.

The automatic depressurization system, which is part of the reactor coolant system, acts in conjunction with the passive core cooling system to mitigate design basis accidents. The automatic depressurization system valves are discussed in subsection 5.4.6 of the DCD.

An earlier AP600 automatic depressurization system design contained four depressurization stages, with motor-operated valves in all stages. Preliminary PRA analysis established that fourth stage failure, in certain combination with failures of other stages, was a major contributor to core damage frequency. Thus, it was concluded that the fourth stage valves should be diverse in design from the valves in other stages to reduce common cause failure.

As a result of joint meetings among the AP600 PRA, Design, and staff organizations to discuss core melt frequency improvements, the fourth stage automatic depressurization system was changed from a motor-operated valve to a squib (explosively actuated) valve. The new configuration of the system is shown in the reactor coolant system P&ID (Figure 5.1-5 of the DCD). An example of the analytical results that reflect this change is provided in Table 17.4-2. This design feature is included in the AP1000 design to maintain the core melt frequency improvements included in the AP600 design.

As part of the evaluation of the squib valves, a failure modes and effects analysis (FMEA) was prepared to identify subcomponent failures and critical items that could lead to hazardous or abnormal conditions of the automatic depressurization system and the plant. The identification of failure modes facilitated the development of recommended maintenance and in-service testing activities to maximize valve reliability.

The squib valve is a completely static electromechanical assembly. Prior to activation, there are no moving parts. No powered components are needed to hold a stem seat or globe in place by torque, solenoid coils, or friction. The explosive actuator is a simple, passive device that is triggered by an applied voltage.

Because the automatic depressurization system fourth stage valves perform safety-related functions, they will be subject to in-service testing to verify that they are ready to function in an accident. Subsection 3.9.6 of the DCD includes in-service testing requirements for these valves.

Example FMEA results for the fourth stage squib valves and the second and third stage motor-operated valves are included in DCD Table 6.3-3. DCD subsection 3.9.6.3.1 provides testing recommendations for the second and third stage valves.

17.4.8 Glossary of Terms

D-RAP	Design Reliability Assurance Program – performed as part of the AP1000 design effort to assure that the reliability assumptions of the PRA remain valid throughout the plant operating lifetime.
FVW	Fussel-Vesely Worth
O-RAP	Operational Reliability Assurance Process
PRA	Probabilistic Risk Assessment

RAW	Risk Achievement Worth
Risk-significant	Any SSC determined in the PRA or by risk-significance analysis (e.g., Level 2 PRA and shutdown risk analysis) to be a major contributor to overall plant risk
RRW	Risk Reduction Worth
RTNSS	Regulatory Treatment of Nonsafety Systems
SSC	Structures, Systems, and Components

17.5 Combined License Information Items

The Combined License applicant or holder will address its design phase Quality Assurance program, as well as its Quality Assurance program for procurement, fabrication, installation, construction and testing of structures, systems and components in the facility. The quality assurance program will include provisions for seismic Category II structures, systems, and components.

The COL applicant or holder will establish PRA importance measures, the expert panel process, and other deterministic methods to determine the site-specific list of SSCs under the scope of RAP.

The Combined License applicant is responsible for integrating the objectives of the O-RAP into the Quality Assurance Program developed to implement 10 CFR 50, Appendix B. This program will address failures of non-safety-related, risk-significant SSCs that result from design and operational errors in accordance with SECY-95-132, Item E.

The Combined License applicant or holder will address its Quality Assurance program for operations.

The following activities are represented in Figure 17.4-1 as "Plant Maintenance Program."

The Combined License applicant is responsible for performing the tasks necessary to maintain the reliability of risk-significant SSCs. Reference 8 contains examples of cost-effective maintenance enhancements, such as condition monitoring and shifting time-directed maintenance to condition-directed maintenance.

The Maintenance Rule (10 CFR 50.65) is relevant to the Combined License applicant's maintenance activities in that it prescribes SSC performance-related goals during plant operation.

In addition to performing the specific tasks necessary to maintain SSC reliability at its required level, the O-RAP activities include:

- Reliability data base – Historical data available on equipment performance. The compilation and reduction of this data provides the plant with source of component reliability information.

- Surveillance and testing – In addition to maintaining the performance of the components necessary for plant operation, surveillance and testing provides a high degree of reliability for the safety-related SSCs.

- Maintenance plan – This plan describes the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

17.6 References

1. "Energy Systems Business Unit – Quality Management System," Revision 2.

2. WCAP-8370 Revision 12a, "Energy Systems Business Unit - Power Generation Business Unit Quality Assurance Plan."

3. WCAP-8370/7800, Revision 11A/7A, "Energy Systems Business Unit - Nuclear Fuel Business Unit Quality Assurance Plan."

4. WCAP-12600 Revision 4, "AP600 Advanced Light Water Reactor Design Quality Assurance Program Plan," January 1998.

5. APP-GW-GL-022, AP1000 Probabilistic Risk Assessment.

6. Deleted.

7. Letter from NRC to Westinghouse, "Criteria for Establishing Risk Significant Structures, Systems, and Components (SSCs) to be Considered for the AP600 Reliability Assurance Program," January 16, 1997.

8. Lofgren, E. V., Cooper, et al., "A Process for Risk-Focused Maintenance," NUREG/CR-5695, March 1991.

9. Westinghouse Electric Company Quality Management System (QMS), Revision 5, dated October 1, 2002.

Table 17-1 (Sheet 1 of 3)

QUALITY ASSURANCE PROGRAM REQUIREMENTS FOR SYSTEMS, STRUCTURES, AND COMPONENTS IMPORTANT TO INVESTMENT PROTECTION

The following outlines the quality assurance program requirements for suppliers of systems, structures, or components to which the requirements for investment protection short-term availability controls apply. 1. Organization The normal line organization may verify compliance with the requirements of this table. A separate or dedicated quality assurance organization is not required.
2. Quality Assurance Program It is expected that the existing body of supplier's procedures or practices will describe the quality controls applied to the subject equipment. A new or separate QA program is not required.
3. Design Control Measures shall be established to ensure that contractually established design requirements are included in the design. Applicable design inputs shall be included or correctly translated into design documents, and deviations therefrom shall be controlled. Normal supervisory review of the designer's work is an adequate control measure.
4. Procurement Document Control Applicable design bases and other requirements necessary to assure component performance, including design requirements, shall be included or referenced in documents for procurement of items and services, and deviations therefrom shall be controlled.
5. Instructions, Procedures, and Drawings Activities affecting quality shall be performed in accordance with documented instructions, procedures, or drawings of a type appropriate to the circumstances. This may include such things as written instructions, plant procedures, cautionary notes on drawings, and special instructions on work orders. Any methodology which provides the appropriate degree of guidance to personnel performing activities important to the component functional performance will satisfy this requirement.
6. Document Control The issuance and change of documents that specify quality requirements or prescribe activities affecting quality shall be controlled to assure that correct documents are employed.
7. Control of Purchased Items and Services Measures are to be established to ensure that all purchased items and services conform to appropriate procurement documents.

Table 17-1 (Sheet 2 of 3)

QUALITY ASSURANCE PROGRAM REQUIREMENTS FOR SYSTEMS, STRUCTURES, AND COMPONENTS IMPORTANT TO INVESTMENT PROTECTION

8.	Identification and Control of Purchased Items Measures shall be established where necessary, to identify purchased items and preserve their investment protection important functional performance capability. Examples of circumstances requiring such control include the storage of environmentally sensitive equipment or material, and the storage of equipment or material that has a limited shelf-life.
9.	Control of Special Processes Measures shall be established to control special processes, including welding, heat treating, and non-destructive testing. Applicable codes, standards, specifications, criteria, and other special requirements may serve as the basis of these controls.
10.	Inspection Inspections shall be performed where necessary to verify conformance of an item or activity to specified requirements, or to verify that activities are being satisfactory accomplished. Inspections need not be performed by personnel who are independent of the line organization. However, inspections, where necessary, shall be performed by knowledgeable personnel.
11.	Test Control Measures shall be established, as appropriate, to test equipment prior to installation to demonstrate conformance with design requirements. Tests shall be performed in accordance with test procedures. Test results shall be recorded and evaluated to ensure that test requirements have been met.
12.	Control of Measuring and Test Equipment Measures shall be established to control, calibrate, and adjust measuring and test equipment at specific intervals.
13.	Handling, Storage, and Shipping Handling, storage, cleaning, packaging, shipping, and preservation of items shall be controlled to prevent damage or loss and to minimize deterioration.
14.	Inspection, Test, and Operating Status Measures shall be established to identify items that have satisfactory passed required tests and inspections, and to indicate status of inspection, test, and operability as appropriate.
15.	Control of Nonconforming Items Items that do not conform to specified requirements shall be identified and controlled to prevent inadvertent installation or use.

Table 17-1 (Sheet 3 of 3)

QUALITY ASSURANCE PROGRAM REQUIREMENTS FOR SYSTEMS, STRUCTURES, AND COMPONENTS IMPORTANT TO INVESTMENT PROTECTION

16.	Corrective Action Measures shall be established to ensure that failures, malfunctions, deficiencies, deviations, defective components, and nonconformances are properly identified, reported, and corrected.
17.	Records Records shall be prepared and maintained to furnish evidence that the above requirements for design, procurement, document control, inspection, and test activities have been met.
18.	Audits Audits which are independent of line management are not required, if line management periodically reviews and documents the adequacy of the suppliers process and takes any necessary corrective action. Line management is responsible for determining whether reviews conducted by line management or audits conducted by and organization independent of line management are appropriate. If performed, audits shall be conducted and documents to verify compliance with design and procurement documents, instructions, procedures, drawings, and inspection and test activities.

DCD Table 17.4-1 (Sheet 1 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
System: Component Cooling Water (CCS)		
Component Cooling Water Pumps (CCS-MP-01A/B)	EP	These pumps provide cooling of the normal residual heat removal system (RNS) and the spent fuel pool heat exchanger. Cooling the RNS heat exchanger is important to investment protection during shutdown reduced-inventory conditions. CCS valve realignment is not required for reduced-inventory conditions.
System: Containment System (CNS)		
Containment Vessel (CNS-MV-01)	EP, L2	The containment vessel provides a barrier to steam and radioactivity released to the atmosphere following accidents.
Hydrogen Igniters (VLS-EH-1 through -64)	EP, L2, Regulations	The hydrogen igniters provide a means to control H_2 concentration in the containment atmosphere, consistent with the hydrogen control requirements of 10 CFR 50.34f.
System: Chemical and Volume Control System (CVS)		
Makeup Pumps (CVS-MP-01A/B)	RAW/CCF	These pumps provide makeup to the RCS to accommodate leaks and to provide negative reactivity for shutdowns, steam line breaks, and ATWS.
Makeup Pump Suction and Discharge Check Valves (CVS-PL-V113, -V160A/B)	RAW	These CVS check valves are normally closed and have to open to allow makeup pump operation.
System: Diverse Actuation System (DAS)		
DAS Processor Cabinets and Control Panel (used to provide automatic and manual actuation) (DAS-JD-001, -002, OCS-JC-020)	RAW	The DAS is diverse from the PMS and provides automatic and manual actuation of selected plant features including control rod insertion, turbine trip, passive residual heat removal (PRHR) heat exchanger actuation, core makeup tank actuation, isolation of critical containment lines, and passive containment cooling system (PCS) actuation.
Annex Building UPS Distribution Panels (EDS1-EA-1, EDS1-EA-14, EDS2-EA-1, EDS2-EA-14)	RAW	These panels distribute power to the DAS equipment.
Rod Drive MG Sets (Field Breakers) (PLS-MG-01A/B)	RAW	These breakers open on a DAS reactor trip signal demand to de-energize the control rod MG sets and allow the rods to drop.

Table 17.4-1 (Sheet 2 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
Containment Isolation Valves Controlled by DAS (Note 5)	RAW	These containment isolation valves are important in limiting offsite releases following core melt accidents.
System: Main ac Power System (ECS)		
Reactor Coolant Pump Switchgear (ECS-ES-31, -32, -41, -42, -51, -52, -61, -62)	RAW/CCF	These breakers open automatically to allow core makeup tank operation.
Ancillary Diesel Generators (ECS-MS-01, -02)	EP	For post-72 hour actions, these generators are available to provide power for Class 1E monitoring, MCR lighting and for refilling the PCS water storage tank and spent fuel pool.
System: Main and Startup Feedwater System (FWS)		
Startup Feedwater Pumps (FWS-MP-03A/B)	EP	The startup feedwater system pumps provide feedwater to the steam generator. This capability provides an alternate core cooling mechanism to the PRHR heat exchangers for non-loss-of-coolant-accidents or steam generator tube ruptures.
System: General I&C(4)		
Low Pressure/DP Sensors - IRWST level sensors (PXS-045, -046, -047, -048)	RAW/CCF	The in-containment refueling water storage tank (IRWST) level sensors support PMS functions. They are used in automatic actuation, and they provide indications to the operator. IRWST level supports IRWST recirculation actions.
High Pressure/DP Sensors - RCS Hot Leg Level (RCS-160A/B) - Pressurizer Pressure (RCS-191A/B/C/D) - Pressurizer Level (RCS-195A/B/C/D) - SG Narrow-Range Level (SGS-001, -002, -003, -004, -005, -006, -007, -008) - SG Wide-Range Level (SGS-011, -012, -013, -014, -015, -016, -017, -018)	RAW/CCF	The following sensors are included in this group. These sensors support PMS and PLS functions. They are used in reactor trip and ESF functions, and provide indications to the operator. Main feedwater flow sensors support startup feedwater actuation and startup feedwater flow sensors support PRHR actuation. The hot leg level sensors automatically actuate the IRWST injection and automatic depressurization system (ADS) valves during shutdown conditions.

Table 17.4-1 (Sheet 3 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
- Main Steamline Pressure (SGS-030, -031, -032, -033, -034, -035, -036, -037) - Main Feedwater Wide-Range Flow (SGS-050A/C/E, -051A/C/E) - Startup Feedwater Flow (SGS-055A/B, -056A/B)		
CMT Level Sensors (PXS-011A/B/C/D, -012A/B/C/D, -013A/B/C/D, -014A/B/C/D)	RAW/CCF	These level sensors provide input for automatic actuation of the ADS. They also provide indications to the operator.
System: Class 1E DC Power and Uninterruptible Power System (IDS)		
125 Vdc 24-hour Batteries, Inverters, and Chargers (IDSA-DB-1A/B, IDSB-DB-1A/B, IDSC-DB-1A/B, IDSD-DB-1A/B, IDSA-DU-1, IDSB-DU-1, IDSC-DU-1, IDSD-DU-1, IDSA-DC-1, IDSB-DC-1, IDSC-DC-1, IDSD-DC-1)	RAW/CCF	The batteries provide power for the PMS and safety-related valves. The chargers are the preferred source of power for Class 1E dc loads and are the source of charging for the batteries. The inverters provide uninterruptible ac power to the I&C system.
125 Vdc and 120 Vac Distribution Panels (IDSA-DD-1, -EA-1/2, IDSB-DD-1, -EA-1/2/3, IDSC-DD-1, -EA-1/2/3, IDSD-DD-1, -EA-1/2)	RAW	These panels distribute power to components in the plant that require 1E power support.
Fused Transfer Switch Boxes (IDSA-DF-1, IDSB-DF-1, IDSC-DF-1, IDSD-DF-1)	RAW	The fused disconnect switches connect the different levels of Class 1E distribution panels.
125 Vac Motor Control Centers (IDSA-DK-1, IDSB-DK-1, IDSC-DK-1, IDSD-DK-1)	EP	These buses provide power for the PMS and safety-related valve operation.

Table 17.4-1 (Sheet 4 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
System: Passive Containment Cooling System (PCS)		
Recirculation Pumps (PCS-MP-01A/B)	EP	These pumps provide the motive force to refill the PCS water storage tank during post-72 hour support actions.
PCCWST Drain Isolation Valves (PCS-PL-V001A/B/C)	EP, L2	These valves (two AOVs and one MOV) open automatically to drain water from a water storage tank onto the outside surface of the containment shell. This water provides evaporative cooling of the containment shell following accidents.
System: Plant Control System (PLS)		
PLS Actuation Hardware (Control functions listed in Note 6)	RAW/CCF	This common cause failure event is assumed to disable all logic outputs from the PLS associated with CVS reactor makeup, RNS reactor injection, spent fuel cooling, component cooling of RNS SFS heat exchangers, service water cooling of CCS heat exchangers, standby diesel generators, and hydrogen igniters.
System: Protection and Safety Monitoring System (PMS)		
PMS Actuation Software	RAW/CCF	The PMS software provides the automatic reactor trip and ESF actuation functions listed in Tables 7.2-2 and 7.3-1.
PMS Actuation Hardware	RAW/CCF	The PMS hardware provides the automatic reactor trip and ESF actuation functions listed in Tables 7.2-2 and 7.3-1.
Main Control Room (MCR) 1E Displays and System Level Controls (OCS-JC-010, -011)	RAW/CCF	This includes the Class 1E PMS (QDPS) displays and controls. These displays and system level controls provide important plant indications to allow the operator to monitor and control the plant during accidents.
Reactor Trip Switchgear (PMS-JD-RTS A01/02, B01/02, C01/02, D01/02)	RAW/CCF	These breakers open automatically to allow insertion of the control rods.
System: Passive Core Cooling System (PXS)		
IRWST Vents (PXS-MT-03)	RAW/CCF	The IRWST vents provide a pathway to vent steam from the tank into the containment. The IRWST vents also have a severe accident function to prevent the formation of standing hydrogen flames close to the containment walls. This function is accomplished by designing the vents located further from the containment walls to open with less IRWST internal pressure than the other vents.

Table 17.4-1 (Sheet 5 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
IRWST Screens (PXS-MY-Y01A/B)	RAW/CCF	The IRWST injection lines provide long-term core cooling following a LOCA. These screens are located inside the IRWST and prevent large particles from being injected into the RCS. They are designed so that they will not become obstructed.
Containment Recirculation Screens (PXS-MY-Y02A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. The screens are located in the containment and prevent large particles from being injected into the RCS. They are designed so that they will not become obstructed.
CMT Discharge Isolation Valves (PXS-PL-V014A/B, PXS-PL-V015A/B)	RAW/CCF	These air-operated valves automatically open to allow core makeup tank injection.
CMT Discharge Check Valves (PXS-PL-V016A/B, PXS-PL-V017A/B)		These check valves are normally open. They close during rapid accumulator injection.
Accumulator Discharge Check Valves (PXS-PL-V028A/B, -V029A/B)	RAW/CCF	These check valves open when the RCS pressure drops below the accumulator pressure to allow accumulator injection.
PRHR Heat Exchanger Control Valves (PXS-PL-V108A/B)	RAW/CCF	The PRHR heat exchangers provide core cooling following non-LOCAs, steam generator tube ruptures, and anticipated transients without scram. The air-operated valves automatically open to initiate PRHR heat exchanger operation.
Containment Recirculation Squib Valves (PXS-PL-V118A/B, PXS-PL-V120A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. These squib valves open automatically to allow containment recirculation when the IRWST level is reduced to about the same level as the containment level. These squib valves can also allow long-term core cooling to be provided by the RNS pumps. These squib valves can provide a rapid flooding of the containment to support in-vessel retention during a severe accident.

Table 17.4-1 (Sheet 6 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
IRWST Injection Check Valves (PXS-PL-V122A/B, -V124A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. These check valves open when the IRWST level is reduced to approximately the same level as the containment level.
IRWST Injection Squib Valves (PXS-PL-V123A/B, -V125A/B)	RAW/CCF	The IRWST injection lines provide long-term core cooling following a LOCA. These squib valves open automatically to allow injection when the RCS pressure is reduced to below the IRWST injection head.
IRWST Gutter Bypass Isolation Valves (PXS-PL-V130A/B)	RAW/CCF	These valves direct water collected in the IRWST gutter to the IRWST. This capability extends PRHR heat exchanger operation.
System: Reactor Coolant System (RCS)		
ADS Stage 1/2/3 Valves (MOV) (RCS-PL-V001A/B, -V002A/B, -V003A/B, -V011A/B, -V012A/B, -V013A/B)	RAW	The ADS provides a controlled depressurization of the RCS following LOCAs to allow core cooling from the accumulator, IRWST injection, and containment recirculation. The ADS provides "bleed" capability for feed/bleed cooling of the core. The ADS also provides depressurization of the RCS to prevent a high-pressure core melt sequence.
ADS Stage 4 Valves (Squib) (RCS-PL-V004A/B/C/D)	RAW/CCF	The ADS provides a controlled depressurization of the RCS following LOCAs to allow core cooling from the accumulator, IRWST injection, and containment recirculation. The ADS provides "bleed" capability for feed/bleed cooling of the core. The ADS also provides depressurization of the RCS to prevent a high-pressure core melt sequence.
Pressurizer Safety Valves (RCS-PL-V005A/B)	EP	These valves provide overpressure protection of the RCS.
Reactor Vessel Insulation Water Inlet and Steam Vent Devices (RCS-MN-01)	EP	These devices provide an engineered flow path to promote in-vessel retention of the core in a severe accident.
Reactor Cavity Doorway Damper	EP	This device provides a flow path to promote in-vessel retention of the core in a severe accident.
Fuel Assemblies (157 assemblies with tag numbers beginning with RXS-FA)	SMA	The nuclear fuel assembly includes the fuel pellets, fuel cladding, and associated support structures. This equipment, which provides a first barrier for release of radioactivity and allows for effective core cooling, had the least margin in the seismic margin analysis.

Table 17.4-1 (Sheet 7 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
System: Normal Residual Heat Removal System (RNS)		
Residual Heat Removal Pumps (RNS-MP-01A/B)	RAW	These pumps provide shutdown cooling of the RCS. They also provide an alternate RCS lower pressure injection capability following actuation of the ADS. The operation of these pumps is important to investment protection during shutdown reduced-inventory conditions. RNS valve realignment is not required for reduced-inventory conditions.
RNS Motor-Operated Valves (RNS-PL-V011, -V022, -V055, -V062)	RRW/FVW	These MOVs align a flow path for nonsafety-related makeup to the RCS following ADS operation, initially from the cask loading pit and later from the containment.
System: Spent Fuel Cooling System (SFS)		
Spent Fuel Cooling Pumps (SFS-MP-01A/B)	EP	These pumps provide flow to the heat exchangers for removal of the design basis heat load.
System: Steam Generator System (SGS)		
Main Steam Safety Valves (SGS-PL-V030A/B, -V031A/B, -V032A/B, -V033A/B, -V034A/B, -V035A/B)	EP	The steam generator main steam safety valves provide overpressure protection of the steam generator. They also provide core cooling by venting steam from the steam generator.
Main Steam and Feedwater Isolation Valves (SGS-PL-V040A/B, -V057A/B)	RAW	The steam generator main steam and feedwater isolation valves provide isolation of the steam generator following secondary line breaks and steam generator tube rupture.
System: Service Water System (SWS)		
Service Water Pumps and Cooling Tower Fans (SWS-MP-01A/B, SWS-MA-01A/B)	EP	These pumps and fans provide cooling of the CCS heat exchanger which is important to investment protection during shutdown reduced-inventory conditions. Service water system valve realignment is not required for reduced-inventory conditions.
System: Nuclear Island Nonradioactive Ventilation System (VBS)		
VBS MCR and I&C Rooms B/C Ancillary Fans (VBS-MA-10A/B, -11, -12)	EP	For post-72 hour actions, these fans are available to provide cooling of the MCR and the two I&C rooms (B/C) that provide post-accident monitoring.

Table 17.4-1 (Sheet 8 of 8)

RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP

System, Structure, or Component (SSC)(1)	Rationale(2)	Insights and Assumptions
System: Chilled Water System (VWS)		
Air Cooled Chillers and Pumps (VWS-MS-02, -03, VWS-MP-02, -03)	RAW/CCF	This VWS subsystem provides chilled cooling water to the CVS makeup pump room. The pumps and chillers are important components of the VWS.
System: Onsite Standby Power System (ZOS)		
Onsite Diesel Generators (ZOS-MS-05A/B)	EP	These diesel generators provide ac power to support operation of nonsafety-related equipment such as the startup feedwater pumps, CVS pumps, RNS pumps, CCS pumps, SWS pumps, and the PLS. Providing ac power to the RNS and the equipment necessary to support its operation is important to investment protection during reduced inventory conditions.
Engine Room Exhaust Fans (VZS-MY-V01A/B, -V02A/B)	EP	These fans provide ventilation of the rooms containing the onsite diesel generators.

Notes:

1. Only includes equipment at the **component** level. Other parts of the SSC or support systems are not included unless specifically listed.
2. Definition of Rationale Terms:
   CCF = Common Cause Failure (for the SSCs whose inclusion rationale is RAW/CCF, the RAW is based on common cause failure of two or more of the specified SSCs.
   EP = Expert Panel
   RAW = Risk Achievement Worth
   RRW = Risk Reduction Worth
   SMA = Seismic Margin Analysis
3. Maintenance/surveillance recommendations for equipment are documented in each appropriate DCD section.
4. This category captures instrumentation and control equipment common cause failures across systems.
5. The following containment isolation valves are controlled by DAS:
   Containment Purge Inlet Containment Isolation Valve ORC VFS-PL-V003
   Containment Purge Inlet Containment Isolation Valve IRC VFS-PL-V004
   Containment Purge Discharge Containment Isolation Valve IRC VFS-PL-V009
   Containment Purge Discharge Containment Isolation Valve ORC VFS-PL-V010
   Sump Discharge Containment Isolation Valve IRC WLS-PL-V055
   Sump Discharge Containment Isolation Valve ORC WLS-PL-V057
6. The PLS provides control of the following functions:
   CVS Reactor Makeup
   RNS Reactor Injection from Cask Loading Pit
   Startup Feedwater from CST
   Spent Fuel Cooling
   Component Cooling of RNS and SFS Heat Exchangers
   Service Water Cooling of the CCS Heat Exchangers
   Onsite Diesel Generators
   Hydrogen Igniters

Table 17.4-2

EXAMPLE OF RISK-SIGNIFICANT RANKING OF SSCs FOR THE AUTOMATIC DEPRESSURIZATION SYSTEM

Rank(1)	Event Code	Description
1	ED3MOD07	EDS3 EA1 distribution panel failure or unavailable due to testing and maintenance
2	AD4MOD07, AD4MOD08, AD4MOD09, AD4MOD10	Hardware failure of 2 of 4 automatic depressurization system Stage 4 squib valves
3	EC1BS001TM, ECBS012TM, EC1BS121TM, EC2BS002TM, EC2BS022TM, EC2BS221TM	Unavailability of bus ECS ES due to unscheduled maintenance
4	AD2MOD01, AD2MOD02, AD2MOD03, AD2MOD04	Hardware failure of 2 of 4 automatic depressurization system Stages 2 and 3 of lines 1 and 2 (includes motor-operated valves)
5	EC0MOD01	Main generator breaker ES01 fails to open
6	ED3MOD01	Fixed component fails: circuit breaker, inverter or static transfer switch
7	ZO1MOD01, Z02MOD01	Diesel generator fails to start and run or breaker 102 fails to close
8	Z02DG001TM, Z02DG001TM	Standby diesel generator unavailable due to testing and maintenance

Note:
1. The ranking is in the order of decreasing risk achievement component importance.

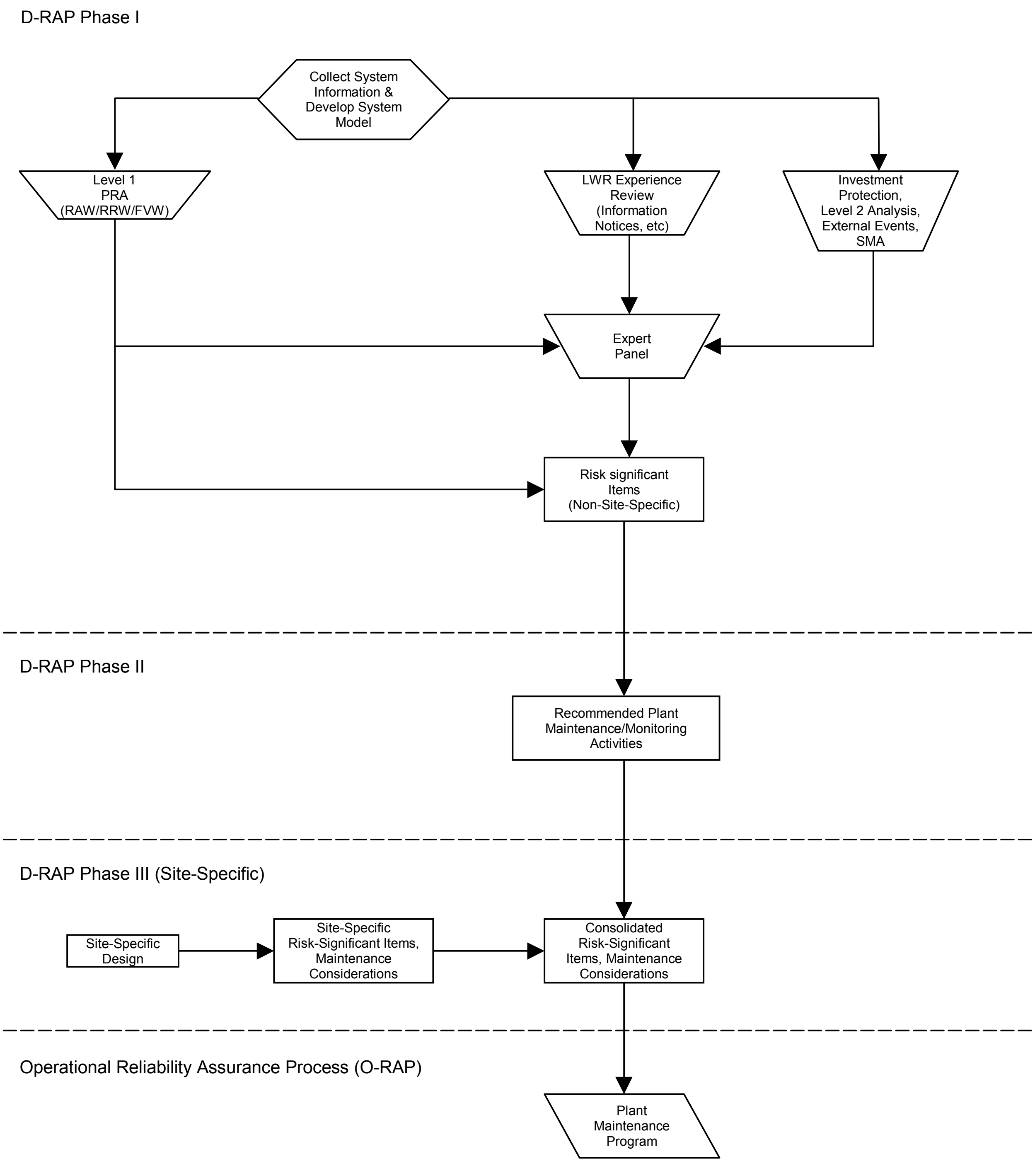

Figure 17.4-1

Design Reliability Assurance Program and O-RAP

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CHAPTER 18

HUMAN FACTORS ENGINEERING

18.1 Overview

Human factors engineering deals with designing and implementing resources and environments that help people perform tasks more reliably. Traditionally, human factors engineering includes the consideration of:

- Anthropometric or physical fit of humans to either their task-assisting machines or to their surroundings (for example, height, reach, and visual limitations)

- Biomechanical fit of the physical capabilities and limitations of humans relative to the requirements of their tasks (for example, lifting limits and push-pull limits)

- Biophysical fit of the physiological capabilities and limitation of humans to their environment (for example, tolerance to heat or cold, harmful chemicals, and noise)

More recently, the human factors engineering discipline has begun to model human error. Human errors include:

- Errors of execution or “slips”
- Errors of intention or “mistakes” (Reference 1)

Slips are errors in which a person’s intentions are correct, but an incorrect method for executing the action is chosen. Mistakes are errors in which the person forms an incorrect intention but then correctly executes it. Slips tend to be the result of poorly designed physical interfaces (for example, switches on a control board that look or feel alike) or of a poorly designed work environment (for example, temperatures that cause worker exhaustion). Mistakes are cognitive or mental errors. Human factors engineering includes cognitive systems engineering. This discipline focuses on the design of interfaces between humans and machines that support the operator decision-making activities that are required by the task. Cognitive systems engineering is particularly important when designing an interface for operators that control a real-time process, such as a nuclear power plant.

The rapid changes in digital computer and color graphics display technology offer the AP1000 design team an opportunity to improve the real-time decision support for the AP1000 operating staff. The AP1000 has a plant-wide network that provides pre-processed plant data to those members of the plant’s staff who have need of it. The real-time process control interface between the plant’s staff and the plant’s process equipment is the instrumentation and control (I&C) equipment driving graphical display devices in an integrated Human System Interface. Cognitive systems engineering is applied in the design of the human system interface.

The layout and environmental design of the main control room and the remote shutdown room, and the supplementary support areas, such as the technical support center, are sites of application of the traditional disciplines of human factors engineering.

Input from the designers is provided to the Combined License applicant that includes decisions made in the design of the AP1000 that affect those interfaces in the Combined License applicant's scope. This includes input on the operating staff training program and on the development of the plant operating procedures.

Because of the rapid changes that are taking place in the digital computer and graphic display technology employed in a modern human system interface, design certification of the AP1000 focuses upon the process used to design and implement human system interfaces for the AP1000, rather than on the details of the implementation. As a result, this chapter describes the processes used to provide human factors engineering in the design of the AP1000.

This chapter describes the application of the human factors engineering disciplines to the design of the AP1000. [*The basis for the human factors engineering program is the human factors engineering process specified in Reference 2*.]* Figure 18.1-1 illustrates the elements of the human factors engineering program. These elements correspond to the elements specified in Reference 2 and Reference 10. The organization of this chapter parallels these elements. In addition to the elements of the program review model, this chapter includes a description of the minimum inventory of controls, displays, and alarms present in the main control room and at the remote shutdown workstation. The following provides an annotated outline of the chapter. A number of References are identified which were developed for the AP600 Design Certification. Since the AP1000 operating philosophy and approach are the same for AP600 and AP1000, the References identified below are applicable to AP1000.

Section 18.2, Human Factors Engineering Program Management—presents the AP1000 human factors engineering program plan that is used to develop, execute, oversee, and document the human factors engineering program. This program plan includes the composition of the human factors engineering design team.

Section 18.3, Operating Experience Review—and Reference 3 present the results of a review of applicable operating experience. This operating experience review identifies, analyzes, and addresses human factors engineering-related problems encountered in previous designs.

Section 18.4, Functional Requirements Analysis and Allocation—and Reference 4 present the results of the functional requirements analysis and function allocation process applied to the AP1000. The functional requirements analysis defines the plant's safety functions, decomposes each safety function, compares the safety functions and processes with currently operating Westinghouse pressurized water reactors, and provides the technical basis for those processes that have been modified. The function allocation documents the methodology used to arrive at the AP1000 level of automation for the plant functions, processes, and systems involved in maintaining plant safety, and documents the results and rationale for function allocation decisions.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Section 18.5, Task Analysis—presents the scope and implementation plan for task analysis. The task analysis provides one of the bases for the human system interface design; provides input to procedure development; provides input to staffing, training, and communications requirements of the plant; and ensures that human performance requirements do not exceed human capabilities.

Section 18.6, Staffing—and Reference 5 provide input from the designer to the Combined License applicant for the determination of the staffing level of the operating crew in the AP1000 main control room.

Section 18.7, Integration of Human Reliability Analysis with Human Factors Engineering—and [*Reference 6 present the implementation plan for the integration of human reliability analysis with the human factors engineering program.*]*

Section 18.8, Human System Interface Design—presents the implementation plan for the design of the human system interface.

Section 18.9, Procedure Development—Reference 7 provides input to the Combined License applicant for the development of plant operating procedures, including information on the AP1000 emergency response guidelines and emergency operating procedures.

Section 18.10, Training Program Development—Reference 8 provides input from the designer on the training of the operations personnel who participate as subjects in the human factors verification and validation.

Section 18.11, Human System Interface Verification and Validation Program—[*Reference 9 presents a programmatic level description of the human factors verification and validation*.]*

Section 18.12, Inventory—presents the minimum inventory of controls, displays, and alarms present in the main control room and at the remote shutdown workstation. The design basis and the selection criteria used to identify the minimum inventory are presented.

Section 18.13, Design Implementation—In accordance with Reference 2, this issue is addressed under Section 18.11 as "Issue Resolution Verification" and "Final Plant HFE Verification."

Section 18.14, Human Performance Monitoring—Human performance monitoring applies after the plant is placed in operation, and is a Combined License applicant responsibility.

18.1.1 References

1. Reason, J. T., "Human Error," Cambridge, U.K., Cambridge University Press, 1990.

[*2. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994*.]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3. WCAP-14645, "Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant," Revision 2, December 1996.

4. WCAP-14644, "AP600 Functional Requirements Analysis and Function Allocation," Revision 0, September 1996.

5. WCAP-14694, "Designer's Input To Determination of the AP600 Main Control Room Staffing Level," Revision 0, July 1996.

[*6. WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

7. WCAP-14690, "Designer's Input To Procedure Development for the AP600," Revision 1, June 1997.

8. WCAP-14655, "Designer's Input to The Training of The Human Factors Engineering Verification and Validation Personnel," Revision 1, August 1996.

[*9. WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Revision 2, October 2003.*]*

10. NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," May 2002.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

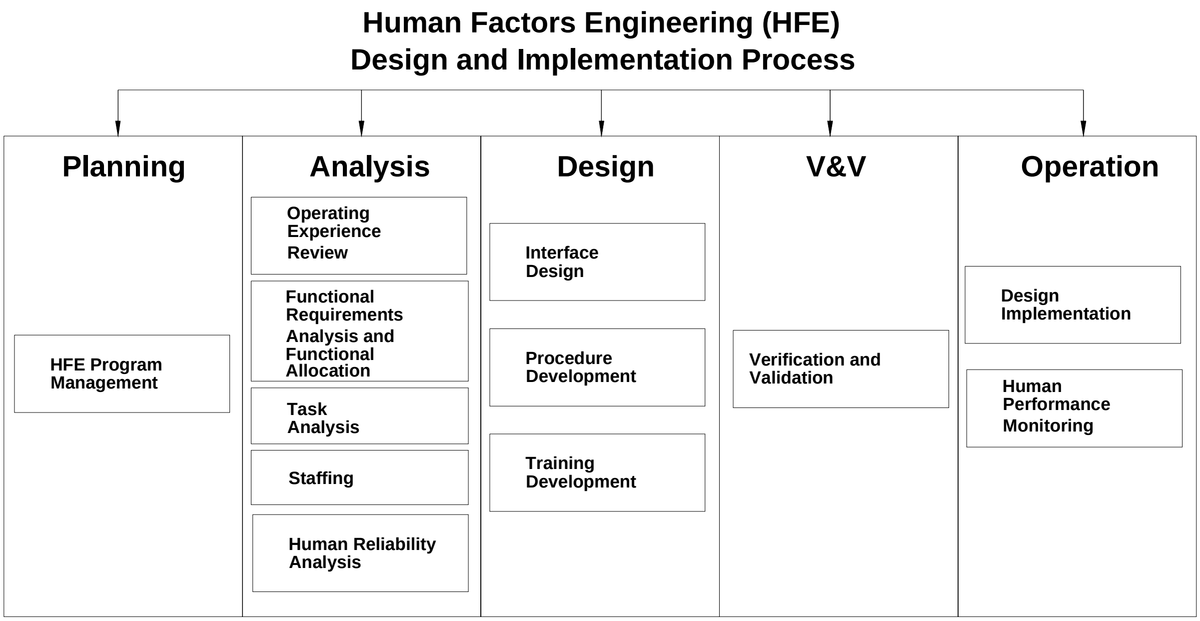

Figure 18.1-1

Human Factors Engineering (HFE)
Design and Implementation Process

18.2 Human Factors Engineering Program Management

The purpose of this section is to describe the goals of the AP1000 human factors engineering program, the technical program to accomplish these goals, the human system interface design team, and management and organizational structure that support the implementation of the technical program.

Human factors engineering is the system engineering of human system interfaces. The program management tools and procedures that govern the design of AP1000 systems apply to the human factors engineering activity. This approach is expected to integrate the design of human system interfaces with other plant systems.

18.2.1 Human Factors Engineering Program Goals, Scope, Assumptions, and Constraints

18.2.1.1 Human Factors Engineering Program Goals

The goal of the human factors engineering program is to provide the users of the plant operation and control centers effective means for acquiring and understanding plant data and executing actions to control the plant’s processes and equipment.

The objective is to enable personnel tasks to be accomplished within time and performance criteria.

18.2.1.2 Assumptions and Constraints

There are a number of inputs to the human factors engineering design process that specify assumptions or constraints on the human factors engineering program and the human system interfaces design.

Major design inputs include regulatory guidelines, guidance from utilities and utility representative groups, utility requirements documents, and AP1000 plant systems design specifications. The requirements resulting from these design inputs are captured in human system interface specification documents and functional requirements documents.

While assumptions and constraints specified by design inputs are provisionally treated as design requirements, the appropriateness of these requirements is evaluated as part of the human factors engineering design process. Results of human factors engineering activities such as operating experience review, task analyses, mockup activities and verification and validation activities are used to provide feedback on the adequacy of initial human system interface design assumptions and constraints. If results of human factors engineering analyses or evaluations indicate that initial human system interface design assumptions or constraints are inadequate, then the human system interface design requirements are revised utilizing the standard AP1000 design configuration change control process.

Listed below are some of the major inputs to the AP1000 human system interface design and the assumptions and constraints they impose on the AP1000 human system interface design process and human system interfaces design.

Regulatory Requirements

One of the requirements for the AP1000 human factors engineering program is that it complies with applicable regulatory requirements. [*The human factors engineering process is designed to meet the human factors engineering design process requirements specified in NUREG-0711 (Reference 1).*]*

Utility Requirements

Another source of design input is utility customer requirements. Utility input can take the form of utility requirements documents, and/or input from utility representative groups serving in an advisory capacity.

Examples of utility requirements that impact the human system interface design are:

- **Operating staff assumptions.** A single reactor operator (RO) should be able to control major plant functions performed from the main control room during normal power operations.

- **Assumptions with respect to human system interface resources.** The human system interface design shall include an integrating overview display and mimic in the main control room.

The AP1000 design goals with respect to control room staffing are addressed in Section 18.6 and WCAP-14694 (Reference 3). As noted in WCAP-14694, a number of elements of the AP1000 human factors engineering design process are used to help achieve, verify and validate the control room staffing design goal. These include operating experience review, function analysis and allocation, task analysis, human reliability assessment, human system interface design, procedures, training, and human factors engineering verification and validation.

As described in Section 18.8, one of the human system interface resources is a wall panel information system. The wall panel information system is intended to meet the utility requirement for an integrating overview display and mimic in the main control room. A number of design activities establish the basis and functional requirements for the wall panel information system. Design activities include conducting operating experience reviews in nuclear power plants and related industries to examine the requirements for individual and group situation awareness and how these can best be supported.

Plant System Design Information

The design of the plant systems is an essential input to the human system interface design process. The physical implementation specifications as well as the systems designer's intent with regard to expected systems operation and performance are used as input to the design of the AP1000 human system interfaces. System design data are documented in the individual system specification documents. The input representing the plant's physical structure is represented by the piping and instrumentation drawings, general arrangement drawings, and equipment drawings.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

System design specifications include specifications with respect to function allocation between automated systems and human operators. The system design specifications indicate which functions are to be automated, which are to be manual, and which require joint input of person and machine. In addition, the system design specifications indicate the set of instruments and controls that are implemented in the AP1000.

The AP600 function requirements analysis and function allocation document (Reference 4) provides information on the approach to initial function allocation and presents the results for AP600 safety functions. The results include a specification of level of automation and personnel responsibility for AP1000 safety functions, processes, and systems. The results also document the rationale for function allocation decisions for AP1000 safety functions.

The report also describes human factors activities that are conducted as part of the AP1000 human system interface design process to verify the adequacy of function allocation decisions, and establish the ability of operators to perform the role assigned to them. Function-based task analyses are used to verify that the sensors and controls that are provided are sufficient to enable operators to perform the role assigned to them in system performance. Workload analyses are used to evaluate the adequacy of the integrated roles assigned to operators across systems. Integrated system validation is used to establish the adequacy of the function allocation using man-in-the-loop tests in dynamic simulated plant conditions.

Technology Limits

Recent advances in the technology of digital computing have made it possible and practical to change the performance and role of the human system interface in a process control application such as a nuclear power plant. For the AP1000, a position regarding the limits of the implementation technology to be assumed for the human system interfaces is derived from assessment of existing technology and anticipated advancements. An emphasis is placed on utilization of proven, reliable technology. The decision on the specific technology to be employed is made on a case-by-case basis after available technology alternatives are evaluated.

18.2.1.3 Applicable Facilities

[*Facilities included in the scope of the AP1000 human factors engineering program are the main control room (MCR), the technical support center (TSC), the remote shutdown room, the emergency operations facility (EOF), and local control stations.*]*

The Combined License applicant is responsible for designing the EOF, including specification of a location, in accordance with the AP1000 human factors engineering program. Communication with the emergency operations facility is the responsibility of the Combined License applicant. Section 13.3 discusses the responsibility for emergency planning.

18.2.1.4 Applicable Human System Interfaces

[*The scope of the human system interfaces encompasses the instrumentation and control systems which perform the monitoring, control, and protection functions associated with all modes of plant normal operation as well as off-normal, emergency, and accident conditions. Both the*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

physical and the cognitive characteristics of those humans involved in the use, control, maintenance, test, inspection, and surveillance of plant systems are accommodated.]*

18.2.1.5 Applicable Plant Personnel

[*The AP1000 human factors engineering program and the design of the human system interfaces includes the selection, synthesis, and distribution of process data to plant operations personnel as well as other plant personnel. These additional users include management, engineering, maintenance, health physics and chemistry personnel.*]*

18.2.1.6 Technical Basis

[*The human factors engineering program is performed in accordance with accepted industry standards, guidelines, and practices.*]* The references listed at the end of each Chapter 18 section and within any supporting documentation and reports are used to guide the human factors engineering program. [*The human factors engineering process specified in Reference 1 is used.*]*

18.2.2 Human System Interface Design Team and Organization

The human system interface design team is part of the AP1000 systems engineering function and has similar responsibility, authority, and accountability as the rest of the design disciplines. Figure 18.2-1 depicts the process used by the human system interface design team members. Figure 18.2-2 shows the organization of the human system interface design team and its relationship to the AP1000 design organization.

18.2.2.1 Responsibility

[*The mission of the human system interface design team is to develop the main control room and ancillary control facilities (such as remote shutdown workstation) that support plant personnel in the safe operation and maintenance of the plant. The human system interface design team is responsible for coordinating the human factors aspects associated with designing the structures, systems, and components that make up the main control room and ancillary control facilities.*

The human system interface design team is responsible for:

- *Development of human system interface plans and guidelines*
- *Oversight and review of human system interface design, development, test, and evaluation activities*
- *Initiation, recommendation, and provision of solutions for problems identified in the implementation of the human system interface activities*
- *Assurance that human system interface activities comply with the human system interface plans and guidelines*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

18.2.2.2 Organizational Placement and Authority

The organization of the human system interface design team and its relation to the AP1000 design organization is depicted in Figure 18.2-2. The structure of the organization may change, but the functional nature of the human system interface design team is retained through the change. The human system interface design team consists of an instrumentation and control system manager, advisors/reviewers team, core human system interface design team, and human system interface technical lead. The technical disciplines described in subsections 18.2.2.3 and 18.2.2.4 are organized by function within the core human system interface design team. The core human system interface design team and the advisors/reviewers team report to the instrumentation and control system manager. The human system interface technical lead works within the human system interface design function and reports to the instrumentation and control system manager through the manager of the human system interface design function. The instrumentation and control system manager is responsible for the design of the AP1000 instrumentation and control systems which include the human system interfaces. The instrumentation and control system manager reports to the AP1000 project manager.

The manager of the human system interface design function, who performs the function of technical project management for the human factors engineering design process, is responsible for the overall human system interface design and for integration of the human system interface design with the overall plant design. The advisors/reviewers team is responsible for overseeing the general progress of the human system interface design, providing guidance within the core human system interface design team, reviewing and providing comments on documents, specifications, and drawings pertaining to the human system interface design, and providing supplemental expertise in particular areas of design. The responsibility of the core human system interface design team is to produce the detailed design of the human system interfaces. The human system interface design function is responsible for the functional design of the human system interfaces, main control room and workstation layout (ergonomics), controls, the information system (displays), the wall panel information system, the qualified data processing system, the alarm system, and computerized procedures system design and specification. The responsibilities of the human system interface technical lead include coordinating the technical work of the functional engineering groups, providing the administrative and technical interface between the functional engineering groups and the advisors/reviewers team, and tracking the identification and resolution of human factors engineering design issues through operating experience review.

18.2.2.3 Composition

[*The human system interface design team consists of a multi-disciplinary technical staff. The team is under the leadership of an individual experienced in the management of the design and operation of process control facilities for complex technologies. The technical disciplines of the design team include:*

- *Technical project management*
- *Systems engineering*
- *Nuclear engineering*
- *Instrumentation and control (I&C) engineering*
- *Architect engineering*

- *Human factors engineering*
- *Plant operations*
- *Computer system engineering*
- *Plant procedure development*
- *Personnel training*
- *Systems safety engineering*
- *Maintainability/inspectability engineering*
- *Reliability/availability engineering*]*

The responsibilities of the individual technical disciplines include:

- Technical Project Management
  - Provide central point of contact for management of the human factors engineering design and implementation process
  - Develop and maintain schedule for human factors engineering design process
- Systems Engineering
  - Provide knowledge of the purpose, technical specifications, and operating characteristics of plant systems
  - Provide input to human factors engineering task analyses
  - Participate in development of procedures and scenarios for task analyses, and integrated system validation
- Nuclear Engineering
  - Provide knowledge of the processes involved in reactivity control and power generation
  - Provide input to human factors engineering task analyses
  - Participate in development of scenarios for task analyses, and integrated system validation
- Instrumentation and Control (I&C) Engineering
  - Provide knowledge of control and display hardware design, selection, functionality, and installation
  - Provide input to software quality assurance programs
  - Participate in the design, development, test, and evaluation of the human system interfaces

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Architect Engineering
  - Provide knowledge of plant component layout and the overall structure of the plant including design characteristics and performance requirements for the containment building, control room, remote shutdown room, and local control stations
  - Provide input to human factors engineering task analyses
  - Participate in development of scenarios for task analyses, and integrated system validation
- Human Factors Engineering
  - Provide knowledge of human performance capabilities and limitations, human factors design and evaluation practices, and human factors principles, guidelines, and standards
  - Develop and perform human factors analyses and participate in resolution of human factors problems
- Plant Operations
  - Provide knowledge of operational activities relevant to characterizing tasks and environment and development of human system interface components, procedures, and training programs
  - Participate in development of scenarios for task analyses, and integrated system validation
- Computer System Engineering
  - Provide knowledge of data processing required for human system interface displays and controls
  - Participate in design and selection of computer-based equipment
  - Participate in development of scenarios for task analyses, and integrated system validation, particularly those involving failures of the human system interface data processing systems
- Plant Procedure Development
  - Provide knowledge of operational tasks and procedure formats
  - Provide input for development of emergency operating procedures, computer-based procedures, and training systems
  - Participate in development of scenarios for task analyses, and integrated system validation

- Personnel Training
  - Develop content and format of personnel training programs
  - Participate in development of scenarios for task analyses, and integrated system validation
- Systems Safety Engineering
  - Identify safety concerns
  - Perform system safety hazard analysis such as thermal atmospheric analysis, toxicology analysis, and radiological analysis
- Maintainability/Inspectability Engineering
  - Provide knowledge of maintenance, inspection, and surveillance activities
  - Provide input in the areas of maintainability and inspectability
  - Support design, development, and evaluation of control room and other human system interface components
  - Participate in development of scenarios for task analyses, and integrated system validation
- Reliability/Availability Engineering
  - Provide knowledge of plant system and component reliability and availability and assessment methodologies
  - Provide input to design of human system interface equipment
  - Participate in development of scenarios for task analyses, and integrated system validation

18.2.2.4 Team Staffing Qualifications

In choosing the human system interface design team members, greater emphasis is placed on the individual’s relevant experience to the specific discipline than on formal education. Alternative personal credentials may be selectively substituted for the education and experience requirements specified below. The professional experience of the human system interface design team as a

collective whole satisfy the experience qualifications. The human system interface design team members have the following backgrounds:

- Technical Project Management
  - Bachelor's degree
  - Five years experience in nuclear power plant design or operations and three years of management experience
- Systems Engineering
  - Bachelor of Science degree
  - Four years of cumulative experience of the following areas of systems engineering: design, development, integration, operation, and test and evaluation
- Nuclear Engineering
  - Bachelor of Science degree
  - Four years of experience in the following areas of nuclear engineering: design, development, test, or operations
- Instrumentation and Control (I&C) Engineering
  - Bachelor of Science degree
  - Four years of experience in hardware and software design aspects of process control systems; familiarity with software quality assurance and control
  - Experience in at least one of the following areas of instrumentation and control engineering: development, power plant operations, test evaluations
- Architect Engineering
  - Bachelor of Science degree
  - Four years experience in design of power plant structures and building services
- Human Factors Engineering
  - Bachelor's degree in Human Factors Engineering, Engineering Psychology, or related science
  - Four years experience in the following areas of human factors engineering: human factors aspects of human system interfaces (design, development, and test and evaluation of human system interfaces for process control applications) and four years

experience in human factors aspects of workplace design (design, development, and test and evaluation of workplaces)

- Plant Operations
  - Current or prior senior reactor operator (SRO) license/senior reactor operator instructor certification
  - Two years experience in PWR nuclear power plant operations
- Computer System Engineering
  - Bachelor's degree in Electrical Engineering or Computer Science or graduate degree in other engineering discipline
  - Four years experience in design of computer systems and real-time system applications; familiarity with software quality assurance and control
- Plant Procedure Development
  - Bachelor's degree
  - Four years experience in developing nuclear power plant operating procedures
- Personnel Training
  - Bachelor's degree
  - Four years experience in the development of personnel training programs for power plants and experience in the application of systematic training development methods
- Systems Safety Engineering
  - Bachelor of Science degree or Bachelor's degree in Science
  - Experience in system safety engineering, such as thermal atmospheric analysis, toxicology, radiological analysis and applicable OSHA limits
- Maintainability/Inspectability Engineering
  - Bachelor of Science degree or Bachelor's degree in Science
  - Four years of cumulative experience in at least two of the following areas of power plant maintainability and inspectability engineering activity: design, development, integration, test and evaluation, and analysis/resolution of maintenance problems

- Reliability/Availability Engineering
  - Bachelor's degree
  - Four years of cumulative experience in at least two of the following areas of power plant reliability engineering activity: design, development, integration, and test and evaluation. Knowledge of computer-based, human system interfaces.

18.2.3 Human Factors Engineering Processes and Procedures

Activities performed relating to human factors engineering are performed in accordance with documented procedures under the quality assurance program for the AP1000. These procedures provide for control of processes as described below.

18.2.3.1 General Process and Procedures

The instrumentation and control system function is responsible for development of the AP1000 instrumentation and control (I&C), including human system interfaces, and coordinating and integrating AP1000 instrumentation and control and human system interfaces with other AP1000 plant design activities. The overall operation of the project instrumentation and control systems function is defined. The function includes human system interface design of control rooms and control boards, instrumentation and control design, and control room/equipment design. The function includes definition of an engineering plan, review of inputs, production of system documentation, verification of work, procurement and manufacturing follow-up, and acceptance testing. An iterative feature is built into the process.

Documents produced as part of the instrumentation and control and human system interface design process include:

- Operating experience review documents
- Task analysis documents
- Functional requirements documents
- Human system interface design guidelines documents
- Design specification documents
- Instrumentation and control architecture diagrams
- Block diagrams
- Room layout diagrams
- Instrumentation lists
- System specification documents

The procedures governing instrumentation and control engineering work specify methods for verification of work. The types of verification include:

- Design verification by design reviews
- Design verification by independent review/alternative calculations
- Design verification by testing

System Specification Documents

System specification documents identify specific system design requirements and show how the design satisfies the requirements. They provide a vehicle for documenting the design and they address information interfaces among the various design groups.

System specification documents follow established format and content requirements. The content of a system specification document includes:

- Purpose of the system
- Functional requirements and design criteria for the system
- System design description including system arrangement and performance parameters
- Layout
- Instrumentation and control requirements
- Interfacing system requirements

The section on interfacing system requirements describes the support needed from and provided to other systems.

System specification documents document human factors and human system interaction requirements. This includes specification of task requirements, information requirements, and equipment requirements for operations, surveillance, test, and maintenance activities.

System specification documents provide specification of instrument and control requirements including:

- System input to the I&C channel list
- Reference to control logic diagrams
- Alarm requirements and characteristics
- Requirements and characteristics of plant status indications

A system specification document for the operation and control centers system provides a mechanism for documenting and tracking human system interface requirements and design specifications. The operation and control centers system specification document is the umbrella document for capturing generic human factors requirements. It provides a uniform operational philosophy and a design consistency among human system interface resources, including alarm system, plant information system, wall panel information system, computerized procedures.

Functional requirements and design specifications for the AP1000 operation and control centers system, including the main control room, the technical support center, the remote shutdown room, and local control stations are provided in the operation and control centers system specification document. Functional requirements documents and design specification documents are generated for each of the individual human system interface resources (including alarm system, plant information system, wall panel information system, computerized procedures, controls). Functional requirements documents specify the applicable codes, standards, and design requirements and constraints to be met by the design. These documents are referenced by the operation and control centers system specification document.

Design specification documents provide the design specifications for individual human system interface resources and their integration. Included in these specifications are layout and arrangement drawings, algorithms, and display system descriptions, including display task descriptions, display layouts, and navigation mechanisms.

The operation and control centers system specification document, the functional requirement documents, and design specification documents provide input to the generation of I & C system specification documents such as the system specification document for the data display and processing system.

Design Configuration Change Control Process

Design changes are controlled to assure that proposed changes to design documents under configuration control are appropriately evaluated for impacts and that approved changes are communicated to the responsible design organizations.

The design configuration change control process is used to control and implement changes to the design. It is used when the design to be changed has been previously released in a document for project use and placed under configuration control. A design change proposal is the vehicle used to initiate and document review of proposed design changes. Design change proposals include identification of impacts of the proposed design change from affected functional groups. In some instances, human factors engineering issues are addressed by the initiation of design change proposals. In other instances, they are addressed as a consequence of human factor engineering review of design change proposals originating from other disciplines. Design change proposals are maintained in a database that is used to track the status of each design change proposal from initiation through implementation and closure.

Design Review of Human Factors Engineering Products

Design reviews by a multi-disciplined review team are established as a verification method. Requirements for the design review process, including selection of the review team, preparation of information for review, identification and follow of action items, and documentation of the proceedings, are defined.

Design reviews provide a method of design verification consisting of a systematic overall evaluation of a design that is conducted by an independent design review team. Design reviews are conducted at appropriate stages of design development to provide an objective, independent review of design adequacy, safety, performance, and cost. Design reviews are performed by persons not directly associated with the specific design development, but who, as a group, are knowledgeable in the appropriate technical disciplines.

Original designs, as well as major design changes, are subject to the design review process. For each design review, a design review data package is prepared. It includes checklists, including one specifically addressing human factor engineering questions, which are used by design review committee members to aid their review. For each design issue identified through the use of checklists or otherwise, an action item is initiated.

[*Action items are tracked through the design issues tracking system database as described in subsection 18.2.4. The responsibility of entering design review action items into the design issues tracking system database is assigned to the manager responsible for the system reviewed. The responsible design manager is responsible for tracking and addressing open action items.*]*

18.2.3.2 Process Management Tools

Tools are provided to facilitate communication across design disciplines and organizations to enhance consistency. An AP1000 design database enables parties involved in the engineering design of the plant to access up-to-date plant design data. Procedures define requirements and responsibilities for moving data into the database.

Tools are provided to guide the design review process. These include design review checklists that support evaluation of design adequacy, and a database for tracking action items generated as a result of the design review process. Further details on the process of tracking action items generated by design reviews are provided in subsections 18.2.3.1 and 18.2.4.

A design configuration change control process is used to control and implement proposed design changes. Design change proposals are maintained in a database that is used to track the status of each design change proposal from initiation through implementation and closure.

A design issues tracking system database is used to document and track design issues that are identified during the plant design process. Further details on the design issues tracking system are provided in subsection 18.2.4.

18.2.3.3 Integration of Human Factors Engineering and Other Plant Design Activities

The AP1000 design process provides for the integration of human factors engineering activities among the design groups.

The instrumentation and control systems design function is responsible for the development of the AP1000 instrumentation and control systems, including the human system interface. Coordination and integration of the instrumentation and control and human system interface design with other plant design activities is performed by the instrumentation and control systems design function. An iterative design process, that includes review and feedback from other engineering and design groups at the design interface is specified. Subsection 18.2.3.1 describes the responsibilities and design process of the instrumentation and control system design function.

System specification documents provide the primary vehicle for transmitting system design data and interface requirements, including human factors engineering and human system interface requirements, to the affected AP1000 design and analysis groups. The system specification documents include a section on interfacing system requirements that describes the support needed from and provided to other systems in the plant. Interface control is performed at the design interfaces and design changes affecting the interfaces are coordinated. Subsection 18.2.3.1 provides details on system specification documents.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

A design configuration change control process provides the process and actions to implement design changes. Subsection 18.2.3.1 provides further details on this process.

Engineering design databases serve as a repository of AP1000 design data for parties involved in engineering design activities of the plant. A technical document control system is used to track the status of AP1000 documents. By using the engineering design databases and the technical document control system, parties have access to up-to-date design data to perform their respective design activities.

Section 18.8 presents the implementation plan for the design of the human system interface. Figure 18.2-3 provides an overview of the AP1000 human factors engineering process, including the design stages of the human system interface. The relationship of other human factors engineering process elements to the human system interface design is shown.

18.2.3.4 Human Factors Engineering Documentation

Procedures address documentation for AP1000, including document preparation, review, retention, access, and configuration control. These procedures apply to all AP1000 activities, including human factors engineering.

Documents refer to any self contained portrayal of the AP1000 design or its basis. These include design criteria, descriptions, specifications, drawings, analysis reports, safety reports and calculations.

A procedure establishes requirements and responsibilities for the preparation, review, and approval of AP1000 design documents. The procedure specifies that documents are to be reviewed by appropriate reviewers, and comments are to be resolved prior to issuance of the document. Appropriate reviewers include responsible engineers or managers impacted by the information in the document.

Changes to released documents are reviewed and approved in accordance with the design configuration change control procedure for the AP1000 program.

Procedures establish content and format requirements for system specification documents. Other procedures addressing documentation requirements include those for design configuration change control, design reviews, design criteria, and control of subcontractor submittals.

Sections 18.3 through 18.12 provide information on the types of documents that are generated as part of the AP1000 human factors engineering program.

18.2.3.5 Human Factors Engineering in Subcontractor Efforts

Human factors engineering and human system interface requirements are passed on to subcontractors through engineering documents including design criteria and system specification documents.

Activities within subcontractor design organizations are performed in accordance with the written procedures of those organizations. [*The AP1000 Program Procedure Matrix in WCAP-15847 (Reference 6) identifies the procedures that apply to subcontractor design organizations. The procedures of WCAP-15847 that describe the design documentation, apply to these external organizations with respect to content and format requirements. Effective implementation of each organization's quality assurance program is monitored by their respective internal audit programs, and by supplier audits.*]* See Section 17.3 for quality assurance requirements associated with subcontractor human factors engineering design efforts.

18.2.4 Human Factors Engineering Issues Tracking

A tracking system is used to address human factors issues that are known to the industry and/or identified throughout the life cycle of the human factors engineering/human system interface design, development, and evaluation. The tracking system enables the documentation and tracking of issues that need to be addressed at some later date.

Tracking of human factors engineering issues is accomplished within the framework of the overall plant design process. In this manner, human factors engineering issues are addressed in the same way as those for other disciplines.

[*The design issues tracking system database is used to track AP1000 design issues to resolution, including human factors engineering issues. This database receives input from the following three sources:*

- *Operating experience review*
- *Design reviews*
- *Design issues associated with the design of the human system interface and the operation and control centers system*]*

For each design issue entered into the database, the actions taken to address the issue and the final resolution of the issue are documented.

The human factors issues in the operating experience review report (Reference 1) that are identified as requiring further consideration by the AP1000 design are entered into the design issues tracking system database.

[*The design review process also provides input to the design issues tracking system database. For each design issue identified through the design review process, an action item is initiated. Action items are entered into the design issues tracking system database. Human factors action items from design reviews are included in the database. For preliminary and intermediate design reviews, some action items may be deferred to a more appropriate, subsequent design review. The responsibility of entering design review action items into the design issues tracking system database is assigned to the manager responsible for the system reviewed.*]*

Human factors engineering design issues directly associated with the AP1000 human system interfaces and the operation and control centers system (such as the main control room, remote shutdown room, and technical support center) are entered into the design issues tracking system

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

database. These are design issues that are identified by the human system interface and operation and control centers system designers as issues that need to be addressed by the human system interface design.

The AP1000 project manager, as shown on Figure 18.2-2, is responsible for the maintenance and documentation of the design issues tracking system. For each issue entered into the design issues tracking system database, a "responsible engineer" field is used to assign an engineer the responsibility for resolution of the issue.

18.2.5 Human Factors Engineering Technical Program and Milestones

[*The human factors engineering program is performed in accordance with the human factors engineering process specified in NUREG-0711 (Reference 1).*]* Figure 18.1-1 shows the elements of the AP1000 human factors engineering program. [*These elements conform to the elements of the Program Review Model specified in Reference 1, as augmented by Reference 7.*]*

Human factors engineering Program Management is addressed in Section 18.2. The remaining elements are addressed in Sections 18.3 through 18.11, 18.13, and 18.14.

These sections address the activities conducted as part of the corresponding human factors engineering element, including the accepted industry standards, guidelines, and practices used as technical guidance, the inputs to the element, and the products, including documents that are generated as output. The facilities, equipment, and tools employed are also addressed in the section corresponding to each element.

Operating Experience Review (Section 18.3) and Functional Requirements Analysis and Function Allocation (Section 18.4) are completed. Implementation plans are provided for Task Analysis (Section 18.5), Integration of Human Reliability Analysis (Section 18.7) and Human System Interface Design (Section 18.8). Staffing (Section 18.6), Procedure Development (Section 18.9), Training Development (Section 18.10), and Human Performance Monitoring (Section 18.14) are Combined License applicant responsibilities. A programmatic level description is provided for Human Factors Verification and Validation (Section 18.11). Human Factors Verification and Validation also addresses the activities identified under Design Implementation (Section 18.13).

Figure 18.2-3 provides an overview of the Westinghouse human factors engineering process. The figure summarizes the major activities of the human factors engineering program, their relative order, and the inputs and outputs for the major activities. The boxes in the diagram indicate major human factors engineering activities. The activities are presented in approximate chronological order, with the outputs of each activity serving as inputs to subsequent activities. The items listed below the activity boxes are the document outputs from that human factors engineering activity. The human factors engineering process includes iterations considering the outcomes of subsequent analysis and design activities, design reviews, and testing. In this approach, design issues are addressed and resolved through the iterative stages of the human factors engineering process. Potential points of iteration are indicated in Figure 18.2-3. Further details on the activities, inputs, and output documents associated with the various elements of the human factors engineering program are provided in the sections corresponding to each human factors engineering element.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Figure 18.2-3 provides a program milestone schedule of human factors engineering tasks showing relationships between human factors engineering elements and activities, products, and reviews. Internal design reviews are performed at various points throughout the design process.

18.2.6 Combined License Information

The Combined License applicant referencing the AP1000 certified design is responsible for the execution of the NRC approved human factors engineering program as presented by Section 18.2.

The Combined License applicant referencing the AP1000 certified design is responsible for designing the emergency operations facility, including specification of the location, in accordance with the AP1000 human factors engineering program.

18.2.7 References

[*1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

2. WCAP-14645, "Human Factors Engineering Operating Experience Review Report For The AP600 Nuclear Power Plant," Revision 2, December 1996.

3. WCAP-14694, "Designers Input to Determination of the AP600 Main Control Room Staffing Level," Revision 0, July 1996.

4. WCAP-14644, "AP600 Functional Requirements Analysis and Allocation," Revision 0, September 1996.

5. Reason, J. T., "Human Error," Cambridge, U.K., Cambridge University Press, 1990.

[*6. WCAP-15847, "AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Sections 18.2 and 18.8," Revision 1, December 2002.*]*

[*7. NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," U.S. NRC, May 2002.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

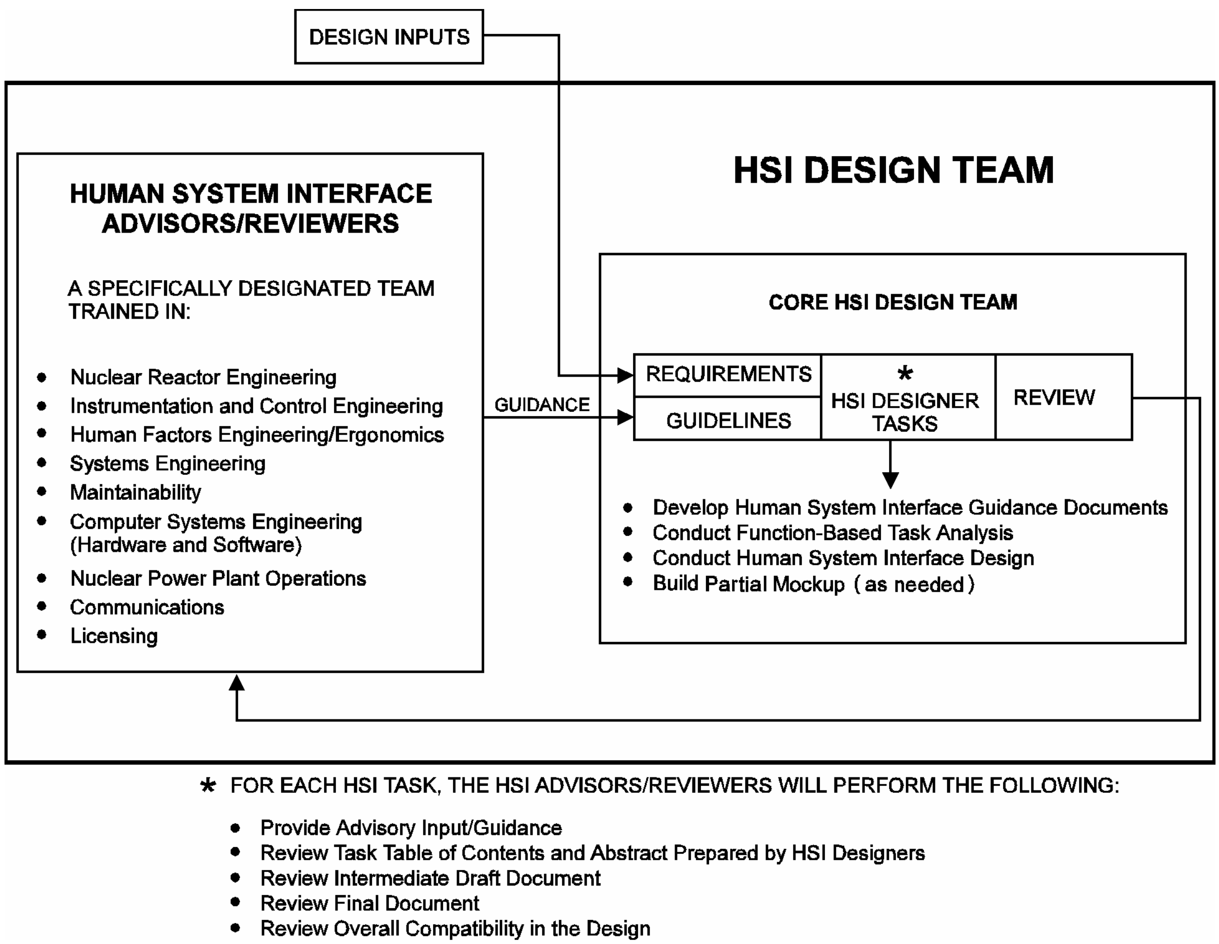

Figure 18.2-1

[Human System Interface (HSI) Design Team Process]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

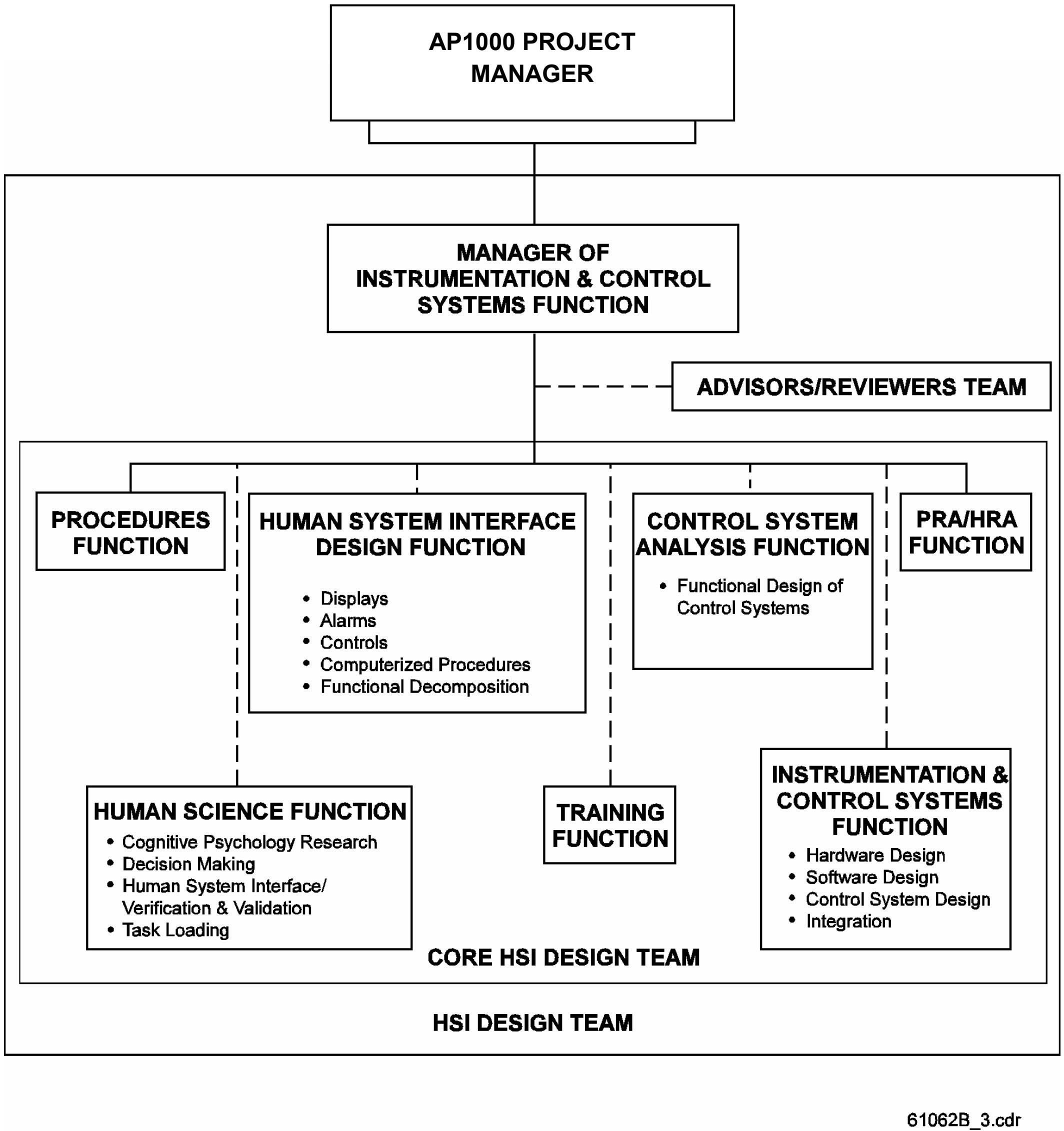

Figure 18.2-2

Human System Interface (HSI) Design Team Organization and Relationship to AP1000 Organization

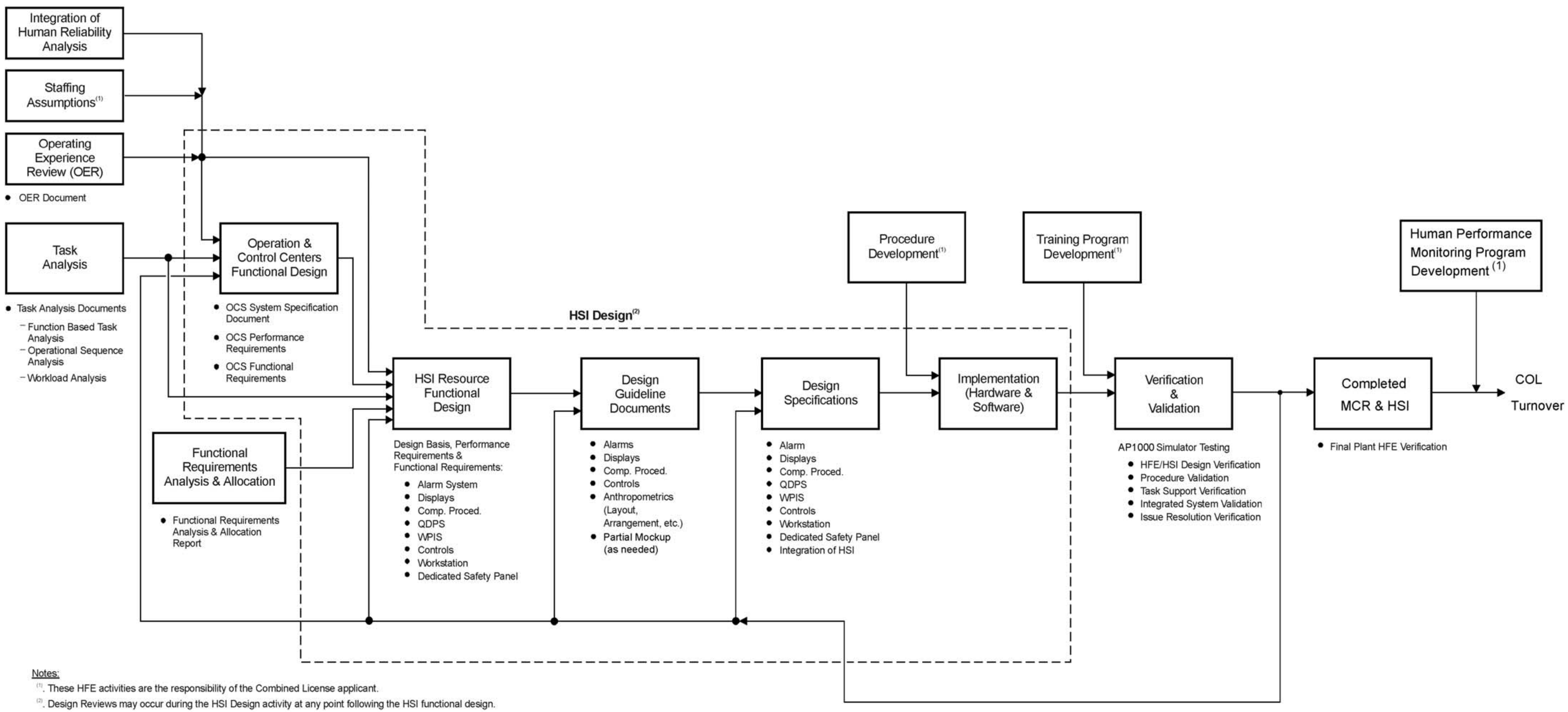

Figure 18.2-3

Overview of the AP1000 Human Factors Engineering Process

18.3 Operating Experience Review

The objective of the operating experience review is to identify and analyze human factors engineering-related problems and issues encountered in previous designs that are similar to the AP1000. Reference 1 documents the results of this review, including descriptions of how the AP600 design addresses each identified issue. Since AP1000 is like AP600 in its operation, Reference 1 is directly applicable to AP1000.

18.3.1 Combined License Information

Combined License applicant responsibilities identified in Reference 1 are presented in Sections 10.4.12, 16.2, 18.2.6, 18.6.1, 18.9.1 and 18.10.1.

18.3.2 References

1. WCAP-14645, "Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant," Revision 2, December 1996.

18.4 Functional Requirements Analysis and Allocation

Functional requirements and function allocation analyses are performed to establish and document design decisions with respect to level of plant automation.

Functional requirements analysis is defined as the "identification of those functions that must be performed to satisfy plant safety objectives, that is, to prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public" (Reference 1).

Function allocation is defined as the "analysis of the requirements for plant control and the assignment of control functions to (1) personnel (e.g., manual control), (2) system elements (e.g., automatic control and passive, self-controlling phenomena), and (3) combinations of personnel and system elements (e.g., shared control and automatic systems with manual backup)" (Reference 1).

Reference 2 documents the methods and results of the functional requirements analysis and function allocation conducted for AP600.

The report provides a description of the AP600 approach to functional requirements analysis and presents the results for AP600 safety functions. The results include a description of AP600 processes, systems, and components involved in maintaining AP600 safety functions. The report also includes a similar analysis for current Westinghouse pressurized water reactor designs to serve as a reference in identifying areas where the AP600 plant differs from previous designs for which operating experience exists. An explicit comparison of the AP600 design with the reference plant design is provided that identifies plant functions, processes, and systems that are new or modified relative to the reference plant design. This includes changes in level of automation.

The report also describes the AP600 approach to initial function allocation and presents the results for AP600 safety functions. A methodology adapted from Reference 3 is used to document the rationale for initial allocation decisions and verify the acceptability of the initial allocation from a human factors perspective. The results include a specification of level of automation and personnel responsibility for AP600 safety functions, processes, and systems. The rationale for the function allocation decisions for AP600 safety functions is documented.

Since AP1000 is like AP600 in its operation and approach to safety functions, Reference 2 is directly applicable to AP1000. It is used as is for functional requirements and function allocation analyses for AP1000.

The report includes a description of human factors activities that are conducted as part of the AP600 HSI design process to verify the adequacy of function allocation decisions and establish the capability of operators to perform the role assigned to them. This is applied to AP1000 and includes:

- How human factors input is provided early in the design process

- How the integrated role of the operator across the systems is confirmed for acceptability

- Mechanisms available for reconsidering, and if necessary, changing AP1000 function allocations in response to operating experience, and the outcomes of ongoing analyses and trade studies

18.4.1 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

18.4.2 References

1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.

2. WCAP-14644, "AP600 Functional Requirements Analysis and Function Allocation," Revision 0, September 1996.

3. NUREG/CR-3331, "A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control," 1983.

18.5 AP1000 Task Analysis Implementation Plan

[*Task analysis, according to the Human Factors Engineering Program Review Model (Reference 1), has the following objectives:*

- *Provide one of the bases for the human system interface design decisions*
- *Match human performance requirements with human capabilities*
- *Provide input to procedure development*
- *Provide input to staffing, training, and communications requirements of the plant*]*

This section describes the scope of the AP1000 task analysis activities and the task analysis implementation plan. In addition to Reference 1, References 2 through 12 are inputs to this plan. Execution and documentation of this task analysis implementation plan is the responsibility of the Combined License applicant.

18.5.1 Task Analysis Scope

[*The scope of the AP1000 task analysis is divided into two complementary activities: function-based task analysis (FBTA) and traditional task analysis, or operational sequence analysis (OSA). The scope of the function-based task analysis is the Level 4 functions*]* identified in Figure 18.5-1. This figure is the functional decomposition (goal-means analysis) for normal power operations in a standard pressurized water reactor. Examples of functions at Level 4 are "Control RCS Coolant Pressure" and "Control Containment Pressure." This set of functions define the breadth of functions to be analyzed. The function-based task analysis will be expanded in scope to include any additional Level 4 functions identified.

[*The traditional task analysis, or operational sequence analysis, is developed for a representative set of operational and maintenance tasks. The following guidelines are applied to select tasks:*

- *Tasks are selected to represent the full range of operating modes, including startup, normal operations, abnormal and emergency operations, transient conditions, and low-power and shutdown conditions.*

- *Tasks are selected that involve operator actions that are identified as either critical human actions or risk-important tasks, based on the criteria in Reference 13.*

- *Tasks are selected to represent the full range of activities in the AP1000 emergency response guidelines.*

- *Tasks are selected that involve maintenance, test, inspection, and surveillance (MTIS) actions. A representative set of maintenance, test, inspection, and surveillance tasks are analyzed for a subset of the "risk-significant" systems/structures/components (SSCs).*

The set of tasks to be analyzed are not identified as a part of design certification. The OSAs listed below are included in the set of tasks to be analyzed: (Each of these satisfies one or more of the selection criteria described above.)

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- *Plant heatup and startup from post-refueling to 100% power*
- *Reactor trip, turbine trip, and safety injection*
- *Natural circulation cooldown (startup feedwater with steam generator)*
- *Loss of reactor or secondary coolant*
- *Post loss-of-coolant accident cooldown and depressurization*
- *Loss of RCS inventory during shutdown*
- *Loss of the normal residual heat removal system (RNS) during shutdown*
- *Manual automatic depressurization system (ADS) actuation*
- *Manual reactor trip via PMS, via diverse actuation system (DAS)*
- *ADS valve testing during Mode 1*

The human factors engineering program review model (Reference 1) indicates that task analysis should include tasks that are considered to be high-risk and tasks that require critical human actions. Reference 13 defines criteria for critical human actions and risk-important tasks and has identified a list of examples of AP600 tasks that meet these criteria. Reference 13 is applicable to AP1000.]*

Section 16.2 identifies the systems/structures/components included in the Reliability Assurance Program. A subset of these systems/structures/components and a representative set of associated maintenance, tests, inspection and surveillance tasks will be selected by an expert panel. This panel will be comprised of representatives with expertise from relevant groups in the design process, such as systems engineering, reliability engineering, probabilistic risk analysis, human factors engineering, and human system interface design. The set of maintenance, test, inspection and surveillance tasks identified through the expert panel process will be considered to be "risk important" tasks, and will be included in task analysis activities.

18.5.2 Task Analysis Implementation Plan

Figure 18.5-2 shows the proposed sequence of task analyses. Figure 18.5-2 provides information concerning the task analysis and human system interface design elements. *[Task analysis includes both a function-based task analysis and an operational sequence analysis.*]* In Figure 18.5-2, the operational sequence analysis in the task analysis box is designated as OSA-1 since two operational sequence analyses will be implemented.

18.5.2.1 Function-Based Task Analyses

Function-based task analysis is applied to each of the Level 4 functions. There are four components to a function-based task analysis. First, analysis is performed to identify the set of goals relevant to the function. Second, a functional decomposition is performed. This decomposition identifies the processes that, either individually or in combination, have a significant effect on the function. Third, a process analysis is performed by applying a set of questions derived from Rasmussen's model (References 6-9) analysis approach. [*The set of questions used and basis for the methodology is provided in Reference 12.*]* An example of a question from the process analysis is "Are the process data valid?" The results of the process analysis identify the indications, parameters, and controls that the operator uses to make decisions about the respective function. Finally, there is a verification that the indications and controls, identified in the process analysis are included in the AP1000 design.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

From the function-based task analyses, the following types of information are obtained:

- A completeness check on the availability of needed indications, parameters, and controls. This includes indications and controls needed for supervisory control of automated systems and manual over-ride.

- Input to the specification and layout of functional displays.

18.5.2.2 OSA-1

The operational sequence analysis completed as part of the task analysis process focuses on specifying the operational requirements for the complete set of tasks selected. For each task, an operational sequence diagram of the task's performance is created that includes the following:

- Plant state data required at each step
- Source of the data (alarm, display, oral communication)
- Action to be taken or decision to be made from the data
- Relevant criterion or reference values
- Information that provides feedback on the action's adequacy
- Time available for action
- Other temporal constraints (ordering, tasks that need to be done in parallel)
- Task support requirements needed (required tools)
- Considerations of work environment

The operational sequence diagrams are developed from the emergency response guidelines, the Probabilistic Risk Assessment event sequences associated with critical or risk-important actions, and the function-based task analysis. The following potential limitations on task performance are considered:

- Limits on human performance
- Limits on hardware and software performance
- Limits on crew communications

This first operational sequence analysis provides the following types of information:

- Frequency and co-occurrence of plant state parameters and controls
- Display design and organization constraints
- Performance time constraints
- Inventory of alarms, controls, and parameters needed to perform the sequences

As shown in Figure 18.5.2, the function-based task analysis and OSA-1 feed into the human system interface design by providing a set of requirements and constraints on task performance. The display and operator workstation design is based on this information.

18.5.2.3 OSA-2

The critical issues for the second operational sequence analysis are:

- Completeness of available information - This analysis determines whether necessary information is available to the operator performing the task activities. The human system interface design indicates the number of human system interface elements that are used for each action or decision to occur.

- Time to perform tasks - Operational sequence modeling tools are used to provide a set of performance time assumptions and then determine the time required for actions to be completed. Assumptions can be made about minimum times to access displays and controls and, by running the task modeling network with these assumptions, the time required to perform tasks can be determined. The operational sequence analysis begins with conservative assumptions regarding the performance of hardware, software, and humans, and assumes minimal use of parallel task performance. These assumptions provide a conservative estimate of task performance times that can be compared to performance time requirements.

- Operator workload measures - Task network modeling tools are used to evaluate the effect of the human system interface design on operator workload. Operator workload can be assessed at three levels of detail. First, workload can be measured against time available to perform each task related to time estimates to perform. When time to perform estimates are larger than the time available, operator workload is too high, and some corrective action is required. Second, operator workload estimates can be broken out into resource "channels." Typically, an analysis uses four to six independent channels, which may include visual, auditory, verbal, cognitive, psychomotor, and kinesthetic channels. For each task or activity, an assessment is made about the level of activity in each channel. When the task network model is executed, the workload values are accumulated over short time intervals (for example, every 2 seconds). Workload values on each channel are graphed and the analyst identifies points in task performance where workload exceeds some threshold value. When workload is too high, due either to demands from concurrent tasks or demands from a single task, some corrective action is required. The third approach to estimating operator workload is to add a consideration of cross-channel interference. Workload theories indicate that, although it is useful to think of multiple mental resources being tapped by task performance, there is also a need to be concerned with interference between concurrent activities. Several tools make it possible to extend the analysis of separate channels and create an interference matrix that reveals additional demands on operator workload. These tools use task rating schemes with built-in assumptions about interference to produce the additional workload estimates.

- Operational crew staffing - The workload operational sequence analysis provides an indication of the adequacy of staffing assumptions. In cases where the operational sequence analysis indicates high operator workload values, or insufficient time available for

performance, alternative staffing assumptions or changes to the human system interface design or task allocation to reduce operator workload is evaluated.

This second operational sequence analysis is performed for a representative subset of tasks that include the critical human actions and risk-important tasks and tasks that have human performance concerns (for example, potential for high workload or high error rates).

18.5.2.4 Task Analysis of Maintenance, Test, Inspection and Surveillance Tasks

The maintenance, test, inspection, and surveillance tasks that are identified to be "risk-important" are analyzed using operational sequence task analyses. OSA-1 analyses are conducted on the set of maintenance, test, inspection, and surveillance tasks identified to be "risk-important."

18.5.3 Job Design Factors

Section 18.6 addresses the control room staffing that applies to the AP1000. The staffing level of the main control room, job design considerations, and crew skills are the responsibility of the Combined License applicant.

18.5.4 Combined License Information Item

Combined License applicants referencing the AP1000 certified design will address the execution and documentation of the task analysis implementation plan presented in Section 18.5.

Combined License applicants referencing the AP1000 certified design will document the scope and responsibilities of each main control room position, considering the assumptions and results of the task analysis.

18.5.5 References

[*1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

2. U.S. NRC Guidance, NUREG/CR-3371, "Task Analysis of Nuclear Power Plant Control Room Crews."

3. IEC-964, "Design for Control Rooms of Nuclear Power Plants."

4. Department of Defense Documents: DI-H-7055, "Critical Task Analysis Report," and MIL-STD-1478, "Task Performance Analysis."

5. NATO Document, "Applications of Human Performance Models to System Design," edited by McMillan, Beevis, Salas, Strub, Sutton, & van Breda, New York: Plenum Press, 1989.

6. Rasmussen, J., "Information Processing and Human-Machine Interaction, An Approach to Cognitive Engineering," New York: North-Holland, 1986.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

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9. Vicente, K. J., "Task Analysis, Cognitive Task Analysis, Cognitive Work Analysis: What's the Difference?" Proceedings of the Human Factors and Ergonomics Society 39th Annual Meeting, San Diego, Ca., 1995, pp. 534-537.

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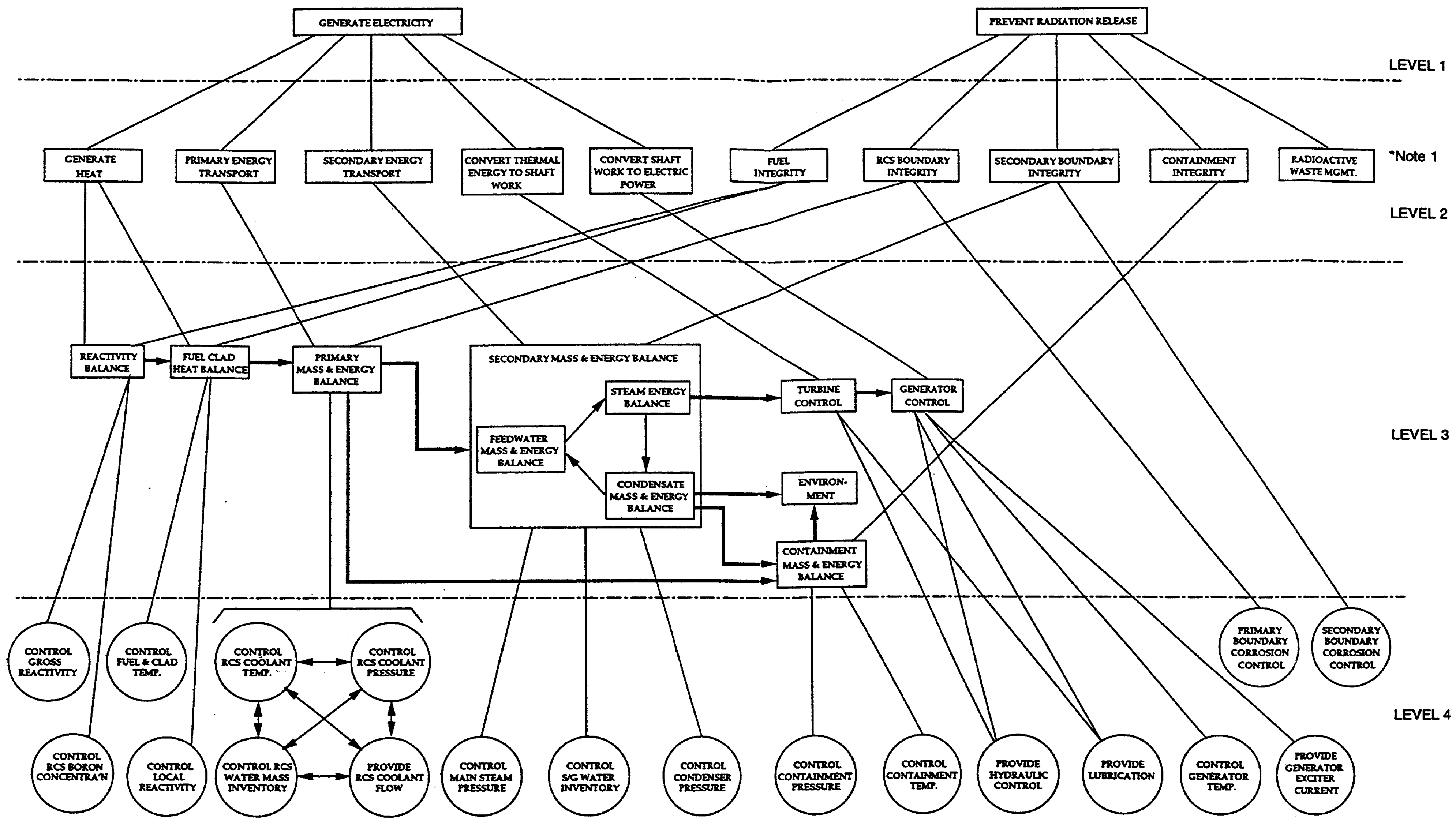
[*12.* *WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Revision 0, July 1996.*]*

[*13.* *WCAP-14651, "Integration of Human Reliability Analysis and Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.



*Note 1: Decomposition and subsequent task analysis of this activity is performed as part of a similar process applied to the radioactive waste control center.

Figure 18.5-1

Top Four Levels of the Normal Power Operation for a Westinghouse PWR

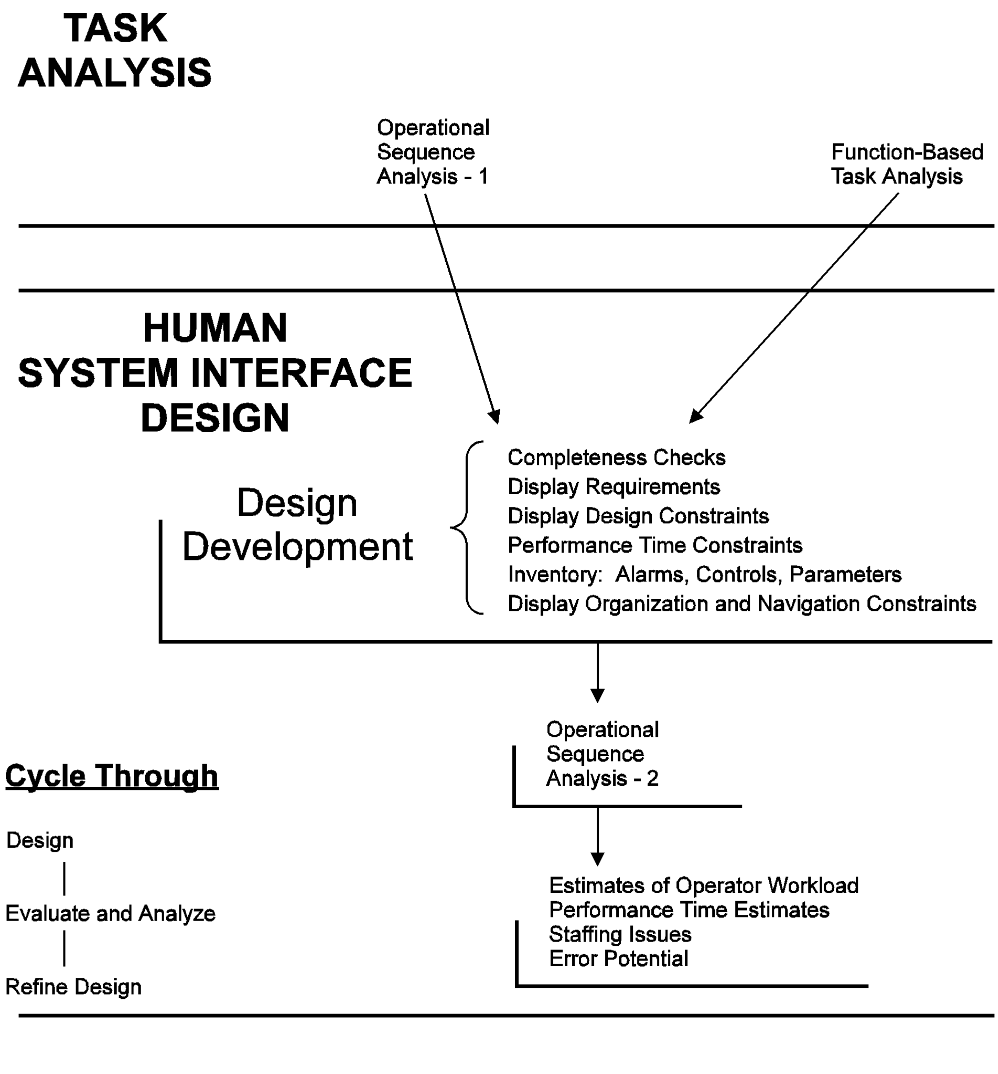


Figure 18.5-2

Task Analysis Utilized as Design Input

18.6 Staffing

Staffing levels and qualifications of plant personnel are a Combined License applicant responsibility. This includes personnel from operations, maintenance, engineering, instrumentation and controls, radiological protection, security, and chemistry. Reference 1 presents input from the designer to the Combined License applicant for the determination of the staffing level of the operating crew in the AP600 main control room. Since the operation of AP1000 is the same as for AP600, this WCAP is provided as input to the AP1000 Combined License applicant.

18.6.1 Combined License Information Item

Combined License applicants referencing the AP1000 design will address the staffing levels and qualifications of plant personnel including operations, maintenance, engineering, instrumentation and control technicians, radiological protection technicians, security, and chemists. The number of operators needed to directly monitor and control the plant from the main control room, including the staffing requirements of 10CFR50.54(m), will be addressed.

18.6.2 References

1. WCAP-14694, "Designer's Input To Determination of the AP600 Main Control Room Staffing Level," Revision 0, July 1996

18.7 Integration of Human Reliability Analysis with Human Factors Engineering

Human reliability analysis (HRA) evaluates the potential for human error that may affect plant safety. There are important interfaces between the human factors engineering program and human reliability analysis. Human reliability analysis makes use of outputs of human factors engineering/HSI design activities including analyses of operator functions and tasks and specifications of HSI characteristics. Human reliability analysis is a source of input to human factors engineering/HSI design in identifying plant scenarios, human actions, and HSI components that are important to plant safety and reliability.

[*The objective of integration of human reliability analysis with human factors engineering is to specify the interfaces between human reliability analysis and human factors engineering activities. Reference 1 documents the implementation plan for the integration of human reliability analysis with human factors engineering design.*]* Execution and documentation of this implementation plan is the responsibility of the Combined License applicant.

[*The objective of the human reliability analysis/human factors engineering integration implementation plan is to enable:*

- *Human reliability analysis activity to integrate the results of the human factors engineering design activities*
- *Human factors engineering design activities to address critical human actions, risk important tasks, and human error mechanisms, in order to minimize the likelihood of personnel error and to provide for error detection and recovery capability*]*

Human reliability analysis methodology and results are described in Chapter 30 of the AP1000 PRA.

18.7.1 Combined License Information

Combined License applicants referencing the AP1000 certified design will address the execution and documentation of the human reliability analysis/human factors engineering integration implementation plan that is presented in Section 18.7.

18.7.2 References

[*1. WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

18.8 Human System Interface Design

This section provides an implementation plan for the design of the human system interface (HSI) and information on the human factors design for the non-HSI portion of the plant. The human system interface includes the design of the operation and control centers system (OCS) and each of the human system interface resources. Execution and documentation of this implementation plan is the responsibility of the Combined License applicant.

The operation and control centers system includes the main control room, the technical support center, the remote shutdown room, emergency operations facility, local control stations and associated workstations for each of these centers. The AP1000 human system interface resources include:

- Wall panel information system
- Alarm system
- Plant information system
- Computerized procedure system
- Soft controls/dedicated controls
- Qualified data processing system

The wall panel information system presents information about the plant for use by the operators. No control capabilities are included. The wall panel information system provides dynamic display of plant parameters and alarm information so that a high level understanding of current plant status can be readily ascertained. It is located at one end of the main control area at a height such that both operators and the shift supervisor can view it while sitting at their respective workstations. It provides information important to maintaining the situation awareness of the crew and for supporting crew coordination. The wall panel information station provides a dynamic plant display of the plant. It also serves as the alarm system overview panel display. The display of plant disturbances (alarms) and plant process data is integrated on this wall panel information system display. The wall panel information system is a nonsafety-related system. It is designed to have a high level of reliability.

The mission of the AP1000 alarm system, together with the other human system interface resources, is to provide the operation and control centers operating staff with the means for acquiring and understanding the plant's behavior. The alarm system improves the performance of the operating crew members, when acting both as individuals and as a team, by improving the presentation of the plant's process alarms. [*The alarm system supports the control room crew members in the following steps or activities of Rasmussen's operator decision-making model (Reference 25):*]*

- The "alert" activity, which alerts the operator to off-normal conditions

- The "observe what is abnormal" activity, which aids the user in focusing on the important issue(s)

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- The process “state identification” activity, which aids the user in understanding the abnormal conditions and provides corrective action guidance. It guides the operating crew into the information display system.

The plant information system is a subset of the data display and processing system (non-Class 1E system), presenting plant process information for use by the operators. The plant information system provides dynamic indications of plant parameters and visual alerts so that an understanding of current plant conditions and status is readily ascertained. The plant information system uses color-graphic video display units located on the operation and control centers workstations to display plant process data. These displays provide information important to monitoring, planning, and controlling the operation of plant systems and obtaining feedback on control actions. The displays provided by the plant information system are nonsafety-related displays, but provide information on both safety-related and nonsafety-related systems.

The computerized procedure system has a mission to assist plant operators in monitoring and controlling the execution of plant procedures. The computerized procedures system is a software system. It runs on the hardware selected for the operation and control centers. The computerized procedure system is accessible from the operator workstations in the main control room. Procedure development, as stated in Section 13.5 and 18.9, is the responsibility of the Combined License applicant. A procedure writer’s guide is developed as part of the human system interface design implementation plan for the computerized procedure system. The writer’s guide is the design guidelines document for the computerized procedure system. Information on the writer’s guide and on the computerized procedure system is found in Reference 31. Application of the computerized procedure system for emergency operating procedures is licensed outside the United States and is being used in an operating nuclear power plant. Additionally, the application of the computerized procedure system for turbine-generator startup and shutdown is being used in another operating nuclear power plant located outside the United States. Human factors engineering review guidance for computer-based procedures is presented by Reference 9. The design of a backup to the computerized procedure system, to handle the unlikely event of a loss of the computerized procedure system, is developed as part of the human system interface design process. Design options include the use of a paper backup. [*The acceptability of the computerized procedure system and its backup will be confirmed as integral elements of the AP1000 design by the implementation of the AP1000 verification and validation program (Reference 24).*]* Procedure development is the responsibility of the Combined License applicant, as stated in Sections 13.5 and 18.9.

The mission of the controls in the main control room is to allow the operator to operate the plant safely under normal conditions, and to maintain it in a safe condition under accident conditions. The main control room includes both safety-related and nonsafety-related controls. The types of controls in the main control room include both discrete (dedicated) control switches and soft controls. The discrete control switches are controls dedicated to a single function, with each switch having a single action. As shown in Figure 18.8-1, the soft control units are control devices whose resulting actions are selectable by the operator. The instrumentation and control architecture uses both discrete control switches and soft control

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

units. The soft control units are used to provide a compact alternative to the traditional control board switches by substituting virtual switches in the place of the discrete switches.

The final configuration of these elements is dependent upon the results of the human system interface design process described in subsection 18.8.1 below.

The mission of the qualified data processing system is to provide a Class 1E system to present to the main control room operators the plant parameters which demonstrate the safety of the plant. The qualified data processing system provides for the display of the variables as described in Section 7.5 through safety-related displays. The informational content of qualified data processing system displays is provided to the remote shutdown workstation through the plant information system.

18.8.1 Implementation Plan for the Human System Interface Design

Figure 18.2-3 provides an overview of the AP1000 human factors engineering process, including the design stages of the human system interface. The relationship of other human factors engineering process elements to the human system interface design is shown.

The functional design of the operation and control centers system and the human system interface is the activity where the functional requirements for the human system interface resources of the main control room and related operation and control centers system are developed. The output of the functional design is a set of documents that specify the mission, design bases, performance requirements, and functional requirements for each human system interface resource. These functional requirement documents are applied to an appropriate set of human factors engineering design guidelines to develop the design specifications. The design specifications are provided as input to the hardware and software system designers for design implementation.

The following subsections describe the activities conducted as part of the human system interface design and the documents that are produced.

18.8.1.1 Functional Design

A system specification document for the operation and control centers system documents and tracks human system interface requirements and design specifications. The operation and control centers system specification document is the umbrella document for capturing human factors requirements and providing a uniform operational philosophy, and design consistency among the individual human system interface resources.

Included in the operation and control centers system specification document are functional requirements and specifications for the AP1000 operation and control centers system, including the main control room, the technical support center, the remote shutdown room, and local control stations. In addition, functional requirement documents are generated for each of the individual human system interface resources. These documents are referenced by the operation and control centers system specification document.

The operation and control centers system specification document and the individual human system interface functional requirement documents include mission statements and performance requirements. The mission statements establish the high level goals and main tasks to be supported by the control center or human system interface resource. Performance requirements represent high level design goals and help to clarify the functional designer's intent. They are high level requirements that may not be readily verifiable by testing or other quantitative means, but are important considerations for meeting the goals defined in the mission statements. The design bases establish the foundation for the design and the rationale behind engineering decisions made and criteria established for the design. Functional requirements include requirements needed to meet the criteria defined in the applicable codes, standards, and customer requirements. The functional requirement documents include requirements to meet failure, diversity, electrical separation, and other applicable criteria; they establish requirements related to access control, redundancy, independence, identification and test capability; they define requirements on system inputs and outputs; they specify the system safety classification and define applicable quality assurance, reliability goals, and environmental qualification requirements. The functional requirements document for each human system interface resource includes a specification of the cognitive activities in the operator decision-making model that the human system interface resource is intended to support.

Reference 25 describes the operator decision-making model and associated operator cognitive activities. As shown in Figure 18.8-2, the HSI interface resources are mapped to four major classes of operator cognitive activities in the model (detection and monitoring, interpretation, control, and feedback).

The contents of this map are then considered in terms of sources of operational complexity that add operator performance demands. The two general sources of complexity considered are 1) use of multiple as opposed to single HSI resources, and 2) increasing situational or scenario-based complexity. Considering the impact of complexity on the mapping leads to "issues"; that is, general cases where adequate human performance should be confirmed.

Table 18.8-1 presents the resulting set of human performance issues. Note that "feedback" issues have been addressed under "control," rather than as a separate activity, because feedback activities follow directly from control activities. These human performance issues serve as input to the development of the performance requirements for the operation and control centers system specification document and to the individual human system interface functional requirement documents. The human performance issues and requirements will be addressed by the verification and validation activities described by Reference 24.

18.8.1.2 Design Guidelines

Guidelines for the human system interface design are developed for each of the human system interface resources to facilitate the standard and consistent application of human factors engineering (HFE) principles to the design. This guidance is contained in a set of standards and conventions guidelines documents that tailor generic human factors engineering guidance to the AP1000 human system interface design and define how those human factors engineering principles are applied.

These guidelines become a tool that enables groups of people to simultaneously develop the human system interface in a consistent manner in accordance with the human factors engineering principles established for the design. [*The guidelines are used to perform the human factors engineering design verification activity of the human factors verification and validation plan (Reference 24).*]*

Human system interface design guideline documents include:

- Anthropometric guidelines
- Alarm guidelines
- Display guidelines
- Controls guidelines
- Computerized procedures guidelines

AP1000 human system interface guideline documents provide:

- Statements of their intended scope, references to source materials, and instructions for their proper use

- Specification of accepted human factors engineering guidelines, standards, and principles to which the AP1000 human system interface conforms

- Specification of design conventions (for example, coding conventions) to which the AP1000 human system interface conforms

- Documentation of deviations from human factors engineering guidelines, standards and principles, and justification based on documented rationale such as trade study results, literature-based evaluations, demonstrated operational experience, and tests and experiments

An illustrative subset of accepted human factors engineering guidelines documents that will be used in compiling human factors engineering guidelines, standards, and principles to be included in the AP600 human system interface guideline documents are found in References 1 through 8. These documents apply directly to AP1000.

18.8.1.3 Design Specifications

Design specifications are written for the operation and control centers system and the human system interface resources. The design specification documents are the result of applying the guidelines to the functional design. They provide the design for each human system interface resource, including the integration of the hardware and software modules, to satisfy the human system interface functional design requirements. Included in these specifications are layout and arrangement drawings, algorithms, display layouts, display task descriptions, navigation mechanisms and resource lists.

The functional requirement documents are used to define the bases for the system design specifications.

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The operation and control centers system specification document and human system interface functional requirements and design specification documents provide input to the generation of instrumentation and control system specification documents, such as the system specification document for the data display and processing system. These specification documents are used as inputs to the hardware and software system designers to generate implementation documents such as hardware and software specifications.

18.8.1.4 Man-in-the-Loop Testing

An integral part of the human system interface design process is the conduct of man-in-the-loop engineering tests to obtain feedback from prototype design products early in the design process.

The use of engineering tests is a good engineering practice, which reflects an iterative design process. By providing feedback early, before the detailed design is complete, engineering tests can help to improve the design and to avoid problems in the final product. Engineering tests also may offer concrete insight on questions that cannot be resolved logically (for example, by guidance or analysis). Finally, results from engineering tests provide evidence of design adequacy. Engineering tests thus serve to increase confidence and reduce project risk in the design process.

Engineering tests are performed to obtain empirical results that can be applied directly to understanding and improving the design product. More specifically, engineering tests are designed to produce the following types of results for the prototype design:

- Design-specific operating experience
- Confirmation of necessary performance and integration
- Identification of specific problems
- Subjective feedback from expert users and observers

[*The man-in-the-loop test plan to obtain feedback from prototype design products early in the design process is defined and documented in Reference 46*.]* The results of the engineering testing are used to refine the design of the operation and control centers system and the human system interface.

18.8.1.5 Mockup Activities

A mockup of portions of the main control room working area is constructed as part of the human system interface design process. The partial mockup consists mainly of non-operational representations of the desks, displays, and panels. The mockups are constructed to the anthropometric profiles and arranged in the floor layout intended for the main control room.

The partial mockup is used to examine and verify, as needed, physical layout aspects such as availability of workspace, physical access, visibility, and related anthropometric and human factors engineering issues. It will also be used for walk-through exercises to examine issues such as staffing levels, task allocation, and procedure usage.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

18.8.1.6 Human System Interface Design Documentation

The human system interface design is documented through a system specification document for the operation and control centers system, functional requirement documents, design criteria documents, design review documents, and documentation of design configuration change control.

18.8.1.7 Task-Related Human System Interface Requirements

As shown in Figure 18.2-3, the results of other human factors engineering program elements are used as input and bases for developing the operation and control center system and human system interface resources functional design (mission statements, performance requirements, design basis, functional requirements), guideline documents and the design specification documents. Staffing assumptions, operating experience reviews, functional requirements analysis and allocations, task analysis, and integration of human reliability analysis provide the bases for identifying the human system interface requirements needed to support human functions and tasks. The resulting human system interface requirements are documented in the human system interface resource functional design documents (operation and control centers system specification document and the individual human system interface resource functional requirements document), guidelines document and design specification documents. Subsections 18.8.1.1 through 18.8.1.3 provide descriptions of these documents.

The AP1000 task analysis, described in Section 18.5, includes two complimentary activities: function-based task analysis (FBTA) and traditional task analysis, or operational sequence analysis (OSA). The function-based task analysis identifies the indications, parameters, and controls that the operator needs to make decisions about the respective function. There is also a verification that the indications and controls identified in the process analysis are included in the design. The operational sequence analysis, completed as part of the task analysis process, focuses on specifying the operational requirements for the complete set of tasks selected. One of the guidelines used in selecting tasks for analysis are those tasks that represent the full range of activities in the AP1000 emergency response guidelines. One type of information provided by the operational sequence analysis is an inventory of alarms, controls, and parameters needed to perform the task sequences. The operational task analysis results include the identification of controls, alarms, and parameters needed by the operator to execute task sequences found within the emergency response guidelines. These results serve as a cross-check with the function-based task analysis results. Design reviews held during the human system interface design serve as another means of verifying completeness and identifying and correcting omissions. [*The task support verification activity of the human factors verification and validation (Reference 24) verifies that the human system interface design provides the necessary alarms, displays, and controls to support personnel tasks.*]*

The collective results of the task analysis activities identify the tasks and operational information needed by the operator to execute these tasks. For each display, a display task description is written. The display task description includes the identification of the informational needs to be supported by the display. The features, dynamic characteristics, calculated values, and supporting algorithms for the display are part of the display task description. The design specification of a display includes the range, precision, and

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

measurement units of the parameters provided in the display. These parametric characteristics are chosen to support the task and the operator informational needs. The parametric characteristics, identified in the design specification, are provided using the guidelines presented in the design guidelines document for displays. The basis for the parametric characteristics chosen for the displays is found in the design guidelines document.

18.8.1.8 General Human System Interface Design Feature Selection

The AP1000 human system interface resources include the wall panel information system, alarm system, plant information system, computerized procedure system, controls, (soft and dedicated) and the qualified data processing system. These human system interface resources are used as a starting point to define how the human system interface supports operator performance. [*Reference 25 describes the operator decision-making model that is used by the task analysis activities to identify the operator's information and control requirements*.]* The human system interface resources are mapped to the major classes of operator activities identified from this model. Figure 18.8-2 illustrates this mapping. The human performance requirements that each human system interface resource supports are identified as part of the design process.

The human system interface resources are chosen based upon utility requirements and review of operating experience. The goal of the human system interface design is to provide the operators with effective means for acquiring and understanding plant data and executing actions to control the plant's processes and equipment. Through implementation of the human system interface design process, the identified AP1000 human system interface resources are developed.

Design alternatives for a feature within an human system interface resource (such as the use of a mouse, trackball, or touchscreen for soft controls) are evaluated. A decision is made based upon evaluation methods including human factors/trade-off studies, reviews of nuclear industry operating experience or reviews of other industry experience, experience gained from past projects, and utility input. The basis and rationale for the decisions are provided in the functional design documentation.

18.8.1.9 Human System Interface Characteristics: Identification of High Workload Situations

Identification of high operator workload situations and their consequent changes in operator response times or likelihood of operator error, is a usability issue. Potential impact on operator workload is a criterion in selecting the human performance issues identified in Table 18.8-1.

Identification of high-workload situations through analytic techniques and part-task simulations, is part of the human factors engineering program (Section 18.5 on Task Analysis).

Use of Workload Measurement Techniques

As part of task analysis activities (Section 18.5), analytic approaches are used to estimate workload. Analytic methods include the use of computer-based models of cognitive

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

responses to control room events. This tool or functionally similar tools are used to support workload analysis.

Usability Guidance

Design guideline documents are developed that synthesize results of reviews of the relevant human system interface literature and experience in nuclear power plants and related industries. These documents contribute to the design basis for design of human system interface resources. For example, the use of soft controls in the design of the AP1000 human system interface builds on existing human system interface guidelines and experience with the use of "soft controls" in existing plants (fossil plants).

Workstation Usage Scenarios

The physical layout of the AP1000 control room and related control centers follows established ergonomic guidelines including consideration of fatigue and alertness of operators sitting at workstations.

Environmental Conditions

Determination of environmental conditions (lighting, noise, ambient working temperatures, radiation, air quality, and humidity) in the control room, the remote shutdown room, and at local control stations employ well-accepted standards from the fields of industrial and human engineering such as References 14, 15 and 16. Relevant guidance from prior studies in the nuclear power area (References 17 through 20) is also used.

The worst credible conditions that can be encountered by operators in the main control room are identified as outcomes of design basis scenarios. Effects on operator performance and the effects of extremes of habitability during degraded conditions are considered in the design specification.

Local Control Actions

Critical human actions and risk important tasks are identified by the probabilistic risk assessment/human reliability analysis process. [*Reference 23 presents the process of identifying the critical human actions and risk important tasks and the implementation plan for integrating human reliability analysis into the human factors engineering program*.]* Critical human actions or risk important tasks are examined by task analysis, human system interface design, and procedure development, to identify changes to the operator task or the control and display environment to reduce or eliminate sources of error.

18.8.1.10 Human System Interface Software Design and Implementation Process

This subsection describes the software design, implementation, and verification process established to verify that human system interface functional requirements are implemented by the software. The software design, implementation, and verification process uses a top-down approach to incorporate the system design requirements and the functional requirements into software module design.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Software refers to the computer instructions and information provided to implement a subset of the human system interface functional requirements. The software design and implementation process is a subset of the overall human system interface design process. It consists of system software design specifications, software design, software implementation, and software verification.

The system software design specification activity takes as its input the system functional requirement and specification documents and produces software design requirements documents and the software verification test procedures. Software design requirements documents list the functions, performance, design constraints, and attributes of the system software.

The software design activity takes software design requirements and produces software design specification documents. Software design specification documents provide the details for the software design at the module level and assembly level. These documents define the software language, logical structure, variable names, information flow, logical processing steps, and data structure of the system software programs. They also describe the functions performed, support software, storage and execution limitations, interface constraints, error conditions, error detection, error response actions, and details of the software operation in the hardware environment.

The software implementation activity implements the software design specifications in the form of documented source programs and object code. The source program and associated documentation contain the comments, functional diagrams, external references, and internal module descriptions.

The object code is generated from the source program and installed in processor memory to perform the functions specified by the software design specifications.

In the software verification testing activity, the software is tested to verify that it complies to the system software design requirements. The software is tested according to the software verification test procedures.

Nonconformances of the software to the software verification test procedures are documented by trouble reports, and changes are made. In the case where the error is a result of an error in the system software design requirements or the software design specifications, these documents are revised. The software test results report presents a summary of the software verification testing results.

18.8.2 Safety Parameter Display System (SPDS)

[*The Safety Parameter Display System is designed following the human system interface design implementation plan*]* described in subsection 18.8.1. [*The Safety Parameter Display System is integrated into the design of the AP1000 human system interface resources*.]*

As noted in Section 4.1.a of Reference 27 "...the principle purpose and function of the Safety Parameter Display System is to aid the control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether

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abnormal conditions warrant corrective action by operators to avoid a degraded core. This can be particularly important during anticipated transients and the initial phase of an accident." Since the main intended use is during relatively rare occurrences, human-factors engineering suggests that the operators will find that the use of data acquisition habits acquired and repeated during the normal operation of the plant will be the most successful. A system in the control room that only varies its output during abnormalities may require a shift in mental focus and in data acquisition habits and subsequent analysis. An effective means for conveying the safety state of the plant is to provide data and displays for normal operation that employs the Safety Parameter Display System required principles for data synthesis, concentration and display. This operator interface is operational over the range of plant conditions specified by the Safety Parameter Display System requirements, as well as during normal operations.

The operator-interface to the plant is improved by integrating Safety Parameter Display System requirements into the overall human system interface design to avoid the need for another system that is infrequently used.

The following subsections describe [*the approach to meeting the regulatory requirements for a Safety Parameter Display System by addressing the Safety Parameter Display System requirements of References 26 and 27.*]*

18.8.2.1 General Safety Parameter Display System Requirements

The AP1000 human system interface resources used to address the Safety Parameter Display System requirements are the alarm system, plant information system (workstation visual display unit displays), and the computerized procedure system. The AP1000 human system interface data display (alarms and visual display unit displays) is organized around the Safety Parameter Display System requirement of plant process functions. Expressing plant state in terms of process functions is incorporated in the AP1000 control room design. This is expected to improve the human interface by making the data presentation interface seamless as the plant moves from one operational state to another.

An alarm system which organizes the presentation of alarms by process function and adapts a "dark board" approach (for all plant modes) continually indicates the state of each of the functions. By remaining dark when the process is performing as expected, the process functions are interpreted as being satisfied. An alarm indication displayed in any function indicates that the function is in jeopardy. In this way, the set of alarms that is active is the minimum set. The alarm system is capable of displaying a full range of alarms based on important plant parameters and data trends. The alarms indicate when process limits are being approached and exceeded.

Section 18.7 and [*Reference 23 present an implementation plan for integrating the human reliability analysis with human factors engineering.*]* The critical human actions and the risk important tasks identified through the execution of this plan are used as an input to the task analysis activities and subsequently to the design of the human system interface. They are also used to evaluate the Safety Parameter Display System functions and parameters selected to monitor these functions. The human system interface, which includes the integration of

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Safety Parameter Display System requirements, is designed to reduce the likelihood of operator error and provide for error detection and recovery capability for the identified critical human actions and risk important tasks.

18.8.2.2 Display of Safety Parameters

The functionally organized plant information system displays, including the Safety Parameter Display System-related displays, are accessed on the workstation visual display units (VDU) using a cursor. The AP1000 operator workstations employ a windowing system which allows a single cursor to cover the visual display unit screens. The design allows the operator to recover a specific parameter within one or two actuations of the pointing device.

The design goal for the AP1000 human system interface is to update the displays every 1 to 2 seconds. The process data sampling rate is 1 second or less. Sequence of events (SOE) points can be sampled at a rate of once every milli-second and are available within the AP1000 human system interface. The Safety Parameter Display System responds to user commands in less than 10 seconds. The design goal for graphical display response time, from user command to developed graphical display, in the AP1000 human system interface is 2 seconds.

The AP1000 alarm system includes plant overview alarms that are organized around the concept of plant process functions. These process functions address the five SPDS functions. The alarm system overviews, including the functional organization, are integrated into the wall panel information system displays.

During the execution of emergency operating procedures, the computerized procedure system provides a continuous display of the status of each critical safety function.

The Safety Parameter Display System data and data display organization are available to the control room staff.

[*The AP1000 human system interface process display set (from the plant information system) is organized into two hierarchies that are linked together. One is focused upon providing the process data from a functional perspective and the other from a physical perspective. Both follow the concept of abstraction/aggregation suggested by Rasmussen as described in Reference 25. Top levels in the hierarchy are plant wide summaries, lower levels are component details. The hierarchy is structured so as to reflect the plant process functional decomposition performed during the function based task analysis described in Reference 25*.]*

Process display presentation for the control room users is organized by functions. The function based task analysis integrates the functional organization design principles dictated by the Safety Parameter Display System requirements into the AP1000 human system interface.

Plant process displays and plant controls necessary to operate the plant are located on each of two redundant workstations. These two reactor operator workstations are in the main control area of the AP1000 control room.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Because the Safety Parameter Display System requirements are an integral part of the AP1000 human system interface design, the Safety Parameter Display System workstation is the AP1000 human system interface control room workstation, the Safety Parameter Display System displays are the workstation displays; and the display accessing “controls” used to access Safety Parameter Display System displays are the same as those used to access any workstation display.

Safety Parameter Display System-related information is physically displayed such that the information can be read from the Safety Parameter Display System user’s position. Each reactor operator’s workstation contains the human system interface operator process displays. The control room supervisor (shift foreman) has an independent workstation that has the operator process displays. The wall panel information system is available to the main control room staff.

The AP1000 human system interface provides the status of the Safety Parameter Display System functions. The Safety Parameter Display System functions include:

- Reactivity control
- Reactor core cooling and heat removal from the primary system
- Reactor coolant system integrity
- Radioactivity control
- Containment conditions

The AP1000 alarm system provides overview alarms addressing the five Safety Parameter Display System functions. These overview alarms, integrated into the wall panel information system displays, are continuously displayed. Most of the safety parameters used to monitor the status of each Safety Parameter Display System function are continuously displayed on the wall panel information system displays. Those that are not continuously displayed on the wall panel are accessible at the operator’s workstation through one navigational action. During the execution of emergency operating procedures, the AP1000 computerized procedure system provides a continuous display of the status of the critical safety functions.

Safety Parameter Display System-related information is physically displayed such that the information is readable from the reactor operator workstation. Each reactor operator’s workstation contains the plant information system process displays. The control room supervisor (shift foreman) has an independent workstation that also has the process displays. The wall panel information system is available to the main control room staff.

18.8.2.3 Reliability

The AP1000 instrumentation and control (I&C) systems, including the human system interface, have reliability/availability design criteria. A description of the instrumentation and control system design features is found within Section 7.1.

The human system interface design includes the capability to build password or key-lock accessibility on the human system interface database. In addition, the system carries and displays data quality on the data in the system.

The alarm overviews integrated into the wall panel information system include indication of the operability of the alarm system itself.

18.8.2.4 Isolation

The Safety Parameter Display System as integrated into the overall human system interface is isolated from safety systems. Electrical isolation devices are discussed in subsection 7.1.2.

18.8.2.5 Human Factors Engineering

Section 5 of Reference 28 presents the need for human-factors engineering in the design of the Safety Parameter Display System. The Safety Parameter Display System is designed using the implementation plan described in subsection 18.8.1. [*This implementation plan includes the application of human factors engineering principles that address the criteria of the Human Factors Engineering Program Review Model (Reference 29).*]*

The AP1000 main control room and human system interface design reduces the number of individual computerized operator support systems by incorporating the requirements of the Safety Parameter Display System into the design requirements for the AP1000 human system interface. This is accomplished primarily by those human system interface resources that produce and display the process abnormality alarms and the process graphical visual display units.

Parameter units of measure, labels, and abbreviations displayed by the human system interface resources are consistent with the units of measure, labels, and abbreviations included in the emergency operating procedures.

The human system interface displays information is in a form that does not require transformation or calculation. High- and low-level setpoints are consistent with the reactor protection system setpoints. The high- and low-level setpoints are visible in both the messages created by the AP1000 alarm system and on the indications, trends and graphs that appear as part of the process displays of the AP1000 plant information system.

Consistency of calculated values, such as subcooling margin, is maintained. The AP1000 instrumentation and control and human system interface architecture shares process data through a database.

The technical basis for software specifications are verified with plant data (for example, heat-up and cool-down limits, steam generator setpoints and high- and low-level alarm setpoints). The AP1000 human system interface is designed so that the plant data is a separate data file independent of the software specifications.

18.8.2.6 Minimum Information

The AP1000 human system interface resources used to address the Safety Parameter Display System requirements are the alarm system, plant information system, and the computerized procedure system. The AP1000 human system interface displays sufficient information to determine plant safety status with respect to the Safety Parameter Display System safety

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

functions. [*The safety functions and respective parameters presented in Table 2 of Reference 32 are used as a starting point for the AP1000.*]* The human system interface design implementation plan is described in subsection 18.8.1 and includes the integration of Safety Parameter Display System requirements into the human system interface. [*The Safety Parameter Display System design issue of "minimum information" is tracked by the human factors engineering issues tracking system.*]*

18.8.2.7 Procedures and Training

As stated in Sections 13.2 and 13.5, the development of training programs and plant procedures are the responsibility of the Combined License applicant. Reference 30 describes how training insights are passed from the designer to the Combined License applicant. Reference 31 provides input to the Combined License applicant for the development of plant operating procedures.

18.8.3 Operation and Control Centers System

The human system interface includes the design of the operation and control centers system. The design of each of these control centers is conducted using the human system interface implementation plan presented in subsection 18.8.1. The mission for each of the operation and control centers in the AP1000 is provided in the following subsections. Coupled with each mission statement is a brief description of the major tasks and design features that are supported by that center.

18.8.3.1 Main Control Room Mission and Major Tasks

The mission of the main control room is to provide a seismically qualified habitable and comfortable location for housing the resources for a limited number of humans to monitor and control the plant processes.

The major tasks performed in the main control room include monitoring, supervising, managing, and controlling those aspects of the plant processes related to the thermodynamic and energy conversion processes under normal, abnormal, and emergency conditions. Operating staff can monitor, supervise, manage, and control processes that have a real-time requirement for protecting the health and safety of operating personnel. The main control room supports the operator's decision-making process, and promotes the interaction with other plant personnel, while preventing distractions by non-operating personnel. The main control room provides the interfacing resources between the operation of the plant and the maintenance of the plant. Its areas include the main control area, the switching and tagging area, the shift supervisor's office, the shift supervisor's clerk's office, and the operations staff's area (see Figure 1.2-8). Habitability systems are described in Sections 6.4 and 9.4.

18.8.3.2 Main Control Area Mission and Major Tasks

[*The mission of the main control area is to provide the support facilities necessary for the operators to monitor and control the AP1000 efficiently and reliably. Figure 6.4-1 provides a view of the main control area. The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

information system. The layout, size and ergonomics of the operator workstations and the wall panel information system depicted in this figure does not reflect the results of the human system interface design implementation plan]* described in subsection 18.8.1. The actual size, shape, ergonomics and layout of the operator workstations and the wall panel information system is an output of the implementation plan.

[*The major task of the main control area is to provide the human system interface resources that determine the plant state and implement the desired changes to the plant state during both normal and emergency plant operations. The main control area provides alarms to alert the operator to the need for further investigation. Plant process data displays permit the operator to observe abnormal conditions and identify the plant state. The controls enable the operator to execute actions. The process data displays and the alarms provide feedback to enable the operator to observe the effects of the control actions.*

Each reactor operator workstation contains the displays and controls to start up the plant, maneuver the plant, and shut down the plant.]* Reference 44 presents input from the designer to the Combined License applicant for the determination of the staffing level of the operating crew in the main control room. [*Each workstation is designed to be manned by one operator. There is sufficient space and operator interface devices for two operators. The physical makeup of the reactor operator workstations is identical. The human system interface resources available at each workstation are:*

- *Plant information system displays*
- *Control displays (soft controls)*
- *Alarm system support displays*
- *Computerized procedure displays*
- *Screen and component selector controls*

The supervisor workstation is identical to the reactor operator workstations, except that its controls are locked-out. The supervisor workstation contains both internal plant and external plant communications systems.

Upon failure of a reactor operator workstation, the failed workstation is locked out, and the supervisor workstation controls are unlocked. This modified workstation configuration maintains independent, redundant workstations.

A dedicated safety panel is located in the main control area. The qualified data processing system visual display units and the dedicated safety system controls are provided in this panel. These visual display units are the only monitoring display devices in the main control room that are seismically qualified and provide the post-accident monitoring capabilities in accordance with Regulatory Guide 1.97. Dedicated system-level safety system control switches are located on the dedicated safety panel to provide the operators with safety system actuation capabilities.]* A minimum inventory of these dedicated displays and controls are presented in Section 18.12.

[*There is storage space for supplies, protective clothing and some spare parts. Cabinets are provided for necessary documents, and a drawing laydown area is provided for the*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

operators' use. Restroom and kitchen facilities are provided for the main control room operations crew.]*

18.8.3.3 Switching and Tagging Area Mission and Major Tasks

The mission of the switching and tagging area is to provide an interface between plant maintenance and plant operations personnel. Figures 1.2-8 and 6.4-1 provide the layout of the switching and tagging area. The operations staff monitors and approves the state of systems, major components, and equipment. The maintenance staff is informed of maintenance required by the operations staff. The means for initiating, tracking, and logging maintenance work orders is provided.

The major task of the switching and tagging area is to ease the management and implementation of the switching and tagging operations. The switching and tagging area generates notifications that equipment is not available due to testing, maintenance, or equipment failure. These notifications alert plant operating personnel to the unavailability of equipment. Notifications are provided to plant maintenance personnel, alerting them that operating personnel are aware of the equipment status. The switching and tagging area facilitates a systematic and organized approach to removing equipment from service as well as returning it to service.

18.8.3.4 Remote Shutdown Workstation Mission and Major Tasks

[*The mission of the remote shutdown workstation is to provide the resources to bring the plant to a safe shutdown condition after an evacuation of the main control room. The remote shutdown workstation resources are based on an assumed evacuation of the main control room without an opportunity to accomplish tasks involved in the shutdown except reactor trip.*]* Subsection 7.4.3 discusses safe shutdown using the remote shutdown workstation, including design bases information.

18.8.3.5 Technical Support Center Mission and Major Tasks

The mission of the technical support center (TSC) is to provide an area and resources for use by personnel providing plant management and technical support to the plant operating staff during emergency evolutions. The TSC relieves the reactor operators of peripheral duties and communications not directly related to reactor system manipulations and prevents congestion in the control room.

Communications needs are established for the staff within the TSC, and between the TSC and the plant (including the main control room and operational support center), the emergency operations facility, the Combined License holder management, the outside authorities (including the NRC), and the public.

The design includes adequate shielding as discussed in Chapter 12. Adequate space, resources and access is provided for maintenance, emergency equipment and storage.

Consistent with NUREG 0737, the technical support center is nonsafety-related and is not required to be available after a safe shutdown earthquake.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The size of the TSC complies with the size requirements of Reference 28. The TSC is located adjacent to the passage from the annex building to the nuclear island control room as shown in Figure 1.2-19. [*The TSC complies with the habitability requirements of Reference 27 when electrical power is available.*]*

When a source of ac power is available, the nuclear island nonradioactive ventilation system (VBS) provides HVAC service to the main control room and the TSC during normal and abnormal conditions. The VBS and its support systems provide these functions in a reliable and failure tolerant fashion. If offsite power is not available, backup power is automatically provided by either of the two nonsafety-related diesels within the onsite standby power system. Subsection 9.4.1 provides additional design details of the VBS.

The VBS system provides for cooling, heating, humidity control, filtration, (HEPA and charcoal), and pressurization following design basis accidents except for a station blackout (loss of nonsafety-related ac power, including the nonsafety-related diesels). If nonsafety-related ac power is not available, including the diesels, the habitability of the main control is provided by the main control room emergency habitability system (VES) as discussed in Section 6.4. Although the TSC is not supplied by either the VBS or the VES during a station blackout, it still remains habitable. The doors to the TSC can be opened to aid with ventilation and control of room temperature for the two hours that the workstations continue to operate. The TSC workstations are powered from the non-Class 1E uninterruptable power supplies, therefore plant monitoring capability from the TSC exists for two hours following a station blackout.

Should habitability be challenged within the TSC due to lack of cooling or a high radiation level resulting from a beyond-design-basis accident, the plant management function of the TSC is transferred to the main control room.

The Combined License applicant is responsible for the EOF design, including the specification of its location (subsection 18.2.6) and emergency planning, and associated communication interfaces among the main control room, the TSC, and the EOF (Section 13.3).

Subsection 18.2.1.2 provides a description of assumptions and constraints, including utility requirements, that are used as inputs to the human factors engineering program and the human system interface design. As stated earlier under Section 18.8, the human system interface design includes the design of the operation and control centers system (main control room, TSC, remote shutdown room, emergency operations facility, local control stations and associated workstations) and each of the human system interface resources. The main control room design (environment, layout, number and design of workstations) supports emergency operations with a maximum crew compliment consisting of eleven individuals. These eleven include two individuals with senior reactor operator licenses, three with reactor operator licenses, one observer from the NRC, one from the plant owner's management and one communicator.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[*The design of the TSC's interfaces is included with the design of the human system interface*.]* Subsection 18.8.1 provides an implementation plan for the design of the human system interface. As shown in Figure 18.2-3, the results of the human factors engineering program elements are used as input and bases for developing the operation and control center system and human system interface resources functional design. This includes task analysis. Section 18.5 provides the implementation plan for the task analysis activities.

The non-Class 1E dc and uninterruptable power supply system provide approximately two hours of backup power supply to the TSC displays should offsite power and both diesels fail. The probability of the loss of all ac is calculated based on the probability of a loss of offsite power and the probability of both diesel generators failing (Reference 45).

18.8.3.6 Operational Support Center Mission and Major Tasks

The operational support center (OSC) is not within the scope of the human factors engineering program, but it is an emergency response facility. The mission of the operational support center is to provide a habitable area for operations support personnel and the resources to coordinate the assignment of duties and tasks to personnel outside of the main control room and the technical support center in support of plant emergency operation. The operational support center and the TSC are in different locations in the annex building. The location of the operational support center is shown in Figure 1.2-18.

The major task of the operational support center is to provide a centralized area and the necessary supporting resources for the assembly of predesignated operations support personnel during emergency conditions. The operational support center provides the resources for communicating with the main control room and the technical support center. This permits personnel reporting to the operational support center to be assigned to duties in support of emergency operations.

18.8.3.7 Radwaste Control Area Mission and Major Tasks

The mission of the radwaste control area is to provide a habitable area and the appropriate resources for the operation of the radwaste processing systems. These resources include alarms, displays, controls, and procedures. These resources are located in a control area outside of the main control room.

18.8.3.8 Local Control Stations Mission and Major Tasks

The mission of local control stations is to provide the resources, outside of the main control room, the remote shutdown room, and the radwaste control area, for operations personnel to perform monitoring and control activities. The capability to access displays and controls (controls as assigned by the main control room operators) for local control and monitoring, from selected locations throughout the plant, is provided. Activities that are implemented through local control stations are reviewed to verify that their removal from the main control room is consistent with the operator staffing and performance considerations. Human system interface locations are provided for single task operations such as the operation of a manual valve.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

18.8.3.9 Emergency Operations Facility

As stated in subsection 18.2.6, the Combined License applicant is responsible for designing the emergency operations facility, including specification of the location, in accordance with the AP1000 human factors engineering program.

18.8.4 Human Factors Design for the Non-Human-System Interface Portion of the Plant

18.8.4.1 General Plant Layout and Design

The AP1000 design process incorporates a human engineering approach to operations and maintenance. Maintainability design guidelines and human factors and as-low-as-reasonably-achievable (ALARA) checklists are used to meet the requirements of a human engineered environment. The design objectives include reducing worker exposure and eliminating unnecessary inspection and maintenance tasks.

18.8.4.1.1 Maintainability

Design features such as component selection, layout and standardization increase the probability that targeted repair times are achieved. These features coupled with a preventative maintenance program help the AP1000 meet its objectives for operation and maintenance. Design requirements from the utility industry and industry design practices establish criteria for layout, changeout, and replacement for parts and components; access for major pieces of equipment; and vehicle passage.

Critical path outage models are prepared for the AP1000. A typical refueling and maintenance outage schedule is used by design engineers. The model indicates maintenance windows for major outage events. Maintenance and testing of equipment and necessary plant operations (for example, refueling, heatup, and cooldown) are scheduled within the outage window.

18.8.4.1.2 Accessibility and Equipment Laydown Provisions

AP1000 maintainability design guidelines assist designers in identifying top-level layout requirements for equipment accessibility. Component engineers specify space requirements for routine maintenance, inservice inspection, testing and component replacement.

Frequency of inspection and maintenance dictates whether permanent platforms, ladders, and scaffolding are provided.

Overhead access is considered when equipment or tooling must be lifted into place or supported by a crane. Removable floor gratings and plugs are examples of features that provide overhead accessibility.

Permanent lifting devices are provided to enhance maintainability.

The use of robotics and automated devices are considered in the AP1000 design.

Robotic devices, such as refueling cavity decontamination units, are considered in the layout of the refueling cavity so that such interferences as light fixtures, tool hangers and personnel ladders are removable or do not affect the use of the robotic units.

Valve space enveloping drawings indicate the minimum space requirements. Equipment and module designers locate and arrange the valves to maintain the required space envelope.

The turbine-generator contains built-in features to increase accessibility for in-place inspection and maintenance. Access ports in the turbine housings allow routine inspections to be performed without dismantling the turbine casing. Laydown area is provided in the turbine building to access components and to allow for concurrent work.

18.8.4.1.3 Lighting

The AP1000 normal and emergency lighting system is designed to provide illumination levels required for the safe performance of plant operation under normal and emergency conditions.

18.8.4.1.4 Radiation Protection and Safety

The AP1000 design process incorporates radiation exposure reduction principles to keep worker dose ALARA. ALARA checklists are used in design evaluations. Exposure length, distance, shielding, and source reduction are the fundamental criteria incorporated into the design process.

Design features such as readily detachable insulation, as-built smooth surfaces for non-destructive examination, and “modular type” replacement components reduce worker time in radiation areas.

The large AP1000 containment vessel provides laydown space to transfer subcomponents to storage areas until needed. The reactor head is remotely located on the operating deck to reduce background radiation to refueling personnel.

Provisions for remotely operated tooling are considered during the design process. Space is provided to clean and inspect the reactor vessel O-ring grooves using a remotely operated device. Remotely controlled radiation and surveillance equipment is considered for high radiation areas.

Special provisions for radiation shielding are included in the AP1000 design. Permanent shielding built into the integrated head package reduces worker exposure resulting from the incore instrumentation operation.

Material selection and surface conditioning are important elements in radiation exposure reduction. Electropolishing of surfaces exposed to reactor coolant primary water is considered to reduce crud deposits and aid in decontamination.

The AP1000 radioactive waste processing facilities are designed to concentrate radioactive waste processing and drumming activities in remote areas to reduce contact with the majority of plant personnel.

18.8.4.1.5 Communication

The AP1000 communication system provides voice communication during normal operations, plant outages, and emergency operations. The system includes broadcast of alarm signals in plant-wide emergency situations. The wireless telephone system enables plant personnel to remain in direct communication via wireless, hand-carried telephones throughout the plant. Headset-style telephones are available for individuals requiring hands-free operation. Some communication devices have built-in compatibility with protective clothing including respirators.

A paging system is used as a backup to the wireless telephone system. In the event of a failure of the wireless system, personnel communicate via a plant-wide broadcast and five party lines. Emergency broadcasts are announced through this system.

Communication during AP1000 refueling and maintenance outages is enhanced by a sound-powered communication system. Refueling, maintenance, and cold shutdown loops are provided. Jacks are placed in locations where plant personnel are located during these activities.

A private automatic branch exchange system is capable of duplex voice communication between stations. These telephones are placed in acoustic booths in those areas having high ambient noise levels to improve user interface. See subsection 9.5.2 for information on the communication system.

18.8.4.1.6 Temperature, Humidity, Ventilation

Radioactive and nonradioactive ventilation systems are provided in required areas. The ventilation systems are designed to control the environment within the plant and to protect the environment outside the plant. Requirements for temperature, humidity, and ventilation vary, depending on work location, frequency of use, and work description.

18.8.4.1.7 Emergency Equipment

Emergency equipment for treatment of injured personnel is placed in appropriate locations. Provisions for emergency equipment are considered during plant layout.

18.8.4.1.8 Storage

Storage facilities are identified in the AP1000. Radioactively clean and contaminated storage areas are designated.

18.8.4.1.9 Coding and Labeling

Equipment located in the AP1000 has a unique identifier and plant descriptive name. The configuration management system includes the identification of the equipment in the plant. Each component is assigned an identifier during the design process. The identifier is maintained through manufacturing, construction, and operation. The components are labeled according to the assigned identifier. These labels help avoid errors in operating or working on the wrong equipment and in reporting problems or conditions observed in the plant. The labels help reduce the training burden for operating and maintenance personnel.

Color, syntax, abbreviations and symbols are consistently applied. The labels are located in an easily visible location on the component and are not hidden by insulation, equipment covers, or surrounding equipment. Labels are fastened to the component to prevent easy detachment of the label.

18.8.5 Combined License Information

Combined License applicants referencing AP1000 certified design will address the execution and documentation of the human system interface design implementation plan that is presented by Section 18.8.

18.8.6 References

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20. International Electrotechnical Commission, "Operating Conditions for Industrial-Process Measurement and Control Equipment," IEC Standard 654-1, 1979.

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22. 29CFR1910, "Occupational Safety and Health Standards," 1975.

[*23. WCAP-14651, "Integration of Human Reliability Analysis With Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

[*24. WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Revision 2, October 2003.*]*

[*25. WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Revision 0, July 1996.*]*

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*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 18.8-1 (Sheet 1 of 2)

[HUMAN PERFORMANCE ISSUES TO BE ADDRESSED BY THE HSI DESIGN]*

Operator Activity: Detection and Monitoring

Issue 1: Do the wall panel information system and the workstation summary and overview displays support the operator in maintaining an awareness of plant status and system availability without needing to search actively through the workstation displays?

Issue 2: Does the wall panel information system support the operator in getting more detail about plant status and system availability by directed search of the workstation functional and physical displays?

Issue 3: Do the HSI features support efficient navigation to locate specific information?

Issue 4: Do the HSI features effectively support crew awareness of plant condition?

Operator Activity: Interpretation and Planning

Issue 5: Does the alarm system convey information in a way that enhances operator awareness and understanding of plant condition?

Issue 6: Does the physical and functional organization of plant information on the workstation displays enhance diagnosis of plant condition and the planning/selection of recovery paths?

Issue 7: Does the integration of alarms, wall panel information system, workstation, and procedures support the operator in responding to single-fault events?

Issue 8: Does the integration of alarms, wall panel information system, workstation and procedures support the operator in interpretation and planning during multiple-fault events?

Issue 9: Does the integration of alarms, wall panel information system, workstation and procedures support the crew in interpretation and planning during multiple-fault events?

Issue 10: Does the integration of alarms, wall panel information system, workstation, and procedures support the crew in interpretation and planning during severe accidents?

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 18.8-1 (Sheet 2 of 2)

[HUMAN PERFORMANCE ISSUES TO BE ADDRESSED BY THE HSI DESIGN]*

Operator Activity: Controlling Plant State

Issue 11: Do the HSI features support the operator in performing simple, operator-paced control tasks?

Issue 12: Do the HSI features support the operator in performing control tasks that require assessment of preconditions, side effects and post-conditions?

Issue 13: Do the HSI features support the operator in performing control tasks that require multiple procedures?

Issue 14: Do the HSI features support the operator in performing event paced control tasks?

Issue 15: Do the HSI members features support the operator in performing control tasks that require coordination among crew?

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

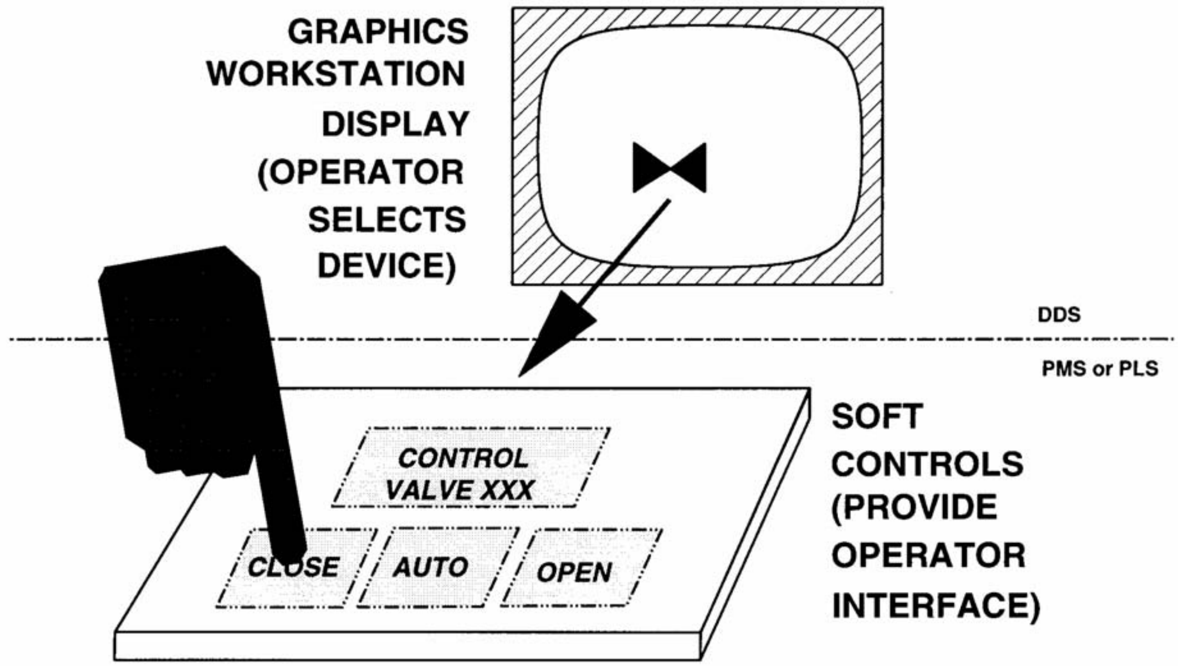

Figure 18.8-1

Soft Control Interactions

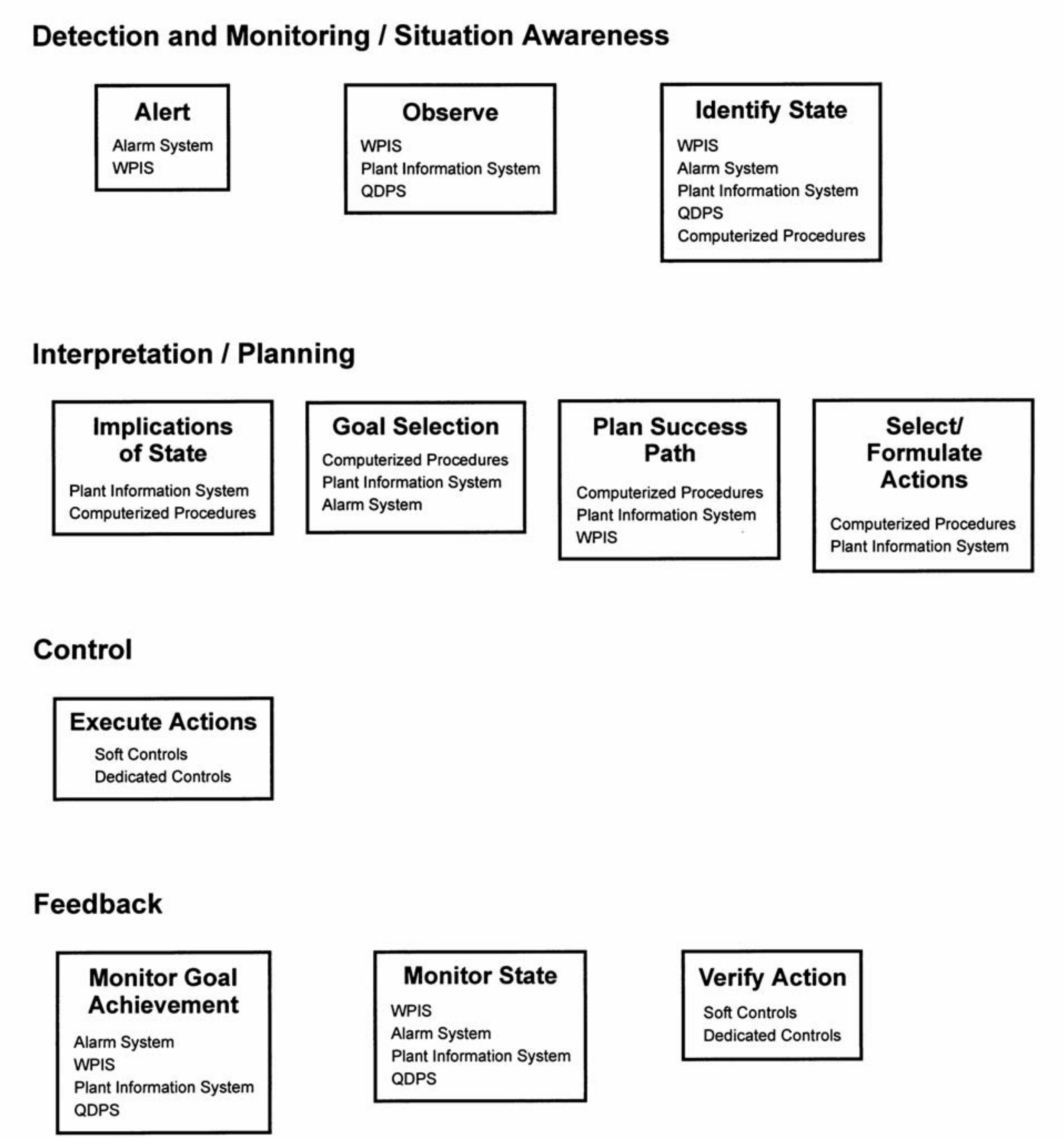

Figure 18.8-2

Mapping of Human System Interface Resources to Operator Decision-Making Model

18.9 Procedure Development

WCAP-14690, "Designer's Input to Procedure Development for the AP600" (Reference 1), provides input to the Combined License applicant for the development of plant operating procedures, including information on the development and design of the AP600 emergency response guidelines and emergency operating procedures. This WCAP is provided as input for the Combined Licensed applicant. It applies directly to AP1000 since AP1000 is operated in the same manner as AP600. The WCAP also includes information on the computerized procedure system, which is the human system interface through which operators execute the plant procedures.

18.9.1 Combined License Information

See Section 13.5 for a discussion of the responsibility for procedure development.

18.9.2 References

1. WCAP-14690, "Designer's Input to Procedure Development for the AP600," Revision 1, June 1997.

18.10 Training Program Development

WCAP-14655, "Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel" (Reference 1), describes the design and implementation of the training program for the training of the operations personnel who participate as subjects in the Human Factors Engineering (HFE) Verification and Validation. This WCAP is provided as input for the Combined Licensed applicant. The WCAP also describes the process used to develop the specification of the role of the operator for AP1000 and how this role and training insights can be passed from the designer to the Combined License applicant.

18.10.1 Combined License Information

See Section 13.2 for a discussion of the responsibility for training program development.

18.10.2 References

1. WCAP-14655, "Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel," Revision 1, August 1996.

18.11 Human Factors Engineering Verification and Validation

A programmatic level description of the AP1000 human factors engineering verification and validation program is provided by Reference 1. Figure 18.11-1 shows the verification and validation activities conducted as part of AP1000 human factors engineering program. Using the programmatic level description, it is the responsibility of the Combined License applicant to develop an implementation plan for the AP1000 human factors engineering verification and validation. The Combined License applicant is responsible for the execution and documentation of the plan.

18.11.1 Combined License Information

Combined License applicants referencing the AP1000 certified design will address the development, execution and documentation of an implementation plan for the verification and validation of the AP1000 human factors engineering program. The programmatic level description of the AP1000 verification and validation program, presented and referenced by Section 18.11, will be used by the Combined License applicant to develop the implementation plan.

18.11.2 References

[*1. WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Revision 2, October 2003.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

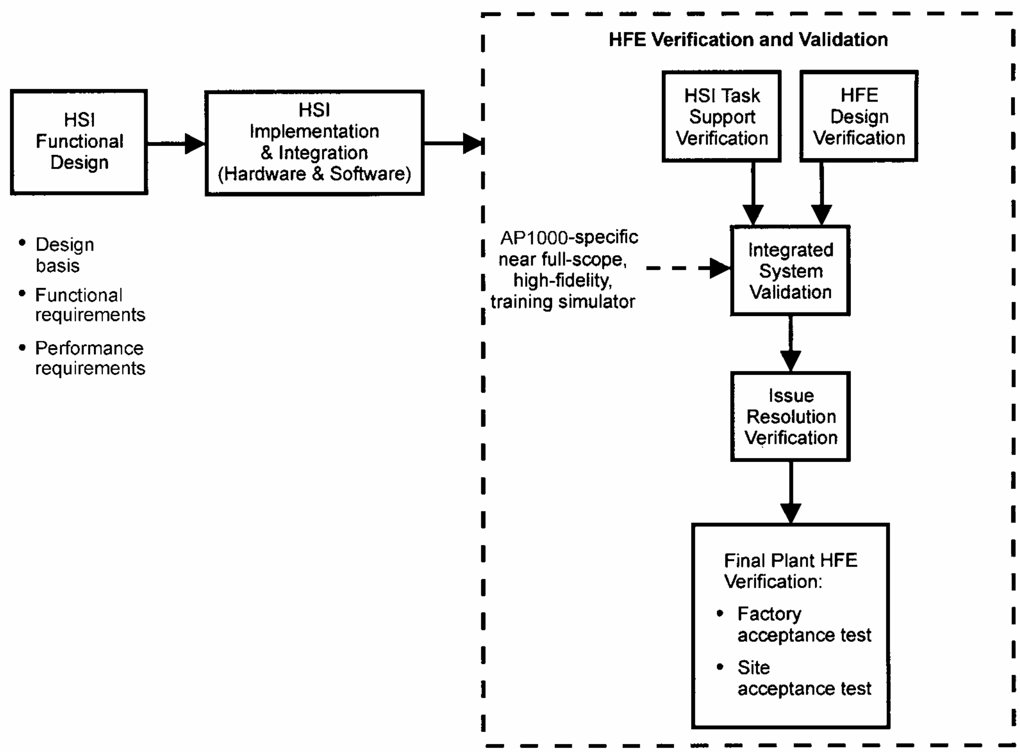

Figure 18.11-1

AP1000 HFE Verification and Validation

18.12 Inventory

18.12.1 Inventory of Displays, Alarms, and Controls

[*An inventory of instruments, alarms, and controls for the AP1000 systems is provided in the respective system piping and instrumentation diagrams.*

The AP1000 system design engineers determine the specific sensors, instrumentation, controls, and alarms that are needed to operate the various plant systems. The instruments, alarms, and controls for each system are documented in the piping and instrumentation diagram. An instrument, alarm, and control is specified by the system design engineer if it is needed to control, verify, or monitor the operation of the system and its components. System functions and their respective functional requirements are considered by the system designer when determining the need for a specific instrument, alarm, or control.

The role of the Human System Interface design team in the determination of the total inventory list is one of verification. As described in Section 18.5, human system interface design team has functionally decomposed the plant. The top four levels of this model for the AP1000 are shown in Figure 18.5-1. Each Level 4 function has a function-based task analysis (FBTA) performed as described in the Task Analysis Implementation Plan. Considering the plant operating modes and emergency operations, the function-based task analysis:

- *Identifies the functions goals*
- *Identifies the processes used to achieve each goal*
- *Documents the performance of a cognitive task analysis of each process*

The cognitive task analysis of each process answers the monitoring/feedback, planning, and controlling questions. The answers to these questions identify the data for each functional process (instrumentation, indications, alarms, and controls) needed by the operator to make decisions. The results of the cognitive task analysis phase of each function-based task analysis are used to verify the inventory list of instruments, controls, and alarms developed by the AP1000 system designers and documented in the respective design documents.]*

18.12.2 Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls

Background

[The human system interface design includes the appropriate plant displays, alarms, and controls needed to support a broad range of expected power generation, shutdown, and accident mitigation operations. Soft control displays and plant information displays are generated by a computer and can be changed to perform different functions, allow control of different devices, or display different information. These displays appear on display devices such as cathode ray tubes, flat panel screens, or visual display units. Alarms are used to direct operator attention. Soft controls are provided through devices such as a keyboard, touch screen, mouse, or other equivalent input devices. The majority of the operations for both the AP1000 main control room and the remote shutdown workstation are expected to employ soft control displays and plant information displays.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The AP1000 human system interface design also includes a minimum inventory of dedicated or fixed-position displays and controls. The minimum inventory of AP1000 fixed-position instrumentation includes those displays, controls, and alarms that are used to monitor the status of critical safety functions and to manually actuate the safety-related systems that achieve these critical safety functions.

Fixed-position alarms and displays are available at a fixed location and are continuously available, though not necessarily displayed, to the operator. Fixed-position displays can be accessed by the operator to monitor the plant status, based on indications from critical plant variables or parameters. Fixed-position alarms are designed to direct operator attention to the need to perform safety-related functions for which there is no automatic actuation function. Although not continuously displayed, the fixed-position displays and alarms are quickly and easily retrievable.

Fixed-position controls provide a means for manual reactor and turbine trip, and safety-related system/component actuation. Fixed-position controls are available to the operator to perform tasks in the operation of safety-related systems and components used to mitigate the consequences of an accident and to establish and maintain safe shutdown conditions following an accident. The fixed-position controls are a manual backup to the automatic protection signals provided by the protection and safety monitoring system.]*

Design Basis and Minimum Inventory

[*A systematic process was implemented to identify the minimum inventory of AP1000 fixed-position controls, displays, and alarms, using established selection criteria directly related to the specific AP1000 accident mitigation operator actions and the critical safety functions identified in the emergency response guidelines.*

The AP1000 design basis for accident mitigation protects the following three fission product barriers:

- *Fuel matrix/fuel rod cladding*
- *Reactor coolant system pressure boundary*
- *Containment*

Therefore, the minimum inventory of fixed instrumentation includes those displays, controls, and alarms used to monitor the status of these fission product barriers and manually actuate the safety-related systems that achieve the critical safety functions protecting these barriers.

Six critical safety functions are identified in the Emergency Response Guidelines (ERGs). These critical safety functions are physical processes, conditions, or actions designed to maintain the plant conditions within the acceptable design basis.

The AP1000 critical safety functions are:

- *Reactivity control*
- *Reactor core cooling*
- *Heat sink maintenance*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- *Reactor coolant system integrity*
- *Containment environment*
- *Reactor coolant system inventory control*

The minimum inventory of AP1000 fixed instrumentation includes those displays, controls, and alarms that are used to monitor the status of these critical safety functions and to manually actuate the safety-related systems that achieve these critical safety functions.]*

Minimum Inventory Selection Criteria

[*The following selection criteria are used to develop the minimum inventory of instrumentation controls, displays, and alarms:*

- *Regulatory Guide 1.97 Types A, B, and C, Category 1 instrumentation*
- *Dedicated controls for manual safety-related system actuation (reactor trip, turbine trip, engineered safety feature actuation)*
- *Controls, displays, and alarms required to perform critical manual actions as identified from the PRA analysis*
- *Alarms provided for operator use in performing safety functions to respond to design basis events for which there is no automatically-actuated safety function*
- *Controls, displays, and alarms necessary to maintain the critical safety functions and safe shutdown conditions*

For the main control room, the minimum inventory of displays is provided by the safety-related displays of the qualified data processing system. For the remote shutdown workstation, the minimum inventory of displays is provided by the nonsafety-related displays of the plant information system.

An alarm is a device that provides warning by means of a signal or sound. The parameters and associated alarms, listed in DCD Table 18.12.2-1, identify challenges to the critical safety functions. This minimum inventory of alarms is embedded in displays as visual signals. For example, the visual signal may involve a change of color, brightness, flashing, or a combination of these. For clarity, these alarms are called visual alerts to distinguish them from other alarms which may include sound. For the main control, the visual alerts are embedded in the safety-related displays. For the remote shutdown workstation, the visual alerts are embedded in the nonsafety-related displays.

The minimum inventory resulting from the implementation of these selection criteria is provided in Table 18.12.2-1.]*

Regulatory Guide 1.97

[*The guidelines in Regulatory Guide 1.97 provide an effective basis for selection criteria to identify the minimum inventory of fixed displays, controls, and alarms, since these guidelines*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

are consistent with monitoring the status of the fission product barriers and the associated critical safety functions in the AP1000 Emergency Response Guidelines.

Regulatory Guide 1.97 provides a method to identify the post-accident monitoring (PAMS) instrumentation to monitor plant variables and systems during and following an accident. Selected post-accident monitoring instrumentation is required to remain functional over the range of the accident conditions and must be able to survive the accident environment for the length of time its function is required. The instrumentation helps the operator to identify the accident, to implement proper corrective actions, and to observe plant response to these actions in order to determine the need for additional actions. Five types of accident monitoring instrumentation and associated performance criteria are provided in the regulatory guide.

Within each type of post-accident monitoring instrumentation, there are three categories (Categories 1, 2, and 3) that are related to the qualification (seismic and environmental conditions) and reliability (safety-related power supply and single failures) of the specific instrumentation.

The Category 1 variables are considered as primary variables and meet appropriate qualification, design, and interface requirements discussed in subsection 7.5.2.2.1 and listed in Tables 7.5-2 and 7.5-3. These variables provide the appropriate capabilities and reliability that are required for the parameters. Only the Category 1 (primary) variables are included in the minimum inventory selection criteria. Category 2 and Category 3 instrumentation are not included in the selection criteria for the minimum inventory.

Type A, Type B, and Type C are considered in developing the selection criteria for identification of the minimum inventory, since these three types are related to monitoring the three fission product barriers. The details of instrumentation designed to meet the guidelines in Regulatory Guide 1.97 are presented in Section 7.5.

Type A variables are defined in subsection 7.5.2.1.1. As discussed in subsection 7.5.3.1, Type A variables provide primary information to permit the main control room operating staff to:

- *Perform the diagnosis in the AP1000 emergency operating procedures*
- *Take specified preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to accomplish their safety-related function to recover from a design basis accident*

There are no specific, preplanned, manually-controlled actions for safety-related systems to recover from design basis events in the AP1000 design. Therefore, as reflected in Table 7.5-4, there are no Type A variables.

Type B variables are defined in subsection 7.5.2.1.2. As discussed in subsection 7.5.3.2, Type B variables provide information to the main control room operating staff to assess the process of accomplishing critical safety functions in the emergency response guidelines. The Type B variables are identified in Table 7.5-5.

Type C variables are defined in subsection 7.5.2.1.3. As discussed in subsection 7.5.3.3, Type C variables provide the control room operating staff with information to monitor the potential for breach or the actual gross breach of:

- *Incore fuel cladding*
- *Reactor coolant system boundary*
- *Containment boundary*

The Type C variables are identified in Table 7.5-6.]*

Dedicated Controls

[*The selection criteria of AP1000 minimum inventory include dedicated, fixed-position controls that provide the capability to manually initiate system-level actuation signals for the safety-related systems and components that are used to achieve the critical safety functions. These dedicated controls provide the capability to initiate manual reactor and turbine trip, safeguards actuation, individual actuation of various safety-related, passive components and containment isolation.*]*

Probabilistic Risk Assessment Critical Human Actions

[*As described in Section 18.7 and Reference 1, the human factors engineering design process includes integration of PRA and the associated human reliability analysis insights into the AP1000 design. The human reliability analysis integration includes the identification of critical human actions through the consideration of specific deterministic and PRA criteria. These selection criteria for minimum inventory identify dedicated, fixed-position displays, alarms, and controls required to support critical human actions identified from the integration of human reliability analysis into the human factors engineering design process.*]*

Dedicated Alarms

[*As specified by Criterion 1, the minimum inventory of instrumentation requires dedicated instrumentation displays of the Regulatory Guide 1.97 Type A variables so that the operator can identify the need to take preplanned manually-controlled actions to mitigate the consequences of a design basis event, where a safety-related system needed to support a critical safety function is not automatically actuated.*

The fourth criterion for minimum inventory is included to identify alarms needed to automatically alert the operator to the need to take these preplanned manually controlled actions.

One of the design goals of the AP1000 is to minimize the need for operator actions to mitigate the consequences of design basis events. As part of the implementation of this design goal, the safety-related systems required to mitigate the consequences of design basis events are automatically actuated. There are no specific preplanned, manually-controlled actions required for the safety-related systems to mitigate design basis events in the AP1000 design.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Another design goal for the AP1000 is to enhance defense in depth, which includes the use of automatically actuated safety-related systems as a backup to other automatically actuated safety-related systems. For example, if beyond-design-basis failures occurred such that the safety-related passive residual heat removal heat exchanger failed to actuate, other safety-related systems would automatically actuate to provide core cooling, without the need for operator action for either group of safety-related components. This design approach enhances overall plant safety.

The AP1000 minimum inventory includes a criterion for evaluating the need for dedicated alarms for preplanned operator actions. However, as a result of these two design approaches, the level of protection available to mitigate the consequences of an accident and to achieve the critical safety functions is provided without the need for preplanned operator actions for either the primary safety-related systems or the backup safety-related systems. Since there are no specific preplanned, manually-controlled actions for safety-related systems required to respond to design basis events in the AP1000 design, there are also no dedicated, fixed-position alarms identified in the minimum inventory list.]*

Critical Safety Functions and Safe Shutdown

[*The design basis for the AP1000 requires protecting the three fission product barriers in the plant (the fuel matrix and cladding, the reactor coolant system pressure boundary, and containment) following design basis events. The AP600 system/event matrix (Reference 2) identifies four safety-related, post-accident mitigation functions that are required as part of the design basis for the AP600 to protect the integrity of these fission product barriers. This document is directly applicable to AP1000. The design basis of the AP1000 requires safety-related systems that can perform these four safety-related functions for design basis events.*

The AP1000 Emergency Response Guidelines were developed by using the system/event matrix document as the plant response design basis and following the standardized process for Emergency Response Guideline development for Westinghouse PWRs. The design approach described in the system/event matrix document organizes the identified safety-related and nonsafety-related Systems, structures and components into the appropriate groups that perform the four safety-related design basis functions. In developing the AP1000 Emergency Response Guidelines, the same groups of safety-related and nonsafety-related systems in the system/event matrix are used to perform their basic design functions, but they are organized somewhat differently from the system/event matrix to support development of symptom-based functional guidelines that can be more effectively used by the operators. These four design basis safety functions identified in Reference 2 are expanded into the six critical safety functions in writing the symptom-based AP1000 Emergency Response Guidelines.

The six Emergency Response Guidelines critical safety functions (and the four design basis safety functions that the critical safety functions must satisfy) are physical processes, conditions, or actions taken using the safety-related and nonsafety-related systems to maintain the plant conditions within the acceptable design basis. These systems provide the physical equipment used to initiate and control the processes that achieve the critical safety functions.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

By accomplishing the emergency response guideline critical safety functions following a design basis event, the plant is able to mitigate the consequences of the event and to establish and maintain safe shutdown conditions. The minimum inventory list identifies sufficient controls, displays, and alarms to monitor and control operation of the safety-related systems to achieve the six critical safety functions identified in the Emergency Response Guidelines and to establish and maintain safe shutdown conditions following an accident.

Tables 7.5-4, 7.5-5, and 7.5-6 identify the instrumentation and the associated Emergency Response Guidelines critical safety functions that each instrument supports for each of the Type A, B, and C post-accident instrumentation, respectively.]*

Minimum Inventory Selection Criteria Implementation Process

[*Section 7.5 provides a discussion of the development of the requirements of Regulatory Guide 1.97 and the implementation process for the AP1000 (Criteria 1, 2, and 4).*

Section 18.7 and Reference 1 provide a discussion of the implementation process for identification of critical PRA operator actions (Criteria 3). Chapter 30 of the AP1000 PRA describes the process for the human reliability analysis.]*

18.12.3 Remote Shutdown Workstation Displays, Alarms, and Controls

[*Subsection 7.4.3 discusses safe shutdown using the remote shutdown workstation following an evacuation of the main control room.*

The main control room provides the capability to perform accident mitigation and safe shutdown tasks for design basis events. The only types of events that would require evacuation of the main control room and control from the remote shutdown workstation are localized emergencies where the main control room environment is unsuitable for the operators or where the main control room workstations and equipment become damaged.

Evacuation of the main control room is not expected to occur coincident with any other design basis events. Subsection 9.5.1 of the Standard Review Plan (NUREG-0800) specifically excludes consideration of other design basis events coincident with a fire.

The design capability for the remote shutdown workstation is to provide the capability to establish and maintain safe shutdown conditions following a main control room evacuation, as described in subsection 7.4.3.1.1. The controls, displays, and alarms listed in Table 18.12.2-1 are retrievable from the remote shutdown workstation.]*

18.12.4 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

18.12.5 References

[*1. WCAP-14651, "Integration of Human Reliability Analysis With Human Factors Engineering Design Implementation Plan," Revision 2, May 1997*.]*

2. WCAP-13793, "The AP600 System/Event Matrix," June 1994.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 18.12.2-1 (Sheet 1 of 2)

MINIMUM INVENTORY OF FIXED POSITION CONTROLS, DISPLAYS, AND ALERTS

Description	Control	Display	Alert[2]
Neutron flux		x	x
Neutron flux doubling			x
Startup rate		x	x
RCS pressure		x	x
Wide range T_{hot}		x	
Wide range T_{cold}		x	x
RCS cooldown rate compared to the limit based on RCS pressure		x	x
Wide range T_{cold} compared to the limit based on RCS pressure		x	x
Change of RCS temperature by more than 5°F in the last 10 minutes			x
Containment water level		x	x
Containment pressure		x	x
Pressurizer water level		x	x
Pressurizer water level trend		x	
Pressurizer reference leg temperature		x	
Reactor vessel - Hot leg water level		x	x
Pressurizer pressure		x	
Core exit temperature		x	x
RCS subcooling		x	x
RCS cold overpressure limit		x	x
IRWST water level		x	x
PRHR flow		x	x
PRHR outlet temperature		x	x
PCS storage tank water level		x	
PCS cooling flow		x	
IRWST to RNS suction valve status		x	x
Remotely operated containment isolation valve status[3]		x	
Containment area high range radiation level		x	x
Containment pressure (extended range)		x	
CMT level[1]		x	

Table 18.12.2-1 (Sheet 2 of 2)

MINIMUM INVENTORY OF FIXED POSITION CONTROLS, DISPLAYS, AND ALERTS

Description	Control	Display	Alert(2)
Manual reactor trip (Also initiates turbine trip Figure 7.2-1, sheet 19.)	x		
Manual safeguards actuation	x		
Manual CMT actuation	x		
Manual main control room emergency habitability system actuation(4)	x		
Manual ADS actuation (1-3 and 4)	x		
Manual PRHR actuation	x		
Manual containment cooling actuation	x		
Manual IRWST injection actuation	x		
Manual containment recirculation actuation	x		
Manual containment isolation	x		
Manual main steamline isolation	x		
Manual feedwater isolation	x		
Manual containment hydrogen igniter (nonsafety-related)	x		

Notes:
1. Although this parameter does not satisfy any of the selection criteria of subsection 18.12.2, its importance to manual actuation of ADS justifies its placement on this list.
2. These parameters are used to generate visual alerts that identify challenges to the critical safety functions. For the main control room, the visual alerts are embedded in the safety-related displays as visual signals. For the remote shutdown workstation, the visual alerts are embedded in the nonsafety-related displays as visual signals.
3. These instruments are not required after 24 hours. (Subsection 7.5.4 includes more information on the class 1E valve position indication signals, specified as part of the post-accident monitoring instrumentation.)
4. This manual actuation capability is not needed at the remote shutdown workstation.

18.13 Design Implementation

This process element is added by Reference 2 to the Program Review Model specified in Reference 1. However, it mostly applies to plant modernization. The portions of the added element that apply to new plants were formerly addressed under the Verification and Validation element in Reference 1. Since these aspects of the Program Review Model are unchanged, AP1000 will continue to address them under Section 18.11 as "Issue Resolution Verification" and "Final Plant HFE Verification."

18.13.1 References

1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.

2. NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," U.S. NRC, May 2002.

18.14 Human Performance Monitoring

Human performance monitoring applies after the plant is placed in operation, and is a Combined License applicant responsibility. Guidance and additional information on the objectives, scope, and methods of such programs are presented in Element 13 of Reference 1.

18.14.1 References

1. NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," U.S. NRC, May 2002.

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CHAPTER 19

PROBABILISTIC RISK ASSESSMENT

19.1 Introduction

Part 52 of the 10 Code of Federal Regulations requires that a probabilistic risk assessment (PRA) be submitted as a part of an application for design certification. The PRA provides an evaluation of the design, including plant, containment, and typical site analyses that consider both internal and external events.

The AP1000 design process iincludes a risk assessment of the design prior to being finalized to optimize the plant with respect to safety. Westinghouse accomplishes this by committing to the early application of probabilistic analysis techniques in the AP1000 design process. This work resulted in information used in the selection of design alternatives, with a goal that the overall level of safety of the completed design exceeds design objectives.

19.1.1 Background and Overview

The AP1000 PRA was developed to support the application for Design Certification of the AP1000 nuclear plant. The AP1000 design is based extensively on the AP600 standard nuclear plant that received Design Certification in December 1999. The AP600 PRA, which was reviewed by the US NRC in detail during the seven-year review of the AP600, is used as the starting point for the AP1000 PRA. Since the configuration of the AP1000 reactor and safety systems is the same as the AP600, the AP600 PRA is used as the basis of the AP1000 PRA with relevant changes implemented in the model to reflect the AP1000 design changes. AP1000 plant-specific T&H analyses are performed in order to determine the system success criteria. The core damage frequency and large release frequency are calculated for internal events. The external events and shutdown models are also assessed to derive plant insights and plant risk conclusions.

The purpose of the PRA is to provide inputs to the optimization of the AP1000 design and to verify that the US NRC PRA safety goals have been satisfied. As in the AP600, the PRA is being performed interactively with the design, analysis and operating procedures. The PRA results show that there are only minor impacts on the PRA results compared to AP600, and that the very low risk of the AP600 has been maintained in the AP1000; the AP1000 PRA meets the US NRC safety goals with significant margin. Insights from the analysis are provided discussing the effect on the PRA of differences between the AP600 and the AP1000 designs.

19.1.2 Objectives

The objectives of the AP1000 PRA are to:

- Provide an integrated view of the AP1000 behavior in response to transients and accidents, including severe accidents

- Satisfy the NRC regulatory requirements that a design-specific PRA be conducted as part of the application for design certification (10 CFR 52.47(a)(i)(v))

- Demonstrate that the design meets the proposed safety goals for core damage frequency and large fission product releases

- Construct a PRA Level 1 (core damage frequency), Level 2 (large release frequency), and Level 3 (offsite dose) model that is consistent with the AP1000 design configuration and operation requirements and the ALWR URD requirements on PRA methodology (Reference 19.1-1)

- Demonstrate the low vulnerability and insensitivity of the AP1000 design to human interaction

- Provide input to the design process (that is, provide a tool to investigate detailed design solutions and operational strategies to optimize AP1000 safety)

- Demonstrate compliance with the hydrogen control criteria set forth in 10 CFR 50.34(f)(2)(ix)

- Serve as a basis for an accident management program

19.1.3 Technical Scope

The technical tasks for the AP1000 PRA are defined in the following categories:

- Level 1 Analysis for Internal Events
- Level 2 Analysis for Internal Events
- Level 3 Analysis for Internal Events
- Sensitivity, Importance, and Uncertainty Analyses for Internal Events
- Shutdown Risk Assessment
- External Events Risk Assessment

The ALWR URD document serves as the base document to define the source of data.

The Level 1 analysis includes:

- Internal initiating events evaluation
- Event tree and success criteria analyses
- Plant systems analysis using fault tree models
- Common cause failure and human reliability analyses
- Data analysis
- Fault tree and event tree quantification to calculate the core damage frequency

The Level 2 analysis includes:

- An evaluation of severe accident phenomena and fission product source terms
- Modeling of the containment event tree and associated success criteria
- Analysis of hydrogen burning and mixing

The Level 3 analysis is an offsite dose evaluation.

The low power and shutdown analysis includes Level 1 shutdown assessment.

External events analyses include:

- Internal fire assessment
- Internal flooding assessment
- Seismic margin assessment

19.1.4 Project Methodology Overview

Guidelines have been developed for the major tasks. These guidelines provide homogeneity among similar tasks that are performed by different analysts (such as fault tree construction) and to standardize the methodology for selected tasks (such as human reliability or common cause failure analysis).

The major activities performed during this study include:

- Initiating event and event tree analysis - Evaluations are performed to identify a comprehensive set of initiating events. This evaluation includes review of pressurized water reactor (PWR) operating experience, past PRAs, and consideration of AP1000-specific features. For each initiating event category, an event tree is constructed to model the accident sequences that may result.

- Success criteria - Extensive analyses are performed with MAAP4 (Reference 19.1-2), NOTRUMP, and other codes to determine the success criteria for system mitigation following initiating events.

- Analysis of individual systems - Qualitative analysis and fault tree construction are performed for safety-related and nonsafety-related front-line systems and supporting systems that contribute to prevention or mitigation of severe accident events. The analysis identifies the importance of each component for each system.

- Human reliability analysis - A detailed human reliability analysis is performed, with emphasis on the evaluation of the effect of single operator decisions on more than one system.

- Common cause failure analysis - An analysis is performed to identify and model the dependencies (common cause failures), both internal to individual systems and among systems, that use similar components exposed to similar environments.

- Severe accident analysis - Analyses are performed with the MAAP4 code to study the progression of severe accident sequences and to define the radionuclide source terms.

- Dose evaluation - The dose at the plant site boundary for the various fission product release categories are calculated.

- Hydrogen control analysis - Analyses to demonstrate the effectiveness of the hydrogen igniters are carried out using the MAAP4 code.

- Shutdown assessment - The frequency of core damage is assessed for low power and shutdown conditions.

- Fire and flood assessment - Internal fire and internal flood risk assessment evaluate potential vulnerabilities within the plant.

- Seismic margin assessment - Seismic margin methodology is used to identify potential seismic vulnerabilities and to assess the margin beyond the design-level safe shutdown earthquake.

- Assembly of results - The frequency of the dose at the site boundary exceeding a certain level is obtained by combining the results of the core damage analysis, severe accident analysis, and dose analysis.

19.1.5 Results

The AP1000 PRA is an integrated view of the AP1000 behavior in response to transients and accidents, including severe accidents.

The AP1000 core damage frequency for internal events from at-power conditions is extremely low. The core damage frequency calculated for internal events at shutdown conditions is also very low. The combined core damage frequency from internal events at power and at shutdown conditions meets the NRC and URD safety goals with substantial margin.

The AP1000 large release frequency of the dose at the site boundary exceeding 1 rem effective dose equivalent in 24 hours after core damage for internal events from at-power conditions is very low. Like the core damage frequency, the combined large release frequency from internal events at power and at shutdown conditions meets the NRC safety goals with substantial margin.

In the AP600 licensing process, an initial set of sensitivity analyses were made to assess the importance of non-safety related systems. Later on, this exercise grew into a full-fledged PRA model which was named the focused PRA. The focused PRA was performed to assess the importance of the nonsafety-related systems. The results of the focused PRA (Reference 19.1-3) demonstrated that the AP600 passive plant design was able to meet the NRC safety goals crediting only safety-related equipment, with no credit for any of the nonsafety-related systems. To resolve the regulatory treatment of nonsafety-related systems, Westinghouse and the NRC agreed to availability controls of selected nonsafety-related systems for the purposes of providing defense-in-depth as well as investment protection.

The AP1000 PRA demonstrates a very similar low risk profile for the AP1000 as for the AP600. Sensitivity studies performed for the AP1000 demonstrates that no nonsafety-related system is of high risk importance. The same nonsafety-related system availability controls adopted for the AP600 will be applied to the AP1000 for the purpose of providing defense-in-depth and investment protection and are discussed in DCD Section 16.3.

There are no critical operator actions in the AP1000 PRA analyses. The core damage frequency remains relatively small even if all operator actions are assumed to fail. Only a small improvement in the core damage frequency can be realized by improving the reliability of the plant operators.

The AP1000 containment is capable of providing an effective barrier to the release of fission-products to the environment and includes effective hydrogen control measures. The AP1000 design meets the criteria in 10 CFR 50.34(f)(2)(ix).

These results demonstrate that the AP1000 meets and exceeds the design goals specified in Section 19.1.2.

Insights regarding the AP1000, derived from or verified by this PRA, include:

- Passive safety-related systems eliminates the dependence of safety-related system operation on ac electric power and compressed air. This significantly reduces the core damage frequency resulting from a loss of offsite power or station blackout event.

- Reactor coolant pump seal loss-of-coolant accidents are eliminated because of the use of canned motor reactor coolant pumps.

- Simplified passive safety-related systems reduce the need for, and importance of, operator action.

- The analysis shows that many of the events, which in the past, were leading contributors to the risk of nuclear power plants, are not as significant for the AP1000. The contribution of interfacing systems loss-of-coolant accidents, which are typically the highest risk severe accident sequences, is made insignificant by the design of the AP1000.

- The ability to flood the reactor cavity is an important contributor to maintaining a low release frequency for AP1000. This feature and the design of the reactor insulation that provides for cooling of the reactor vessel keeps a damaged core inside the reactor vessel. This reduces the potential for ex-vessel severe accident events.

- The AP1000 design provides a passive means of maintaining the containment integrity by removing decay heat from the containment with water on the containment shell or through air cooling. This cooling ability reduces the potential of containment failure due to overpressurization after severe accident.

- The AP1000 containment design enhances the deposition of aerosols before they are released to the environment and reduces the potential environmental effects of a severe accident that has failed the containment.

19.1.6 Plant Definition

19.1.6.1 General Description

See Chapter 1.

19.1.6.2 AP1000 Design Improvement as a Result of Probabilistic Risk Assessment Studies

Design improvements were incorporated in the AP600 design based on the results of the AP600 PRA and other design analyses and are discussed in Reference 19.1-3. These improvements have been retained in the AP1000 design. Additional design changes have been incorporated in the AP1000 as a result of the AP1000 PRA. The most significant design changes prompted by the AP1000 PRA are:

- Two recirculation lines, each containing a motor-operated valve and a squib valve or a check valve and a squib valve in series, are used to provide recirculation flow from containment sump to the core through direct vessel injection line. Diversity is provided in the actuation by using diverse squib valves. The motor-operated valve is designed so that it remains open in case of failure.

- Three parallel supply lines allow water flow from PCCWST to the containment shell. Diversity is provided in the actuation by using motor-operated valves for one path.

19.1.7 References

19.1-1 Advanced Light Water Reactor Requirements Document, Volume III, Appendix A to Chapter 1, "PRA Key Assumptions and Groundrules," Revisions 5 and 6, December 1993.

19.1-2 EPRI MAAP 4.0 Users Manual.

19.1-3 AP600 PRA.

19.2 Internal Initiating Events

This section intentionally blank.

19.3 Modeling of Special Initiators

This section intentionally blank.

19.4 Event Tree Models

This section intentionally blank.

19.5 Support Systems

This section intentionally blank.

19.6 Success Criteria Analysis

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19.7 Fault Tree Guidelines

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19.8 Passive Core Cooling System - Passive Residual Heat Removal

See subsection 6.3.1.1.1.

19.9 Passive Core Cooling System - Core Makeup Tanks

See subsections 5.4.13 and 6.3.2.2.1.

19.10 Passive Core Cooling System - Accumulator

See subsection 6.3.2.2.2.

19.11 Passive Core Cooling System - Automatic Depressurization System

See subsections 5.4.6 and 6.3.2.2.8.5.

19.12 Passive Core Cooling System - In-Containment Refueling Water Storage Tank

See subsection 6.3.2.2.3.

19.13 Passive Containment Cooling

See subsection 6.2.2.

19.14 Main and Startup Feedwater System

See subsection 10.4.9.

19.15 Chemical and Volume Control System

19.15.1 System Description

See subsection 9.3.6.2.

19.15.2 System Operation

See subsection 9.3.6.4.

19.15.3 Performance during Accident Conditions

See subsection 9.3.6.4.5.

19.15.4 Initiating Event Review

This section intentionally blank.

19.15.5 System Logic Models

19.15.5.1 Assumptions and Boundary Conditions

The following assumptions are used for the chemical and volume control system PRA model:

a. - i. Intentionally blank.

j. Either one of the two makeup pumps is sufficient to deliver borated water to the reactor coolant system. To simplify the PRA model, it is assumed that one makeup pump is always the operating pump and the other makeup pump is always the standby pump.

k. - q. Intentionally blank.

19.15.5.2 Fault Tree Models

This section intentionally blank.

19.15.5.3 Human Interactions

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19.15.5.4 Common Cause Failures

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TABLES 19.15-1 THROUGH 19.15-9 NOT INCLUDED IN THE DCD.
FIGURE 19.15-1 NOT INCLUDED IN THE DCD.

19.16 Containment Hydrogen Control System

See subsection 6.2.4.

19.17 Normal Residual Heat Removal System

See subsection 5.4.7.

19.18 Component Cooling Water System

See subsection 9.2.2.

19.19 Service Water System

See subsection 9.2.1.

19.20 Central Chilled Water System

See subsection 9.2.7.

19.21 ac Power System

See subsection 8.3.1.

19.22 Class 1E dc & UPS System

See subsection 8.3.2.1.1.

19.23 Non-Class 1E dc & UPS System

See subsection 8.3.2.1.2.

19.24 Containment Isolation

See subsection 6.2.3.

19.25 Compressed and Instrument Air System

See subsection 9.3.1.

19.26 Protection and Safety Monitoring System

See subsection 7.1.2.

19.27 Diverse Actuation System

See subsection 7.7.1.11.

19.28 Plant Control System

See subsection 7.1.3.

19.29 Common Cause Analysis

This section intentionally blank.

19.30 Human Reliability Analysis

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19.31 Other Event Tree Node Probabilities

This section intentionally blank.

19.32 Data Analysis and Master Data Bank

This section intentionally blank.

19.33 Fault Tree and Core Damage Quantification

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19.34 Severe Accident Phenomena Treatment

19.34.1 Introduction

This section describes how the AP1000 containment addresses challenges from severe accident phenomena, and how the challenges are evaluated in the probabilistic risk assessment (PRA). In the PRA, the Modular Accident Analysis Program (MAAP) version 4.04 code (Reference 19.34-8) is used to evaluate severe accident scenarios. Severe accident phenomenological uncertainties are treated with Risk-Oriented Accident Analysis Methodology (ROAAM) (Reference 19.34-2) phenomenological evaluations, with AP1000-specific decomposition event tree phenomenological evaluations, or with assumptions that certain low-frequency severe accident phenomena fail the containment. The objective of these studies is to show, with a high degree of confidence, that the AP1000 containment will accommodate the effects of severe accidents in a range of scenarios for at least the first 24 hours after the onset of core damage. Such evaluations demonstrate the robustness of the containment design.

19.34.2 Treatment of Physical Processes

The following eight issues are identified in Reference 19.34-1 as being representative of the phenomenological issues pertaining to severe accident conditions:

1. Loss-of-coolant accident (LOCA)
2. Fuel-coolant interaction (steam explosion)
3. Hydrogen combustion and detonation
4. Melt attack on concrete structure or containment pressure boundary
5. High-pressure melt ejection
6. Core-concrete interaction (CCI)
7. Containment pressurization from decay heat
8. Elevated temperature (equipment survivability)

The challenge to the containment integrity from a LOCA blowdown is covered in the containment design basis and is not specifically addressed here. Treatment of physical processes affecting the remaining challenges is discussed in this chapter.

19.34.2.1 In-Vessel Retention of Molten Core Debris

In-vessel retention (IVR) of core debris by external reactor vessel cooling is a severe accident mitigation attribute of the AP1000 design; it is discussed in detail in Chapter 19.39. With the reactor vessel intact and debris retained in the lower head, phenomena such as molten core-concrete interaction and ex-vessel steam explosion, which occur as a result of core debris relocation to the reactor cavity, are prevented.

The AP1000 reactor vessel insulation and containment geometry promote in-vessel retention. Engineered design features of the AP1000 containment flood the containment reactor cavity region during accidents, and thereby, submerge the reactor vessel in water.

Chapter 39 of the AP1000 PRA presents an AP1000-specific evaluation to determine the likelihood that sufficient heat can be removed from the outside surface of the submerged reactor pressure vessel lower head to prevent reactor vessel failure and relocation of debris to containment. The methodology used to quantify the margin to vessel failure in Reference 19.34-2 for the AP600 was adapted to the AP1000. For the AP1000 the methodology assumes that:

- The RCS is depressurized.
- The reactor vessel is submerged above the 98-ft elevation in the containment.
- The reflective insulation promotes the two-phase natural circulation in the reactor vessel cooling annulus.
- The external surface treatment promotes wetability of the reactor vessel.

The containment event tree includes a node to ascertain that the reactor coolant system (RCS) is depressurized and a node to determine if adequate water is available in the cavity to achieve two-phase natural circulation. Success at both of these nodes is required to demonstrate that the conditions and assumptions of the IVR analysis are met. The AP1000 design specifies that the reactor vessel insulation is designed appropriately and that the outer surface of the reactor vessel promotes wetability.

Accounting for the uncertainties in thermal-hydraulic parameters, the heat fluxes to the vessel wall and reactor vessel internals from the debris pool are calculated. The results show large margin to failure for the reactor vessel if it is externally cooled by water.

19.34.2.2 Fuel-Coolant Interaction (Steam Explosions)

A steam explosion may occur as a result of molten metal or oxide core debris mixing with water and interacting thermally. Steam explosions are postulated to occur inside the reactor vessel when debris relocates from the core region into the lower plenum and in the reactor cavity if the vessel fails and debris is ejected from it into water in the reactor cavity.

19.34.2.2.1 In-Vessel Fuel-Coolant Interaction

In-vessel steam explosions were studied extensively in the AP600 analyses. A ROAAM analysis of the AP600 reactor vessel lower head integrity under in-vessel steam explosion loading is presented in Reference 19.34-3. Typically, in-vessel steam explosion analyses focus on the α-mode containment failure, which is induced by the reactor vessel upper head failure. The ROAAM analysis focused on failure of the lower head since that steam explosion vessel failure mode would impair the in-vessel retention capability of the reactor vessel. The ROAAM analysis concludes that lower-head vessel failure from in-vessel steam explosion is physically unreasonable with very large margin to failure.

Based on the in-vessel core relocation scenario for the AP1000, the in-vessel steam explosion ROAAM analysis presented for the AP600 can be extended to the AP1000. The mass flow rate, superheat and composition of debris in the relocation from the upper core region to the

lower head is expected to be essentially the same as the AP600. The geometry of the lower head of the AP1000 is the same as the AP600. Therefore, it is reasonable to extend the results of the AP600 in-vessel steam explosion ROAAM analysis to the AP1000.

The results of the in-vessel steam explosion ROAAM can also be extended to containment failure induced by in-vessel steam explosions (α-mode containment failure). The likelihood for vessel failure and subsequent containment failure due to in-vessel steam explosion is so small as to be negligible. This conclusion is in agreement with the conclusions of the U.S. Nuclear Regulatory Commission (NRC)-sponsored Steam Explosion Review Group (Reference 19.34-4).

19.34.2.2.2 Ex-Vessel Fuel-Coolant Interaction

The first level of defense for ex-vessel steam explosion is the in-vessel retention of the molten core debris. If molten debris does not relocate from the vessel to the containment, there are no conditions for ex-vessel steam explosion. In the event that the reactor cavity is not flooded and the vessel fails, the PRA containment event tree assumes that the containment fails in the early time frame.

An analysis of the structural response of the reactor cavity was performed for the AP600 (Reference 19.34-5, Appendix B). As in the in-vessel steam explosion analysis, the results of this AP600 ex-vessel steam explosion analysis are extended to the AP1000. The vessel failure modes for AP600 and AP1000 are the same. The initial debris mass, superheat and composition are assumed to be the same as the AP600. The reactor cavity geometry and water depth prior to vessel failure are the same as AP600. Therefore, the results of the AP600 ex-vessel steam explosion analysis are considered to be appropriate for the AP1000.

19.34.2.3 Hydrogen Combustion and Detonation

A decomposition event tree analysis discussed in Section 19.41 evaluates the potential for hydrogen combustion threatening the containment integrity during a severe accident sequence in the AP1000. The analysis examines diffusion flame burning and local detonation occurring during in-vessel hydrogen generation prior to hydrogen mixing in the containment and global deflagration and detonation, which may occur later when the hydrogen is mixed throughout the containment. Only in-vessel hydrogen generation is considered, since vessel failure and ex-vessel debris relocation is assumed to fail containment.

The AP1000 provides defense-in-depth to address hydrogen diffusion flames that may challenge containment integrity. The first level of defense is the stage four automatic depressurization system (ADS Stage 4) lines from the RCS, which prevent significant hydrogen releases to the in-containment refueling water storage tank (IRWST) and Passive Core Cooling System (PXS) compartments. ADS Stage 4 vents from the RCS hot legs to the loop compartments, which are shielded from the containment shell and have a constant source of oxygen from the natural circulation in the containment. Hydrogen can burn as a diffusion flame in the loop compartments without threatening the containment integrity. If ADS Stage 4 fails, the AP1000 has provided design considerations in IRWST vents to mitigate diffusion flames near the containment walls. Vents from the passive injection system compartments and chemical volume and control system compartment are located away from

the containment shell and penetrations in order to mitigate the threat from hydrogen diffusion flames.

Containment failure from a directly initiated detonation wave is not considered to be a credible event for the AP1000 containment. There are no ignition sources of sufficient energy to directly initiate a detonation in the AP1000 containment. Deflagration to detonation transition (DDT) is considered to the be the only likely mechanism to produce a detonation in the AP1000 containment.

The likelihood of DDT in the AP1000 containment is evaluated locally in confined compartments during in-vessel hydrogen generation and globally after in-vessel generation is concluded and hydrogen is mixed in the containment. For a DDT to occur, the combination of the gas mixture sensitivity to detonation and the geometric configuration potential for flame acceleration must be conducive to DDT. Since the hydrogen concentration necessary to form a detonable mixture depends on the size of the enclosure, concentration requirements for DDT in different regions of the AP1000 containment are extrapolated from the FLAME facility data (Reference 19.34-6) using scaling arguments based on the detonation cell width. The geometric requirement is evaluated considering aspects such as the degree of confinement and the extent and type of obstacles present in the postulated flame propagation path. In all cases, DDT is assumed to result in containment failure in the containment event tree analysis.

Global hydrogen deflagration and the potential for containment failure are modeled on the containment event tree. Adiabatic, isochoric, complete combustion (AICC) is assumed, and peak pressure probability distributions are developed for the accident scenarios. The probability of containment failure due to hydrogen deflagration is evaluated from the containment failure probability distribution combined with the peak pressure probability distribution.

19.34.2.4 High-Pressure Melt Ejection

The AP1000 incorporates design features that prevent high-pressure core melt. These features include the passive residual heat removal (PRHR) system and the ADS. These design features provide primary system heat removal and depressurization to prevent high pressure core damage conditions. The consequences from postulated high pressure melt ejection (HPME) are mitigated by the containment layout which provides a torturous pathway to the upper compartment, and no direct pathway for the impingement of debris on the containment shell.

In high-pressure core damage sequences the potential exists for creep-rupture-induced failures of the RCS piping at the hot-leg nozzles, the surge line, the steam generator tubes and, given debris relocation to the lower plenum, in the reactor vessel lower head. Failure of the hot-leg nozzle or surge line prior to failures of other components results in the rapid depressurization of the RCS. Failure of the steam generator tubes results in a containment bypass and a large release of fission products to the environment. Failure of the lower head of the reactor vessel results in the potential for HPME.

Hot-leg nozzle failure is expected prior to steam generator tube failure, but because of large uncertainties, hot-leg nozzle creep rupture failure is not credited with preventing steam

generator tube failure. In the PRA, steam generator tube failure is assumed for high-pressure sequences in the containment event tree analysis unless operator action to depressurize the RCS with the ADS is successful.

19.34.2.5 Core Debris Coolability

In accident sequences where the reactor pressure vessel failure is not prevented, core debris may be discharged into the reactor cavity. The likely vessel failure modes produce a low pressure melt ejection (LPME) to the containment. The AP1000 cavity design provides area for the core debris to spread. Condensate from the passive containment cooling system (PCS) returns to the reactor cavity, thereby providing a long-term supply of water to cool the core debris.

At vessel failure it is very likely that the cavity will be filled with water from the RCS, core makeup tanks (CMTs), and accumulators to at least the 83-ft elevation. There are significant uncertainties associated with debris spreading into a water-filled cavity. Debris-spreading is mainly a function of the highly uncertain vessel failure mode. A large-scale lower-head failure releasing debris at a high rate would enhance spreading, while a localized failure mode would release debris at a slow rate, which would most likely cause the debris to pile up under the reactor vessel and minimize spreading.

Given the uncertainties in the debris-spreading and in non-condensable gas generation and combustion, the containment event tree analysis does not credit containment integrity in the event of failure of the lower head of the vessel and relocation of the core.

A limited set of deterministic analyses of debris spreading and core-concrete interaction in the AP1000 cavity is presented in Appendix 19-B. The analyses show that basemat melt-through is not predicted to occur within 24 hours of the accident initiation. Basemat melt through is predicted to occur before pressurization of the containment by non-condensable gases challenges the containment integrity.

19.34.2.6 Containment Pressurization from Decay Heat

The AP1000 containment is cooled via the PCS (see Section 19.40). Evaporative water cooling of the containment shell provides long term containment cooling and limits the containment pressure to less than the design pressure for all severe accident events except hydrogen combustion (which is addressed separately). Containment water is provided to the top of the containment via redundant, diverse system of valves and lines, including a line that can be connected to an outside water source, such as a fire truck.

In the unlikely event that water cannot be supplied to the top of the containment shell for an extended period of time, air-only cooling by air flowing through the PCS annulus provides significant cooling to the containment. Under the right environmental conditions, the containment is expected to reach an equilibrium pressure that will not challenge containment integrity. However, under nominal-to-conservative environmental conditions, containment integrity by air-cooling alone cannot be assured. In this case, containment failure is predicted to occur more than 24 hours after accident initiation.

A significant amount of time is available for operator action to vent the containment under the severe accident management guidance (SAMG). Containment venting mitigates uncontrolled releases of fission products from a failed containment. The AP1000 can be vented on an ad-hoc basis under the SAMG from a number of containment penetrations. Containment venting also reduces the partial pressure of non-condensable gases in the containment, and thus creates a new containment underpressure failure mode that may occur if containment is cooled after venting.

19.34.2.7 Elevated Temperatures (Equipment Survivability)

Reference 19.34-7 states that equipment identified as being useful to mitigate the consequences of severe accidents must be designed to provide reasonable assurance that it will continue to operate in a severe accident environment for the length of time needed to accomplish its function. Also, 10 CFR 50.34(f) requires safety equipment to continue performing its function after being exposed to a containment environment created as a consequence of generating a quantity of hydrogen equivalent to that from 100-percent cladding oxidation. As the AP1000 design uses thermal igniters to burn hydrogen in a controlled manner, it is necessary to demonstrate that the safety equipment can continue to perform its function in the high-temperature environment created by the hydrogen burning.

The functions of the equipment in containment for which credit is taken in the AP1000 PRA were reviewed to determine if the equipment is required to operate in a severe accident environment and beyond design basis limits. The equipment and the basis for operation are the same as the AP600. Therefore, the results of the AP600 are extended to the AP1000 for equipment survivability.

19.34.2.8 Summary

The potential for and the consequences of severe accident phenomena are evaluated. The preventive and mitigative features of the AP1000 addressing the severe accident phenomena are discussed. This information is applied to the containment event trees and used in the quantification of the large release frequency.

19.34.3 Analysis Method

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19.34.4 Severe Accident Analyses

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19.34.5 Insights and Conclusions

The analyses of the severe accident phenomena for the AP1000 PRA highlight the following insights and conclusions:

- The design of the AP1000 reactor vessel, vessel insulation, and reactor cavity; and the ability to flood the cavity after a severe accident reduce the potential challenges to the containment integrity by maintaining the vessel integrity.
- Should a failure of the reactor vessel occur, the design of the reactor cavity enhances the ability to cool any core debris that exits the vessel.
- Lower head vessel failure due to in-vessel steam explosions is physically unreasonable.
- The ADS and PRHR system are design features that can be used to prevent high-pressure core melt in a severe accident.
- A directly-initiated hydrogen detonation in the AP1000 containment is not a credible event.
- The equipment needed to mitigate the consequences of a severe accident is designed to provide reasonable assurance that it will continue to operate during an accident.

19.34.6 References

19.34-1 Letter from D. A. Ward, Advisory Committee on Reactor Safeguards, to K. A. Carr, Chairman, Nuclear Regulatory Commission, "Proposed Criteria to Accommodate Severe Accidents in Containment Design," dated May 17, 1991.

19.34-2 Theofanous, T. G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

19.34-3 Theofanous, T. G., et al., "Lower Head Integrity Under In-Vessel Steam Explosion Loads," DOE/ID-10541, July 1996.

19.34-4 NUREG-1116, *A Review of the Current Understanding of the Potential for Containment Failure From In-Vessel Steam Explosions*, 1985.

19.34-5 GW-GL-022, AP600 Probabilistic Risk Assessment, August 1998.

19.34-6 Sherman, M. P., Tieszen, S. R., and Benedick, W. B., *FLAME Facility - The Effects of Obstacles and Transverse Venting on Flame Acceleration and Transition to Detonation for Hydrogen-Air Mixtures at Large Scale*, NUREG/CR-5275, April 1989.

19.34-7 Attachment to letter from D. M. Crutchfield, Office of Nuclear Reactor Regulation, to E. E. Kintner, Advanced Light Water Reactor Steering Committee, "Major Technical and Policy Issues Concerning the Evolutionary and Passive Plant Designs," dated February 27, 1992.

19.34-8 "EPRI MAAP 4.0 Users Manual."

TABLES 19.34-1 THROUGH 19.34-26 NOT INCLUDED IN THE DCD.
FIGURES 19.34-1 THROUGH 19.34-391 NOT INCLUDED IN THE DCD.

19.35 Containment Event Tree Analysis

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19.36 Reactor Coolant System Depressurization

19.36.1 Introduction

Depressurization of the reactor coolant system is required for the external water cooling of the reactor vessel that will prevent vessel failure and core debris relocation to the containment (Reference 19.36-1). If the reactor coolant system (RCS) is at high pressure during core damage, containment failure may be postulated by several severe accident phenomena including induced failure of the steam generator tubes, high-pressure melt ejection, and direct containment heating.

19.36.2 Definition of High Pressure

High pressure is defined to support the assumptions of the PRA model. Induced steam generator tube rupture, high-pressure melt ejection, and reactor vessel failure into the flooded cavity will not occur if there is successful reactor coolant system depressurization.

Vessel failure can occur at elevated pressures with melted core debris in the vessel. This could cause the ejection of core debris from the vessel, followed by entrainment of debris in the high-velocity steam and water blowdown that would follow. Direct containment heating (DCH) and shifting of the reactor vessel are postulated containment failure mechanisms related to high pressure ejection of molten core debris.

Vessel failure and ex-vessel severe accident phenomena are prevented in the AP1000 by external cooling of the reactor vessel when the cavity is flooded. Flooding of the cavity occurs when the in-containment refueling water storage tank (IRWST) water fills the cavity. This can happen because of depressurization and subsequent in-containment refueling water storage tank water injection or when the cavity flood lines on the in-containment refueling water storage tank are opened. This cooling confirms the core debris will remain in the vessel. Heat transfer from the molten debris in the vessel through the lower head will thin the vessel wall and reduce the capability of the vessel to withstand higher pressures. It is conservatively assumed in this analysis that molten core debris in the vessel could cause failure at pressures greater than 150 psig.

If there is no molten core debris in the vessel, the vessel and the rest of the reactor coolant system, including the stream generator tubes, are expected to remain intact at pressures up to 3200 psig. This is consistent with the design of the reactor coolant system primary side.

19.36.3 References

19.36-1 Theofanous, T. G., et al., "In-Vessel Coolability And Retention of a Core Melt," DOE/ID-10460, July 1995.

19.37 Containment Isolation

Containment isolation is required before significant fission-product release after core uncovery. If the containment is not isolated, then the core damage results in a fission-product release to the environment. Containment isolation following an accident is achieved automatically by the protection and safety monitoring system or by the operator as instructed by an Emergency Response Guideline.

19.38 Reactor Vessel Reflooding

Reflooding of the in-vessel core debris will occur following an accident if the reactor coolant system is sufficiently depressurized and if the in-containment refueling water storage tank water can enter the reactor vessel, either through one or both in-containment refueling water storage tank gravity injection lines or through a break in the reactor coolant system.

Successful reflooding of the reactor vessel following an accident that resulted in core damage provides additional cooling to core debris and the vessel wall. It may also have the undesirable effect of leading to the production of hydrogen if water reacts with unoxidized zirconium and molten core debris.

19.39 In-Vessel Retention of Molten Core Debris

19.39.1 Introduction

In-vessel retention of molten core debris through water cooling of the external surface of the reactor vessel is a severe accident management feature of the AP1000. During postulated severe accidents, the accident management strategy to flood the reactor cavity with in-containment refueling water storage tank water and submerge the reactor vessel is credited with preventing vessel failure in the AP1000 probabilistic risk assessment. The water cools the external surface of the vessel and prevents molten debris in the lower head from failing the vessel wall and relocating into containment. Retaining the debris in the reactor vessel protects containment integrity by eliminating the occurrence of ex-vessel severe accident phenomena, such as ex-vessel steam explosion and core-concrete interaction, which have large uncertainties with respect to containment integrity.

The AP1000 provides for in-vessel retention with features that promote external cooling of the reactor vessel:

- The reliable multi-stage reactor coolant system depressurization system results in low stresses on the vessel wall after the pressure is reduced.

- The vessel lower head has no vessel penetrations to provide a failure mode for the vessel other than creep failure of the wall itself.

- The floodable reactor cavity can submerge the vessel above the coolant loop elevation with water intentionally drained from the in-containment refueling water storage tank.

- The reactor vessel insulation provides an engineered pathway for water-cooling the vessel and for venting steam from the reactor cavity.

19.39.2 Background on the Application of In-Vessel Retention to the Passive Plant

The Risk-Oriented Accident Analysis Methodology (ROAAM) analysis of the in-vessel retention phenomena (References 19.39-1 and 19.39-2) provided the basis for the application of the in-vessel retention accident management strategy to the AP600 passive plant and quantification of vessel failure in the AP600 PRA (Reference 19.39-3). The ROAAM included an analysis of the in-vessel melt progression and evaluation of the structural and thermal challenges to the vessel during the relocation to the lower head, including in-vessel steam explosion. Testing and evaluation of the uncertainties associated with the thermal loads produced by the in-vessel circulating molten debris pool, and heat removal limitations due to boiling crisis on the exterior vessel surface were performed in the ACOPO (19.39-4) and ULPU programs (References 19.39-1 and 19.39-5). The ROAAM concluded that the limiting challenge to the vessel integrity is the thermal loading produced during the steady-state heat transfer to the lower head wall after complete debris relocation to the lower plenum. The in-vessel retention ROAAM analyses and testing showed that the water in the AP600 cavity will remove the heat produced by the molten debris bed in the lower head with significant margin while the structural integrity of the lower head was maintained.

Based on the ROAAM results, vessel failure in the AP600 was considered to be physically unreasonable, and a probability of zero was applied to vessel failure in the AP600 PRA (Reference 19.39-3) if the following conditions of the ROAAM analysis were met:

- The reactor coolant system was depressurized.
- The reactor vessel was submerged sufficiently to wet the heated surface.
- Reactor vessel reflective insulation and containment water recirculation flow paths allowed sufficient ingress of water and venting of steam from the cavity.
- The treatment of the lower head outside surface (painting, coatings, etc.) did not interfere with water cooling of the vessel.

19.39.3 Application of In-Vessel Retention to the AP1000 Passive Plant

To establish a strong basis for crediting in-vessel retention in the AP1000, the following steps are taken:

- Establish design measures to increase the capability of the water to remove heat from the external surface of the reactor vessel (increase critical heat flux).
- Demonstrate that the thermal failure remains the limiting failure over the structural failure for the AP1000.
- Demonstrate that the AP1000 in-vessel melt progression does not change from the AP600 melt progression in such as way as to challenge the vessel integrity during relocation.
- Demonstrate that the heat load correlation, as applied from the ACOPO program (Reference 19.39-4), scales appropriately to the AP1000.
- Quantify the thermal loads using probability distributions developed specifically for the AP1000.

These items are discussed in the following sections.

19.39.4 Reactor Vessel Failure Criteria

The conclusions of the structural analyses performed for the AP600 in Reference 19.39-1 can be extrapolated to the AP1000. Thus, for the AP1000, success of in-vessel retention can be based solely on the thermal success criterion.

19.39.5 In-Vessel Melt Progression and Relocation

The AP1000 core and lower internals geometry has been changed from the AP600 geometry as a result of the higher power output. The core is made up of 157 fuel assemblies with a 14-foot active fuel length. To accommodate the larger reactor core, the thick stainless steel reflector has been replaced by a 7/8″ thick core stainless steel shroud. The thick bottom plate of the shroud is

mounted flush on the support plate. There are no former plates in the annulus between the shroud and the core barrel. The core barrel is 2″ thick and hangs from the upper head flange. Cooling holes through the core shroud provide cooling flow to the shroud from the core flow.

The phenomena associated with melting the core and the relocation of the molten debris to the lower plenum play an important role in the composition and configuration of the debris pool (Reference 19.39-2). In turn, the characteristics of the debris pool significantly impact the heat loading to the lower head wall and the challenge to lower head integrity (Reference 19.39-1). Therefore, understanding the melting and relocation scenarios plays an important role in the assessment of in-vessel retention of molten core debris in the lower plenum.

The important conclusions from the analysis of the lower plenum debris pool formation are:

- The lower plenum debris bed is cooled with water during the entire relocation process prior to contact with the support plate. Transient debris configurations are not predicted to threaten vessel integrity.

- The lower plenum oxide debris subsumes the lower core support plate before dry out in the lower plenum occurs. If the relocated debris is assumed to be instantaneously quenched in the lower plenum water, the oxide debris contacts the lower support plate before the debris can return to a superheated condition. Therefore, the lower core support plate, core shroud and a sizeable fraction of the core barrel are subsumed in the debris bed. The focusing effect is mitigated.

- The lower plenum debris bed is predicted to form a metal layer over oxide pool configuration.

- The potential for debris interaction creating a bottom metal pool of uranium dissolved in zirconium is expected to be small.

- The earliest time to achieve the fully molten, circulating debris bed in the lower plenum is 2.7 hours after event initiation.

19.39.6 Application of Heat Transfer Correlations to the AP1000

19.39.6.1 Debris Pool to Vessel Wall Heat Transfer

The heat transfer from the oxide pool containing the decay heat producing fission products to the lower head of the reactor vessel is described using correlations that were developed in the Department of Energy (DOE) program for the AP600 in-vessel retention assessment.

The correlations developed in the ACOPO experiments and used in the AP600 in-vessel retention ROAAM for heat transfer from the debris pool to the lower head wall are applicable for use in the AP1000 in-vessel retention analysis.

19.39.6.2 Vessel Wall to External Cooling Water Heat Transfer

The heat transfer from the vessel wall to the cooling water is limited by the transition to film boiling at the external surface of the vessel wall. The maximum heat flux that can be removed prior to the transition to film boiling is the critical heat flux. If the heat flux from the debris pool to the wall is less than the critical heat flux, the vessel maintains sufficient strength to carry the load on the vessel. At heat fluxes above the critical heat flux, the external wall temperature increases significantly, the strength of the wall is lost, and the vessel fails.

Testing has been performed with ULPU-2000 Configuration IV (reference 19.39-4) which demonstrates the feasibility of increasing the critical heat flux for AP1000. The heat removal capability is enhanced by constructing a hemispherical baffle outside the lower head to channel the cooling water flow and by assuring the flooding level in the containment outside the reactor vessel is sufficient for two phase natural circulation (Reference 19.39-4).

The AP1000 employs a reactor vessel insulation design that provides water inlet, steam venting and a baffle around the lower head to enhance the heat removal and increase the critical heat flux on the reactor vessel external surface. The insulation is vented from the annulus between the insulation and vessel to the vessel nozzle gallery at the 98 ft elevation.

19.39.7 Quantification of Heat Load on the Reactor Vessel Wall

With the baffle installed in the AP1000 and the cavity adequately flooded, significant margin-to-failure for in-vessel retention via external reactor vessel cooling is achieved.

Based on the results of the ROAAM testing and analysis and the UPLU-2000 Configuration IV testing, vessel failure is concluded to be physically unreasonable in the AP1000 PRA provided the following conditions are met:

- The reactor coolant system is depressurized.
- The vessel is submerged adequately to promote natural circulation of water through the baffle surrounding the lower head.
- Reactor vessel reflective insulation remains structurally sound under the pressure loads produced by the boiling external to the reactor vessel, allows water inlet at the bottom and venting of steam at the top, and provides the proper baffling to increase the critical heat flux on the external surface of the vessel lower head.
- The reactor vessel external surface conditions do not preclude the wetting phenomena identified as the cooling mechanism in the ULPU testing.

19.39.8 Reactor Coolant System Depressurization

Reactor coolant system depressurization is discussed in Section 19.36.

19.39.9 Reactor Cavity Flooding

Reactor cavity flooding is accomplished through either operator action or through the progression of the accident. The operator floods the cavity by opening a motor-operated valve and a squib valve in the recirculation lines between the in-containment refueling water storage tank and the containment recirculation sump, as shown in Figure 19.39-15. The operator action is prescribed by entering the AFR-C.1 Function Restoration Guideline (Reference 19.39-6) when the core-exit thermocouples reach 1200°F. The water floods the containment by flowing out of the recirculation screens, filling the containment floodable region of the containment, shown in Figure 19.39-15, to at least the 107′ 2″ elevation, shown in Figure 19.39-16.

To achieve the high critical heat flux for the AP1000 lower head, water level in containment must be sufficient for two phase natural circulation flow. The vents from the AP1000 reactor vessel insulation exit to the vessel nozzle gallery at the 98 ft elevation. It is conservatively assumed that the water level in the containment has to reach the 98 ft elevation within seventy minutes after the core exit temperature exceeds 1200°F, for successful vessel cooling.

The AP600 procedures instructed the operator to flood the reactor cavity at the end of AFR-C.1 Function Restoration Guideline before entering the severe accident management guidelines. The AP1000 requires the cavity to be flooded to a higher level and more quickly than the AP600. For the AP1000, the operator action to initiate cavity flooding has been moved to the entry of the AFR-C.1 Function Restoration Guideline to meet the time requirement for cavity flooding success.

19.39.10 Reactor Vessel Insulation Design Concept

With respect to in-vessel retention severe accident management, the goal of the reactor vessel insulation is to ensure that there will always be an adequate water layer next to the reactor vessel to promote heat transfer from the reactor vessel. The insulation will define an optimized flow path next to the lower head to enhance the critical heat flux. The cooling of the vessel in a severe accident is accomplished by providing:

- A means of allowing water free access to the region between the reactor vessel and insulation.

- A frame that maintains the structural integrity of the insulation surrounding the lower head which provides the baffle for the water flow next to the vessel.

- A means to vent steam generated by the water cooling the vessel wall from the insulation surrounding the reactor vessel.

- A support frame to prevent the insulation panels above the vessel lower head from breaking free and blocking water from cooling the reactor vessel exterior surface.

19.39.10.1 Description of Reactor Vessel Insulation and Venting

Subsection 5.3.5 provides a description of the reactor vessel insulation and the functional requirements for the insulation.

19.39.10.2 Design Analysis of the Insulation and Support Frame

The insulation forms an engineered pathway to enhance the cooling of the external surface of the reactor vessel during in-vessel retention. Structural support to maintain this pathway must be provided.

19.39.10.3 Reactor Vessel External Surface Treatment

Based on the reactor vessel system design specification, the only treatment of the external surface of the reactor vessel is a protective paint applied by the manufacturer prior to shipping. The paint protects the vessel carbon steel surface. Testing of the paint in ULPU-2000 configuration III concluded that the aged painted surface did not inhibit the wetability of the lower head (Reference 19.39-1).

19.39.11 Reactor Vessel Failure

Based on the analysis of in-vessel retention, an intact reactor vessel remains intact if the reactor coolant system is depressurized and the reactor vessel is adequately submerged.

19.39.12 Summary

In-vessel retention of molten core debris via external reactor vessel cooling can be accomplished in the AP1000.

- The reactor vessel insulation must provide a structurally sound baffle around the lower head and lower cylinder of the vessel to channel the flow between the vessel and insulation. An insulation design that provides the proper water inlet, steam venting and flow baffling is specified for the AP1000.

- The reactor cavity must be flooded to an elevation of at least 98 ft prior to the onset of the steady–state heat flux to the vessel wall from the debris to produce the driving head required to enhance the critical heat flux on the vessel surface. The operator action to flood the cavity has been moved to the first step of the emergency operating procedures to provide adequate flooding.

19.39.13 References

19.39-1 Theofanous, T.G., et al., “In-Vessel Coolability and Retention of a Core Melt,” DOE/ID-10460, July 1995.

19.39-2 Theofanous, T.G., et al., “Lower Head Integrity Under In-Vessel Steam Explosion Loads,” DOE/ID-10541, June 1996.

19.39-3 AP600 PRA Report, GW-GL-022, August 1998.

19.39-4 Theofanous, T.G., and S. Angeli, "Natural Convection for In-Vessel Retention at Prototypic Rayleigh Numbers," Nuclear Engineering and Design, 200, 1-9 (2000).

19.39-5 Angelini, S., et al., "The Mechanism and Prediction of Critical Heat Flux in Inverted Geometries," Nuclear Engineering and Design, 200, 83-94 (2000).

19.39-6 AP600 Emergency Response Guidelines.

TABLES 19.39-1 THROUGH 19.39-3 NOT INCLUDED IN THE DCD.
FIGURES 19.39-1 THROUGH 19.39-15 NOT INCLUDED IN THE DCD.

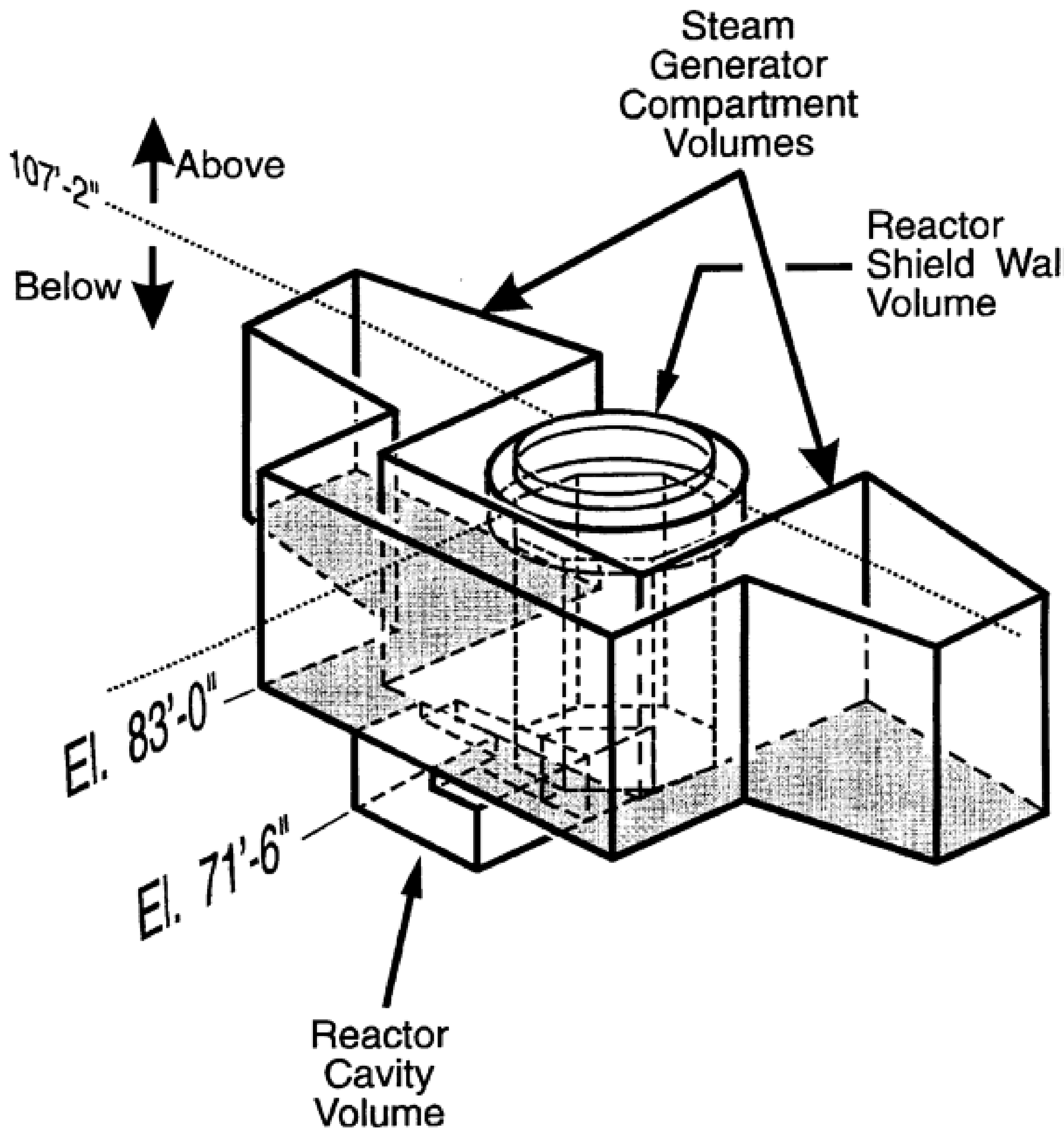

Figure 19.39-16

Containment Floodable Region

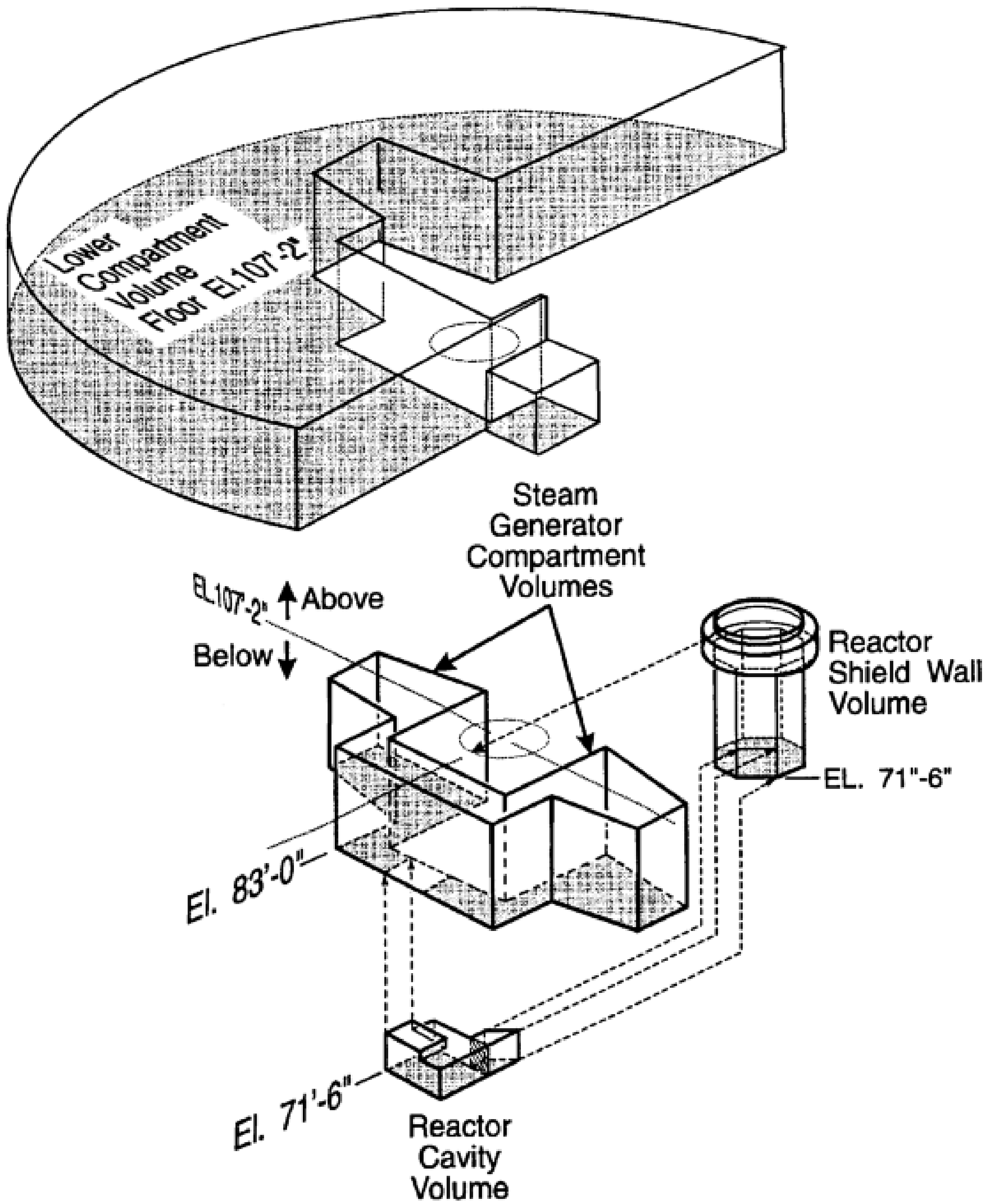

Figure 19.39-17

Containment Floodable Region – Expanded View

FIGURES 19.39-18 AND 19.39-19 NOT INCLUDED IN THE DCD.

19.40 Passive Containment Cooling

The Nuclear Regulatory Commission (NRC) containment performance goal for advanced containment systems is to provide a leak-tight barrier to fission product release for 24 hours following an accident, and to remain as a barrier against uncontrolled releases following that time. The AP1000 containment is cooled via the passive containment cooling system (PCS). Barring hydrogen combustion and ex-vessel phenomena that are addressed elsewhere in the AP1000 containment event tree analysis, the AP1000 containment is not expected to exceed the design-basis pressure during a severe accident. No threat to the containment integrity from long-term overpressurization is predicted.

In the event that design-basis cooling fails, the containment pressure will exceed the design basis, although containment failure within 24 hours is predicted to be highly unlikely. After 24 hours, the operator may vent the containment to prevent uncontrolled failure of the containment per the severe accident management guidelines. Once vented, the steam concentration in the containment will increase and improve the heat removal capacity of the passive cooling such that no further venting would be required.

19.41 Hydrogen Mixing and Combustion Analysis

19.41.1 Introduction

In the course of a severe accident, a substantial amount of combustible gases can be generated in-vessel from the oxidation of the zirconium and other metals. The AP1000 containment is provided with nonsafety-related hydrogen igniters to control the concentration of combustible gases. If the igniters operate, combustion of hydrogen plumes may present a thermal load to the containment. Combustible gas can accumulate in the containment at flammable concentrations if the igniter system fails to function. The AP1000 hydrogen analysis quantifies the threat to containment integrity with and without hydrogen igniters.

If vessel failure does not occur, the amount of hydrogen in the containment is limited to the mass generated during the in-vessel core heatup and relocation. If vessel failure occurs with water in the cavity, an additional amount of hydrogen may be generated from ex-vessel fuel-coolant interactions. Furthermore, if the debris layer in the cavity is not coolable or if insufficient water is available in the containment to cool the debris, and subsequent thermal attack of concrete occurs, additional hydrogen and other combustible gas, such as carbon monoxide, will be generated. The AP1000 PRA assumes containment failure if vessel failure is predicted, so the evaluation of containment integrity from hydrogen combustion only considers in-vessel hydrogen generation.

Hydrogen combustion is evaluated during two time frames: early (during the in-vessel relocation and hydrogen generation) and intermediate (prior to 24 hours after the onset of core damage). In the early time frame, containment challenge is considered from hydrogen burning as an unmixed plume (diffusion flame) and from local detonation at high concentrations in confined compartments below the operating deck. In the intermediate time frame when the hydrogen is mixed, containment challenge from global deflagration and potential detonation due to stratification of gases is considered. The hydrogen is assumed to burn within 24 hours of core damage.

19.41.2 Controlling Phenomena

The conditions required for combustion in the containment are flammable gas mixtures and the presence of an ignition source. Typically, a spark is sufficient to cause ignition. If the mixture temperature is above ~1000 K, auto-ignition can occur without the presence of an ignition source. The flammability limits are determined by the concentrations and temperature of the combustible gas-air-diluent mixture. Hydrogen and the oxygen in the air are the reactants in the combustion reaction. Steam, carbon dioxide, and excess nitrogen in the mixture act as inertants that may inhibit the reaction.

Hydrogen-air-steam mixtures can burn in several modes: diffusion flames, slow and accelerated deflagrations, and detonations (Reference 19.41-1). Burning of an unmixed hydrogen plume near the source results in a diffusion flame. Diffusion flames are stationary and result primarily in thermal loads on nearby structures or equipment. Deflagrations or detonations are burning of premixed gases. In practical terms, a slow deflagration is a flame that travels at a speed much slower than the speed of sound such that the pressure inside the containment equilibrates during the combustion. No dynamic loads are generated. Accelerated deflagrations travel fast enough to

generate shock waves and dynamic loads. Detonations travel at supersonic velocities and also generate dynamic loads. The static loads that result from deflagrations can be predicted and bounded. The maximum dynamic loads from accelerated flames and detonations are difficult to calculate.

Standing diffusion flames on the in-containment refueling water storage tank pool or at the in-containment refueling water storage tank vents can be postulated early into an accident following core uncovery for sequences in which the automatic depressurization system stages 1 through 3 provide a primary depressurization mechanism. A standing diffusion flame at the vent could present a thermal load to the containment steel shell, which is close to some of the vents. If the primary system break is in one of the PXS valve/accumulator rooms which flood with water and submerge the break, diffusion flames can also be postulated at the room exit in the maintenance floor. This location has a direct line of sight with the personnel and equipment hatches, electrical penetrations, and the containment shell, and may present a thermal loading challenge.

The static loads associated with deflagrations are limited by thermodynamics. If all of the chemical energy available in the mixture is converted to temperature and pressure, then the maximum pressure is limited by the adiabatic, isochoric (constant volume), complete combustion (AICC) pressure. The actual pressure would drop over time from this peak because of heat losses to water, structures, and equipment in containment. Dynamic pressure loads are not limited by the adiabatic, isochoric, complete combustion value because the local pressure is due to very rapid, nonequilibrium combustion.

The mode of combustion depends on the mixture concentrations, initial conditions, and boundary conditions (Reference 19.41-1). Near the hydrogen source, hydrogen may not be mixed significantly with the air in the containment. If ignition occurs there, then a diffusion flame may be formed. Further downstream from the hydrogen source, mixing will have occurred and a deflagration or detonation may result, depending on the hydrogen concentration and geometric boundary factors. In some cases, accelerated flames may also develop to detonations, which is called deflagration-to-detonation transition (DDT). The occurrence of flame acceleration and deflagration-to-detonation transition is complex and not completely understood. It is dependent on a number of parameters. These include hydrogen and oxygen concentrations; nature and concentration of inertants; gas temperature and pressure before ignition; ignition source; the size and shape of the compartment in which the combustion occurs; and the number, size, and shape of any obstacles in the compartment.

In AP1000, direct initiation of detonation by sufficiently high-energy sources from equipment in containment is unlikely (Reference 19.41-2: Since AP1000 is very similar to AP600, the phenomenological evaluations are valid for AP1000.), but mechanisms to accelerate a flame to a detonation may occur. Deflagration-to-detonation transition is considered the most likely mechanism. Transition to detonation is considered in several sections of the containment for accident sequences that result in hydrogen concentrations greater than 10 volume percent, including the passage connecting the two steam generator compartments, the core makeup tank and equipment bay, in-containment refueling water storage tank gas space, steam generator compartments, and steam generator operating deck.

19.41.3 Major Assumptions and Phenomenological Uncertainties

Because of phenomenological uncertainties, a number of assumptions are necessary in the hydrogen analysis.

19.41.3.1 Hydrogen Generation

The degree to which the cladding is oxidized during the in-vessel phase of the accident sequence and the availability of water to the core determines the rate and the mass of hydrogen released to the containment during the early time phase. The rate and mass of hydrogen produced are important parameters in determining the hydrogen concentration and the flammability limits of the gas mixtures in the containment compartments.

19.41.3.2 Containment Pressure

The containment pressure is an important parameter in the determination of the pre-burn boundary conditions. A higher initial pressure can result in a higher peak pressure, but the increased steam mass can inert the mixture and prevent combustion. If the passive containment cooling system water is not operational, containment pressures are elevated and combustion is steam inerted.

19.41.3.3 Flammability Limits

A flammable condition is determined by flammability limits. Flammability limits of a combustible gas mixture are defined as the limiting gas compositions at a given temperature and pressure in which a deflagration will propagate once ignited. There is information on flammability limits of hydrogen-air-steam mixtures at temperatures less than 149°C. For hydrogen, there are two lean propagation limits considered, upward and downward. At lean upward propagation limits, flames will propagate upward because of buoyancy. At lean downward propagation limits, flames will propagate upward and downward throughout the volume by their own reaction kinetics. Hence, the extent of flame propagation (or combustion completeness) for combustion at lean flammability limits is determined by the hydrogen concentration. This relation is a result from the Nevada Test Site (Reference 19.41-3). The addition of steam or other inert gas has a strong effect on the hydrogen concentration and flammability (Reference 19.41-4).

Combustion initiated by igniters occurs at lean upward flammability limits with a small pressure rise. However, with the failure of igniters, combustion at a hydrogen mixture at a concentration above the lean downward propagation limits may result in much larger pressure and temperature consequences. The global burn considered in the analysis is defined as combustion at or above the lean downward propagation limits. This definition includes the possibility that a global burn becomes a detonation, since the occurrence of a detonation requires a hydrogen concentration much above the lean downward propagation limits. Combustion regimes and associated adiabatic, isochoric, complete combustion pressure are approximately demonstrated for hydrogen-air mixtures in Reference 19.41-5.

19.41.3.4 Detonation Limits and Loads

A detonation is a supersonic combustion front that produces a dynamic load in excess of the adiabatic, isochoric, complete combustion value. The energy release from the combustion of the

hydrogen-air-steam mixture sustains the shock structure that ignites and burns the mixture. The detonation limits cannot currently be predicted by any first-principles theory. Engineering correlations used to predict the limits have been developed based on a measurable quantity called the detonation cell width. For simplified discussion, the detonation cell width can be considered a characteristic length that describes the sensitivity of the mixture to detonation. The smaller the detonation width, the easier it is to get the mixture to detonate and sustain propagation. Deflagration-to-detonation transition is considered, and the method of NUREG/CR-4803 (Reference 19.41-6) is used to evaluate the potential for flame acceleration.

Since the lowest hydrogen concentration for which deflagration-to-detonation transition has been observed in the intermediate-scale FLAME facility at Sandia is 15 percent (Reference 19.41-7), and 10 CFR 50.34(f) limits hydrogen concentration to less than 10 percent, the likelihood of deflagration-to-detonation transition is assumed to be zero if the hydrogen concentration is less than 10 percent.

19.41.3.5 Igniter System

The AP1000 nonsafety-related hydrogen igniter system, if operational during a severe accident, will burn hydrogen as soon as the lean upward flammability limits are met. Thus, the concentration of hydrogen is maintained, on average, at the lean upward flammability limits. However, depending on the hydrogen release rate, location and oxygen availability, locally high concentrations may exist in the in-containment refueling water storage tank or in the subcompartment where the pipe break occurs.

The hydrogen igniters are actuated by manual action when core-exit temperature exceeds a predetermined temperature as directed by the emergency response guidelines (ERG). The indication and actuation are done with containment conditions within the equipment qualification limits of the systems used, within the design basis of the plant and systems, and before fission-product releases to the containment, so equipment survivability of the monitoring and actuation systems during the time frame that they are required to perform is supported.

19.41.3.6 Other Ignition Sources

A flammable mixture will not burn without an ignition source unless the temperature of the mixture is sufficiently high (~1000 K) that auto-ignition becomes possible. Hot surfaces or random sparks from equipment or static electricity may be postulated ignition sources. High-temperature gas jets exiting from the reactor coolant system may become an ignition source. However, the gas stream may not have enough momentum to entrain the surrounding flammable mixture, especially in the depressurized cases.

19.41.3.7 Severe Accident Management Actions

Severe accident management guidance that is considered in the AP1000 PRA is the operator action to flood the reactor cavity in the event of core damage. This action often results in the late reflooding of a damaged core due to the time required for the operator to diagnose the problem and take the action. Some events will lead to core reflooding through the natural progression of the accident.

19.41.4 Hydrogen Generation and Mixing

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19.41.5 Hydrogen Burning at Igniters

Analyses of AP600 demonstrated the effectiveness of the hydrogen igniter system as placed in the passive containment geometry. The cases in the burning analysis were chosen for variation in hydrogen generation rate, release locations into containment, in-containment refueling water storage tank water level, and PXS compartment flooding. The cases considered 100 percent cladding reaction. The behavior of the AP1000 is essentially the same as the AP600 with respect to hydrogen release rates and locations.

Generally, the reactor coolant system is depressurized prior to hydrogen generation. Hydrogen is released to the containment through ADS stage 4 as it is generated in the core. Natural circulation in the containment provides oxygen for burning the hydrogen at the igniters in the loop compartments, close to the source. The loop compartments are shielded from the containment shell and most equipment and instrumentation that would be used to mitigate and monitor the accident.

Igniters located in the IRWST, PXS and CVS compartments, CMT room and at various elevations in the upper compartment provide coverage for hydrogen that may be released through the IRWST, PXS/CVS or in the CMT room.

The igniter system maintains the global uniform hydrogen concentration in the containment at or below lower flammability limits. In the most likely severe accidents, the hydrogen is burned primarily in a favorable location that protects the integrity of the containment and mitigative and monitoring equipment.

19.41.6 Early Hydrogen Combustion

Early hydrogen combustion is defined as burning that occurs during the period the hydrogen is released from the primary system to the containment. During this time, the hydrogen may not be well mixed in the containment and, depending on release locations, may be concentrated in the in-containment refueling water storage tank, PXS valve/accumulator rooms or chemical and volume control system room, steam generator compartments or maintenance floor. If sufficient oxygen is available, the compartments may become locally detonable. If oxygen is not available in the compartment, the plume may travel to a location where oxygen is available and it can burn as a diffusion flame.

19.41.6.1 Hydrogen Generation Rates

Qualitative hydrogen generation characteristics can be inferred from the availability of steam and the availability of overheated, unreacted zirconium in the reactor vessel. Based on the insights from hydrogen generation and mixing analyses, the hydrogen generation can be classified into one of three categories: boiloff generation rate, early-reflood generation rate, and late-reflood generation rate. This section briefly defines each type of hydrogen release in the AP1000 hydrogen analysis and the conditions under which they occur.

19.41.6.1.1 Boiloff Hydrogen Generation

Boiloff hydrogen generation occurs as the water inventory in the reactor vessel is depleted by decay heat. The steam generation is limited to the decay heat boiloff in the covered fraction of the core and overheated, unreacted zirconium surface area is limited to the upper regions of the core, which have not relocated below the water line. Core relocation to the lower head may produce a rapid steam generation that produces a brief period of rapid oxidation, but by this time, the core geometry is lost and very little unoxidized zirconium surface area is available for sustained hydrogen production.

19.41.6.1.2 Early-Reflood Hydrogen Generation

Early-reflood hydrogen generation occurs in the event of the reflooding of an overheated, relatively intact core. Quenching of the core provides a large quantity of steam and a large, overheated, unreacted zirconium surface area for oxidation. Shattering of the cladding due to thermal stresses can enhance the oxidation rate. In the early-reflood case, the oxidation of the zirconium is limited only by the degree of core uncovery prior to the reflood. The rate and degree of zirconium oxidation is expected to be greater than the no-reflood case.

19.41.6.1.3 Late-Reflood Hydrogen Generation

Late-reflood hydrogen generation occurs in the event of a reflood after the core has degraded significantly and possibly after relocation to the lower head. Much of the core geometry is lost and little surface area is available for oxidation, even when steaming from quenching debris is available.

19.41.6.2 Hydrogen Release Locations

The hydrogen release locations in the containment determine the hydrogen mixing in the containment and regions of high hydrogen concentration in the event that the igniters fail. The flow paths from release points in confined compartments to the volumes where oxygen is available determine possible locations where diffusion flames may occur.

19.41.6.2.1 Automatic Depressurization System Stages 1, 2, and 3

Stages 1, 2 and 3 of the automatic depressurization system relieve the reactor coolant system pressure from the top of the pressurizer to the in-containment refueling water storage tank. The water level in the in-containment refueling water storage tank at the time of the release determines the steam concentration in the tank. If the spargers are covered, the steam is quenched out of the gas flow and the hydrogen is released to the gas space of the tank. If the spargers are not covered, the steam concentration is high and will drive the air out of the tank. If the igniters are available, diffusion flames may be postulated at the in-containment refueling water storage tank vent exits for large sustained hydrogen releases. If igniters are not available, the possibility of hydrogen detonation is evaluated.

19.41.6.2.2 Automatic Depressurization System Stage 4

Stage 4 of the automatic depressurization system relieves steam and hydrogen from the hot leg of the reactor coolant system to the steam generator compartments in the containment. The steam generator compartments, along with the maintenance floor and the upper compartment, form the major natural-circulation path in the containment. Oxygen starvation of any potential diffusion flames in the steam generator compartment is not expected for low-pressure hydrogen releases from automatic depressurization system stage 4. The containment shell is sheltered from flames in the steam generator compartments by the concrete walls, so diffusion flames at the igniters in the steam generator compartments are not considered to be a threat to the containment integrity. If igniters are not available, good mixing in the compartment mitigates the threat of detonation for the low-pressure releases.

19.41.6.2.3 Break Location

The reactor coolant system break provides a pathway from the reactor coolant system to one of several compartments in the containment. A failure of a component in the reactor coolant system loop (hot leg or cold leg) will relieve hydrogen to the loop compartment. Hydrogen released from the break to the loop compartment will behave similarly to the hydrogen released from stage 4 automatic depressurization system.

A failure of the direct vessel injection line or a break in the chemical and volume control system piping will relieve hydrogen to one of the small compartments under the maintenance floor, the chemical and volume control system room or one of the two PXS valve/accumulator rooms. These compartments are dead-ended and communicate with the maintenance floor through stairway or room vents. The initial blowdown through the break fills the compartment with steam and drives the air out of the compartment. After the blowdown and reactor coolant system depressurization, countercurrent flow between the compartment and the maintenance floor slowly replenishes the air.

Each of the dead-ended compartments has a one-way drain to the containment sump in the cavity. The break flow into a dead-ended compartment will not fill the compartment with water, as the draining and flashing of the break flow removes the water to the containment sump. However, a broken direct vessel injection line in a PXS valve/accumulator room may allow the in-containment refueling water storage tank to drain into the PXS valve/accumulator room if the injection valves open in the broken line. The draining of the in-containment refueling water storage tank water into the PXS valve/accumulator room will fill the PXS valve/accumulator room and spill water over the curb into the maintenance floor.

If the igniters are available, hydrogen released to the dead-ended compartments during the core degradation may burn initially, but may become oxygen starved. The plume then rises through the stairway to the maintenance floor, which is amply supplied with oxygen by the containment natural circulation. A diffusion flame can be postulated at the exit of the dead ended compartments in the maintenance floor. The exterior wall of the maintenance floor is the steel containment shell below the passive containment cooling system annulus, the lower-level equipment hatch, and the personnel hatch. Many electrical penetrations pass through the maintenance floor wall to the auxiliary building.

19.41.6.3 Early Hydrogen Combustion Ignition Sources

For a burn to be initiated, an ignition source is required. Igniters mitigate the threat to the containment integrity from global deflagration and detonation. If a hydrogen plume can produce a diffusion flame, the igniters provide the ignition source.

19.41.7 Diffusion Flame Analysis

Diffusion flames can be postulated to occur at vents or exits from compartments with a hydrogen source that are dead-ended or not well-mixed. Incombustible gas mixtures that include a high concentration of hydrogen may develop in the compartment. When the plume of hydrogen exits the compartment into a room containing oxygen and an ignition source, burning of the plume as a standing flame at the vent may produce locally high temperatures. If the release of hydrogen is sustained, the heat load from the burning may threaten equipment, including the containment shell integrity.

The overall geometry of the AP1000 containment is relatively open. Ninety-seven percent of the containment free volume participates in containment natural circulation and is well-mixed. However, the IRWST, PXS and CVS compartments are small, confined rooms that may have a hydrogen source, and thus may be postulated to produce a diffusion flame at vents. This section discusses the conditions that may produce a standing diffusion flame in these locations, and presents the quantification of the containment failure probability given the presence of a sustained diffusion flame at a dead-ended compartment vent.

AP1000 Diffusion Flame Mitigation Strategy

Hydrogen is a byproduct of a severe accident, and hydrogen pathways to the IRWST, PXS and CVS subcompartments cannot be completely ruled out, particularly in the IRWST, to which the effluent of the first stages of the reactor coolant system automatic depressurization system are directed. The other compartments can only have hydrogen releases in the event that a break occurs there, but some of the highest frequency severe accident sequences have breaks in a DVI line, which traverses a PXS compartment. Therefore, the potential for diffusion flames from these subcompartment locations cannot be excluded from the probabilistic risk assessment.

The AP1000 addresses diffusion flames by adopting a defense-in-depth philosophy in the design. In the highest frequency severe accidents, sustained hydrogen release is prevented from occurring in the dead-ended compartments. In sequences where diffusion flames at IRWST or PXS/CVS compartment vents may be postulated, design strategies are initiated to mitigate the threat to the containment integrity by locating hydrogen plumes away from the containment shell.

The first level of defense against the threat to containment integrity from diffusion flames is the prevention of sustained hydrogen releases to dead-ended compartments. The highest frequency severe accident sequences have full reactor coolant system depressurization prior to core damage. Hydrogen is released at low pressure to the containment as it is produced in the core. Stage four of the automatic depressurization system provides a pathway of substantially lower resistance (by approximately one order of magnitude) compared to the maximum break size in the DVI line that relieves to the PXS compartment and to the other three ADS stages that relieve to the IRWST.

Additionally, the ADS spargers in the IRWST generally have a 10-ft static head of water above them, which further increases the resistance to flow of hydrogen to the IRWST.

Hydrogen released from ADS stage 4 is relieved to the loop compartments, which are supplied with oxygen by the containment natural circulation and shielded from the containment shell by high concrete walls. Hydrogen is able to burn in the loop compartments without threatening the containment integrity. Therefore, ADS stage 4 provides the first level of defense against diffusion flames.

In the event that ADS stage 4 fails to adequately direct hydrogen away from confined compartments, the compartment vents are designed to preferentially release the hydrogen at locations where it burns away from the containment shell.

Vents from the PXS and CVS compartments to the CMT room are located well away from the containment shell and containment penetrations. Access hatches to the subcompartments that are near the containment shell are covered and secured closed such that they will not open as a result of a pipe break inside the compartment. Therefore, hydrogen releases to the CMT room from the subcompartments are not considered as a threat to the containment integrity.

19.41.8 Early Hydrogen Detonation

Hydrogen detonation can be initiated from a high-energy ignition source or by deflagration-to-detonation transition during flame acceleration. A review of potential ignition sources in containment concludes that the maximum source is too small to directly initiate a detonation (Reference 19.41-2: Since AP1000 is very similar to AP600, the phenomenological evaluations are valid for AP1000.). Therefore, the occurrence of detonation is related to the potential for deflagration-to-detonation transition in the AP1000 containment analysis.

The methodology of Sherman and Berman (Reference 19.41-6) is used to evaluate the likelihood of deflagration-to-detonation transition. The analysis considers the hydrogen release rates to the containment, core reflooding, the containment release locations, and in-containment refueling water storage tank and PXS valve/accumulator room water levels to determine the probabilities.

19.41.9 Deflagration in Time Frame 3

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19.41.10 Detonation in Intermediate Time Frame

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19.41.11 Safety Margin Basis Containment Performance Requirement

The AP1000 containment meets the criteria of the safety margin basis containment performance requirement.

19.41.12 Summary

The major insights of the hydrogen mixing and combustion analysis are as follows:

- No containment failure from hydrogen is predicted if the hydrogen igniters are operational.
- Operation of the stage 4 automatic depressurization system valves releases much of the hydrogen generated in the reactor coolant system to the steam generator rooms where it can be well mixed in the containment to mitigate the threat of diffusion flames from sustained hydrogen released through the in-containment refueling water storage tank.
- The threat of detonation is predominantly due to hydrogen releases to the PXS valve/accumulator rooms below the 107′ 2″ containment elevation (direct vessel injection line breaks). The compartment is a confined region with little ventilation. Equipment and grating are present to promote turbulence. A break in the compartment induces a high-temperature environment creating good conditions for potential deflagration-to-detonation transition.
- The probability of containment failure due to diffusion flame is very small.
- No containment failure is predicted from deflagration.

Analyses are performed to meet the requirements of 10 CFR 50.34(f). Igniter burning analyses with rapid hydrogen generation and 100-percent cladding reaction conclude that the igniter system maintains the global uniform hydrogen concentration in the containment at or below lower flammability limits. If the stage 4 automatic depressurization system is available, the hydrogen is well mixed in the containment and no excessive concentrations are predicted in the in-containment refueling water storage tank or PXS valve/accumulator rooms. If the stage 4 automatic depressurization system is failed, hydrogen in the in-containment refueling water storage tank and PXS valve/accumulator rooms can reach high concentrations. However, the mixtures are oxygen starved and are not flammable or detonable. The safety margin basis containment performance requirement is met as the loss-of-coolant accident plus 100-percent active cladding reaction hydrogen burn peak pressure provides margin to the ASME Service Level C stress limits.

19.41.13 References

19.41-1 Tieszen, S. R., et al., “Hydrogen Distribution and Combustion,” in Ex-Vessel Severe Accident Review for the Heavy Water New Production Reactor (ed. by K. D. Bergeron), NPRW-SA90-3, Sandia National Laboratories, 1993.

19.41-2 “AP600 Phenomenological Evaluation Summaries,” WCAP-13388 (Proprietary) Rev. 0, June 1992 and WCAP-13389 (Nonproprietary), Rev. 1, 1994.

19.41-3 Ratzel, A. C., “Data Analysis for the Nevada Test Site (NTS) Premixed Combustion Tests,” NUREG/CR-4138, SAND85-0135, Sandia National Laboratories, 1985.

19.41-4 Hertzber, Martin, “Flammability Limits and Pressure Development in Hydrogen-Air Mixtures,” Proc. Workshop on the Impact of Hydrogen on Water Reactor Safety, Volume III, NUREG/CR-2017, SAND81-0661, Sandia National Laboratories, 1981.

19.41-5 Sherman, M. P., et al., “Deliberate Ignition and Water Fogs as H2 Control Measures for Sequoyah,” Proc. Workshop on the Impact of Hydrogen on Water Reactor Safety, Volume IV, NUREG/CR-2017, SAND81-0661, Sandia National Laboratories, 1981.

19.41-6 Sherman, M. P., and Berman, M., “The Possibility of Local Detonation During Degraded Core Accidents in the Bellefonte Nuclear Plant,” NUREG/CR-4803, SAND86-1180, Sandia National Laboratories, 1987.

19.41-7 Sherman, M. P., et al., “FLAME Facility,” NUREG/CR-5275, SAND85-1264, Sandia National Laboratories, 1989.

19.42 Conditional Containment Failure Probability Distribution

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19.43 Release Frequency Quantification

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19.44 MAAP4.0 Code Description and AP1000 Modeling

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19.45 Fission Product Source Terms

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19.46 Deleted

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19.48 Deleted

19.49 Offsite Dose Evaluation

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19.50 Importance and Sensitivity Analysis

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19.51 Uncertainty Analysis

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19.52 Deleted

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19.54 Low Power and Shutdown PRA Assessment

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19.55 Seismic Margin Analysis

19.55.1 Introduction

In accordance with Section II.N, Site-Specific Probabilistic Risk Assessments and Analysis of External Events, of SECY-93-087 (Reference 19.55-1), the U.S. Nuclear Regulatory Commission (NRC) approved the following staff recommendations:

> "PRA insights will be used to support a margins-type assessment of seismic events. A PRA-based seismic margin analysis will consider sequence-level High Confidence, Low Probability of Failures (HCLPFs) and fragilities for all sequences leading to core damage or containment failures up to approximately one and two-thirds the ground motion acceleration of the Design Basis SSE."

The AP1000 risk-based seismic margin analysis (SMA) satisfies this recommendation of SECY-93-087.

Since the AP1000 nonsafety-related components are not Seismic Category I, it is conservatively assumed for the risk-based seismic margin analysis that no credit is taken for the mitigation functions of the nonsafety-related components and systems. For this risk-based seismic margin analysis, HCLPFs are calculated and reported for systems at the sequence level.

The seismic margin analysis is made based on established criteria, design specifications, existing qualification test reports, established basic design characteristics and configurations, and public domain generic data.

Seismic margins methodology is employed to identify potential vulnerabilities and demonstrate seismic margin beyond the design-level safe shutdown earthquake (SSE). The capacity of those components required to bring the plant to a safe, stable condition is assessed. The structures, systems, and components identified as important to seismic risk are addressed.

19.55.2 Calculation of HCLPF Values

19.55.2.1 Seismic Margin HCLPF Methodology

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19.55.2.2 Calculation of HCLPF Values

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19.55.2.2.1 Review of Plant Information

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19.55.2.2.2 System Analysis

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19.55.2.2.3 Analysis of Structure Response

Relay Chatter

Solid-state switching devices and electromechanical relays will be used in the AP1000 protection and control systems. Solid-state switching devices are inherently immune to mechanical switching discontinuities such as contact chatter. Robust electromechanical relays are selected for AP1000 applications such that inherent mechanical contact chatter is within the required system performance criteria.

19.55.2.2.4 Evaluation of Seismic Capacities of Components and Plant

Table 19.55-1 provides the HCLPF values for the equipment, structures, and systems considered in the seismic margin evaluation. The evaluation considers the effect of uplift of the nuclear island basemat from the hard rock foundation. All of the HCLPF values are above the review level earthquake.

In the design of the AP1000, careful consideration is given to those areas that are recognized as important to plant seismic risk. In addition to paying special attention to those critical components that have HCLPF values close to the review level earthquake, the design process considers potential interaction with both safety-related and nonsafety-related systems or structures, as well as adequate anchorage load transfer and structural ductility.

19.55.2.2.5 Verification of Equipment Fragility Data

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19.55.2.2.6 Turbine Building Seismic Interaction

As part of the seismic margin assessment, the seismic interaction between the Turbine Building and the Nuclear Island was evaluated. The Turbine Building is designed to the Uniform Building Code requirements. It is taller than the Auxiliary Building, which is a Seismic Category I structure. The Auxiliary Building contains important safety-related equipment. The Turbine Building is adjacent to the north-end wing of the Auxiliary Building, the wing containing the main control room and the shutdown panel, as well as I&C rooms and I&C penetration rooms. The main structure of the Turbine Building is separated from the Nuclear Island by an access bay. The consequences of the potential Turbine Building collapse onto and falling debris penetrating the Auxiliary Building was evaluated and it was determined that:

- The adjacent Auxiliary Building structural integrity will not be lost with the failure of the Turbine Building.
- It is not likely that the size and energy of debris from the Turbine Building will be large enough to result in penetration through the Auxiliary Building roof structure.

19.55.3 Seismic Margin Model

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19.55.4 Calculation of Plant HCLPF

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19.55.5 Sensitivity Analyses

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19.55.6 Results and Insights

The AP1000 seismic margin analysis has demonstrated that for structures, systems, and components required for safe shutdown, the high confidence of low probability of failures magnitudes are equal to or greater than the review level earthquake.

19.55.7 References

19.55-1 "SECY-93-087 - Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," USNRC Memorandum, July 21, 1993, Chilk to Taylor.

Table 19.55-1 (Sheet 1 of 4)

SEISMIC MARGIN HCLPF VALUES

Description	Median pga [8]	βc	HCLPF Value [8]	Basis
Buildings/Structures				
Shield Building Roof – Tension Ring	-	-	0.74g	[5]
Shield Building Roof – Columns	-	-	0.60g	[5]
Containment Vessel – Buckling	1.57g	0.41	0.61g	[3]
Containment Vessel – Overturning	5.74g	0.62	1.38g	[3]
Containment Baffle Support Failure	-	-	1.4g	[4]
Interior Containment Structure & IRWST Tank	-	-	0.75g	[4]
Primary Components				
Reactor Pressure Vessel	-	-	0.74g	[4]
Reactor Pressure Vessel Supports	1.59g	0.36	0.69g	[3]
Reactor Internals and Core Assembly (includes fuel)	1.5g	0.51	0.5g	[1]
Control Rod Drive Mechanism (CRDM) and Hydraulic Drive Units	2.2g	0.51	0.7g	[1]
Pressurizer	-	-	0.59g	[4]
Pressurizer Support	1.04g	0.29	0.53g	[3]
Steam Generator	-	-	0.61g	[4]
Steam Generator Supports	1.03g	0.22	0.62g	[3]
Reactor Coolant Pump & Supports	2.2g	0.51	0.68g	[1]
Mechanical Equipment				
Polar Crane	-	-	0.94g	[4]
Piping – Support Controlled	3.3g	0.61	0.81g	[1]
Cable Trays – Support Controlled	2.2g	0.61	0.54g	[1]
Heat Exchanger (PRHR)	-	-	0.93g	[4]
Accumulator Tank	2.2g	0.46	0.76g	[1]
Core Makeup Tank	-	-	0.72g	[4]

Table 19.55-1 (Sheet 2 of 4)

SEISMIC MARGIN HCLPF VALUES

Description	Median pga [8]	βc	HCLPF Value [8]	Basis
Valves				
Room Number 11202	-	-	0.86g	[4]
Room Number 11206	-	-	0.86g	[4]
Room Number 11207	-	-	0.86g	[4]
Room Number 11208	-	-	0.86g	[4]
Room Number 11300	-	-	0.86g	[4]
Room Number 11301	-	-	0.86g	[4]
Room Number 11302	-	-	0.86g	[4]
Room Number 11304	-	-	0.86g	[4]
Room Number 11400	3.3g	0.61	0.81g	[1]
Room Number 11403	3.3g	0.61	0.81g	[1]
Room Number 11500	3.3g	0.61	0.81g	[1]
Room Number 11601	3.3g	0.61	0.81g	[1]
Room Number 11603	3.3g	0.61	0.81g	[1]
Room Number 11703	3.3g	0.61	0.81g	[1]
Room Number 12244	-	-	1.10g	[4]
Room Number 12254	-	-	0.86g	[4]
Room Number 12255	-	-	0.86g	[4]
Room Number 12256	-	-	0.86g	[4]
Room Number 12306	-	-	0.86g	[4]
Room Number 12362	3.3g	0.61	0.81g	[1]
Room Number 12401	3.3g	0.61	0.81g	[1]
Room Number 12404	3.3g	0.61	0.81g	[1]
Room Number 12405	3.3g	0.61	0.81g	[1]
Room Number 12406	3.3g	0.61	0.81g	[1]
Room Number 12452	3.3g	0.61	0.81g	[1]
Room Number 12454	3.3g	0.61	0.81g	[1]
Room Number 12555	3.3g	0.61	0.81g	[1]
Room Number 12701	3.3g	0.61	0.81g	[1]

Table 19.55-1 (Sheet 3 of 4)

SEISMIC MARGIN HCLPF VALUES

Description	Median pga [8]	βc	HCLPF Value [8]	Basis
Passive Containment Cooling System	-	-	0.60g	[5]
Electrical Equipment				
Battery	-	-	0.79g	[6]
Battery Racks	3.3g	0.46	1.14g	[1]
Battery Chargers	-	-	0.81g	[6]
125 DC Distribution Panel	-	-	0.58g	[6]
120 VAC Distribution Panel	-	-	0.58g	[6]
Transfer Switches	-	-	0.58g	[6]
125 VDC MCC	-	-	0.86g	[6]
125 VDC Switchboard	-	-	0.58g	[6]
Regulating Transformer	-	-	0.95g	[6]
Inverter	-	-	0.60g	[6]
4.16 KV Switchgear	-	-	0.69g	[6]
Reactor Trip Switchgear	-	-	0.60g	[6]
Hydrogen Monitor	-	-	1.03g	[6]
CMT Level Switch	-	-	0.83g	[6]
Neutron Detector	-	-	0.56g	[6]
Radiation Monitor	-	-	0.61g	[6]
RTD	-	-	3.54g	[6]
Speed Sensors	-	-	2.89g	[6]
Incore Thermocouple	-	-	3.71g	[6]
RCP Bearing Water Temperature Thermocouple	-	-	5.25g	[6]
PCS Water Flow Transmitter (el. 135.3′)	-	-	0.80g	[6]
PCS Water Flow Transmitter (el. 261′)	-	-	0.56g	[6]
PRHR HX Flow Transmitter	-	-	0.93g	[6]
RCS Flow Transmitter	-	-	0.93g	[6]
SG Start Up Flow Transmitter	-	-	0.61g	[6]
IRWST Level Transmitter	-	-	0.76g	[6]
PZR Level Transmitter	-	-	0.76g	[6]

Table 19.55-1 (Sheet 4 of 4)

SEISMIC MARGIN HCLPF VALUES

Description	Median pga [8]	βc	HCLPF Value [8]	Basis
SG Narrow Range Transmitter	-	-	0.77g	[6]
SG Wide Range Transmitter	-	-	0.77g	[6]
Air Storage Tank Pressurizer Transmitter	-	-	0.65g	[6]
Containment Pressurizer Sensor & Transmitter	-	-	0.82g	[6]
RCS Wide Range Pressure Transmitter	-	-	0.76g	[6]
PRZ Pressure Sensor	-	-	0.76g	[6]
MSL Pressure Transmitter	-	-	0.65g	[6]
ESFAC Cabinet	-	-	0.82g	[6]
Protection Logic Cabinet	-	-	0.82g	[6]
Integrated Protection Cabinet SWGR	-	-	0.82g	[6]
Multiplex Cabinet	-	-	0.82g	[6]
QDPS Cabinet	-	-	1.32g	[6]
MCR Support Operation Station	2.8g	0.46	0.97g	[1]
MCR Switch Station	2.8g	0.46	0.97g	[1]
QDPS and MCR Display	-	-	1.08g	[6]
MCR Isolation Damper	-	-	0.61g	[6]
Hydrogen Recombiner	-	-	1.03g	[6]
Power and Control Panels	-	-	1.03g	[6]
Ceramic Insulators	0.2g	0.35	0.09g	[2]

Notes:
1. HCLPF based on URD recommended generic fragility data
2. HCLPF based on recognized generic fragility data
3. HCLPF based probabilistic fragility analysis
4. HCLPF based on deterministic approach
5. HCLPF based on conservative deterministic fragility margin approach
6. HCLPF based on design margin as defined from test data
7. Component support will control HCLPF value
8. pga is the free field peak ground acceleration level for the seismic event

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TABLES 19.55-2 THROUGH 19.55-7 ARE NOT INCLUDED IN THE DCD.
FIGURE 19.55-1 IS NOT INCLUDED IN THE DCD.

19.56 PRA Internal Flooding Analysis

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19.57 Internal Fire Analysis

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19.58 Winds, Floods, and Other External Events

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19.59 PRA Results and Insights

19.59.1 Introduction

This chapter summarizes the use of the AP1000 PRA in the design process, PRA results and insights, plant features important to reducing risk, and PRA input to the design certification process.

AP1000 is expected to achieve a higher standard of severe accident safety performance than current operating plants, because both prevention and mitigation of severe accidents have been addressed during the design stage, taking advantage of PRA insights, PRA success criteria analysis, severe accident research, and severe accident analysis. Since PRA considerations have been integrated into the AP1000 design process from the beginning, many of the traditional PRA insights relating to current operating plants are not at issue for the AP1000. The Level 1, Level 2, and Level 3 results show that addressing PRA issues in the design process leads to a low level of risk. The PRA results indicate that the AP1000 design meets the higher expectations and goals for new generation passive pressurized water reactors (PWRs).

The core damage frequency (CDF) and large release frequency (LRF) for at-power internal events (excluding seismic, fire, and flood events) are 2.41E-07 events per reactor-year and 1.95E-08 events per reactor-year, respectively. These frequencies are at least two orders of magnitude less than a typical pressurized water reactor plant currently in operation. This reduction in risk is due to many plant design features, with the dominant reduction coming from highly reliable and redundant passive safety-related systems that impact both at-power and shutdown risks. These passive systems are much less dependent on operator action and support systems than plant systems in current operating plants.

The Level 3 analysis shows the potential offsite dose from a severe accident is very small and well within the established goals. The risk measured by the potential offsite dose does not increase significantly after the first 24 hours after a severe accident is assumed to cause a release to the environment.

Conservative, bounding fire and flood assessments show the core damage risk from these events is small compared to the core damage risk from at-power and shutdown events.

A synopsis of the insights gained from the PRA about the AP1000 design includes:

- The AP1000 design benefits from the high level of redundancy and diversity of the passive safety-related systems. The passive systems have been shown to be highly reliable, their designs are simple so that a limited number of components are required to function.

- AP1000 is less dependent on nonsafety-related systems than current plants or advanced light water reactor evolutionary plants.

- The nonsafety-related support systems (ac power, component cooling water, service water, and instrument air) have a limited role in the plant risk profile because the passive safety-related systems do not require cooling water or ac power.

- AP1000 is less dependent on human actions than current plants or advanced light water reactor evolutionary plants. Even when no credit is taken for operator actions, the AP1000 meets the NRC safety goal, whereas current plants may not.

- The core damage and large release frequencies are low despite the conservative assumptions made in specifying success criteria for the passive systems. The success criteria have been developed in a more systematic, rigorous manner than typical PRA success criteria. The baseline success criteria are bounding cases for a large number of PRA success sequences. The baseline success sequences, in most cases, have been defined with:

  – Worst (i.e., the most limiting) break size and location for a given initiating event

  – Worst automatic depressurization system (ADS) assumption in the success criterion

  – Worst number of core makeup tanks (CMT) and accumulators

  – Worst containment conditions for in-containment refueling water storage tank (IRWST) gravity injection

  Many less-limiting sequences are therefore represented by a baseline success criterion.

- Single system or component failures are not overly important due to the redundancy and diversity of safety-related systems in the design. For example, the following lines of defense are available for reactor coolant system (RCS) makeup:

  – Chemical and volume control system (CVS)

  – Core makeup tanks

  – Partial automatic depressurization system in combination with normal residual heat removal

  – Full automatic depressurization system with accumulators and in-containment refueling water storage tank

  – Full automatic depressurization system with core makeup tanks and in-containment refueling water storage tank

- Typical current PRA dominant initiating events are significantly less important for the AP1000. For example, the reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) event has been eliminated as a core damage initiator since AP1000 uses canned motor reactor coolant pumps which do not have seals. Another example is the loss of offsite power (LOOP) event. The station blackout and loss of offsite power event is a minor contributor to AP1000 since the passive safety-related systems do not require the support of ac power.

- Passive safety-related systems are available in all shutdown modes. Planned maintenance of passive features is only performed during shutdown modes when that feature is not risk

important. In addition, planned maintenance of nonsafety-related defense-in-depth features used during shutdown is performed at power.

- The AP1000 passive containment cooling design is highly robust. Air cooling alone is significant and may prevent containment failure, although the design has other lines of defense for containment cooling such as fan coolers and passive containment cooling water.

- The potential for containment isolation and containment bypass is lessened by having fewer penetrations to allow fission product release. In addition, normally open and risk important penetrations are fail-closed, thus eliminating the dependence on instrumentation and control (I&C) and batteries.

- The reactor vessel lower head has no vessel penetrations, thus eliminating penetration failure as a potential vessel failure mode. Preventing the relocation of molten core debris to the containment eliminates the occurrence of several severe accident phenomena, such as ex-vessel fuel-coolant interactions and core-concrete interaction, which may threaten the containment integrity. Therefore, AP1000, through the prevention of core debris relocation to the containment, significantly reduces the likelihood of containment failure.

- The potential for the spreading of fires and floods to safety-related equipment is significantly reduced by the AP1000 layout.

19.59.2 Use of PRA in the Design Process

The AP1000 design has evolved over a period of years, including the work done for the AP600 design. PRA techniques have been used since the beginning in an iterative process to optimize the AP600/AP1000 with respect to public safety. Each of these iterations has included:

- Development of a PRA model
- Use of the model to identify weaknesses
- Quantification of PRA benefits of alternate designs and operational strategies
- Adoption of selected design and operational improvements.

The scope and detail of the PRA model has increased from the early studies as the plant design has matured. This iterative design process has resulted in a number of design and operational improvements.

19.59.3 Core Damage Frequency from Internal Initiating Events at Power

Internal initiating events are transient and accident initiators that are caused by plant system, component, or operator failures. External initiating events, which include internal fire and flooding events and events at shutdown are discussed in other subsections.

The AP1000 mean plant core damage frequency for internal initiating events at power is calculated to be 2.41E-07 events per year. Twenty-six separate initiating event categories were defined to accurately represent the AP1000 design. Of these event categories, 11 are loss-of-coolant accidents, 12 are transients, and 3 are anticipated transients without scram

precursors (initiating events that result in an anticipated transient without scram sequence as a result of failure to trip the reactor). Initiating event categories unique to the AP1000 design have been defined and evaluated, including safety injection line breaks, core makeup tank line breaks, and passive residual heat removal heat exchanger (HX) tube ruptures. The resulting core damage frequency is very small; a value of 2.41E-07 means that only one core damage event is expected in 4 million plant-years of operation. This core damage frequency value is two orders of magnitude (i.e., 100 times) smaller than corresponding values typically calculated for current pressurized water reactors.

The contribution of initiating events to the total plant core damage frequency is summarized in Table 19.59-1. Figure 19.59-1 illustrates the relative contributions to core damage frequency from the various at-power initiating events. Table 19.59-2 shows the conditional core damage probability of the initiating events. The conditional core damage probability listed in Table 19.59-2 is the ratio of the core damage frequency contribution for an initiating event divided by the initiating event frequency.

Seven initiating events, including 6 loss-of-coolant accidents, and steam generator tube rupture (SGTR), make up approximately 92 percent of the total at-power plant core damage frequency. The remaining initiating events contribute a total of approximately 8 percent to the core damage frequency from internal events. The dominant initiating events are:

- Safety injection (DVI) line break
- Large loss-of-coolant accident
- Spurious ADS actuation
- Small loss-of-coolant accident
- Medium loss-of-coolant accident
- Reactor vessel rupture
- Steam generator tube rupture

Within this group of events, each of the first three contributes more than 10 percent to the total core damage frequency. These three events account for approximately 70 percent of the total core damage frequency. Small LOCA, medium LOCA, and reactor vessel rupture events contribute 7 percent, 6 percent and 4 percent, respectively.

The results show a very low core damage frequency dominated by rare events (initiating events that are not expected to occur during the lifetime of a plant). This indicates that the AP1000 design is robust with respect to its ability to withstand challenges from more frequent events (e.g., transients) and that adequate protection against the more severe events is provided through the defense-in-depth features.

Information regarding loss-of-coolant accident categories defined for the AP1000 PRA was presented in the discussion of PRA success criteria. For the PRA, the various loss-of-coolant accident categories have been defined based on which plant features are required to mitigate the events. As a result, the PRA and loss-of-coolant accident size definitions are not identical to the loss of coolant accident size definitions used in the Chapter 15, Accident Analyses included in

the *AP1000 Design Control Document* (DCD). The following listing shows how the PRA and DCD break sizes are related and identifies the PRA size criteria:

- DCD Chapter 15 break size definitions are large (break size greater than 1 ft.^{2}) or small (break size less than 1 ft.^{2}).

- PRA break sizes are defined as follows:

  – Large breaks are those with an equivalent inside diameter of approximately 9 in. or larger. Reactor vessel rupture is included in this category. The automatic depressurization system is not required for in-containment refueling water storage tank injection for large breaks. (For large breaks that are slightly larger than a medium break, there is a potential effect of containment isolation upon in-containment refueling water storage tank injection. The success criteria include automatic depressurization system in these cases.)

  – Medium breaks are those with an equivalent inside diameter between approximately 2 in. and 9 in. Core makeup tank line breaks and safety injection line breaks are included in this category (but are evaluated separately). Operation of automatic depressurization system stages 1, 2, or 3 (or, alternatively, passive residual heat removal) is not required to satisfy the automatic depressurization system stage 4 automatic actuation pressure interlock, but is required to depressurize the reactor coolant system to the normal residual heat removal system operating pressure.

  – Small breaks are those with an equivalent inside diameter between approximately 3/8 in. and 2 in. Steam generator tube rupture and passive residual heat removal heat exchanger tube rupture break sizes fall within this range, but are evaluated as separate events based on differing initial plant response. Small breaks are larger than those for which the chemical and volume control system can maintain reactor coolant system water level, but not large enough to allow automatic actuation of automatic depressurization system stage 4 without operation of either automatic depressurization system stages 1, 2, or 3 or passive residual heat removal.

  – Coolant losses smaller than those resulting from small breaks are defined as reactor coolant system leaks. Operation of one chemical and volume control system makeup pump can maintain reactor coolant system water inventory for reactor coolant system leaks.

19.59.3.1 Dominant Core Damage Sequences

A total of 791 potential core damage event sequences for internal initiating events at power are modeled in the AP1000 PRA. These core damage sequences are the combinations of initiating event occurrences and subsequent successes and failures of plant systems and operator actions that result in core damage. Of these 791 event sequences, 190 result in frequencies ranging from 7-08 to 1E-15 events per year. The remaining sequences do not produce any cutsets representing them in the top 19,000 cutsets; that is, their core damage frequencies are not significant relative to the core damage frequencies for the other sequences.

- The 10 sequences with the highest core damage frequencies together contribute 79 percent of the total (approximately 1.92E-07 events per year).
- The top 19 sequences contribute 90 percent of the total (approximately 2.18E-07 events per year).
- The top 58 sequences contribute 99 percent of the total (approximately 2.39E-07 events per year).
- The top 100 sequences contribute 99.9 percent of the total (approximately 2.41E-07 events per year).

The 19 dominant sequences are given in Table 19.59-3.

Moreover, each core damage sequence is composed of component-level cutsets, with a total of approximately 19,000 cutsets included in the baseline internal initiating events at-power analysis (100 percent of 2.41E-07 events per year core damage frequency). A cutset is a combination of initiating event occurrence and the component or operator failures that constitute the various system-level failures that lead to core damage.

- The 100 highest-frequency cutsets together contribute approximately 86 percent of the total core damage frequency (approximately 2.1E-07 events per year).
- The top 200 cutsets contribute approximately 91 percent (2.2E-07 events per year). These cutsets are reported in Section 36.
- The top 500 cutsets contribute approximately 95 percent (2.3E-07 events per year).
- The top 1,000 cutsets contribute approximately 97 percent (2.35E-07 events per year).
- The top 2,000 cutsets contribute approximately 98 percent (2.37E-07 events per year).

The top 10 accident sequences contribute 79 percent of the core damage frequency from internal initiating events at power. These sequences are listed in Table 19.59-3. The top 25 cutsets for these sequences are given in Tables 19.59-4 through 19.59-13.

The first four dominant accident sequences make up 63 percent of the core damage frequency. These sequences are:

1. Safety injection line break event occurs, which is postulated to lead to spilling of one train of core makeup tank, in-containment refueling water storage tank, and recirculation flows. The reactor is tripped. The second core makeup tank successfully injects, and the automatic depressurization system is successfully actuated. Thus, the reactor coolant system pressure is low. However, the remaining in-containment refueling water storage tank line fails to inject; core damage occurs with low reactor coolant system pressure, leading to a postulated 3BE end state. The sequence frequency is 6.9E-08 per year, contributing 29 percent to the plant core damage frequency.

2. Large loss-of-coolant accident event occurs, and the reactor is tripped or is rendered subcritical because of voids in the reactor coolant system. Reactor coolant system rapidly depressurizes but one of the accumulators does not inject water into the RCS. Core damage with low reactor coolant system pressure, leading to the 3BR end state is postulated. The sequence frequency is 4.3E-08 per year, contributing 18 percent to the plant core damage frequency.

3. Spurious ADS actuation event occurs, and the reactor is tripped or is rendered subcritical because of voids in the reactor coolant system. Reactor coolant system rapidly depressurizes and at least one of the two accumulators injects, making up the RCS water loss in the short time frame. The CMT injection or ADS actuation fails. Thus, automatic IRWST injection is not actuated. Core damage with medium reactor coolant system pressure, leading to the 3D end state is postulated. The sequence frequency is 2.1E-08 per year, contributing 9 percent to the plant core damage frequency.

4. Safety injection line break event occurs, which is postulated to lead to spilling of one train of core makeup tank, in-containment refueling water storage tank, and recirculation flows. The reactor is tripped. The second core makeup tank successfully injects, but the automatic depressurization system actuation fails. Core damage is postulated with a medium reactor coolant system pressure, leading to a 3D end state. The sequence frequency is 2.0E-08 per year, contributing 8 percent to the plant core damage frequency.

The fifth dominant sequence, with 4 percent contribution to plant core damage frequency, is a reactor vessel rupture event. By the definition of this event, core damage is postulated to occur. The end state is 3C.

19.59.3.2 Component Importances for At-Power Core Damage Frequency

Chapter 50 presents tables of the relative importances of all basic events appearing in the cutsets for the baseline core damage quantification. These tables indicate risk decrease and risk increase. Risk decrease is the factor by which the core damage frequency would decrease if the failure probability for a given basic event is set to 0.0; it is a useful measure of the benefit that might be obtained as a result of improved component maintenance or testing, better procedures, or operator training. Risk increase is the factor by which the core damage frequency would increase if the failure probability for a given basic event is set to 1.0; it is a useful measure of which components or actions would most adversely affect the core damage frequency if actual operating practices resulted in higher failure probabilities than assumed in the PRA.

The risk decrease results (as discussed in detail in Chapter 50) show that only six components have a risk reduction worth (RRW) of greater than or equal to 1.05. The in-containment refueling water storage tank discharge line strainer plugging has the highest RRW value, followed by common cause failure (CCF) of various components as shown in the following table.

IWA-PLUG	1.27	IRWST discharge Line “A” strainer plugged
ADX-EV-SA2	1.11	CCF of 2 squib valves to operate
REX-FL-GP	1.08	CCF plugging of both recirculation lines due to sump screens
ADX-EV-SA	1.05	CCF of 4th stage ADS squib valves to operate
IWX-CV-AO	1.05	CCF of 4 gravity injection check valves
IWX-EV-SA	1.05	CCF of 4 gravity injection & 2 recirculation squib valves

The remaining components each have a risk reduction worth of 1.04 or less. The contribution to the core damage frequency from unscheduled maintenance is also small. These results indicate that there are no components for which an improvement in design, test, or maintenance (i.e., a change resulting in a significant reduction of the component failure rate) would have a significant impact on the core damage frequency.

Excluding common cause failures, the risk increase results indicate that the accumulator system components have high risk achievement worth (RAW) values, followed by one Non-Class 1E dc and uninterruptible power supply system (EDS) bus, various Class 1E dc and uninterruptible power supply system (IDS) components and CMT components. Other single-component failures have significantly lower risk increase values, corresponding to a factor of six or lower increase in core damage frequency given an assumption of total unreliability for these components.

19.59.3.3 System Importances for At-Power Core Damage

System importances for plant core damage frequency from internal initiating events at power are presented in Chapter 50. They are obtained by setting the failure probabilities for the affected system components to 1.0 in the baseline cutsets and recalculating the core damage frequency.

The results of the sensitivity analyses show that the protection and safety monitoring system and the Class 1E dc power system are most important in maintaining a low core damage frequency. The risk-important systems are safety-related systems. The safety-related systems are all of high or medium importance. The nonsafety-related systems are only marginally important to the plant core damage frequency.

A sensitivity analysis is made for the unavailability of all five of the standby non-safety related systems (chemical and volume control system (CVS), startup feedwater system (SFW), normal residual heat removal system (RNS), diverse actuation system (DAS), diesel generators (DGs)). The plant CDF obtained is 7.40E-6, which is a factor of 31 increase over the base case. This sensitivity analysis shows that the plant CDF is somewhat sensitive to the simultaneous failure of the five systems listed above.

19.59.3.4 System Failure Probabilities for At-Power Core Damage

Some selected system failure probabilities for typical success criteria used in the at-power PRA are listed in Table 19.59-14. A system may have different failure probabilities based on the success criteria assigned. For a key safety-related system such as the automatic depressurization

system, this is especially pronounced; the automatic depressurization system has many success criteria and corresponding failure probabilities that range over a factor of 100. The values in the table are representative of the various cases.

As can be seen from the system unavailabilities listed in Table 19.59-14, the highest unavailabilities (i.e., 10^{-2} to 10^{-3}, indicating lower reliability) are associated with nonsafety-related systems or functions. The lower unavailabilities (i.e., 10^{-4} to 10^{-6}, indicating higher reliability) are associated with safety-related systems.

19.59.3.5 Common Cause Failure Importances for At-Power Core Damage

The common cause importance results are presented in Chapter 50. The risk increase importances for common cause failures of the following sets of components show that these are also of potential significance to the current low level of core damage frequency from internal events: common cause failure of software in the protection and safety monitoring system and plant control system, logic board failures of the protection and safety monitoring system; failures of transmitters used in the protection and safety monitoring system; failures of reactor trip breakers; plugging of containment sump recirculation screens; failures of in-containment refueling water storage tank gravity injection line check valves and squib valves; plugging of strainers in the in-containment refueling water storage tank; failures of fourth-stage automatic depressurization system squib valves and failures of output cards for the protection and safety monitoring system. These and similar common cause failures are of potential significance in maintaining the current level of low plant core damage frequency.

The leading risk decrease common cause failures of hardware are associated with ADS fourth stage squib valves, gravity injection and recirculation line components, and I&C components and sensors.

19.59.3.6 Human Error Importances for At-Power Core Damage

In the PRA, credit is taken for various tasks to be performed in the control room by the trained operators. These tasks are rule-based and proceduralized. Although these tasks are usually termed operator actions, the tasks almost always refer to the completion of a well-defined mission by trained operators following procedures. Further, not every individual or group error during a mission necessarily fails the mission, since procedural recovery is built into the emergency procedures. Moreover, a very strong diversity is introduced through monitoring of the emergency procedure status trees by a shift technical advisor. These considerations are factored into the PRA evaluation of human errors.

The risk decrease results for operator actions (discussed in Chapter 50) show that there are 10 human actions with importances greater than 1 percent. There are no actions for which the internal initiating events at-power core damage frequency contribution would decrease by more than 3 percent if it were assumed that the operators always were successful. This indicates that there would be no significant benefit from additional refinement of the actions modeled, or from special emphasis on operator training in these actions (versus other emergency actions).

The risk increase results show that there are only 7 operator actions with importance greater than 100 percent; i.e., these are the only modeled operator actions whose guaranteed failure would

result in a core damage increase greater than the base case core damage frequency. The most important action in this ranking (operator fails to diagnose a steam generator tube rupture event) has a risk achievement worth of 6.3. It is followed by manual actuation of ADS with a RAW value of 4.25. These results indicate that the plant design is not overly sensitive to failure of operator actions and the core damage models do not take undue credit for operator response.

A sensitivity analysis was performed in which the failure probabilities for the 30 operator actions are set to 0.0 (perfect operator). The resulting core damage frequency is only slightly smaller. This indicates that perfection in human error probabilities is not risk important at the level of plant risk obtained by the base case; there is no significant benefit to be gained by improving operator response beyond the assumptions made in the PRA.

Another sensitivity analysis was performed in which the failure probabilities for the 30 human error probabilities and also for indication failure (protection and safety monitoring system, plant control system, or diverse actuation system originated) are set to 1.0 (failure). The result of the sensitivity analysis shows that the core damage frequency increased to 1.4E-05 events per year. The resulting core damage frequency with no credit for operator actions is still low (about one event in 71,000 reactor-years), on the order of core damage frequency for current plants with credit for operators. This means that, in general, operator actions are important in maintaining a very low plant core damage frequency for internal events at power but are not essential to establishing the acceptability of plant risk. The presence of trained operators will help ensure that the very low core damage frequency prediction is valid. This finding demonstrates a significantly lower dependence on human actions than exists for current plants. The AP1000 meets the core damage frequency safety goal without human action, whereas current plants typically do not.

19.59.3.7 Accident Class Importances

The accident classes (also referred to as end states) are described in Chapter 44, and the contribution of accident classes to plant core damage frequency is presented in the same chapter. Two low-pressure reactor coolant system core damage end states, 3BE and 3BL, contribute 43 percent to the total core damage frequency. Together with 3BR and 3D, full or partially depressurized core damage states make up 87 percent of the core damage. In these end states, the probability of retaining containment integrity is very likely. Thus, severe release potential for these end states is low.

19.59.3.8 Sensitivity Analyses Summary for At-Power Core Damage

Thirty-six importance and sensitivity analyses were performed on the core damage model for internal initiating events at power. These cases and results are discussed in Chapter 50.

The analyses were chosen to address the following issues:

- Importances of individual basic events and their effect on plant core damage frequency
- Importances of safety-related and nonsafety-related systems in maintaining a low plant core damage frequency
- Importances of containment safeguards systems in maintaining a low large-release frequency

- Effect of human reliabilities as a group on plant core damage frequency
- Other specific issues such as passive system check valve reliability, etc.

The sensitivity analyses results are discussed in Chapter 50. They show that:

- If no credit is taken for operator actions, the plant core damage frequency is 1.4E-05 events per year. This compares well with core damage frequencies for existing plants where credit is taken for operator actions.
- The most important systems for core damage prevention are the protection and safety monitoring system, Class 1E dc power, automatic depressurization system, in-containment refueling water storage tank recirculation, core makeup tanks, and accumulators. None of the nonsafety-related systems have high system importance.
- There are no operator actions that would provide a significant risk decrease if they were made to be more reliable. There are only eight operator actions that would increase the core damage frequency by more than the base case if they were assumed to fail. The most important of these is the failure to diagnose a steam generator tube rupture event.
- If the reliability of all check valves is assumed to be a factor of 10 worse, the total plant core damage frequency would only increase to 8.8E-7 events per year. This shows that the passive safety-related systems that depend on check valve opening will perform acceptably, even if pessimistic check valve reliabilities are assumed.
- The plant core damage frequency is not affected by the diesel generator mission time duration. This is due to the AP1000 design's passive features, which do not require ac power for operation.
- The common cause failure basic events, particularly those associated with safety-related systems, are important individually, and also as a group for plant core damage frequency. This is expected for a plant with highly redundant safety-related systems, for which individual component random failure contributions are of reduced significance.

19.59.3.9 Summary of Important Level 1 At-Power Results

The results of the PRA show that the following AP1000 design features provide the ability to respond to internal initiating events and contribute to a very low core damage frequency:

- The manual feed and bleed operation in current pressurized water reactors is replaced by the automatic depressurization system and core makeup tank/in-containment refueling water storage tank injection. This increases the success probability for feed and bleed and helps reduce core damage contribution from transients with failure of decay heat removal.
- The switchover-to-recirculation operation in current pressurized water reactors is replaced with automatic recirculation of sump water into the reactor coolant system loops by natural circulation.

- The diverse actuation system provides diverse backup for automatic or manual actuation of safety-related systems, increasing the system reliability for the passive residual heat removal, core makeup tank, and automatic depressurization systems.

- The AP1000 plant design is based on a defense-in-depth concept. There are several means (both active and passive) of providing reactor coolant system makeup following a loss-of-coolant accident, at both high and low pressures (i.e., chemical and volume control system pumps, core makeup tanks, accumulators, in-containment refueling water storage tank gravity injection, and normal residual heat removal system). Similarly, there are diverse means of core cooling, including the passive residual heat removal and normal residual heat removal systems.

- The ability to depressurize and establish feed and bleed heat removal via the automatic depressurization system and core makeup tanks without operator action provides an additional reliable means of core cooling and inventory control.

- The diversity and redundancy in the design of the automatic depressurization system provide a highly reliable system for depressurizing to allow injection and core cooling by the various sources of water.

- The design of the reactor coolant pumps eliminates the dependence on component cooling water and accompanying reactor coolant pump seal loss-of-coolant accident core damage contribution, which is typically significant for current plants.

- The design of the safety-related heat removal systems eliminates the dependence on service water and ac power during accidents; such dependencies can be significant contributors to core damage for current plants.

Core Damage Contribution from Important Initiating Events

Loss-of-Coolant Events. The at-power core damage results are dominated (top 8 dominant contributors with 93 percent) by various loss-of-coolant events. Thirty-four percent of the contribution is due to the safety injection line break, which is a special initiator, in that its occurrence partially defeats features incorporated into the plant to respond to losses of primary coolant. Even though the safety injection line break core damage frequency dominates the results, its value is very small (one event in 10 million reactor years), with little credit for nonsafety-related systems.

The conditional probability of core damage, given the occurrence of a “conventional” loss-of-coolant accident, is generally in the range of about 1E-03 to 1E-05 (with the exception of reactor vessel rupture and interfacing systems loss-of-coolant accident, for which core damage is assumed). These events have frequencies of about 1E-08 per year to 5E-04 per year. This indicates that the various features of the AP1000 would act to prevent core damage from all but between 1 in 1000 and 1 in 100,000 loss-of-coolant accidents. Since loss-of-coolant accidents are relatively rare events, this is a significant level of protection.

Anticipated Transients Without Scram. Anticipated transients without scram (ATWS) sequences contribute about 2 percent of the at-power core damage frequency, in part due to modeling simplifications whereby, in the absence of specific modeling and success criteria, it has been assumed that core damage will occur given certain combinations of failures. With additional analysis and modeling detail, it is expected that the anticipated transient without scram core damage frequency could be shown to be lower.

Transients. The contribution of transients to core damage frequency is about 5 percent of the at-power core damage frequency (total contribution from all transient initiators with reactor trip is 1 event in 100 million reactor years). This is the result of the defense-in-depth features of the AP1000 design, whereby core cooling following transients is available from main feedwater, startup feedwater, and passive residual heat removal, as well as from feed and bleed, using diverse and redundant sources of makeup (core makeup tanks, accumulators, in-containment refueling water storage tank, normal residual heat removal system), and of depressurization (four stages of automatic depressurization system).

Loss of Offsite Power. The loss of offsite power core damage frequency contribution at power is insignificant (less than 1 percent). AP1000 passive systems require only dc power provided by the long-term batteries for actuation to provide cooling. In addition, the passive residual heat removal heat exchanger is backed up by bleed and feed cooling using the automatic depressurization system and core makeup tanks or in-containment refueling water storage tank gravity injection, which also require only dc power provided by long-term batteries. With onsite power available, startup feedwater provides an additional means of decay heat removal.

Steam Generator Tube Rupture. The steam generator tube rupture event contributes about 3 percent of the at-power core damage frequency. Compared to operating pressurized water reactors this is a very low contribution. Among the reasons for the small steam generator tube rupture core damage contribution are the following:

- The first line of defense is the startup feedwater system and chemical and volume control system

- A reliable safety-related passive residual heat removal system coupled with the core makeup tank subsystem, which provides automatic protection

- A third line of defense using automatic depressurization system and in-containment refueling water storage tank for accident mitigation should the above-mentioned systems fail.

Further, the automatic depressurization system provides a more reliable alternate decay heat removal path through feed and bleed than the high-pressure manual feed and bleed cooling of current operating plants.

Finally, the large capacity of the in-containment refueling water storage tank increases the long-term recovery probability for unisolable steam generator leaks that bypass containment, by preventing depletion of borated water and core damage.

Dependence on Operator Action

The results of the PRA show that the AP1000 is significantly less dependent on operator action to reduce plant risk to acceptable levels than are current plants. This was shown through the sensitivity analyses and the operator action contributions from both the risk decrease and risk increase measures. Almost all operator actions credited in this PRA are performed in the control room; there are very few local actions outside the control room. Further, the human actions modeled in the AP1000 PRA are generally simpler than those for current plants. Thus, the tasks for AP1000 operators are easier and less likely to fail. If it were assumed that the operators never perform any actions credited in the PRA, the internal events core damage frequency would still be lower than the result obtained for many current pressurized water reactors including operator actions.

Dominant System/Component Failure Contributors

Contribution to Core Damage Frequency. Component-related contributors to core damage frequency from internal events at power are dominated by common cause failures. The single component failures are limited to strainer or tank failures, and accumulator check valve failures.

Dependence on Component Reliability. Most of the component failures with relatively high risk increase worth are common cause failures. This is an indication of the high degree of built-in redundancy and diversity of AP1000 safety-related systems, particularly in view of the low baseline core damage frequency. The results demonstrate a well-balanced design, for which diversity eliminates the strong dependence on active valves or on the specific type of valve.

Sensitivity to Numerical Values and Modeling Assumptions. The core damage results are not strongly sensitive to increases in the failure probabilities of basic events. Check valves are relatively important; if the check valve failure probability is increased by a factor of 10, the core damage frequency increases by a factor of 4. This increase is not large, and the core damage goal of 1E-05 is comfortably met. Finally, the modeling assumptions in system and accident sequence success criteria are bounding (e.g., conservative) whenever a range of conditions are represented by a single selected condition or success criterion. Since the modeling assumptions already represent an upper bound type estimate, there are no significant contributions to core damage due to conditions outside the assumed ranges that are unaccounted for. As an example, the automatic depressurization system success criteria for loss-of-coolant accident events are selected to cover the worst conditions (e.g., break size, break location) of the range.

System Reliability and Defense-in-Depth. The results show that the safety-related systems have demonstrated high reliabilities (e.g., failure probability in the range of 1E-05 to 1E-03), due to the nature of the system designs (passive systems). Moreover, multiple means of success exist for transients and credible loss-of-coolant accident events. This means that a failure of a safety-related system will not lead to core damage, because other diverse systems back up the first one. This defense-in-depth philosophy contributes to the low core damage frequency.

19.59.4 Large Release Frequency for Internal Initiating Events at Power

The results of the Level 2 (containment response) and Level 3 (plant risk) analyses for the internal initiating events at power demonstrate that the AP1000 containment design is robust in its ability to prevent releases following a severe accident and that the risk to the public due to severe accidents for AP1000 is very low. The large release frequency (containment failure frequency) of the AP1000 can be divided into two types of failures: 1) initially failed containment, in which the integrity of the containment is either failed due to the initiating event or never achieved from the beginning of the accident; and 2) containment failure induced by high-energy severe accident phenomena. The total of these failures is the overall large release frequency. The following summarizes important results of the containment event tree quantification with respect to large release frequency.

The overall release frequency for AP1000 is 1.95E-08 events per year. This is approximately 8 percent of the core damage frequency for internal initiating events at power. The ability of the containment to prevent releases (i.e., the containment effectiveness) is 92 percent.

The Level 3 analysis shows that the resulting risk to the population is small and well within the established goals.

19.59.4.1 Dominant Large Release Frequency Sequences

The large release frequency is dominated by release categories BP (bypass), with a 54-percent contribution and CFE (early containment failure) with a contribution of 38 percent. The total frequency of these two categories is 1.8E-08 events per year. These two categories make up 92 percent of the plant large release frequency, followed by 7.0 percent contribution from containment isolation failure category. Contributions of the late containment failure (CFL) and intermediate containment failure (CFI) release categories to large release frequency are negligible.

The early containment failures are caused by sump flooding, vessel failure, and core reflooding failure plus containment overtemperature failure due to diffusion flame.

The dominant accident class in the large release frequency is the Class 6 with a 21-percent contribution. This class represents sequences in which steam generator tube rupture or interfacing LOCA events occur. It is followed by accident class 3A, with a 21 percent contribution. 3A contains core damage events with high RCS pressure and ATWS events.

The dominant large release frequency sequences are shown below. These sequences make up 98 percent of the large release frequency. Two containment bypass sequences from 3A and 6 accident classes contribute 21 percent and 19 percent, followed by 2 early containment failures from 3BE and 3D accident sequences with 14 and 11 percent contributions. These four sequences add up to 65 percent of the plant LRF.

Dominant Containment Event Tree (CET) Sequences					
CET SEQ	REL CAT	PDS	FREQ	%	SEQUENCE DESCRIPTION
23	BP	3A	4.08E-09	20.9%	Containment Bypass
23	BP	6	3.78E-09	19.4%	Containment Bypass
21	CFE	2E	2.67E-09	13.7%	Sump Flooding Fails
21	CFE	3D	2.05E-09	10.5%	Sump Flooding Fails
23	BP	1A	2.04E-09	10.5%	Containment Bypass
10	CFE	3C	9.97E-10	5.1%	Vessel Failure
12	CFE	3D	9.71E-10	5.0%	Core Reflooding Fails; Diffusion Flame
23	BP	1P	6.05E-10	3.1%	Containment Bypass
22	CI	2L	5.83E-10	3.0%	Containment Isolation Fails
6	CFE	2E	4.75E-10	2.4%	Hydrogen Igniters Fail; Early deflagration to detonation transition (DDT)
22	CI	3D	3.62E-10	1.9%	Containment Isolation Fails
21	CFE	6	1.86E-10	1.0%	Sump Flooding Fails
4	CFI	2E	1.82E-10	0.9%	Hydrogen Igniters fail; Intermediate DDT

19.59.4.2 Summary of Important Level 2 At-Power Results

The results of the PRA show that the following AP1000 design features provide the ability to respond to various severe accidents and contribute to a very small release frequency and a small release of radioactive material to the environment.

- The capability to flood the reactor cavity prevents the failure of the reactor vessel given a severe accident without water in the cavity. The vessel and its insulation are designed so that the water in the cavity is able to cool the vessel and prevent it from failing (in-vessel retention - IVR). By maintaining the vessel integrity, the core debris in the vessel eliminates the potential of a large release due to ex-vessel phenomena and its potential to fail the containment.

- The capability to depressurize the reactor coolant system in a high-pressure transient mitigates the consequences of a high-pressure severe accident. Such accidents have a large potential to fail the reactor coolant system pressure boundary vessel, piping, or steam generator tubes, and such a failure is assumed without further analysis if the reactor coolant system remains at high pressure. A high-pressure failure of the reactor coolant system pressure boundary is assumed to fail or bypass the containment. Thus, the capability to

depressurize the reactor coolant system reduces the large release frequency due to high-pressure severe accidents.

- The annular spaces between the steel containment vessel and the shield building help to reduce the release of radioactive materials to the environment by enhancing the deposition of the materials before they exit the containment.

The Level 2 results highlight some insights in the AP1000 design:

- The containment effectiveness for AP1000 is over 90 percent, which provides an order of magnitude decrease from CDF to LRF. Since this result already includes CDF sequences that directly bypass the containment, the containment effectiveness for remaining sequences is actually much better. For example, for 5 (3BE, 3BL, 3BR, 3C, 3D) of the 9 accident classes studied, the containment effectiveness ranges from 90 to 99.8 percent.

- The containment effectiveness is lowest for the 3A accident class where the RCS pressure is high after core damage. The post-core-damage depressurization for this class proves to be ineffective since failure of ADS by common cause failures leading to core damage also causes failure of post-core-damage depressurization.

- Based on detailed analysis, the containment effectiveness for accident class 6, mainly SGTR events, is 56.9 percent, due to those sequences where the RCS pressure is low after the postulated core damage. In such sequences, the fission products can be retained in the pressure vessel, shielded by the water in the faulted steam generator. A sensitivity analysis where all accident class 6 events are assigned to LRF shows that the plant containment effectiveness drops slightly to 89.7 percent (from 91.9 percent). Thus, the LRF results are not very sensitive to the treatment of the SGTR events for LRF.

- A frequency of 1.0E-08/year has been assigned to the vessel failure initiating event (accident class 3C). In 90 percent of these events, the vessel is assumed to undergo failures that will be above the beltline – in which case the molten core could be cooled and containment would not be challenged. In the remaining 10 percent of the cases, the failure is assumed to be below the pressure vessel beltline, whereby the molten core would drop into the containment. In this case, it is conservatively assumed that the containment would fail. A sensitivity analysis is made where by 100 percent of the failures would be below the beltline. The result shows that the containment effectiveness drops to 88.2 percent. This change is not significant, and the assumptions behind the case are very conservative.

- The LRF results are sensitive to failure of hydrogen igniters. If no credit is taken for hydrogen igniters, the containment effectiveness drops to 74 percent.

- However, LRF is not very sensitive to the reliability of hydrogen igniters; if IG reliability is assumed to be degraded (0.1) across the board for all accident classes, the containment effectiveness becomes 90.5 percent, which is an insignificant change from the base case.

- For accident classes 3D and 1AP, if the large hydrogen releases through the IRWST is conservatively assumed to cause containment failure, the containment effectiveness drops to

84.5 percent. The LRF increases to 7.58E-08/year. The increase is about a factor of 4 of the base. Such an increase is significant. This sensitivity analysis addresses the uncertainties in hydrogen mixing model for the case where the hydrogen is released into the IRWST and comes out from the IRWST vents above the operating deck.

- The LRF is dominated (53.9 percent) by containment failures or bypasses due to SGTR, and unmitigated high-RCS-pressure core damage sequences, classified as BP. The remaining containment failures are dominated by an early containment failure due to reactor cavity flooding failure.

- The LRF is not very sensitive to the reliability of PCS. If PCS reliability is assumed to be 0.001 across the board for all accident classes, the LRF becomes 1.97E-08, which is an insignificant change from the base case.

- The LRF is sensitive to the operator action to flood the reactor cavity in a short time following core damage. This operator action has been moved to the beginning of Emergency Response Guideline (ERG) AFR.C-1 to increase its likelihood of success.

- The potential for a release of radioactive materials to the environment is very small. This is largely due to the very small core damage frequency and very small release frequency. The containment design provides enhanced deposition of core materials that could be released in a severe accident, and the passive containment cooling system minimizes the energy available to expel such materials from the containment.

The results of the at-power analyses show the AP1000 design includes redundancy and diversity not found in current plants. The safety-related passive systems do not require ac power or operator actions to actuate, and the plant design is robust in the prevention and mitigation of the consequences of an accident. The AP1000 core damage frequency and large release frequency are much lower than has been seen in current generation plants, despite the many conservatisms built into the PRA models. The assumed dose to the environment given a severe accident and a large release is well within the goals set for that analysis.

19.59.5 Core Damage and Severe Release Frequency from Events at Shutdown

19.59.5.1 Summary of Shutdown Level 1 Results

As shown by the dominant cutsets of the AP600 and AP1000 shutdown models (shutdown risk evaluation is presented in Chapter 54), the risk profiles of these plants for events during shutdown conditions are almost identical. The results indicate that the three events dominating the CDF are loss of component cooling/service water during drained condition, loss of offsite power during drained condition, and loss of RNS during drained condition. The AP1000 and AP600 initiating event core damage contributions are included in Chapter 54. This data shows the initiating event importance to be similar for the two plants.

The dominant sequences are described in the subsections that follow. The 12 dominant accident sequences comprise 77 percent of the level 1 shutdown core damage frequency. These dominant sequences consist of:

- Loss of component cooling or service water system initiating event during drained condition with a contribution of 64 percent of the CDF
- Loss of RNS initiating event during drained condition with a contribution of 6 percent of the CDF
- Loss of offsite power initiating event during drained condition with a contribution of 5 percent of the CDF
- RCS overdraining event during drainage to mid-loop with a contribution of a 2 percent of the CDF

Loss of Component Cooling or Service Water System Initiating Event During Drained Condition

These sequences are described as the loss of decay heat removal initiated by failure of the component cooling water or service water system during drained condition. The loss of decay heat removal occurs following loss of circulating water system (CWS) or service water system (SWS) during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling.

The major contributors to risk due to loss of CWS or SWS during drained condition are the following failures:

- Hardware failures of both service water pumps or common cause failure of output logic inputs/outputs (I/Os) from the plant control system (PLS)
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the IRWST high-pressure squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of RNS Initiating Event During Drained Condition

This sequence is described as the loss of decay heat removal initiated by failure of the RNS during drained condition. The loss of decay heat removal occurs following loss of RNS during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling.

The major contributors to risk due to loss of RNS during drained condition are the following failures:

- Common cause failure of the RNS pumps to run
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of Offsite Power Initiating Event During Drained Condition (with failure of grid recovery within 1 hour)

This sequence is initiated by loss of offsite power during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling. Following this initiating event, the RNS does not restart automatically, and the grid is not recovered within 1 hour.

The major contributors to risk given loss of offsite power (without grid recovery) are the following failures:

- Software common cause failure of all cards
- Failure of the RNS pump to run or restart
- Failure of the diesel generator to start or run
- Failure of the main breaker to open
- Failure to recover ac power within 1 hour
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of Offsite Power Initiating Event During Drained Condition (with success of grid recovery within 1 hour)

This sequence is initiated by loss of offsite power during mid-loop/vessel flange operation which has an estimated duration of 120 hours per 18 months refueling. Following this initiating event, the RNS does not restart automatically, the grid is recovered within 1 hour but manual RNS restart after grid recovery fails.

The major contributors to risk, given loss of offsite power (with grid recovery), are the following failures:

- Software common cause failure of all cards
- Failure of the RNS pump to run or restart
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

RCS Overdraining Event During Drainage to Mid-loop

This sequence is described as RCS overdraining initiating event during drainage to mid-loop condition; draining to mid-loop has an estimated duration of 39 hours per 18 months refueling. Following the initiating event, manual isolation of the RNS fails.

The major contributors to risk due to RCS overdraining are the following failures:

- Common cause failure of the CVS air-operated valves to close automatically upon receipt of low hot leg level signals and failure of the operator to stop draining
- Operator fails to isolate the RNS
- Common cause failure of the ADS 4th stage squib valves
- Operator fails to open IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Conclusions

The conclusions drawn from the shutdown Level 1 study are as follows:

- The overall shutdown core damage frequency is very small (1.23E-07/year).
- Initiating events during reactor coolant system drained conditions contribute approximately 90 percent of the total shutdown core damage frequency. Loss of decay heat removal capability (during drained condition) due to failure of the component cooling water system or service water system are the initiating events with the greatest contribution (approximately 70 percent of the shutdown core damage frequency).
- Common cause failures of in-containment refueling water storage tank components contribute approximately 59 percent of the total shutdown core damage frequency. Common cause failure of the in-containment refueling water storage tank valves contributes approximately 33 percent of the total shutdown core damage frequency.
- Common cause failures of the automatic depressurization system stage 4 squib valves contribute approximately 18 percent to the total shutdown core damage frequency. The function of the automatic depressurization system is important to preclude the effects of surge line flooding. This indicates that maintaining the reliability of the automatic depressurization system is important.

  Common cause failures of the containment sump recirculation squib valves contribute approximately 15 percent to the total shutdown core damage frequency. This function is

important during drained conditions. This indicates that maintaining the reliability of the recirculation line squib valves is important.

- Human errors are not overly important to shutdown core damage frequency. There is no particular dominant contributor. Sensitivity results show that the shutdown core damage frequency would remain very low even with little credit for operator actions.

  One action, operator failure to recognize the need for reactor coolant system depressurization during safe/cold shutdown conditions, is identified as having a significant risk increase value. This indicates it is important that the procedures include this action and the operators understand and are appropriately trained for it.

- Individual component failures are not significant contributors to shutdown core damage frequency, and there is no particular dominant contributor. This confirms the at-power conclusion that single independent component failures do not have a large impact on core damage frequency for AP1000 and reflects the redundancy and diversity of protection at shutdown as well.

- The in-containment refueling water storage tank provides a significant benefit during shutdown because it serves as a passive backup to the normal residual heat removal system.

19.59.5.2 Large Release Frequency for Shutdown and Low-Power Events

The baseline PRA shutdown large release frequency for AP600 was calculated to be 1.5E-08 per reactor-year, associated with a shutdown CDF of 9.0E-08 per year. The AP1000 LRF is estimated to be 2.05E-08 per year, with the same risk profile as that of AP600 (see Table 19.59-15). This LRF compares well with the at-power LRF of 1.95E-08 per year.

19.59.5.3 Shutdown Results Summary

The results of the low-power and shutdown assessment show that the AP1000 design includes redundancy and diversity at shutdown not found in current plants. In particular, the in-containment refueling water storage tank provides a unique safety backup to the normal residual heat removal system. Maintenance at shutdown has less impact on the defense-in-depth features for AP1000 than for current plants. In accordance with plant technical specifications, safety-related system planned maintenance is performed only during those shutdown modes when the protection provided by the safety-related system is not required. Further, maintenance of nonsafety systems, such as the normal residual heat removal system, component cooling water system, and service water system, is performed at power to avoid adversely affecting shutdown risk. These contribute to the extremely low shutdown core damage and the small release frequency.

19.59.6 Results from Internal Flooding, Internal Fire, and Seismic Margin Analyses

19.59.6.1 Results of Internal Flooding Assessment

A scoping internal flooding analysis was performed based on AP1000 design information, with conservative assumptions or engineering judgement used for simplifying the analysis.

The AP1000 design philosophy of minimizing the number of potential flooding sources in safety-related areas, along with the physical separation of redundant safety-related components and systems from each other and from nonsafety-related components, minimizes the consequences of internal flooding. The core damage frequencies from flooding events at power is not an appreciable contributor to the overall AP1000 core damage frequency. The internal flooding-induced core damage frequencies are estimated to be 8.8E-10 events per year for power operations.

The internal flooding analysis conservatively assumes that flooding of nonsafety-related equipment results in system failure of the affected system. As shown in AP600 PRA, this results in a higher flooding-induced core damage frequency at shutdown than at power, because of the use of the nonsafety-related normal residual heat removal system as the primary means of decay heat removal at shutdown.

The top five at-power flooding scenarios comprise 91 percent of the at-power flooding-induced core damage frequency. Each of these scenarios relate to large pipe breaks in the turbine building with an initiating event frequency in the range of 1.4 - 2.0E-03/year, leading to a loss of CCS/SWS event. Each scenario has a CDF of 1.2 - 1.8E-10/year.

Internal flooding events during shutdown operations are also evaluated. A quantitative internal flooding PRA of AP1000 design performed to estimate plant CDF and LRF for at-power and during low-power and shutdown events provided the following results:

	Plant CDF	Plant LRF
Internal Flooding During At-Power Events	8.82E-10/yr	7.14E-11/yr
Internal Flooding During Low-Power and Shutdown Events	3.22E-09/yr	5.37E-10/yr

The minimization of potential flooding sources in the safety-related areas, in addition to the physical separation of redundant safety-related components and systems from each other and from nonsafety-related components, reduces the consequences of internal flooding. The core damage and large release frequencies arising from flooding events during shutdown operations are not appreciable contributors to overall AP1000 risk.

19.59.6.2 Results of Internal Fire Assessment

The total at-power, fire-induced core damage frequency is 5.61E-08 per reactor year. The estimated LRF is 4.54E-09/yr. Results of the AP1000 fire PRA analysis are summarized below.

The estimated core damage frequency from main control room fires at power is insignificant (less than 3.18E-12 per year). This low contribution is a result of the following:

- The ignition frequency is low because of the use of low-voltage 48v 10 mA dc cables in the control room. These low-voltage cables do not produce enough energy to heat the cables, thus ignition is not probable.

- Redundancy in control room operations is available within the control room itself; that is, if control room evacuation is not required, there is at least one other means available within the control room to shut down and control the plant.

- If control room evacuation is necessary, the remote shutdown workstation provides complete redundancy in terms of control for safe shutdown functions.

- Loss of control of one division of power or for a whole system is not risk-significant. In addition, the passive systems are designed to operate without the need for operator interaction. Therefore, operator actions that might be disrupted by the fire scenario are backup actions, and are not significant.

The results of the internal fire evaluation indicate that the plant's system and layout promote a low fire-induced core damage frequency compared with existing plants. Also, the results indicate that, when nonsafety-related systems are not credited and containment is treated as a special case, the fire-induced core damage frequency profile is relatively flat (i.e., no fire area is significantly more important than others).

The results from the AP1000 fire analysis confirm that the inherent design characteristics of the AP1000 also provide an effective barrier against fire hazards. This is true even within the pessimistic assumptions used throughout the study.

Conservatisms employed in the AP1000 fire analysis included the following:

- In order to minimize potential uncertainty in the results arising from the lack of as-built equipment location and cable routing information, a bounding approach to quantification, using the focused PRA models, was taken in accordance with the Reference methodology.

- A fire originating from any ignition source in an area is assumed to disable all equipment located in the fire area. The historical evidence indicates that most fires are localized fires with limited severity.

- An assumed total at-power fire initiating event frequency corresponding to about one fire with significant consequences every 4 reactor years, well in excess of current plant experience and of that anticipated for AP1000, was assumed.

- Manual fire suppression is not credited to limit the extent of damage in an area nor to prevent fire propagation to an adjoining area. Historical evidence indicates that the majority of suppressed fires were manually suppressed with little or no additional damage.

- The assumption was made that a single hot short could result in spurious automatic depressurization system actuation.

- The estimation of containment fire frequency, not normally included in fire risk assessments, was done by making a conservative interpretation of the limited available data.

Because the approach taken in performing the internal fire analysis makes various conservative assumptions and is bounding, the results of uncertainty, sensitivity, or importance analyses would be biased. Therefore, these analyses were not performed based on the judgement that they would be of little value in providing additional insights to determine whether fire vulnerabilities exist for beyond-design-basis fires.

The major reasons for the AP1000's relatively low overall fire-induced core damage frequency, even on a bounding basis, include the following:

- The fire protection design provides, to the extent possible, separation of the alternate safety-related shutdown components and cabling using 3-hour-rated fire barriers. For example, areas containing safety-related cabling or components are physically separated from one another and from the areas that do not contain any safety-related equipment by 3-hour-rated fire barriers. This defense-in-depth feature diminishes the probability of a fire to impact more than one safety-related shutdown system.

- Since the passive safety-related systems do not require cooling water or ac power, they are less susceptible to being unavailable due to a fire than currently operating plants' active safe shutdown equipment. As a result, the impact of fires on the shutdown capability is significantly reduced compared to current plants.

The results of this analysis show that the AP1000 design is sufficiently robust that internal fires during either power operation or shutdown do not represent a significant contribution to core damage frequency.

19.59.6.3 Results of Seismic Margin Analysis

The seismic margin analysis (SMA) shows the systems, structures, and components required for safe shutdown. The high confidence, low probability of failure (HCLPF) values are greater than or equal to 0.50g. This HCLPF is determined by the seismically induced failure of the fuel in the reactor vessel, core assembly failures, IRWST failure, or containment interior failures. The SMA result assumes no credit for operator actions at the 0.50g review level earthquake, and assumes a loss of offsite power for all sequences.

The seismic margin analysis shows the plant to be robust against seismic event sequences that contain station blackout coupled with other seismic or random failures. The analysis also shows the plant's capability to respond to seismic events without benefit of the operators' actions.

19.59.7 Plant Dose Risk From Release of Fission-Products

Chapter 49 discusses the Level 3 results for at-power and shutdown internal events. The dose risks are quantified by multiplying the fission product release category frequency vector by the release category mean dose vectors. The goal is that a 24-hour, whole-body, site boundary dose greater than 25 rem has a frequency (large release frequency) of less than 1E-06 per year. The AP1000 large release frequency is 1.95E-08 per year, which is a factor of 50 times less than the goal.

The total at-power risk from a postulated release of fission products (the 24-hour, site boundary effective dose equivalent (EDE) is 1.83E-04 rem per reactor-year. For shutdown, this risk was

calculated to be 7.1E-05 rem per reactor-year for AP600. For AP1000, this shutdown risk could be estimated as 9.7E-05 rem per reactor-year (estimated the same way as shutdown LRF in Table 19.59-15). Table 19.59-16 and Figure 19.59-2 summarize the plant dose results.

Containment bypass failures account for 79 percent of the dose risk. These types of failures are usually assumed as a result of steam generator tube rupture. A less conservative analysis of the containment bypass failures may show a smaller frequency, and, as a result, a smaller dose risk.

19.59.8 Overall Plant Risk Results

The total plant risk expressed in terms of plant core damage frequency and severe release frequency for all events studied in this PRA are summarized in Table 19.59-17.

The contribution of various events to the at-power core damage frequency is shown in Figure 19.59-1.

The total plant core damage and large release frequency analysis results show the following:

- The total mean core damage frequency is at least two orders of magnitude smaller than those for existing pressurized water reactors. The cumulative core damage probability for a population of 50 AP1000 units operating for 60 years each would be less than 0.001, which is a low probability of occurrence.

- The total plant severe release frequency is another order of magnitude smaller than that of the core damage frequency; that places such a release frequency in the range of incredible events.

- A bounding analysis of the core damage due to internal fire and internal flooding events shows that these two categories of internal events are lower for AP1000 than are calculated for currently operating plants.

- The severe release frequency is about equal for at-power and shutdown events. The severe release frequency as a percentage of core damage frequency is 8 percent for at-power events and 17 percent for shutdown events.

- The results show that the design goals of low core damage frequency and low severe release frequency have been met. The AP1000 frequencies are lower than the Nuclear Regulatory Commission (NRC) goals set for new plant designs, as shown in Table 19.59-17. These results show the effectiveness of passive systems in mitigating severe accidents and reflect the reduced dependence of AP1000 on nonsafety systems and human actions.

Figure 19.59-2 shows the 24-hour, whole-body EDE site boundary dose cumulative distribution.

19.59.9 Plant Features Important to Reducing Risk

Westinghouse used PRA results extensively in the AP1000 design process to identify areas for design improvement and areas for further risk reduction. These results were also compared with existing commercial nuclear power plants to identify additional area of risk reduction. Examples

of the more significant AP1000 plant features and operator actions that reduce risk are discussed in this section. Examples are provided in the area of reactor design, system design, plant structures and layout, and containment design.

AP1000 has more lines of defense as compared to current operating plants, which provide more success paths following an initiating event and provide redundancy and diversity to address common cause-related concerns. Examples of extensive AP1000 lines of defense follow:

- Criticality control:
  - Control rod insertion via reactor trip breaker opening
  - Control rod insertion via motor-generator set de-energization
  - Ride out via turbine trip
- Core heat removal:
  - Main feedwater
  - Startup feedwater
  - Passive residual heat removal
  - Automatic depressurization system and feed-and-bleed via normal residual heat removal injection
  - Automatic depressurization system and passive feed-and-bleed via in-containment refueling water storage tank injection
- Reactor coolant system makeup:
  - Chemical and volume control system
  - Core makeup tanks
  - Automatic depressurization system and normal residual heat removal
  - Automatic depressurization system, accumulators, and in-containment refueling water storage tank injection
  - Automatic depressurization system, core makeup tanks, and in-containment refueling water storage tank injection
- Containment cooling:
  - Fan coolers
  - Normal residual heat removal
  - Passive containment cooling system with passive water drain
  - Passive containment cooling system with alternate water supply

- Passive containment cooling system without water (air only)
- Fire water

19.59.9.1 Reactor Design

The AP1000 reactor coolant system has many features that reduce the plant risk profile. The pressurizer is larger than those used in comparable current operating plants, resulting in a longer drainage time during small loss-of-coolant accident events. The larger pressurizer increases transient operation margins, resulting in a more reliable plant with fewer reactor trips, avoiding challenges to the plant and operator during transients. The larger pressurizer also eliminates the need for fast-acting power-operated relief valves (PORVs), which are a possible source of reactor coolant system leaks.

The AP1000 steam generators have large secondary-side water inventories, allowing significant time to recover steam generator feedwater or other means of core heat removal. The AP1000 steam generators also employ improved materials and design features that significantly reduce the probability of forced outages or tube rupture.

The AP1000 has canned reactor coolant pumps, thus avoiding seal loss-of-coolant accident issues and simplifying the chemical and volume control system. The reactor coolant system has fewer welds, which reduces the potential for loss-of-coolant accident events. The probability of a loss-of-coolant accident is also reduced by the application of "leak-before-break" to reactor coolant system piping.

19.59.9.2 Systems Design

System design aspects intended to reduce plant risk are discussed in terms of safety-related and nonsafety-related systems.

19.59.9.2.1 Safety-Related Systems

The AP1000 uses passive safety-related systems to mitigate design basis accidents and reduce public risk. The passive safety-related systems rely on natural forces such as density differences, gravity, and stored energy to provide water for core and containment cooling. These passive systems do not include active equipment such as pumps. One-time valve alignment of safety-related valves actuates the passive safety-related systems using valve operators such as:

- DC motor-operators with power provided by Class 1E batteries
- Air-operators that reposition to the safeguards position on a loss of the nonsafety-related compressed air that keeps the safety-related equipment in standby
- Squib valves
- Check valves

The passive systems are designed to function with no operator actions for 72 hours following a design basis accident. These systems include the passive containment cooling system and the passive residual heat removal system.

Diversity among the passive systems further reduces the overall plant risk. An example of operational diversity is the option to use passive residual heat removal versus feed-and-bleed for decay heat removal functions, and an example of equipment diversity is the use of different valve operators (motor, air, and squib) to avoid common cause failures.

The passive residual heat removal heat exchanger protects the plant against transients that upset the normal steam generator feedwater and steam systems. The passive residual heat removal subsystem of the passive core cooling system contains no pumps and significantly fewer valves than conventional plant auxiliary feedwater systems. This increases the reliability of the system. There are fewer potential equipment failures (pumps and valves) and less maintenance activities.

For reactor coolant system water inventory makeup during loss-of-coolant accident events, the passive core cooling system uses three passive sources of water to maintain core cooling through safety injection: the core makeup tanks, accumulators, and in-containment refueling water storage tank. These sources are directly connected to two nozzles on the reactor vessel so that no injection flow can be spilled for larger pipe break events.

The automatic depressurization system is incorporated into the design for depressurization of the reactor coolant system. The automatic depressurization system has 10 paths with diverse valves to avoid common cause failures, and it is designed for automatic or manual actuation by the protection and safety monitoring system or manual actuation by the diverse actuation system. The automatic depressurization system can be used in a partial depressurization mode to provide long-term reactor coolant system cooling with normal residual heat removal system injection, or it can be used in full depressurization mode for passive in-containment refueling water storage tank injection for long-term reactor coolant system cooling. Switchover from injection to recirculation is automatic without manual actions.

The safety-related Class 1E dc and UPS system has a battery capacity sufficient to support passive safety-related systems for 72 hours. This system has four 24-hour batteries, two 72-hour batteries, and a spare battery. The presence of the spare battery improves testability.

The passive containment cooling system provides the safety-related ultimate heat sink for the plant. Heat is removed from the containment vessel following an accident by a continuous natural circulation flow of air, without any system actuations. By using the passive containment cooling system following an accident, the containment stays well below the predicted failure pressure. The steaming and condensing action of the passive containment cooling system enhances activity removal.

AP1000 containment isolation is significantly improved over that of conventional PWRs due to a large reduction in the number of penetrations. The number of normally open penetrations is reduced. Containment isolation is improved due to the chemical and volume control system being a closed system; the safety-related passive safety injection components being located inside the

containment; and the number of heating, ventilation, and air conditioning (HVAC) penetrations being reduced (no maxi purge connection).

Vessel failure potential upon core damage is reduced (in-vessel retention of the damaged core) by providing a provision to dump in-containment refueling water storage tank water into the reactor cavity. The vessel insulation enables this water to cool the vessel.

For events at shutdown, the AP1000 has passive safety-related systems for shutdown conditions as a backup to the normal residual heat removal system. This reduces the risk at shutdown through redundancy and diversity.

Post-72-hour connections are incorporated into the passive system design to allow for long-term accident management. These connections allow for the refill of the in-containment refueling water storage tank, or the reactor cavity, should such actions become necessary.

19.59.9.2.2 Nonsafety-Related Systems

The AP1000 has nonsafety-related systems capable of mitigating accidents. These systems use redundant components, which are powered by offsite and onsite power supplies. The AP1000 has certain design features in the nonsafety-related systems to reduce plant risk compared to current operating plants. During transient events, the startup feedwater system can act as a backup to the main feedwater system if the latter is unavailable due to the nature of the initiating event or fails during the transient. During loss of ac power events, startup feedwater pumps are powered by the diesel generators and can be used to remove decay heat since main feedwater is not available. The main feedwater and startup feedwater pumps are motor-driven, rather than steam-driven, for better reliability. Main feedwater controls are digital for better reliability. Thus, the main feedwater and startup feedwater system creates fewer transients and provides additional nonsafety-related means for decay heat removal for transients. This makes the plant response to transients very robust due to the existence of two nonsafety-related systems in addition to the passive safety-related means of removing decay heat.

The nonsafety-related normal residual heat removal system plays a role in decay heat removal in response to power and shutdown events. The normal residual heat removal system has additional isolation valves and is designed to withstand the reactor coolant system pressure to eliminate interfacing systems loss-of-coolant accident concerns that lead to containment bypass. The normal residual heat removal system provides reliable shutdown cooling, incorporating lessons learned from shutdown events. During mid-loop operations, operation procedures require both normal residual heat removal system pumps to be operable for risk reduction.

Component cooling water and service water systems have a limited role in the plant risk profile because the passive safety-related systems do not require cooling, and the canned-motor reactor coolant pumps do not require seal cooling from the component cooling water.

The nonsafety-related ac power system (onsite and offsite) also has a limited role in the plant risk profile since the plant safety-related systems do not depend on ac power. The loss of offsite power event is less important for the AP1000 than in current operating plants. The plant has full load rejection capability to minimize the number of reactor trips although this is not modeled in the

PRA and no credit is taken for it. The onsite ac power has two nonsafety-related diesel generators. The diesel generator life is improved and the run failure rate is reduced by avoiding fast starts.

The compressed and instrument air system has low risk importance since the safety-related air-operated valves are fail safe if the air system fails. This causes the loss of air event to be less important than in current plant PRAs.

19.59.9.3 Instrumentation and Control Design

Three instrumentation and control systems are modeled in the AP1000 PRA: protection and safety monitoring system, plant control system, and diverse actuation system. Both the protection and safety monitoring system and plant control system are microprocessor-based. Four trains of redundancy are provided for the protection and safety monitoring system; 2-out-of-4 actuation logic in the protection and safety monitoring system reduces the potential for spurious trips due to testing and allows for better testing. Automatic testing for the protection and safety monitoring system, and diagnostic self-testing for the protection and safety monitoring system and the plant control system, provide higher reliability in these systems. Both the protection and safety monitoring system and the plant control system use fiber-optic cables (with fire separation) for data transmission. Unlike current plants, there is no cable spreading room. This eliminates a potential fire hazard. Additional fault tolerance is built into the plant control system so that one failure does not prevent the operation of important functions.

Improvements in the plant control system and the protection and safety monitoring system are coupled with an improved control room and man-machine interfaces; these include improvements in the form and contents of the information provided to control room operators for decision making to limit commission errors. In addition, the remote shutdown workstation is designed to have functions similar to the control room.

The diverse actuation system provides a diverse automatic and manual backup function to the protection and safety monitoring system and reduces risk from anticipated transients without scram events. The diverse actuation system also compensates for common cause failures in the protection and safety monitoring system.

19.59.9.4 Plant Layout

The plant layout minimizes the consequences of fire and flooding by maximizing the separation of electrical and mechanical equipment areas in the non-radiologically controlled area of the auxiliary building. This separation is designed to minimize the potential for propagation of leaks from the piping areas and the mechanical equipment areas to the Class 1E electrical and Class IE instrumentation and control equipment rooms. The potential flooding sources and volumes in areas of the plant that contain safety-related electrical and I&C equipment are limited to minimize the consequences of internal flooding.

The AP1000 is designed to provide better separation between divisions of safety-related equipment.

19.59.9.5 Containment Design

The containment pressure boundary is the final barrier to the release of fission products to the environment. The AP1000 containment has provisions that help to maintain containment integrity in a severe accident.

19.59.9.5.1 Containment Isolation and Leakage

Failure of the containment isolation system before a severe accident will lead to a direct release pathway from the containment volume to the environment. The AP1000 has approximately 55 percent fewer piping penetrations and a lower percentage of normally open penetrations compared to current generation plants. Normally open penetrations are closed by automatic valves, and diverse actuation is provided for valves on penetrations with significant leakage potential. All isolation valves have control room indication to inform the operator of the current valve position.

Similarly to containment isolation failure, leakage of closed containment isolation valves in excess of technical specifications may result in larger releases to the environment. Valves that historically have the greatest leakage problems have been eliminated, or their number significantly reduced in the design. Large purge valves have been replaced by smaller more reliable valves, and check valves have been used only in mild service where wear and service conditions would not be a challenge to successful operation.

Equipment and personnel hatches have the capability of being tested individually to ensure a leak-tight seal. Hatch seals can easily be verified.

Therefore, the AP1000 provides significant protection against the failure to isolate the containment and against the failure of isolation valves to fully close.

19.59.9.5.2 Containment Bypass

Historically, containment bypass, an accident in which the fission products are released directly to the environment from the reactor coolant system, is the leading contributor to risk in a nuclear power plant. Typically the containment bypass accident class consists of two types of accident sequences: interfacing systems loss-of-coolant accidents and steam generator tube ruptures.

An interfacing systems loss-of-coolant accident is the failure of valves that separate the high pressure reactor coolant system with a lower pressure interfacing system, which extends outside the containment pressure boundary. The failure of the valve causes the reactor coolant system to pressurize the interfacing system beyond its ultimate capacity and can result in a loss-of-coolant accident outside the containment. Reactor coolant is lost outside the containment, providing a pathway for the direct release of fission products to the environment. In AP1000, systems connected to the reactor coolant system are designed with higher design pressure, which reduces the likelihood of a pipe rupture in the event of the failure of the interfacing valves. This results in a very low interfacing systems loss-of-coolant-accident contribution to core damage to containment bypass.

Steam generator tube ruptures release coolant from the reactor coolant system to the secondary system. The AP1000 has multiple and diverse automatically actuated systems to reduce the reactor

coolant system pressure and mitigate the steam generator tube rupture. The passive residual heat removal subsystem is actuated automatically on the S-signal and effectively reduces the reactor coolant system pressure to stop the break flow. If the passive residual heat removal does not stop the loss of coolant, the secondary relief valve can open to keep the secondary system pressure below the opening pressure of the steam generator safety valve. If the loss of reactor coolant continues, the RCS automatic depressurization system will actuate and depressurize the system. No operator actions are required to mitigate the accident, and the secondary system remains sealed against releases to the environment after the relief valve or its block valve are closed.

To create a containment bypass release pathway from a steam generator tube rupture, the accident scenario must include multiple system failures such that the steam generator tube rupture is not mitigated, and the secondary system pressure increases enough to open a safety valve. The safety valve must fail to reseat, and thereby provide a containment bypass pathway for the loss of coolant and for the possible release of fission products to the environment.

Multiple, diverse systems act to mitigate steam generator tube rupture. Therefore, the likelihood of a steam generator tube rupture progressing to containment bypass has been significantly reduced in AP1000.

19.59.9.5.3 Passive Containment Cooling

The passive containment cooling system provides protection to the containment pressure boundary by removing the decay and chemical heat that slowly pressurize the containment. The heat is transferred to the environment through the steel pressure boundary. The heat transfer on the outside of the steel shell is enhanced by an annular flow path, which creates a convective air flow across the shell, and by the evaporation of water that is directed onto the top of the containment in the event of an accident. The evaporative heat transfer prevents the containment from pressurizing above the design conditions during design basis accidents.

In some postulated multiple-failure accident scenarios, the water flow may fail. The heat removal is limited to convection heat transfer to the air flow and radiation to the annulus baffle. With no water film on the containment shell to provide evaporative cooling, the containment pressurizes above the design pressure to remove decay heat. Containment failure within 24 hours is highly unlikely.

19.59.9.5.4 High-Pressure Core Melt Scenarios

The automatic depressurization system and the passive residual heat removal heat exchanger provide reliable and diverse reactor coolant system depressurization, which significantly reduces the likelihood of high-pressure core damage. High-pressure core damage sequences have the potential to fail steam generator tubes and create a containment bypass release, or to cause severe accident phenomena at the time of vessel failure, which may threaten the containment pressure boundary. Reducing the reactor coolant system pressure during a severe accident significantly lowers the likelihood of phenomena that may induce large fission product releases early in the accident sequence.

19.59.9.5.5 In-Vessel Retention of Molten Core Debris

The AP1000 reactor vessel and containment configuration have features that enhance the design's ability to maintain molten core debris in the reactor vessel. The AP1000 automatic depressurization system provides reliable pressure reduction in the reactor coolant system to reduce the stresses on the vessel wall. The reactor vessel lower head has no vessel penetrations. This eliminates penetration failure as a potential vessel failure mode. The containment configuration directs water to the reactor cavity and allows the in-containment refueling water storage tank water to be drained into the cavity to submerge the vessel to cool the external surface of the lower head. Cooling the vessel and reducing the stresses prevent the creep rupture failure of the vessel wall. The reactor vessel reflective insulation has been designed with provisions to allow water inside the insulation panel to cool the vessel surface, and with vents to allow steam to exit the insulation without failing the insulation support structures. The insulation is designed so that it promotes the cooling of the external surface of the vessel.

Preventing the relocation of molten core debris to the containment eliminates the occurrence of several severe accident phenomena, such as ex-vessel fuel-coolant interactions and core-concrete interaction, which may threaten the containment integrity. Through the prevention of core debris relocation to the containment, the AP1000 design significantly reduces the likelihood of containment failure.

19.59.9.5.6 Combustible Gases Generation and Burning

In severe accident sequences, high-temperature metal oxidation, particularly zirconium, results in the rapid generation of hydrogen and possibly carbon monoxide. The first combustible gas release occurs in the accident sequence during core uncovery when the oxidation of the zircaloy cladding by passing steam generates hydrogen. A second release may occur if the vessel fails and ex-vessel debris degrades the concrete basemat. Steam and carbon dioxide are liberated from the concrete and are reduced to hydrogen and carbon monoxide as they pass through the molten metal in the debris. These gases are highly combustible and in high concentrations in the containment may lead to detonable mixtures.

The AP1000 uses a nonsafety-related hydrogen igniter system for severe releases of combustible gases. The igniters are powered from ac buses from either of the nonsafety-related diesel generators or from the non-Class 1E batteries. Multiple glow plugs are located in each compartment. The igniters burn the gases at the lower flammability limit. At this low concentration, the containment pressure increase from the burning is small and the likelihood of detonation is negligible. The igniters are spaced such that the distance between them will not allow the burn to transition from deflagration to detonation. The combustible gases are removed with no threat to the containment integrity.

There is little threat of the failure of the system power in the event that it is required to operate. The igniters are needed only in core damage accidents, and the AP1000 is designed to mitigate loss of power events without the sequence evolving into a severe accident. Loss of ac power is a small contributor to the core damage frequency.

The reliability of reactor coolant system depressurization reduces the threat to the containment from sudden releases of hydrogen from the reactor coolant system. Low pressure release of in-vessel hydrogen enhances the ability of the igniter system to maintain the containment atmosphere at the lower flammability limit.

During a severe accident, hydrogen, which could be injected from the reactor coolant system into the containment through the spargers in the in-containment refueling water storage tank or into the core makeup tank room, has the potential to produce a diffusion flame. A diffusion flame is produced when a combustible gas plume that is too rich to burn enters an oxygen-rich atmosphere and is ignited by a glow plug or a random ignition source. The plume is ignited into a standing flame, which lasts as long as there is a fuel source. Via convection and radiation, the flame can heat the containment wall to high temperatures, increasing the likelihood of creep rupture failure of the containment pressure boundary. The AP1000 uses a defense-in-depth approach to release hydrogen in benign locations away from the containment shell and penetrations. Therefore, the potential for containment failure from the formation of a diffusion flame at the in-containment refueling water storage tank vents is considered to be low.

There is little threat to the containment integrity from severe accident hydrogen releases and hydrogen combustion events. The igniter system maintains the hydrogen concentration at the lower flammability limit.

19.59.9.5.7 Intermediate and Long-Term Containment Failure

The passive containment cooling system reduces the potential for decay heat pressurization of the containment. However, containment failure can also occur as a result of combustion. Due to the high likelihood of in-vessel retention of core debris, the potential for ex-vessel combustible gas generation from core-concrete interaction is low. The frequency of containment failures due to hydrogen combustion events is low given the high reliability of the hydrogen igniters.

19.59.9.5.8 Fission-Product Removal

The AP1000 relies on the passive, natural removal of aerosol fission products from the containment atmosphere, primarily from gravitational settling, diffusiophoresis, and thermophoresis. Natural removal is enhanced by the passive containment cooling system, which provides a large, cold surface area for condensation of steam. This increases the diffusiophoretic and thermophoretic removal processes. Accident offsite doses at the site boundary, which could exist in the first 24 hours after a severe accident, are either less than 25 rem, or for those releases that are greater than 25 rem, have a frequency of much less than 1E-06. Minimal credit is taken for deposition of fission products in the auxiliary building. The site boundary dose and large release frequency are much less than the established goals.

19.59.10 PRA Input to Design Certification Process

The AP1000 PRA was used in the design certification process to identify important safety insights and assumptions to support certification requirements, such as the reliability assurance program (RAP).

19.59.10.1 PRA Input to Reliability Assurance Program

The AP1000 RAP identifies those systems, structures, and components (SSC) that should be given priority in maintaining their reliability through surveillance, maintenance, and quality control actions during plant operation. The PRA importance and sensitivity analyses identify those systems and components that are important in plant risk in terms of either risk increase (for example, what happens to plant risk if a system or component, or a train is unavailable), or in terms of risk decrease (for example, what happens to plant risk if a component or a train is perfectly reliable/available). This ranking of components and systems in such a way provides an input for the reliability assurance program. For more information on the AP1000 reliability assurance program, refer to Section 17.4.

19.59.10.2 PRA Input to Tier 1 Information

Section 14.3 summarizes the design material contained in AP1000 that has been incorporated into the Tier 1 Information from the PRA.

19.59.10.3 PRA Input to MMI/Human Factors/Emergency Response Guidelines

The PRA models, including modeling of operator actions in response to severe accident sequences, follow the ERGs. The most risk important of these actions is manual actuation of systems in the highly unlikely event of automatic actuation failure. These operator actions and the main human reliability analysis (HRA) model assumptions are reviewed by human factors engineers for insights that they may provide to the human system interface (HSI) and human factors areas. For more information on the AP1000 HSI, refer to Chapter 18.

In addition, the human reliability analysis models and operator actions modeled in the PRA were reviewed by the engineers writing the ERGs for consistency between the PRA models and the actual ERGs.

The PRA results and sensitivity studies show that the AP1000 design has no critical operator actions and few risk important actions. A critical operator action is defined as that action, when assumed to fail, would result in a plant core damage frequency of greater than 1.0E-04 per year; there are no such operator actions in the AP1000 PRA.

19.59.10.4 Summary of PRA Based Insights

The use of the PRA in the design process is discussed in subsection 19.59.2. A summary of the overall PRA results is provided in subsections 19.59.3 through 19.59.8. A discussion of the AP1000 plant features important to reducing risk is provided in subsection 19.59.9. PRA-based insights are developed from this information and are summarized in Table 19.59-18.

19.59.10.5 Combined License Information

The Combined License applicant referencing the AP1000 certified design will review differences between the as-built plant and the design used as the basis for the AP1000 seismic margins analysis. A verification walkdown will be performed with the purpose of identifying differences between the as-built plant and the design. Any differences will be evaluated to determine if there

is a significant adverse effect on the seismic margins analysis results. Spacial interactions are addressed by COL information item 3.7-3. Details of the process will be developed by the Combined License applicant.

The Combined License applicant referencing the AP1000 certified design should compare the as-built SSC HCLPFs to those assumed in the AP1000 seismic margin evaluation. Deviations from the HCLPF values or assumptions in the seismic margin evaluation should be evaluated to determine if vulnerabilities have been introduced. The requirements to which the equipment is to be purchased are included in the equipment specifications. Specifically, the equipment specifications include:

1. Specific minimum seismic requirements consistent with those used to define the Table 19.55-1 HCLPF values.

   This includes the known frequency range used to define the HCLPF by comparing the required response spectrum (RRS) and test response spectrum (TRS). The range of frequency response that is required for the equipment with its structural support is defined.

2. Hardware enhancements that were determined in previous test programs and/or analysis programs will be implemented.

The Combined License applicant referencing the AP1000 certified design will review differences between the as-built plant and the design used as the basis for the AP1000 PRA and Table 19.59-18. If the effects of the differences are shown, by a screening analysis, to potentially result in a significant increase in core damage frequency or large release frequency, the PRA will be updated to reflect these differences. Based on site-specific information, the COL should also reevaluate the qualitative screening of external events (PRA Section 58.1). If any site-specific susceptibilities are found, the PRA should be updated to include the applicable external event.

The Combined License applicant referencing the AP1000 certified design will review differences between the as-built plant and the design used as the basis for the AP1000 internal fire and internal flood analysis. Differences will be evaluated to determine if there is significant adverse effect on the internal fire and internal flood analysis results.

The Combined License applicant referencing the AP1000 certified design will develop and implement severe accident management guidance using the suggested framework provided in WCAP-13914, “Framework for AP600 Severe Accident Management Guidance,” (Reference 19.59-1).

The Combined License applicant referencing the AP1000 certified design will perform a thermal lag assessment of the as-built equipment required to mitigate severe accidents (hydrogen igniters and containment penetrations) to provide additional assurance that this equipment can perform its severe accident functions during environmental conditions resulting from hydrogen burns associated with severe accidents. This assessment is required only for equipment used for severe accident mitigation that has not been tested at severe accident conditions. The Combined License applicant will assess the ability of the as-built equipment to perform during severe accident

hydrogen burns using the Environment Enveloping method or the Test Based Thermal Analysis method discussed in EPRI NP-4354 (Reference 19.59-2).

19.59.11 References

19.59-1 "Framework for AP600 Severe Accident Management Guidance," WCAP-13914, Revision 3, January 1998.

19.59-2 "Large Scale Hydrogen Burn Equipment Experiments," EPRI-NP-4354, December 1985.

Table 19.59-1

CONTRIBUTION OF INITIATING EVENTS TO CORE DAMAGE

	Core Damage Contribution	Initiating Event Category	Percent Contribution	Initiating Event Frequency
1	9.50E-08	SAFETY INJECTION LINE BREAK INITIATING EVENT	39.4%	2.12E-04
2	4.50E-08	LARGE LOCA INITIATING EVENT	18.7%	5.00E-06
3	2.96E-08	SPURIOUS ADS INITIATING EVENT	12.3%	5.40E-05
4	1.81E-08	SMALL LOCA INITIATING EVENT	7.5%	5.00E-04
5	1.61E-08	MEDIUM LOCA INITIATING EVENT	6.7%	4.36E-04
6	1.00E-08	REACTOR VESSEL RUPTURE INITIATING EVENT	4.2%	1.00E-08
7	6.79E-09	STEAM GENERATOR TUBE RUPTURE INITIATING EVENT	2.8%	3.88E-03
8	3.68E-09	CMT LINE BREAK INITIATING EVENT	1.5%	9.31E-05
9	3.61E-09	ATWS PRECURSOR WITH NO MFW INITIATING EVENT	1.5%	4.81E-01(*)
10	3.08E-09	TRANSIENT WITH MFW INITIATING EVENT	1.3%	1.40E+00
11	1.71E-09	RCS LEAK INITIATING EVENT	0.7%	6.20E-03
12	1.66E-09	CORE POWER EXCURSION INITIATING EVENT	0.7%	4.50E-03
13	1.24E-09	LOSS OF CONDENSER INITIATING EVENT	0.5%	1.12E-01
14	9.58E-10	LOSS OF OFFSITE POWER INITIATING EVENT	0.4%	1.20E-01
15	8.70E-10	LOSS OF MAIN FEEDWATER INITIATING EVENT	0.4%	3.35E-01
16	7.12E-10	ATWS PRECURSOR WITH MFW AVAILABLE INITIATING EVENT	0.3%	1.17E+00(*)
17	6.72E-10	LOSS OF COMPRESSED AIR INITIATING EVENT	0.3%	3.48E-02
18	6.06E-10	MAIN STEAM LINE STUCK-OPEN SV INITIATING EVENT	0.3%	2.39E-3
19	5.02E-10	PASSIVE RHR TUBE RUPTURE INITIATING EVENT	0.2%	1.34E-04
20	4.53E-10	LOSS OF MFW TO ONE SG INITIATING EVENT	0.2%	1.92E-01
21	3.23E-10	LOSS OF CCW/SW INITIATING EVENT	0.1%	1.44E-01
22	1.31E-10	MAIN STEAM LINE BREAK UPSTREAM OF MSIV INITIATING EVENT	0.1%	3.72E-04
23	1.11E-10	ATWS PRECURSOR WITH SI SIGNAL INITIATING EVENT	0.1%	1.48E-02(*)
24	5.00E-11	INTERFACING SYSTEMS LOCA INITIATING EVENT	0.0%	5.00E-11
25	3.52E-11	LOSS OF RCS FLOW INITIATING EVENT	0.0%	1.80E-02
26	9.15E-12	MAIN STEAM LINE BREAK DOWNSTREAM OF MSIV INITIATING EVENT	0.0%	5.96E-04
	2.41E-07	Totals	100.0%	2.38(*)

(*) = Note that the ATWS precursor frequencies are not included in the total initiating event frequency, since they are already accounted for in the other categories.

Table 19.59-2

CONDITIONAL CORE DAMAGE PROBABILITY OF INITIATING EVENTS

	Core Damage Contribution	Initiating Event Category	Initiating Event Frequency	Conditional CD Prob.
6	1.00E-08	REACTOR VESSEL RUPTURE INITIATING EVENT	1.00E-08	1.00E+00
24	5.00E-11	INTERFACING SYSTEMS LOCA INITIATING EVENT	5.00E-11	1.00E+00
2	4.50E-08	LARGE LOCA INITIATING EVENT	5.00E-06	8.99E-03
3	2.96E-08	SPURIOUS ADS INITIATING EVENT	5.40E-05	5.48E-04
1	9.50E-08	SAFETY INJECTION LINE BREAK INITIATING EVENT	2.12E-04	4.48E-04
8	3.68E-09	CMT LINE BREAK INITIATING EVENT	9.31E-05	3.95E-05
5	1.61E-08	MEDIUM LOCA INITIATING EVENT	4.36E-04	3.70E-05
4	1.81E-08	SMALL LOCA INITIATING EVENT	5.00E-04	3.62E-05
19	5.02E-10	PASSIVE RHR TUBE RUPTURE INITIATING EVENT	1.34E-04	3.74E-06
7	6.79E-09	STEAM GENERATOR TUBE RUPTURE INITIATING EVENT	3.88E-03	1.75E-06
18	6.06E-10	MAIN STEAM LINE STUCK-OPEN SV INITIATING EVENT	2.39E-03	2.54E-07
12	1.66E-09	CORE POWER EXCURSION INITIATING EVENT	4.50E-03	3.69E-07
22	1.31E-10	MAIN STEAM LINE BREAK UPSTREAM OF MSIV INITIATING EVENT	3.72E-04	3.51E-07
11	1.71E-09	RCS LEAK INITIATING EVENT	6.20E-03	2.75E-07
17	6.72E-10	LOSS OF COMPRESSED AIR INITIATING EVENT	3.48E-02	1.93E-08
26	9.15E-12	MAIN STEAM LINE BREAK DOWNSTREAM OF MSIV INITIATING EVENT	5.96E-04	1.54E-08
13	1.24E-09	LOSS OF CONDENSER INITIATING EVENT	1.12E-01	1.11E-08
14	9.58E-10	LOSS OF OFFSITE POWER INITIATING EVENT	1.20E-01	7.98E-09
9	3.61E-09	ATWS PRECURSOR WITH NO MFW INITIATING EVENT	4.81E-01	7.49E-09
23	1.11E-10	ATWS PRECURSOR WITH SI SIGNAL INITIATING EVENT	1.48E-02	7.48E-09
15	8.70E-10	LOSS OF MAIN FEEDWATER INITIATING EVENT	3.35E-01	2.60E-09
20	4.53E-10	LOSS OF MFW TO ONE SG INITIATING EVENT	1.92E-01	2.36E-09
21	3.23E-10	LOSS OF CCW/SW INITIATING EVENT	1.44E-01	2.24E-09
10	3.08E-09	TRANSIENT WITH MFW INITIATING EVENT	1.40E+00	2.20E-09
25	3.52E-11	LOSS OF RSC FLOW INITIATING EVENT	1.80E-02	1.96E-09
16	7.12E-10	ATWS PRECURSOR WITH MFW AVAILABLE INITIATING EVENT	1.17E+00	6.09E-10
	2.41E-07	Totals	2.38E+00	

Table 19.59-3 (Sheet 1 of 4)

INTERNAL INITIATING EVENTS AT POWER DOMINANT CORE DAMAGE SEQUENCES

	Sequence Frequency	Percent Contrib	Cumulative % Contrib	Sequence Identifier	Sequence Description
1	6.88E-08	28.52	28.52	2esil-07	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS RCPS TRIP AND CMT INJECTION IS SUCCESSFUL – 1 OF 2 CMT TRAINS SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF ONE OF ONE IRWST INJECTION LINE
2	4.26E-08	17.66	46.18	2rllo-09	LARGE LOCA INITIATING EVENT OCCURS ANY ONE OF TWO ACCUMULATOR TRAINS FAIL
3	2.13E-08	8.82	55.00	3dsad-08	SPURIOUS ADS INITIATING EVENT OCCURS SUCCESS OF 1/2 OR 2/2 ACCUMULATORS FAILURE OF ADS OR CMT
4	1.98E-08	8.23	63.23	3dsil-08	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS RCPS TRIP AND CMT INJECTION IS SUCCESSFUL – 1 OF 2 CMT TRAINS FAILURE OF FULL ADS DEPRESSURIZATION
5	1.00E-08	4.15	67.38	3crvr-02	REACTOR VESSEL RUPTURE INITIATING EVENT OCCURS
6	8.44E-09	3.5	70.88	2lslo-05	SMALL LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP SUCCESS OF PASSIVE RHR SYSTEM SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE SUCCESS OF TWO OF TWO IRWST INJECTION LINES SUCCESS OF CIS & PRE-EXISTING CONTAINMENT OPENING FAILURE OF RECIRCULATION

Table 19.59-3 (Sheet 2 of 4)

INTERNAL INITIATING EVENTS AT POWER DOMINANT CORE DAMAGE SEQUENCES

	Sequence Frequency	Percent Contrib	Cumulative % Contrib	Sequence Identifier	Sequence Description
7	7.35E-09	3.05	73.93	2lmlo-05	MEDIUM LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE SUCCESS OF TWO OF TWO IRWST INJECTION LINES SUCCESS OF CIS & PRE-EXISTING CONTAINMENT OPENING FAILURE OF RECIRCULATION
8	5.11E-09	2.12	76.05	3dslo-12	SMALL LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP SUCCESS OF PASSIVE RHR SYSTEM FAILURE OF FULL ADS DEPRESSURIZATION SUCCESS OF PARTIAL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE
9	4.46E-09	1.85	77.90	3dmlo-12	MEDIUM LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP FAILURE OF FULL ADS DEPRESSURIZATION SUCCESS OF PARTIAL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE
10	3.72E-09	1.54	79.44	2rsad-09	SPURIOUS ADS INITIATING EVENT OCCURS FAILURE OF 2/2 ACCUMULATORS
11	3.67E-09	1.52	80.96	2esad-07	SPURIOUS ADS INITIATING EVENT OCCURS SUCCESS OF 1/2 OR 2/2 ACCUMULATORS SUCCESS OF ADS & CMT FAILURE OF IRW OR CMT

Table 19.59-3 (Sheet 3 of 4)

INTERNAL INITIATING EVENTS AT POWER DOMINANT CORE DAMAGE SEQUENCES

	Sequence Frequency	Percent Contrib	Cumulative % Contrib	Sequence Identifier	Sequence Description
12	3.57E-09	1.48	82.44	2lsil-03	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS RCPS TRIP AND CMT INJECTION IS SUCCESSFUL – 1 OF 2 CMT TRAINS SUCCESS OF FULL ADS DEPRESSURIZATION IRWST INJECTION IS SUCCESSFUL – 1 OF 1 TRAINS SUCCESS OF CIS & PRE-EXISTING CONTAINMENT OPENING FAILURE OF RECIRCULATION
13	3.55E-09	1.47	83.91	6esgt-41	SGTR EVENT SEQUENCE CONTINUES FAILURE OF CMT OR RCP TRIP SUCCESS OF PASSIVE RHR SYSTEM FAILURE OF FULL ADS DEPRESSURIZATION FAILURE OF PARTIAL ADS DEPRESSURIZATION
14	3.31E-09	1.37	85.28	3aatw-23	ATWS PRECURSOR WITH NO MFW EVENT SEQUENCE CONTINUES SUCCESS OF SFW OR PRHR SYSTEM SUCCESS OF MANUAL REACTOR TRIP FAILURE OF MANUAL BORATION BY CVS FAILURE OF CMT OR RCP TRIP
15	3.30E-09	1.37	86.65	2eslo-09	SMALL LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP SUCCESS OF PASSIVE RHR SYSTEM SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE FAILURE OF TWO OF TWO IRWST INJECTION LINES

Table 19.59-3 (Sheet 4 of 4)

INTERNAL INITIATING EVENTS AT POWER DOMINANT CORE DAMAGE SEQUENCES

	Sequence Frequency	Percent Contrib	Cumulative % Contrib	Sequence Identifier	Sequence Description
16	2.88E-09	1.19	87.84	2emlo-09	MEDIUM LOCA INITIATING EVENT OCCURS SUCCESS OF CMT & RCP TRIP SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE FAILURE OF TWO OF TWO IRWST INJECTION LINES
17	2.19E-09	0.91	88.75	6esgt-13	SGTR EVENT SEQUENCE CONTINUES SUCCESS OF CMT & RCP TRIP SUCCESS OF PASSIVE RHR SYSTEM FAILURE OF FULL ADS DEPRESSURIZATION FAILURE OF PARTIAL ADS DEPRESSURIZATION
18	1.97E-09	0.82	89.57	3dllo-08	LARGE LOCA INITIATING EVENT OCCURS ACCUMULATOR INJECTION IS SUCCESSFUL – 2 OF 2 TRAINS FAILURE OF ADS OR CMT
19	1.57E-09	0.65	90.22	2lcmt-05	CMT LINE BREAK INITIATING EVENT OCCURS RCPS TRIP AND CMT INJECTION IS SUCCESSFUL – 1 OF 2 CMT TRAINS SUCCESS OF FULL ADS DEPRESSURIZATION FAILURE OF NORMAL RHR IN INJECTION MODE SUCCESS OF TWO OF TWO IRWST INJECTION LINES SUCCESS OF CIS & PRE-EXISTING CONTAINMENT OPENING FAILURE OF RECIRCULATION

Table 19.59-4 (Sheet 1 of 3)

SEQUENCE 1 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-07)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	5.09E-08	74.04	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			IRWST DISCHARGE LINE “A” STRAINER PLUGGED	2.40E-04	IWA-PLUG
2	6.36E-09	9.25	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CCF OF 4 GRAVITY INJECTION CVs	3.00E-05	IWX-CV-AO
3	5.51E-09	8.01	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CCF OF 4 GRAVITY INJECTION & 2 RECIRCULATION SQUIB VALVES	2.60E-05	IWX-EV-SA
4	1.23E-09	1.79	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CCF OF 2 GRAVITY INJECTION SQUIB VALVES IN 1/1 LINES TO OPEN	5.80E-06	IWX-EV1-SA
5	6.49E-10	.94	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 122A FAILS TO OPEN	1.75E-03	IWACV122AO
			CHECK VALVE 124A FAILS TO OPEN	1.75E-03	IWACV124AO
6	5.42E-10	.79	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 122A FAILS TO OPEN	1.75E-03	IWACV122AO
			HARDWARE FAILURE OF VALVE 125A	1.46E-03	IRWMOD06
7	5.42E-10	.79	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 123A	1.46E-03	IRWMOD05
			CHECK VALVE 124A FAILS TO OPEN	1.75E-03	IWACV124AO
8	4.52E-10	.66	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 123A	1.46E-03	IRWMOD05
			HARDWARE FAILURE OF VALVE 125A	1.46E-03	IRWMOD06
9	3.25E-10	.47	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 122A FAILS TO OPEN	1.75E-03	IWACV122AO
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS125AFA
10	3.25E-10	.47	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 124A FAILS TO OPEN	1.75E-03	IWACV124AO
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS123AFA
11	2.71E-10	.39	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 123A	1.46E-03	IRWMOD05
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS125AFA

Table 19.59-4 (Sheet 2 of 3)

SEQUENCE 1 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-07)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
12	2.71E-10	.39	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 125A	1.46E-03	IRWMOD06
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS123AFA
13	1.63E-10	.24	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS123AFA
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS125AFA
14	1.14E-10	.17	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CCF OF GRAVITY INJECTION CVs IN 1/1 LINES TO OPEN	5.40E-07	IWX-CV1-AO
15	1.11E-10	.16	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 122A FAILS TO OPEN	1.75E-03	IWACV122AO
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM
16	1.11E-10	.16	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 122A FAILS TO OPEN	1.75E-03	IWACV122AO
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDD1TM
17	1.11E-10	.16	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 124A FAILS TO OPEN	1.75E-03	IWACV124AO
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM
18	1.11E-10	.16	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CHECK VALVE 124A FAILS TO OPEN	1.75E-03	IWACV124AO
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDD1TM
19	9.29E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 123A	1.46E-03	IRWMOD05
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM
20	9.29E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 123A	1.46E-03	IRWMOD05
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDD1TM
21	9.29E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 125A	1.46E-03	IRWMOD06
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM

Table 19.59-4 (Sheet 3 of 3)

SEQUENCE 1 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-07)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
22	9.29E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF VALVE 125A	1.46E-03	IRWMOD06
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDD1TM
23	5.57E-11	.08	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS125AFA
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM
24	5.57E-11	.08	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS125AFA
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDD1TM
25	5.57E-11	.08	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS123AFA
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM

Table 19.59-5

SEQUENCE 2 – LARGE LOCA DOMINANT CUTSETS (LLOCA-09)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	8.75E-09	20.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
2	8.75E-09	20.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
3	8.75E-09	20.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
4	8.75E-09	20.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
5	3.64E-09	8.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP
6	3.64E-09	8.55	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
7	2.55E-10	.60	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			COMMON CAUSE FAILURE OF 2 ACCUMULATOR CHECK VALVES	5.10E-05	ACX-CV-GO
8	1.20E-11	.03	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			ACCUMULATOR TANK A (T001A) RUPTURES	2.40E-06	ACATK001AF
9	1.20E-11	.03	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			ACCUMULATOR TANK B (T001B) RUPTURES	2.40E-06	ACBTK001AF
10	3.60E-12	.01	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACAOR001EB
11	3.60E-12	.01	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACBOR001EB
12	6.00E-13	.00	LARGE LOCA INITIATING EVENT OCCURS	5.00E-06	IEV-LLOCA
			COMMON CAUSE FAILURE OF ACCUMULATOR TANKS	1.20E-07	ACX-TK-AF

Table 19.59-6 (Sheet 1 of 3)

SEQUENCE 3 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	5.56E-09	26.14	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF ESF INPUT LOGIC (HARDWARE)	1.03E-04	CCX-INPUT-LOGIC
2	3.35E-09	15.75	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF 4 AOVS TO OPEN	6.20E-05	CCX-AV-LA
3	3.19E-09	15.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
4	2.75E-09	12.93	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF 4 CHECK VALVES TO OPEN	5.10E-05	CMX-CV-GO
5	2.07E-09	9.73	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF RTD LEVEL TRANSMITTERS	3.84E-05	CMX-VS-FA
6	1.62E-09	7.62	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
7	5.94E-10	2.79	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF ESF INPUT LOGIC SOFTWARE	1.10E-05	CCX-IN-LOGIC-SW
8	5.94E-10	2.79	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF PMS ESF ACTUATION LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD2-SW
9	5.94E-10	2.79	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF PMS ESF OUTPUT LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD1-SW
10	4.65E-10	2.19	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CCF OF EPO BOARDS IN PMS	8.62E-06	CCX-EP-SAM
11	6.48E-11	.30	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			SOFTWARE CCF OF ALL CARDS	1.20E-06	CCX-SFTW
12	2.85E-11	.13	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	CMA-PLUG
			FLOW TUNING ORIFICE PLUGS	7.27E-04	CMB-PLUG
13	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10

Table 19.59-6 (Sheet 2 of 3)

SEQUENCE 3 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
14	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10
15	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
16	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10
17	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
18	1.82E-11	.09	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
19	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 2 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS002TM
20	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS022TM
21	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS221TM
22	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS001TM
23	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM

Table 19.59-6 (Sheet 3 of 3)

SEQUENCE 3 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
24	6.85E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS121TM
25	6.83E-12	.03	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			PMBMOD32	5.02E-03	PMBMOD32
			PMCMOD33	5.02E-03	PMCMOD33
			PMDMOD34	5.02E-03	PMDMOD34

Table 19.59-7 (Sheet 1 of 3)

SEQUENCE 4 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	1.25E-08	63.00	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
2	6.36E-09	32.06	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
3	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10
4	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10
5	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
6	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 4	5.80E-04	AD4MOD10
7	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 3	5.80E-04	AD4MOD09
8	7.13E-11	.36	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			HARDWARE FAILURE OF ST. #4 LINE 1	5.80E-04	AD4MOD07
			HARDWARE FAILURE OF ST. #4 LINE 2	5.80E-04	AD4MOD08
9	3.65E-11	.18	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COND. PROB. OF REC-MANDAS (FAILURE OF MANUAL DAS AC	5.06E-01	REC-MANDASC
			OPER. FAILS TO RECOG. THE NEED FOR RCS DEPRESS. DURING MLOCA	3.30E-03	LPM-MAN02
			CCF OF ESF INPUT LOGIC (HARDWARE)	1.03E-04	CCX-INPUT-LOGIC
10	3.34E-11	.17	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COND. PROB. OF REC-MANDAS (FAILURE OF MANUAL DAS AC	5.06E-01	REC-MANDASC
			OPER. FAILS TO FULFIL MANUAL ACTUATION OF ADS	3.02E-03	ADN-MAN01
			CCF OF ESF INPUT LOGIC (HARDWARE)	1.03E-04	CCX-INPUT-LOGIC

Table 19.59-7 (Sheet 2 of 3)

SEQUENCE 4 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	2.71E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			FAILURE OF MANUAL DAS ACT.	1.16E-02	REC-MANDAS
			CCF OF PMS ESF OUTPUT LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD1-SW
12	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 2 DUE TO UNSCHEDUL MAINTENANCE	2.70E-03	EC2BS002TM
13	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS022TM
14	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS221TM
15	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS001TM
16	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM
17	2.69E-11	.14	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS121TM
18	2.33E-11	.12	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			FAILURE OF MANUAL DAS REACTOR TRIP HARDWARE	1.00E-02	MDAS
			CCF OF PMS ESF OUTPUT LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD1-SW
19	2.12E-11	.11	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			FAILURE OF MANUAL DAS ACT.	1.16E-02	REC-MANDAS
			CCF OF EPO BOARDS IN PMS	8.62E-06	CCX-EP-SAM
20	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM

Table 19.59-7 (Sheet 3 of 3)

SEQUENCE 4 – SAFETY INJECTION LINE BREAK DOMINANT CUTSETS (SI-LB-08)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
21	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDD1TM
22	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDD1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM
23	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDD1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDD1TM
24	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDCBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDABSDS1TM
25	1.91E-11	.10	SAFETY INJECTION LINE BREAK INITIATING EVENT OCCURS	2.12E-04	IEV-SI-LB
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDCBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDABSDD1TM

Table 19.59-8

SEQUENCE 5 – REACTOR VESSEL RUPTURE CUTSET (RV-RP-02)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	1.00E-08	100.00	REACTOR VESSEL RUPTURE INITIATING EVENT OCCURS	1.00E-08	IEV-RV-RP

Table 19.59-9 (Sheet 1 of 3)

SEQUENCE 6 – SMALL LOCA DOMINANT CUTSETS (SLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	6.00E-09	71.10	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			PLUGGING OF BOTH RECIRC LINES DUE TO CCF OF SUMP SCREENS	1.20E-05	REX-FL-GP
2	2.39E-09	28.32	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
			OPER. FAILS TO ACT. SUMP RECIRC GIVEN IRW LEVEL SIGNAL FAILUR	1.00E-02	REN-MAN04
3	2.88E-11	.34	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
4	9.18E-12	.11	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
			CCF OF CMT LEVEL SWITCHES	3.84E-05	CCX-VS-FA
5	2.63E-12	.03	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF PMS ESF OUTPUT LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD1-SW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
6	2.63E-12	.03	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCX-PMXMOD4-SW	1.10E-05	CCX-PMXMOD4-SW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
7	2.06E-12	.02	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF EPO BOARDS IN PMS	8.62E-06	CCX-EP-SAM
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
8	3.07E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
9	3.07E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
10	2.87E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			SOFTWARE CCF OF ALL CARDS	1.20E-06	CCX-SFTW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR

Table 19.59-9 (Sheet 2 of 3)

SEQUENCE 6 – SMALL LOCA DOMINANT CUTSETS (SLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	2.56E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
12	2.56E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
13	2.39E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			INDICATION FAILURE	1.00E-06	ALL-IND-FAIL
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
14	1.84E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
15	1.84E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
16	1.68E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			CCF OF MOV 120A AND 120B	5.80E-06	IWX-EV2-SA
17	1.53E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
18	1.53E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS120AFA

Table 19.59-9 (Sheet 3 of 3)

SEQUENCE 6 – SMALL LOCA DOMINANT CUTSETS (SLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
19	1.53E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
20	1.53E-13	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWCRS120BFA
21	9.21E-14	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS120AFA
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
22	9.21E-14	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			RELAY FAILS TO OPERATE	8.76E-04	IWCRS120BFA
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
23	8.88E-14	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
24	7.41E-14	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
25	7.41E-14	.00	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12

Table 19.59-10 (Sheet 1 of 3)

SEQUENCE 7 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	5.23E-09	71.13	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			PLUGGING OF BOTH RECIRC LINES DUE TO CCF OF SUMP SCREENS	1.20E-05	REX-FL-GP
2	2.08E-09	28.29	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
			OPER. FAILS TO ACT. SUMP RECIRC GIVEN IRW LEVEL SIGNAL FAILUR	1.00E-02	REN-MAN04
3	2.51E-11	.34	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
4	8.00E-12	.11	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
			CCX-VS-FA	3.84E-05	CCX-VS-FA
5	2.29E-12	.03	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF PMS ESF OUTPUT LOGIC SOFTWARE	1.10E-05	CCX-PMXMOD1-SW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
6	2.29E-12	.03	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCX-PMXMOD4-SW	1.10E-05	CCX-PMXMOD4-SW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
7	1.80E-12	.02	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF EPO BOARDS IN PMS	8.62E-06	CCX-EP-SAM
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
8	2.67E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
9	2.67E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
10	2.50E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			SOFTWARE CCF OF ALL CARDS	1.20E-06	CCX-SFTW
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR

Table 19.59-10 (Sheet 2 of 3)

SEQUENCE 7 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	2.23E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
12	2.23E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
13	2.08E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			INDICATION FAILURE	1.00E-06	ALL-IND-FAIL
			CCF OF TANK LEVEL TRANSMITTERS	4.78E-04	IWX-XMTR
14	1.60E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
15	1.60E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
16	1.47E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			CCF OF MOV 120A AND 120B	5.80E-06	IWX-EV2-SA
17	1.34E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
18	1.34E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 118A	1.46E-03	IRWMOD09
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS120AFA

Table 19.59-10 (Sheet 3 of 3)

SEQUENCE 7 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-05)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
19	1.34E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
20	1.34E-13	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE OF SQUIB VALVE 118B	1.46E-03	IRWMOD11
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWCRS120BFA
21	8.03E-14	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			RELAY FAILS TO OPERATE	8.76E-04	IWDRS120AFA
			SUMP SCREEN B PLUGS AND PREVENTS FLOW	2.40E-04	REB-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWBRS118AFA
22	8.03E-14	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			RELAY FAILS TO OPERATE	8.76E-04	IWCRS120BFA
			SUMP SCREEN A PLUGS AND PREVENTS FLOW	2.40E-04	REA-PLUG
			RELAY FAILS TO OPERATE	8.76E-04	IWARS118BFA
23	7.74E-14	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
24	6.46E-14	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119B FAILS TO OPEN	1.75E-03	REBCV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE OF SQUIB VALVE 120A	1.46E-03	IRWMOD10
25	6.46E-14	.00	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			HARDWARE FAILURE CAUSE RECIRC. CV 119A FAILS TO OPEN	1.75E-03	REACV119GO
			CCF OF 2 OUT 2 LOW PRESSURE RECIRCULATION SQUIB VALVES	5.80E-05	IWX-EV4-SA
			HARDWARE FAILURE OF SQUIB VALVE 120B	1.46E-03	IRWMOD12

Table 19.59-11 (Sheet 1 of 3)

SEQUENCE 8 – SMALL LOCA DOMINANT CUTSETS (SLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	4.16E-10	8.14	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			MECHANICAL FAILURE OF RNS MOV V055	1.41E-02	RN55MOD1
2	4.16E-10	8.14	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILURE OF ISOLATION MOV 011	1.41E-02	RN11MOD3
3	4.16E-10	8.14	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILS TO OPEN MOV V022/CB FTC/RELAY FTC	1.41E-02	RN22MOD4
4	4.16E-10	8.14	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILS TO OPEN MOV V023/CB FTC/RELAY FTC	1.41E-02	RN23MOD5
5	2.95E-10	5.77	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CASK LOADING PIT UNAVAILABLE DUE TO FUEL UNLOADING OPERATIONS	1.00E-02	CLP-UNAVAILABLE
6	2.11E-10	4.13	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			MECHANICAL FAILURE OF RNS MOV V055	1.41E-02	RN55MOD1
7	2.11E-10	4.13	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILURE OF ISOLATION MOV 011	1.41E-02	RN11MOD3
8	2.11E-10	4.13	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILS TO OPEN MOV V022/CB FTC/RELAY FTC	1.41E-02	RN22MOD4
9	2.11E-10	4.13	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILS TO OPEN MOV V023/CB FTC/RELAY FTC	1.41E-02	RN23MOD5
10	1.50E-10	2.93	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			CASK LOADING PIT UNAVAILABLE DUE TO FUEL UNLOADING OPERATIONS	1.00E-02	CLP-UNAVAILABLE

Table 19.59-11 (Sheet 2 of 3)

SEQUENCE 8 – SMALL LOCA DOMINANT CUTSETS (SLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	1.45E-10	2.84	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CCF OF STOP CHECK VALVES V015A/B TO OPEN	4.90E-03	RNX-KV1-GO
12	8.55E-11	1.67	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			OPERATOR FAILS TO ALIGN AND ACTUATE THE RNS	2.90E-03	RHN-MAN01
13	7.97E-11	1.56	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDUL MAINTENANCE	2.70E-03	EC1BS001TM
14	7.97E-11	1.56	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM
15	7.97E-11	1.56	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS122TM
16	7.58E-11	1.48	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILURE OF VALVES ON DVI LINE A (V015A & 017	5.07E-02	RNAMOD09
			HARDWARE FAILURE OF VALVES ON DVI LINE B (V015B & 017	5.07E-02	RNBMOD10
17	7.35E-11	1.44	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			CCF OF STOP CHECK VALVES V015A/B TO OPEN	4.90E-03	RNX-KV1-GO
18	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 2 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS002TM
19	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS022TM
20	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS221TM

Table 19.59-11 (Sheet 3 of 3)

SEQUENCE 8 – SMALL LOCA DOMINANT CUTSETS (SLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
21	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS001TM
22	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM
23	6.35E-11	1.24	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS121TM
24	5.16E-11	1.01	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CHECK VALVE V013 FAILURE TO OPEN	1.75E-03	RNNCV013GO
25	4.50E-11	.88	SMALL LOCA INITIATING EVENT OCCURS	5.00E-04	IEV-SLOCA
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM

Table 19.59-12 (Sheet 1 of 3)

SEQUENCE 9 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	3.63E-10	8.14	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			MECHANICAL FAILURE OF RNS MOV V055	1.41E-02	RN55MOD1
2	3.63E-10	8.14	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILURE OF ISOLATION MOV 011	1.41E-02	RN11MOD3
3	3.63E-10	8.14	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILS TO OPEN MOV V022/CB FTC/RELAY FTC	1.41E-02	RN22MOD4
4	3.63E-10	8.14	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILS TO OPEN MOV V023/CB FTC/RELAY FTC	1.41E-02	RN23MOD5
5	2.57E-10	5.77	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CASK LOADING PIT UNAVAILABLE DUE TO FUEL UNLOADING OPERATIONS	1.00E-02	CLP-UNAVAILABLE
6	1.84E-10	4.13	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			MECHANICAL FAILURE OF RNS MOV V055	1.41E-02	RN55MOD1
7	1.84E-10	4.13	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILURE OF ISOLATION MOV 011	1.41E-02	RN11MOD3
8	1.84E-10	4.13	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILS TO OPEN MOV V022/CB FTC/RELAY FTC	1.41E-02	RN22MOD4
9	1.84E-10	4.13	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			HARDWARE FAILS TO OPEN MOV V023/CB FTC/RELAY FTC	1.41E-02	RN23MOD5
10	1.31E-10	2.94	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			CASK LOADING PIT UNAVAILABLE DUE TO FUEL UNLOADING OPERATIONS	1.00E-02	CLP-UNAVAILABLE

Table 19.59-12 (Sheet 2 of 3)

SEQUENCE 9 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	1.26E-10	2.83	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CCF OF STOP CHECK VALVES V015A/B TO OPEN	4.90E-03	RNX-KV1-GO
12	7.46E-11	1.67	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			OPERATOR FAILS TO ALIGN AND ACTUATE THE RNS	2.90E-03	RHN-MAN01
13	6.95E-11	1.56	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS001TM
14	6.95E-11	1.56	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM
15	6.95E-11	1.56	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS122TM
16	6.61E-11	1.48	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			HARDWARE FAILURE OF VALVES ON DVI LINE A (V015A & 017)	5.07E-02	RNAMOD09
			HARDWARE FAILURE OF VALVES ON DVI LINE B (V015B & 017)	5.07E-02	RNBMOD10
17	6.41E-11	1.44	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			DUE TO CCF OF 4TH STAGE ADS SQUIB VALVES TO OPERATE	3.00E-05	ADX-EV-SA
			CCF OF STOP CHECK VALVES V015A/B TO OPEN	4.90E-03	RNX-KV1-GO
18	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 2 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS002TM
19	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS022TM

Table 19.59-12 (Sheet 3 of 3)

SEQUENCE 9 – MEDIUM LOCA DOMINANT CUTSETS (MLOCA-12)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
20	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC2BS221TM
21	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			UNAVAILABILITY OF BUS ECS ES 1 DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS001TM
22	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS012TM
23	5.53E-11	1.24	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			COMMON CAUSE FAILURE OF THE BATTERIES IDSA-DB-1A/1B	4.70E-05	CCX-BY-PN
			BUS UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.70E-03	EC1BS121TM
24	4.50E-11	1.01	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			CCF OF 2 SQUIB VALVES TO OPERATE	5.90E-05	ADX-EV-SA2
			CHECK VALVE V013 FAILURE TO OPEN	1.75E-03	RNNCV013GO
25	3.92E-11	.88	MEDIUM LOCA INITIATING EVENT OCCURS	4.36E-04	IEV-MLOCA
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDDBSDS1TM
			BUS UNAVAILABLE DUE TO TEST OR CORRECTIVE MAINTENANCE	3.00E-04	IDBBSDS1TM

Table 19.59-13 (Sheet 1 of 3)

SEQUENCE 10 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-09)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
1	2.75E-09	73.90	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF 2 ACCUMULATOR CHECK VALVES	5.10E-05	ACX-CV-GO
2	1.65E-10	4.43	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
3	1.65E-10	4.43	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
4	1.65E-10	4.43	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
5	1.65E-10	4.43	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
6	6.87E-11	1.85	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
7	6.87E-11	1.85	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
8	6.87E-11	1.85	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP
9	6.87E-11	1.85	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP
10	2.85E-11	.77	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP

Table 19.59-13 (Sheet 2 of 3)

SEQUENCE 10 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-09)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
11	6.48E-12	.17	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			COMMON CAUSE FAILURE OF ACCUMULATOR TANKS	1.20E-07	ACX-TK-AF
12	2.27E-13	.01	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			ACCUMULATOR TANK B (T001B) RUPTURES	2.40E-06	ACBTK001AF
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
13	2.27E-13	.01	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			ACCUMULATOR TANK B (T001B) RUPTURES	2.40E-06	ACBTK001AF
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
14	2.27E-13	.01	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
			ACCUMULATOR TANK A (T001A) RUPTURES	2.40E-06	ACATK001AF
15	2.27E-13	.01	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
			ACCUMULATOR TANK A (T001A) RUPTURES	2.40E-06	ACATK001AF
16	9.42E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			ACCUMULATOR TANK B (T001B) RUPTURES	2.40E-06	ACBTK001AF
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP
17	9.42E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
			ACCUMULATOR TANK A (T001A) RUPTURES	2.40E-06	ACATK001AF
18	6.80E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACBOR001EB
			CHECK VALVE 029A FAILS TO OPEN	1.75E-03	ACACV029GO
19	6.80E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACBOR001EB
			CHECK VALVE 028A FAILS TO OPEN	1.75E-03	ACACV028GO
20	6.80E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 029B FAILS TO OPEN	1.75E-03	ACBCV029GO
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACAOR001EB

Table 19.59-13 (Sheet 3 of 3)

SEQUENCE 10 – SPURIOUS ADS ACTUATION DOMINANT CUTSETS (SPADS-09)

NUMBER	CUTSET PROB.	PERCENTAGE	BASIC EVENT NAME		
21	6.80E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			CHECK VALVE 028B FAILS TO OPEN	1.75E-03	ACBCV028GO
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACAOR001EB
22	2.83E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACBOR001EB
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACAOR001SP
23	2.83E-14	.00	SPURIOUS ADS INITIATING EVENT OCCURS	5.40E-05	IEV-SPADS
			FLOW TUNING ORIFICE PLUGS	7.27E-04	ACBOR001SP
			FLOW TUNING ORIFICE RUPTURE	7.20E-07	ACAOR001EB

Table 19.59-14

TYPICAL SYSTEM FAILURE PROBABILITIES, SHOWING HIGHER RELIABILITIES FOR SAFETY SYSTEMS

Failure System/Function	Probability	Fault Tree Name	
CMT Valve Signal	5.7E-07	CMT-IC11	(one train; auto and manual actuation)
PRHR Valve Signal	1.1E-06	RHR-IC01	(one train; auto and manual actuation)
Passive Cont. Cool.	1.8E-06	PCT	
Reactor Trip by PMS	1.2E-05	RTPMS	(including operator actions)
Accumulators	6.9E-05	AC2AB	
IRWST Inj.	6.9E-05	IW2AB	
ADS	9.3E-05	ADS	(including operator actions)
Passive PRHR	2.0E-04	PRT	
Core Makeup Tanks	1.1E-04	CM2SL	
125 vdc 1E Bus	3.1E-04	IDADS1	(one bus only)
DC Bus (Non-1E)	3.4E-04	ED1DS1	(one bus only)
RC Pump Trip	5.9E-04	RCT	
Hydrogen Control	1.0E-01	VLH	
Chilled Water	1.4E-03	VWH	
Containment Isol.	1.6E-03	CIC	
Reactor Trip by DAS	1.7E-03	DAS	(including operator action; excluding MGSET failure)
6900 vac Bus	3.2E-03	ECES1	(one bus only)
CVS	3.4E-03	CVS1	
480 vac Bus	5.9E-03	ECEK11	(one bus only)
Service Water	6.2E-03	SWT	
Comp. Cooling Water	6.3E-03	CCT	
Diesel Generators	1.0E-02	DGEN	
Startup Feedwater	1.7E-02	SFWT	
Compressed Air	1.3E-02	CAIR	
Condenser	2.4E-02	CDS	
Main Feedwater	2.8E-02	FWT	(including condenser)
RNS	9.1E-02	RNR	
Hydrogen Control	1.0E-01	VLH	

Table 19.59-15

SUMMARY OF AP1000 PRA RESULTS

Events	Core Damage Frequency (per year)		Large Release Frequency (per year)	
	At-Power	Shutdown	At-Power	Shutdown
Internal Events	2.41E-07	1.23E-07	1.95E-08	2.05E-08
Internal Flood	8.82E-10	3.22E-09	7.14E-11	5.37E-10
Internal Fire	5.61E-08	8.5E-08(1)	4.54E-09	1.43E-08
Sum =	2.97E-07	2.11E-07	2.41E-08	3.53E-08

Note:

1. Internal fire during shutdown is evaluated quantitatively as a response to an NRC question and is not reported elsewhere in this document.

Table 19.59-16

SITE BOUNDARY WHOLE BODY EDE DOSE RISK – 24 HOURS

Release Category	Release Frequency (/reactor year)	Mean Dose (sieverts)	Dose (REM)	Risk (REM/reactor year)	Percent Contribution to Total Risk
CFI	1.89E-10	2.59E+01	2.59E+03	4.90E-07	0.3
CFE	7.47E-09	4.23E+01	4.23E+03	3.16E-05	17.3
IC	2.21E-07	1.82E-02	1.82E+00	4.02E-07	0.2
BP	1.05E-08	1.37E+02	1.37E+04	1.44E-04	78.6
CI	1.33E-09	5.10E+01	5.10E+03	6.78E-06	3.7
CFL	3.45E-13	3.84E-02	3.84E+00	1.32E-12	0.0
	2.4E-07		**Total Risk =**	1.83E-04	100.0

Table 19.59-17

COMPARISON OF AP1000 PRA RESULTS TO RISK GOALS

Plant/Goal	Core Damage Frequency	Large Release Frequency	Containment Success Probability
Current PWR[(1)]	6.7E-05	5.3E-06	92%
NRC Safety Goal	1E-04	1E-06	90%
AP600	1.7E-07	1.8E-08	89%
AP1000	2.41E-07	1.95E-08	92%

Note:
1. Selected IPE result (two-loop Westinghouse PWR – internal at-power events and at-power flooding only). Note that there is no shutdown PRA requirement for currently operating plants.

Table 19.59-18 (Sheet 1 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1. The passive core cooling system (PXS) is composed of the following: - Accumulator subsystem - Core makeup tank (CMT) subsystem - In-containment refueling water storage tank (IRWST) subsystem - Passive residual heat removal (PRHR) subsystem. The automatic depressurization system (ADS), which is part of the reactor coolant system (RCS), also supports passive core cooling functions.	
1a. The accumulators provide a safety-related means of safety injection of borated water to the RCS.	6.3.2
The following are some important aspects of the accumulator subsystem as represented in the PRA:	
- There are two accumulators, each with an injection line to the reactor vessel/direct vessel injection (DVI) nozzle. Each injection line has two check valves in series.	Tier 1 Information
- The reliability of the accumulator subsystem is important. The accumulator subsystem is included in the D-RAP.	17.4
- Diversity between the accumulator check valves and the CMT check valves minimizes the potential for common cause failures.	6.3.2
1b. ADS provides a safety-related means of depressurizing the RCS.	Tier 1 Information
The following are some important aspects of ADS as represented in the PRA:	
ADS has four stages. Each stage is arranged into two separate groups of valves and lines.	Tier 1 Information
- Stages 1, 2, and 3 discharge from the top of the pressurizer to the IRWST	
- Stage 4 discharges from the hot leg to the RCS loop compartment.	
Each stage 1, 2, and 3 line contains two motor-operated valves (MOVs).	Tier 1 Information
Each stage 4 line contains an MOV valve and a squib valve.	Tier 1 Information
The valve arrangement and positioning for each stage is designed to reduce spurious actuation of ADS.	6.3.2 & 7.3
- Stage 1, 2, and 3 MOVs are normally closed and have separate controls.	
- Each stage 4 squib valve actuation requires signals from two separate PMS cabinets.	
- Stage 4 is blocked from opening at high RCS pressures.	

Table 19.59-18 (Sheet 2 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1b. (cont.)	
The ADS valves are automatically and manually actuated via the protection and safety monitoring system (PMS), and manually actuated via the diverse actuation system (DAS).	Tier 1 Information
The ADS valves are powered from Class 1E power.	Tier 1 Information
The ADS valve positions are indicated and alarmed in the control room.	6.3.7
Stage 1, 2, and 3 valves are stroke-tested every cold shutdown. Stage 4 squib valve actuators are tested every 2 years for 20% of the valves.	3.9.6
Because of the potential for counter-current flow limitation in the surgeline, it is essential to establish and maintain venting capability with ADS Stage 4 for gravity injection and containment recirculation following an extended loss of RNS when the RCS is open during shutdown operations.	6.3.3.4.3
ADS 4th stage squib valves receive a signal to open during shutdown conditions using PMS low hot leg level logic.	6.3.3.4.3
The reliability of the ADS is important. The ADS is included in the D-RAP.	17.4
ADS is required by the Technical Specifications to be available in Modes 1 through 6 without the cavity flooded.	16.1
Stages 1, 2, and 3, connected to the top of the pressurizer, provide a vent path to preclude pressurization of the RCS during shutdown conditions if decay heat removal is lost.	16.1
Depressurization of the RCS through ADS minimizes the potential for high-pressure melt ejection events.	
- Procedures will be provided for use of the ADS for depressurization of the RCS after core uncovery.	Emergency Response Guidelines
The ADS mitigates high pressure core damage events which can produce challenges to containment integrity due to the following severe accident phenomena:	19.36
- High pressure melt ejection	
- Direct containment heating	
- Induced steam generator tube rupture	
- Induced RCS piping rupture and rapid hydrogen release to containment	

Table 19.59-18 (Sheet 3 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1c. The CMTs provide safety-related means of high-pressure safety injection of borated water to the RCS.	6.3.1
The following are some important aspects of CMT subsystem as represented in the PRA:	
There are two CMTs, each with an injection line to the reactor vessel/DVI nozzle.	6.3.2
- Each CMT has a normally open pressure balance line from an RCS cold leg.	
- Each injection line is isolated with a parallel set of air-operated valves (AOVs).	
- These AOVs open on loss of Class 1E dc power, loss of air, or loss of the signal from the PMS.	
- The injection line for each CMT also has two normally open check valves in series.	
The CMT AOVs are automatically and manually actuated from PMS and DAS.	Tier 1 Information
CMT level instrumentation provides an actuation signal to initiate automatic ADS and provides the actuation signal for the IRWST squib valves to open.	6.3.1 & 7.3.1
The CMT AOV positions are indicated and alarmed in the control room.	6.3.7
CMT AOVs are stroke-tested quarterly.	3.9.6
The CMTs are risk-important for power conditions because the level indicators in the CMTs provide an open signal to ADS and to the IRWST squib valves as the CMTs empty.	
- The CMT subsystem is included in the D-RAP.	17.4
CMT is required by the Technical Specifications to be available in Modes 1 through 5 with RCS pressure boundary intact.	16.1

Table 19.59-18 (Sheet 4 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1d. IRWST subsystem provides a safety-related means of performing the following functions: - Low-pressure safety injection following ADS actuation - Long-term core cooling via containment recirculation - Reactor vessel cooling through the flooding of the reactor cavity by draining the IRWST into the containment. The following are some important aspects of the IRWST subsystem as represented in the PRA:	6.3
IRWST subsystem has the following flowpaths: - Two (redundant) injection lines from IRWST to reactor vessel/DVI nozzle. Each line is isolated with a parallel set of valves; each set with a check valve in series with a squib valve. - Two (redundant) recirculation lines from the containment to the reactor vessel/DVI injection line. Each recirculation line has two paths: one path contains a squib valve and a MOV, the other path contains a squib valve and a check valve. - The two MOV/squib valve lines also provide the capability to flood the reactor cavity.	Tier 1 Information
There are screens for each IRWST injection line and recirculation line.	Tier 1 Information
Squib valves provide the pressure boundary and prevent the check valves from normally seeing a high delta-P.	6.3.3
Squib valves and MOVs are powered by Class 1E power.	Tier 1 Information
The squib valves and MOVs for injection and recirculation are automatically and manually actuated via PMS, and manually actuated via DAS.	Tier 1 Information
The squib valves and MOVs for reactor cavity flooding are manually actuated via PMS and DAS from the control room.	Tier 1 Information
The injection squib valves and the recirculation squib valves in series with check valves are diverse from the other recirculation squib valves in order to minimize the potential for common cause failure between injection and recirculation/reactor cavity flooding.	6.3.2
Automatic IRWST injection at shutdown conditions is provided using PMS low hot leg level logic.	6.3.3.4.3 & 7.3.1

Table 19.59-18 (Sheet 5 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1d. (cont.)	
The positions of the squib valves and MOVs are indicated and alarmed in the control room.	6.3.7
IRWST injection and recirculation check valves are exercised at each refueling. IRWST injection and recirculation squib valve actuators are tested every 2 years for 20% of the valves (This does not require valve actuation). IRWST recirculation MOVs are stroke-tested quarterly.	3.9.6
The reliability of the IRWST subsystem is important. The IRWST subsystem is included in the D-RAP.	17.4
IRWST injection and recirculation are required by Technical Specifications to be available in Modes 1 through 6 without the cavity flooded.	16.1
The operator action to flood the reactor cavity is determined in Emergency Response Guideline AFR-C.1, which instructs the operator to flood the reactor cavity when the core-exit thermocouples reach 1200°F.	Emergency Response Guidelines
PXS recirculation valves are automatically actuated by a low IRWST level signal or manually from the control room, if automatic actuation fails.	6.3
1e. Passive residual heat removal (PRHR) provides a safety-related means of performing the following functions:	6.3.1 & 6.3.3
- Removes core decay heat during accidents	
- Allows automatic termination of RCS leak during a steam generator tube rupture (SGTR) without ADS	
- Allows plant to ride out an ATWS event without rod insertion.	PRA App. A4
The following are some important aspects of the PRHR subsystem as represented in the PRA:	
PRHR is actuated by opening redundant parallel air-operated valves. These air-operated valves open on loss of Class 1E power, loss of air, or loss of the signal from PMS.	6.3.2
The PRHR air-operated valves are automatically actuated and manually actuated from the control room by either PMS or DAS.	Tier 1 Information
Diversity of the PRHR air-operated valves from the CMT air-operated valves minimizes the probability for common cause failure of both PRHR and CMT air-operated valves.	6.3.2

Table 19.59-18 (Sheet 6 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1e. (cont.)	
Long-term cooling of PRHR will result in steaming to the containment. The steam will normally condense on the containment shell and return to the IRWST by safety-related features. Connections are provided to IRWST from the spent fuel system (SFS) and chemical and volume control system (CVS) to extend PRHR operation. A safety-related makeup connection is also provided from outside the containment through the normal residual heat removal system (RNS) to the IRWST.	6.3.1 & system drawings
Capability exists and guidance is provided for the control room operator to identify a leak in the PRHR HX of 500 gpd. This limit is based on the assumption that a single crack leaking this amount would not lead to a PRHR HX tube rupture under the stress conditions involving the pressure and temperature gradients expected during design basis accidents, which the PRHR HX is designed to mitigate.	6.3.3 & 16.1
The positions of the inlet and outlet PRHR valves are indicated and alarmed in the control room.	6.3.7
PRHR air-operated valves are stroke-tested quarterly. The PRHR HX is tested to detect system performance degradation every 10 years.	3.9.6
PRHR is required by Technical Specifications to be available from Modes 1 through 5 with RCS pressure boundary intact.	16.1
The PRHR HX, in conjunction with the PCS, can provide core cooling for an indefinite period of time. After the IRWST water reaches its saturation temperature, the process of steaming to the containment initiates. Condensation occurs on the steel containment vessel, and the condensate is collected in a safety-related gutter arrangement, which returns the condensate to the IRWST. The gutter normally drains to the containment sump, but when the PRHR HX actuates, safety-related isolation valves in the gutter drain line shut and the gutter overflow returns directly to the IRWST. The following design features provide proper re-alignment for the gutter system valves to direct water to the IRWST:	6.3.2.1.1 & 6.3.7.6
- IRWST gutter and its drain isolation valves are safety-related	
- These isolation valves are designed to fail closed on loss of compressed air, loss of Class 1E dc power, or loss of the PMS signal	
- These isolation valves are actuated automatically by PMS and DAS.	7.3.1.2.7
The PRHR subsystem provides a safety-related means of removing decay heat following loss of RNS cooling during shutdown conditions with the RCS intact.	16.1

Table 19.59-18 (Sheet 7 of 24)

AP1000 PRA-BASED INSIGHTS

	Insight	Disposition
2.	The protection and safety monitoring system (PMS) provides a safety-related means of performing the following functions:	Tier 1 Information
	- Initiates automatic and manual reactor trip	
	- Automatic and manual actuation of engineered safety features (ESF).	
	PMS monitors the safety-related functions during and following an accident as required by Regulatory Guide 1.97.	7.1.1
	PMS initiates an automatic reactor trip and an automatic actuation of ESF. PMS provides manual initiation of reactor trip. PMS 2-out-of-4 initiation logic reverts to a 2-out-of-3 coincidence logic if one of the 4 channels is bypassed. PMS does not allow simultaneous bypass of 2 redundant channels.	Tier 1 Information
	PMS has redundant divisions of safety-related post-accident parameter display.	7.5.2.2.1 & 7.5.4
	Each PMS division is powered from its respective Class 1E dc and UPS division.	Tier 1 Information
	PMS provides fixed position controls in the control room.	Tier 1 Information
	Reliability of the PMS is provided by the following:	
	- The reactor trip functions are divided into two subsystems.	7.1.2.1.1
	- The ESF functions are processed by two microprocessor-based subsystems that are functionally identical in both hardware and software.	7.1.2.2
	Four sensors normally monitor variables used for an ESF actuation. These sensors may monitor the same variable for a reactor trip function.	7.3.1
	Continuous automatic PMS system monitoring and failure detection/alarm is provided.	7.1.2
	PMS equipment is designed to accommodate a loss of the normal heating, ventilation, and air conditioning (HVAC). PMS equipment is protected by the passive heat sinks upon failure or degradation of the active HVAC.	3.11 & 6.4
	The reliability of the PMS is important. The PMS is included in the D-RAP.	17.4
	The PMS software is designed, tested, and maintained to be reliable under a controlled verification and validation program written in accordance with IEEE 7-4.3.2 (1993) that has been endorsed by Regulatory Guide 1.152. Elements that contribute to a reliable software design include:	App 1A (Compliance with Reg. Guide 1.152)
	- A formalized development, modification, and acceptance process in accordance with an approved software QA plan (paraphrased from IEEE standard, section 5.3, “Quality”)	

Table 19.59-18 (Sheet 8 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
2. (cont.)	
- A verification and validation program prepared to confirm the design implemented will function as required (IEEE standard, section 5.3.4, “Verification and Validation”)	
- Equipment qualification testing performed to demonstrate that the system will function as required in the environment it is intended to be installed in (IEEE standard, section 5.4, “Equipment Qualification”)	
- Design for system integrity (performing its intended safety function) when subjected to all conditions, external or internal, that have significant potential for defeating the safety function (abnormal conditions and events) (IEEE standard, section 5.5, “System Integrity”)	
- Software configuration management process (IEEE standard, section 5.3.5, “Software Configuration Management”).	
3. The diverse actuation system (DAS) provides a nonsafety-related means of performing the following functions:	Tier 1 Information
- Initiates automatic and manual reactor trip	
- Automatic and manual actuation of selected engineered safety features.	
Diversity is assumed in the PRA that eliminates the potential for common cause failures between PMS and DAS.	
- The DAS automatic actuation signals are generated in a diverse manner from the PMS signals. Diversity between DAS and PMS is achieved by the use of different architecture, different hardware implementations, and different software.	Tier 1 Information
DAS provides control room displays and fixed position controls to allow the operators to take manual actions.	7.7.1
DAS actuates using 2-out-of-2 logic. Actuation signals are output to the loads in the form of normally de-energized, energize-to-actuate signals. The normally de-energized output state, along with the dual 2-out-of-2 redundancy, reduces the probability of inadvertent actuation.	7.7.1.11
The actuation devices of DAS and PMS are capable of independent operation that is not affected by the operation of the other. The DAS is designed to actuate components only in a manner that initiates the safety function.	7.7.1.11
The DAS reactor trip function is to trip the control rods by deenergizing the motor-generator set.	7.7.1.11

Table 19.59-18 (Sheet 9 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
3. (cont.)	
In the PRA it is assumed the following eliminates the potential for common cause failures between automatic and manual DAS functions.	
- DAS manual initiation functions are implemented in a manner that bypasses the signal processing equipment of the DAS automatic logic.	Tier 1 Information
The DAS, including the M-G set field breakers, is included in the D-RAP.	17.4
4. The plant control system (PLS) provides a nonsafety-related means of controlling nonsafety-related equipment.	7.1.3 & 7.7.1
- Automatic and manual control of nonsafety-related functions, including “defense-in-depth” functions.	
- Provides control room indication for monitoring overall plant and nonsafety-related system performance.	
PLS has appropriate redundancy to minimize plant transients.	7.1.3 & 7.7.1.12
PLS provides capability for both automatic control and manual control.	7.1.3
Signal selector algorithms provide the PLS with the ability to obtain inputs from the PMS. The signal selector algorithms select those protection system signals that represent the actual status of the plant and reject erroneous signals.	7.1.3.2
PLS control functions are distributed across multiple distributed controllers so that single failures within a controller do not degrade the performance of control functions performed by other controllers.	7.1.3.1
5. The onsite power system consists of the main ac power system and the dc power system. The main ac power system is a non-Class 1E system. The dc power system consists of two independent systems: the Class 1E dc system and the non-Class 1E dc system.	
5a. The onsite main ac power system is a non-Class 1E system comprised of a normal, preferred, and standby power supplies.	8.3.1.1
The main ac power system distributes power to the reactor, turbine, and balance of plant auxiliary electrical loads for startup, normal operation, and normal/emergency shutdown.	8.3.1.1.1
The arrangement of the buses permits feeding functionally redundant pumps or groups of loads from separate buses and enhances the plant operational reliability.	8.3.1.1.1

Table 19.59-18 (Sheet 10 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
5a. (cont.)	
During power generation mode, the turbine generator normally supplies electric power to the plant auxiliary loads through the unit auxiliary transformers. During plant startup, shutdown, and maintenance, the main ac power is provided from the high-voltage switchyard. The onsite standby power system powered by the two onsite standby diesel generators supplies power to selected loads in the event of loss of normal and preferred ac power supplies.	8.3.1.1.1
Two onsite standby diesel generator units, each furnished with its own support subsystems, provide power to the selected plant nonsafety-related ac loads.	8.3.1.1.2.1
On loss of power to a 6900 V diesel-backed bus, the associated diesel generator automatically starts and produces ac power. The normal source circuit breaker and bus load circuit breakers are opened, and the generator is connected to the bus. Each generator has an automatic load sequencer to enable controlled loading on the associated buses.	Tier 1 Information
5b. The Class 1E dc and uninterruptible power supply (UPS) system (IDS) provides reliable power for the safety-related equipment required for the plant instrumentation, control, monitoring, and other vital functions needed for shutdown of the plant.	8.3.2.1
There are four independent, Class 1E 125 Vdc divisions. Divisions A and D each consists of one battery bank, one switchboard, and one battery charger. Divisions B and C are each composed of two battery banks, two switchboards, and two battery chargers. The first battery bank in the four divisions is designated as the 24-hour battery bank. The second battery bank in Divisions B and C is designated as the 72-hour battery bank.	Tier 1 Information
The 24-hour battery banks provide power to the loads required for the first 24 hours following an event of loss of all ac power sources concurrent with a design basis accident. The 72-hour battery banks provide power to those loads requiring power for 72 hours following the same event.	Tier 1 Information
Battery chargers are connected to dc switchboard buses. The input ac power for the Class 1E dc battery chargers is supplied from non-Class 1E 480 Vac diesel-generator-backed motor control centers.	8.3.2.1.1.1
The 24-hour and the 72-hour battery banks are housed in ventilated rooms apart from chargers and distribution equipment.	8.3.2.1.3
Each of the four divisions of dc systems are electrically isolated and physically separated to prevent an event from causing the loss of more than one division.	8.3.2.1.3
The Class 1E batteries are included in the D-RAP.	17.4

Table 19.59-18 (Sheet 11 of 24)

AP1000 PRA-BASED INSIGHTS

	Insight	Disposition
5c.	The non-Class 1E dc and UPS system (EDS) consists of the electric power supply and distribution equipment that provide dc and uninterruptible ac power to nonsafety-related loads.	Tier 1 Information
	The non-Class 1E dc and UPS system consists of two subsystems representing two separate power supply trains.	8.3.2.1.2
	EDS load groups 1, 2, and 3 provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E uninterruptible power supply ac system.	Tier 1 Information
	The onsite standby diesel-generator-backed 480 Vac distribution system provides the normal ac power to the battery chargers.	Tier 1 Information
	The batteries are sized to supply the system loads for a period of at least two hours after loss of all ac power sources.	8.3.2.1.2
6.	The normal residual heat removal system (RNS) provides a safety-related means of performing the following functions:	Tier 1 Information
	- Containment isolation for the RNS lines that penetrate the containment.	
	- Isolation of the reactor coolant system at the RNS suction and discharge lines.	
	- Pathway for long-term, post-accident makeup of containment inventory.	
	RNS provides a nonsafety-related means of core cooling through:	5.4.7
	- RCS recirculation cooling during shutdown conditions.	
	- Low pressure pumped makeup flow from the SFS cask loading pit and long-term recirculation from the IRWST and the containment.	
	- Heat removal from IRWST during PRHR operation.	
	The RNS has redundant pumps and heat exchangers. The pumps are powered by non-Class 1E power with backup connections from the diesel generators.	5.4.7 & 8.3
	RNS is manually aligned from the control room to perform its core cooling functions. The performance of the RNS is indicated in the control room.	5.4.7
	The RNS containment isolation and pressure boundary valves are safety-related. The motor-operated valves are powered by Class 1E dc power.	Tier 1 Information
	The RNS containment isolation MOVs are automatically and manually actuated via PMS.	7.3.1.2.20

Table 19.59-18 (Sheet 12 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
6. (cont.)	
Interfacing system loss-of-coolant accident (LOCA) between the RNS and the RCS is prevented by:	5.4.7.2.2
- Each RNS line is isolated by at least three valves.	
- The RNS equipment outside containment is capable of withstanding the operating pressure of the RCS.	
- The RCS isolation valves are interlocked to prevent their opening at RCS pressures above its design pressure.	
CCS provides cooling to the RNS heat exchanger.	Tier 1 Information
Planned maintenance affecting the RNS cooling function and its support systems CCS and SWS should be performed in modes 1, 2, and 3, when the RNS is not normally operating.	16.3
7. The component cooling water system (CCS) is a nonsafety-related system that removes heat from various components and transfers the heat to the service water system.	Tier 1 Information
The CCS has redundant pumps and heat exchanger.	Tier 1 Information
During normal operation, one CCS pump is operating. The standby pump is aligned to automatically start in case of a failure of the operating CCS pump.	9.2.2.4.2
The CCS pumps are automatically loaded on the standby diesel generator in the event of a loss of normal ac power. The CCS, therefore, continues to provide cooling of required components if normal ac power is lost.	9.2.2.4.5.4
8. The service water system (SWS) is a nonsafety-related system that transfers heat from the component cooling water heat exchangers to the atmosphere.	Tier 1 Information
The SWS has redundant pumps, strainers, and cooling tower cells.	9.2.1.2.1
During normal operation, one SWS train of equipment is operating. The standby train is aligned to automatically start in case of a failure of the operating SWS pump.	9.2.1.2.3.3
The SWS pumps and cooling tower fans are automatically loaded onto their associated diesel bus in the event of a loss of normal ac power. Both pumps and cooling tower fans automatically start after power from the diesel generator is available.	9.2.1.2.3.6

Table 19.59-18 (Sheet 13 of 24)

AP1000 PRA-BASED INSIGHTS

	Insight	Disposition
9.	The chemical and volume control system (CVS) provides a safety-related means to terminate inadvertent RCS boron dilution and to preserve containment integrity by isolation of the CVS lines penetrating the containment.	Tier 1 Information
	The CVS provides a nonsafety-related means to perform the following functions: - Makeup water to the RCS during normal plant operation. - Boration following a failure of reactor trip - Makeup water to the pressurizer auxiliary spray line.	Tier 1 Information
	Two makeup pumps are provided. Each pump provides capability for normal makeup.	9.3.6.3.1
	Two safety-related air-operated valves provide isolation of normal CVS letdown during shutdown operation on low hot leg level.	9.3.6.7
10.	The operation of RNS and its support systems (CCS, SWS, main ac power and onsite power) is RTNSS-important for shutdown decay heat removal during reduced RCS inventory operations.	16.3
	- These systems are included in the D-RAP.	17.4
	Short-term availability controls for the RNS during at-power conditions reduce PRA uncertainties.	16.3
11.	The information used by the COL regarding critical human actions (if any) and risk-important tasks from the PRA, as presented in Chapter 18 of the DCD on human factors engineering, is important in developing and implementing procedures, training, and other human reliability related programs.	18
12.	Sufficient instrumentation and control is provided at the remote shutdown workstation to bring the plant to safe shutdown conditions in case the control room must be evacuated.	7.4.3
	There are no differences between the main control room and remote shutdown workstation controls and monitoring that would be expected to affect safety system redundancy and reliability.	7.4.3.1.1
13.	Separation or protection of the equipment and cabling among the divisions of safety-related equipment and separation of safety-related from nonsafety-related equipment minimizes the probability that a fire or flood would affect more than one safety-related system or train, except in some areas inside containment where equipment will be capable of achieving safe shutdown prior to damage.	3.4.1.1.2 & 9.5.1.1.1, 9.5.1.2.1.1 & 9A
	Although the containment is a single fire area, adequate design features exist for separation (structural or space), suppression, lack of combustibles, or operator action to ensure the plant can achieve safe shutdown.	9A

Table 19.59-18 (Sheet 14 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
13. (cont.)	
To prevent flooding in a radiologically controlled area (RCA) in the Auxiliary Building from propagating to non-radiologically controlled areas, the non-RCAs are separated from the RCAs by 2 and 3-foot walls and floor slabs. In addition, electrical penetrations between RCAs and non-RCAs in the Auxiliary Building are located above the maximum flood level.	3.4.1.2.2.2
14. The following minimizes the probability for fire and flood propagation from one area to another and helps limit risk from internal fires and floods:	
- Fire barriers are sealed, to the extent possible (i.e., doors).	9.5.1.2.1.1
- Structural barriers which function as flood barriers are watertight below the maximum flood level.	3.4.1.1.2
- Establishing administrative controls to maintain the performance of the fire protection system is the responsibility of the COL applicant.	Table 9.5.1-1, Item 29
15. Fire detection and suppression capability is provided in the design. Flooding control features and sump level indication are provided in the design.	3.4.1, 9.5.1.2.1.2, & 9.5.1.8
Establishing administrative controls to maintain the performance of the fire protection system is the responsibility of the COL applicant.	Table 9.5.1-1, Item 29
16. AP1000 main control room fire ignition frequency is limited as a result of the use of low-voltage, low-current equipment and fiber optic cables.	7.1.2 & 7.1.3
There is no cable spreading room in the AP1000 design.	Table 9.5.1-1
17. Redundancy in control room operations is provided within the control room itself for fires in which control room evacuation is not required.	9.5.1.2.1.1
18. The remote shutdown workstation provides redundancy of control and monitoring for safe shutdown functions in the event that main control room evacuation is required.	7.4.3 & 9.5
The remote shutdown workstation is in a fire and flood area separate from the main control room.	3.4.1.2.2.2, 7.1.2, 7.4.3.1.1. & 9A.3.1.2.5
19. Although a main control room fire may defeat manual actuation of equipment from the main control room, it will not affect the automatic functioning of safe shutdown equipment via PMS or manual operation from the remote shutdown workstation. This is because the PMS cabinets, in which the automatic functions are housed, are located in fire areas separate from the main control room.	7.1.2.7 & 9A.3

Table 19.59-18 (Sheet 15 of 24)

AP1000 PRA-BASED INSIGHTS

	Insight	Disposition
20.	The main control room has its own ventilation system, and is pressurized. This prevents smoke, hot gases, or fire suppressants originating in areas outside the control room from entering the control room via the ventilation system.	9.4.1
	There are separate ventilation systems for safety-related equipment divisions (A & C and B & D). This prevents smoke, hot gases, or fire suppressants originating from one fire area to another to the extent that they could adversely affect safe shutdown capabilities.	9.4.1 9.5.1.1.1
	The ventilation system for the remote shutdown room is independent of the ventilation system for the main control room.	9.4.1
21.	AP1000 does not rely on ac power sources for safe shutdown capability since the safety-related passive systems do not require ac power sources for operation. Individual fires resulting in loss of offsite power or affecting onsite standby diesel generator operability do not affect safe shutdown capability.	8.1.4.2
22.	Containment isolation functions are not compromised by internal fire or flood. Redundant containment isolation valves in a given line are located in separate fire and flood areas or zones and, if powered, are served by different control and electrical divisions.	6.2.3
	One isolation component in a given line is located inside containment, while the other is located outside containment, and the containment wall is a fire/flood barrier.	6.2.3, 9.5 & 9A
23.	The AP1000 design minimizes potential flooding sources in safety-related equipment areas, to the extent possible. The design also minimizes the number of penetrations through enclosure or barrier walls below the probable maximum flood level. Walls, floors, and penetrations are designed to withstand the maximum anticipated hydrodynamic loads.	3.4.1
24.	The Combined License applicant will confirm the AP1000 certified design will review differences between the as-built plant and the basis for the AP1000 seismic margin analysis.	19.59.10.5
25.	The depressurization of the reactor coolant system below 150 psi facilitates in-vessel retention of molten core debris.	19.36
26.	The reflective reactor vessel insulation provides an engineered flow path to allow the ingression of water and venting of steam for externally cooling the vessel in the event of a severe accident involving core relocation to the lower plenum.	19.39, 5.3.5 & Tier 1 Information
	The reflective insulation panels and support members can withstand pressure differential loading due to the IVR boiling phenomena.	
	Water inlets and steam vents are provided at the entrance and exit of the insulation boundary.	
	The reactor vessel insulation is included in the D-RAP.	17.4

Table 19.59-18 (Sheet 16 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
27. The reactor cavity design provides a reasonable balance between the regulatory requirements for sufficient ex-vessel debris spreading area and the need to quickly submerge the reactor vessel for the in-vessel retention of core debris.	19.39 & Appendix 19B
28. The design can withstand a best-estimate ex-vessel steam explosion without failing the containment integrity.	Appendix 19B
29. The containment design incorporates defense-in-depth for mitigating direct containment heating by providing no significant direct flow path for the transport of particulated molten debris from the reactor cavity to the upper containment regions.	Appendix 19B
30. The hydrogen control system is comprised of passive autocatalytic recombiners (PARs) and hydrogen igniters to limit the concentration of hydrogen in the containment during accidents and beyond design basis accidents, respectively.	Tier 1 Information
Operability of the hydrogen igniters is addressed by short-term availability controls during modes 1, 2, 5 (with RCS pressure boundary open), and 6 (with upper internals in place or cavity levels less than full).	16.3
The operator action to activate the igniters is the first step in ERG AFR.C-1 to ensure that the igniter activation occurs prior to rapid cladding oxidation.	Emergency Response Guidelines
31. Mitigation of the effects of a diffusion flames on the containment shell are addressed by the following containment layout features:	1.2, General Arrangement Drawings
- Vents from the PXS and CVS compartments (where hydrogen releases can be postulated) to the CMT room are located well away from the containment shell and containment penetrations. The access hatch to the PXS-B compartment is located near the containment wall and is normally closed to address severe accident considerations. The access hatch to the PXS-B compartment is accessible from Room 11300 on elevation 107′-2″.	3.4.1.2.2.1 & 19.41.7
- IRWST vents are designed so that those located away from the containment wall open to vent hydrogen releases. In this situation IRWST vents located close to the containment wall would not open because flow of hydrogen through the other vents would not result in a IRWST pressure sufficient to open them.	6.2.4.5.1
32. The containment structure can withstand the pressurization from a LOCA and the global combustion of hydrogen released in-vessel (10 CFR 50.34(f)).	19.41
33. The steam generator should not be depressurized to cool down the RCS if water is not available to the secondary side. This action protects the tubes from large pressure differential and minimizes the potential for creep rupture. The COL will develop and implement severe accident management guidance using the suggested framework provided in WCAP-13914.	19.59.10

Table 19.59-18 (Sheet 17 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
34. Depressurizing the RCS and maintaining a water level covering the SG tubes on the secondary side can mitigate fission product releases from a steam generator tube rupture accident. The COL will develop and implement severe accident management guidance using the suggested framework provided in WCAP-13914.	19.59.10
35. Loss of ac power does not contribute significantly to the core damage frequency. - Nonsafety-related containment spray does not need to be ac independent.	19.59
36. AP1000 has a nonsafety-related containment spray system. Containment spray is not credited in the PRA. Failure of the nonsafety-related containment spray does not prevent the plant achieving the safety goals. The COL will develop and implement severe accident management guidance for operation of the nonsafety-related containment spray system using the suggested framework provided in WCAP-13914.	6.5.2 19.59 19.59.10
37. Passive containment can withstand severe accidents without PCS water cooling the containment shell. Air cooling alone is sufficient to maintain containment pressure below failure pressure with high probability.	19.40
38. Operation of ADS stage 4 provides a vent path for the severe accident hydrogen to the steam generator compartments, bypassing the IRWST, and mitigating the conditions required to produce a diffusion flame near the containment wall.	19.41
39. Containment isolation valves controlled by DAS are important in limiting offsite releases following core melt accidents. The containment isolation valves are included in the D-RAP. Operability of DAS for selected containment isolation actuations is addressed by short-term availability controls.	17.4 16.3
40. Reflooding the reactor pressure vessel through the break can have a significant effect on a severe accident by quenching core debris, achieving a controlled stable state, and producing hydrogen.	19.38 & 19.41
41. The type of concrete used in the basemat is not important. The reactor cavity design incorporates features that extend the time to basemat melt-through in the event of RPV failure. The cavity design includes: - A minimum floor area of 48 m^2 available for spreading of the molten core debris - A minimum thickness of concrete above the embedded containment liner of 0.85 m	Appendix 19B Appendix 19B

Table 19.59-18 (Sheet 18 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
41. (cont.) - There is no piping buried in the concrete beneath the reactor cavity; sump drain lines are not enclosed in either of the reactor cavity floor or reactor cavity sump concrete. Thus, there is no direct pathway from the reactor cavity to outside the containment in the event of core-concrete interactions. - The openings between the reactor cavity and cavity sump are small diameter openings in which core debris in the cavity will solidify. Thus, there is no direct pathway for core debris to enter the sump, except in the case where it might spill over the sump curbing.	
42. No safety-related equipment is located outside the Nuclear Island.	1.2 & 3.4.1
43. Capability exists to vent the containment. The COL will develop and implement severe accident management guidance for venting containment using the suggested framework provided in WCAP-13914.	Appendix 19D 19.59.10
44. A list of risk-important systems, structures, and components (SSCs) has been provided in the D-RAP. The risk-significant SSCs are included in the D-RAP.	17.4 17.4
45. The Combined License applicant referencing the AP1000 certified design will review differences between the as-built plant and the design used as the basis for the AP1000 PRA and Table 59-18. If the effects of the differences are shown, by a screening analysis, to potentially result in a significant increase in core damage frequency or large release frequency, the PRA will be updated to reflect these differences. Based on site-specific information, the COL should also reevaluate the qualitative screening of external events (PRA Section 58.1). If any site-specific susceptibilities are found, the PRA should be updated to include the applicable external event.	19.59.10
46. There are no watertight doors used for flood protection in the AP1000 design. Plugging of the drain headers is minimized by designing them large enough to accommodate more than the design flow and by making the flow path as straight as possible.	3.4.1.1.2 9.3.5.1.2
47. The maintenance guidelines as described in the Shutdown Evaluation Report (WCAP-14837) should be considered when developing the plant specific operations procedures.	13.5.1
48. The COL will establish procedures to control transient combustibles.	Table 9.5.1-1, Items 77-83

Table 19.59-18 (Sheet 19 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
49. There are two compartments inside containment (PXS-A and PXS-B) containing safe shutdown equipment that normally do not flood although they are below the maximum flood height. Each of these two compartments contains redundant and essentially identical equipment (one accumulator with associated isolation valves as well as isolation valves for one CMT, one IRWST injection line, and one containment recirculation line). A pipe break in one of these compartments can cause that room to flood. These two compartments are physically separated to ensure that a flood in one compartment does not propagate to the other. Drain lines from the PXS-A and PXS-B compartments to the reactor vessel cavity and steam generator compartment are protected from backflow by redundant backflow preventers.	3.4.1.2.2.1
50. There are seven automatically actuated containment isolation valves inside containment subject to flooding. These seven normally closed containment isolation valves would not fail open as a result of the compartment flooding. Also, there is a redundant, normally closed, containment isolation valve located outside containment in series with each of these valves.	3.4.1.2.2.1
51. The passive containment cooling system (PCS) cooling water not evaporated from the vessel wall flows down to the bottom of the containment annulus. Two 100-percent drain openings, located in the side wall of the Shield Building, are always open with screens provided to prevent entry of small animals into the drains.	19.40
52. The major rooms housing divisional cabling and equipment (the battery rooms, dc equipment rooms, I&C rooms, and penetration rooms) are separated by 3-hour fire rated walls. Separate ventilation subsystems are provided for A and C and for B and D division rooms. In order for a fire to propagate from one divisional room to another, it must move past a 3-hour barrier (e.g., a door) into a common corridor and enter the other room through another 3-hour barrier (e.g., another door).	9.5.1 & 9A.3
53. An access bay in the turbine building is provided to protect the north end of the Auxiliary Building, from potential debris produced by a postulated seismic damage of the adjacent Turbine Building.	1.2
54. There are no normally open connections to sources of “unlimited” quantity of water in the electrical and I&C portions of the Auxiliary Building such as that it could affect safe shutdown capabilities.	Figure 9.5.1-1
55. To prevent flooding in a radiologically controlled area (RCA) in the Auxiliary Building from propagating to non-RCAs, the non-RCAs are separated from the RCAs by 2- and 3-foot walls and floor slabs. In addition, electrical penetrations between RCAs and non-RCAs in the Auxiliary Building are located above the maximum flood level.	3.4.1.2.2.2
56. The two 72-hour rated Class 1E division B and C batteries are located above the maximum flood height in the Auxiliary Building considering all possible flooding sources.	3.4.1.2.2.2

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AP1000 PRA-BASED INSIGHTS

Insight	Disposition
57. Flood water in the Turbine Building drains to the yard and does not affect the Auxiliary Building. The presence of watertight walls and floor of the Auxiliary Building valve/penetration room prevents flooding from propagating beyond this area.	3.4.1.2.2.2
58. The mechanical equipment and electrical equipment in the Auxiliary Building are separated to prevent propagation of leaks from the piping and mechanical equipment areas to the Class 1E equipment and Class 1E I&C equipment rooms.	3.4.1.2.2.2
59. Connections to sources of “large” quantity of water are located in the Turbine Building. They are the service water system, which interfaces with the component cooling water system; and the circulating water system, which interfaces with the Turbine Building closed cooling system and the condenser. Features that minimize the flood propagation to other buildings are: - Flow from any postulated ruptures above grade level (elevation 100') in the Turbine Building flows down to grade level via floor grating and stairwells. This grating in the floors also prevents any significant propagation of water to the Auxiliary Building via flow under the doors. - A relief panel in the Turbine Building west wall at grade level directs the water outside the building to the yard and limits the maximum flood level in the Turbine Building to less than 6 inches. Flooding propagation to areas of the adjacent Auxiliary Building, via flow under doors or backflow through the drains, is possible but is bounded by a postulated break in those areas.	3.4.1.2.2.3
60. Flood water in the Annex Building grade level is directed by the sloped floor to drains and to the yard area through the door of the Annex Building. Flow from postulated ruptures above grade level in the Annex Building is directed by floor drains to the Annex Building sump, which discharges to the Turbine Building drain tank. Alternate paths include flow to the Turbine Building via flow under access doors and down to grade level via stairwells and elevator shaft. The floors of the Annex Building are sloped away from the access doors to the Auxiliary Building in the vicinity of the access doors to prevent migration of flood water to the non-RCAs of the Nuclear Island where all safety-related equipment is located.	3.4.1.2.2.3
61. There are no connections to sources of “unlimited” quantity of water, except for fire protection, in the Annex Building.	Figure 9.5.1-1

Table 19.59-18 (Sheet 21 of 24)

AP1000 PRA-BASED INSIGHTS

	Insight	Disposition
62.	To prevent overdraining, the RCS hot and cold legs are vertically offset, which permits draining of the steam generators for nozzle dam insertion with a hot leg level much higher than traditional designs.	7.2.1
	To lower the RCS hot leg level at which a vortex occurs in the RNS suction line, a step nozzle connection between the RCS hot leg and the RNS suction line is used.	5.4.7.2.1 & Figure 5.1-5
	Should vortexing occur, air entrainment into the RNS pump suction is limited.	5.4.7.2.1
	There are two safety-related RCS hot leg level channels, one located in each hot leg. These level instruments are independent and do not share instrument lines. These level indicators are provided primarily to monitor RCS level during midloop operations. One level tap is at the bottom of the hot leg, and the other tap is on the top of the hot leg close to the steam generator.	Tier 1 Information Figure 5.1-5 19E.2.1.1
	Wide range pressurizer level indication (cold calibrated) is provided that can measure RCS level to the bottom of the hot legs. This nonsafety-related pressurizer level indication can be used as an alternative way of monitoring level and can be used to identify inconsistencies in the safety-related hot leg level instrumentation.	Tier 1 Information Figure 5.1-5 19E.2.1.1
	The RNS pump suction line is sloped continuously upward from the pump to the reactor coolant system hot leg with no local high points. This design eliminates potential problems in refilling the pump suction line if an RNS pump is stopped when cavitating due to excessive air entrainment. This self-venting suction line allows the RNS pumps to be immediately restarted once an adequate level in the hot leg is re-established.	5.4.7.2.1
	It is important to maximize the availability of the nonsafety-related wide range pressurizer level indication during RCS draining operations during cold shutdown. The Combined License applicant is responsible for developing procedures and training that encompass this item.	13.5
63.	Solid-state switching devices and electro-mechanical relays resistant to relay chatter will be used in the AP1000 safety-related I&C system.	19.55.2.3
64.	The annulus drains will have the same or higher HCLPF value as the Shield Building so that the drain system will not fail at lower acceleration levels causing water blocking of the PCS air baffle.	19.59.10
65.	The ability to close containment hatches and penetrations during Modes 5 & 6 prior to steaming to containment is important. The COL is responsible for developing procedures and training that encompass this item.	13.5 & 16.1
66.	Spurious actuation of squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations (e.g., routing of ADS cables in low voltage cable trays, and, in the case of PMS, the use of arm and fire signals from separate PMS cabinets), and provisions for operator action to remove power from the fire zone.	9A.2.7.1

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AP1000 PRA-BASED INSIGHTS

Insight	Disposition
67. For long-term recirculation operation, the RNS pumps can take suction from one of the two sump recirculation lines. Unrestricted flow through both parallel paths is required for success of the sump recirculation function when both RNS pumps are running. If one of the two parallel paths fails to open, operator action is required to manually throttle the RNS discharge valve to prevent pump cavitation.	Emergency Response Guidelines
The containment isolation valves in the RNS piping automatically close via PMS with a high radiation signal. The actuation setpoint was established consistent with a DBA non-mechanistic source term associated with a large LOCA. The containment radiation level for other accidents is expected to be below the point that would cause the RNS MOVs to automatically close.	6.2.3 & 7.3.1.2.20
With the RNS pumps aligned either to the IRWST or the containment sump, the pumps' net positive suction head is adequate to prevent pump cavitation and failure even when the IRWST or sump inventory is saturated.	5.4.7
Emergency response guidelines are provided for aligning the RNS from the control room for RCS injection and recirculation.	Emergency Response Guidelines
The following are additional AP1000 features which contribute to the low likelihood of interfacing system LOCAs between the RNS and the RCS: - A relief valve located in the common RNS discharge line outside containment provides protection against excess pressure. - Two remotely operated MOVs connecting the suction and discharge headers to the IRWST are interlocked with the isolation valves connecting the RNS pumps to the hot leg. This prevents inadvertent opening of these two MOVs when the RNS is aligned for shutdown cooling and potential diversion and draining of reactor coolant system. - Power to the four isolation MOVs connecting the RNS pumps to the RCS hot leg is administratively blocked at their motor control centers during normal power operation.	5.4.7.2
Per the Shutdown Evaluation, operability of the RNS is tested, via connections to the IRWST, before its alignment to the RCS hot leg for shutdown cooling.	19E
Inadvertent opening of RNS valve V024 results in a draindown of RCS inventory to the IRWST and requires gravity injection from the IRWST. The COL applicant is responsible for developing administrative controls to ensure that inadvertent opening of this valve is unlikely.	13.5
The reliability of the IRWST suction isolation valve (V023) to open on demand is important. The IRWST suction isolation valve is included in the D-RAP.	17.4

Table 19.59-18 (Sheet 23 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
68. The startup feedwater system pumps provide feedwater to the steam generator. This capability provides an alternate core cooling mechanism to the PRHR heat exchangers for non-LOCA or steam generator tube ruptures. The startup feedwater pumps are included in the D-RAP.	17.4
69. Capability is provided for on-line testing and calibration of the DAS channels, including sensors.	7.7.1.11
Short-term availability controls of the DAS during at-power conditions reduce PRA uncertainties.	16.3
70. One CVS pump is configured to operate on demand while the other CVS pump is in standby. The operation of these pumps will alternate periodically.	9.3.6.3.1 & 19.15
The safety-related PMS boron dilution signal automatically re-aligns CVS pump suction to the boric acid tank. This signal also closes the two safety-related CVS demineralized water supply valves. This signal actuates on reactor trip signal (interlock P-4), source range flux doubling signal, or low input voltage to the Class 1E dc power system battery chargers.	7.3.1.2.14
71. The COL applicant will maintain procedures to respond to low hot leg level alarms.	Emergency Response Guidelines
72. The containment recirculation screens are configured such that the chance of clogging is minimized during operation following accidents at power and at shutdown. The configuration features that reduce the chance of clogging include: - Redundant screens are provided and located in separate locations - Bottom of screens are located well above the lowest containment level as well as the floors around them - Top of screens are located well below the containment floodup level - Screens have protective plates that are located close to the top of the screens and extend out in front and to the side of the screens - Screens have conservative flow areas to account for plugging. Adequate PXS performance can be supported by one screen with at least 90% of its surface area completely blocked - During recirculation operation, the velocities approaching the screens are very low which limits the transport of debris.	6.3.2
73. A COL applicant cleanliness program controls foreign debris from being introduced into the IRWST tank and into the containment during maintenance and inspection operations.	6.3.2.2.7.2, 6.3.2.2.7.3, & 6.3.8.1

Table 19.59-18 (Sheet 24 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
74. For floor drains, from the reactor cavity PXS-A and PXS-B rooms, appropriate precautions such as check valves, back flow preventers, and siphon breaks are assumed to prevent back flow from a flooded space to a nonflooded space.	3.4.1.2.2
75. Plant ventilation systems include features to prevent smoke originating from one fire area to another to the extent that they could adversely affect safe shutdown capabilities.	9.4.2.2
76. An alternative gravity injection path is provided through RNS V-023 during cold shutdown and refueling conditions with the RCS open.	Emergency Response Guidelines
The COL applicant is responsible for developing administrative controls to maximize the likelihood that RNS valve V-023 will be able to open if needed during Mode 5 when the RCS is open, and PRHR cannot be used for core cooling.	13.5
77. The IRWST suction isolation valve (V023) and the RCS pressure boundary isolation valves (V001A/B, V002A/B) are environmentally qualified to perform their safety functions.	Tier 1 Information
78. Following an extended loss of RNS during safe/cold shutdown with the RCS intact and PRHR unavailable, it is essential to establish and maintain venting capability with ADS Stage 4 for gravity injection and containment recirculation.	19.59.5
79. Combined License applicants referencing the AP1000 certified design will provide resolution for generic open items and plant-specific action items resulting from NRC review of the I&C platform.	7.1.6
80. The Combined License applicant will provide an analysis that demonstrates that operator actions, which minimize the probability of the potential for spurious ADS actuation as a result of a fire, can be accomplished within 30 minutes following detection of the fire and the procedure for the manual actuation of the valve to allow fire water to reach the automatic fire system in the containment maintenance floor.	9.5.1.8
81. The Combined License applicant will establish procedures to minimize risk when fire areas are breached during maintenance. These procedures will address a fire watch for fire areas breached during maintenance.	9.5.1.8
82. It is important to maintain the low-temperature overpressure protection provided by the RNS relief valve to ensure that the reactor vessel pressure and temperature limits are not exceeded during shutdown conditions. Isolation of the RNS and its relief valve is permitted during shutdown conditions in case the hot legs empty due to a loss of RCS inventory; if the RNS is isolated, an alternate vent path would be opened, such as the ADS Stage 1, 2, and 3 valves.	16.1 (LCO Basis 3.4.14)

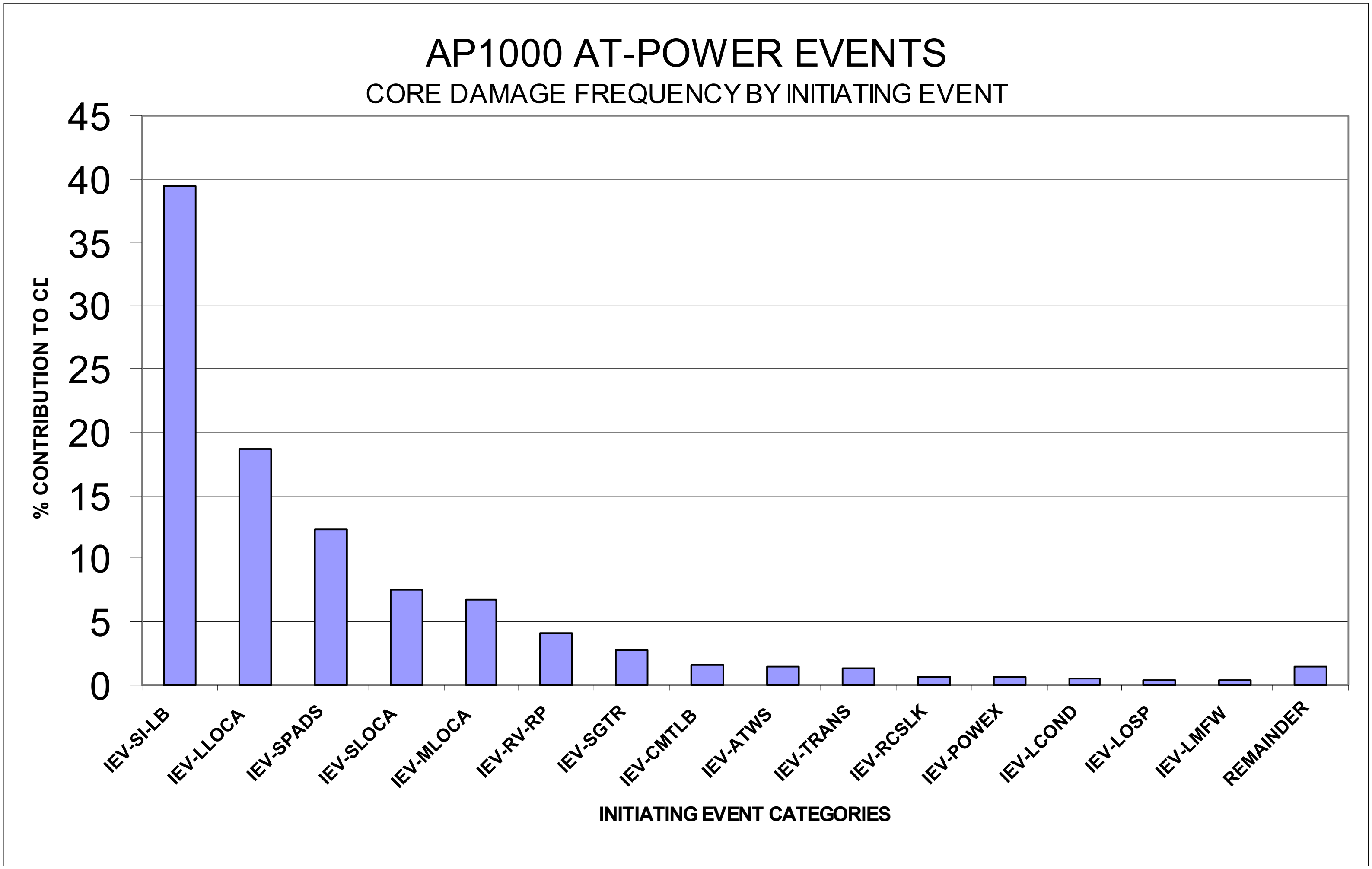

Figure 19.59-1

Contribution of Initiating Events to Core Damage

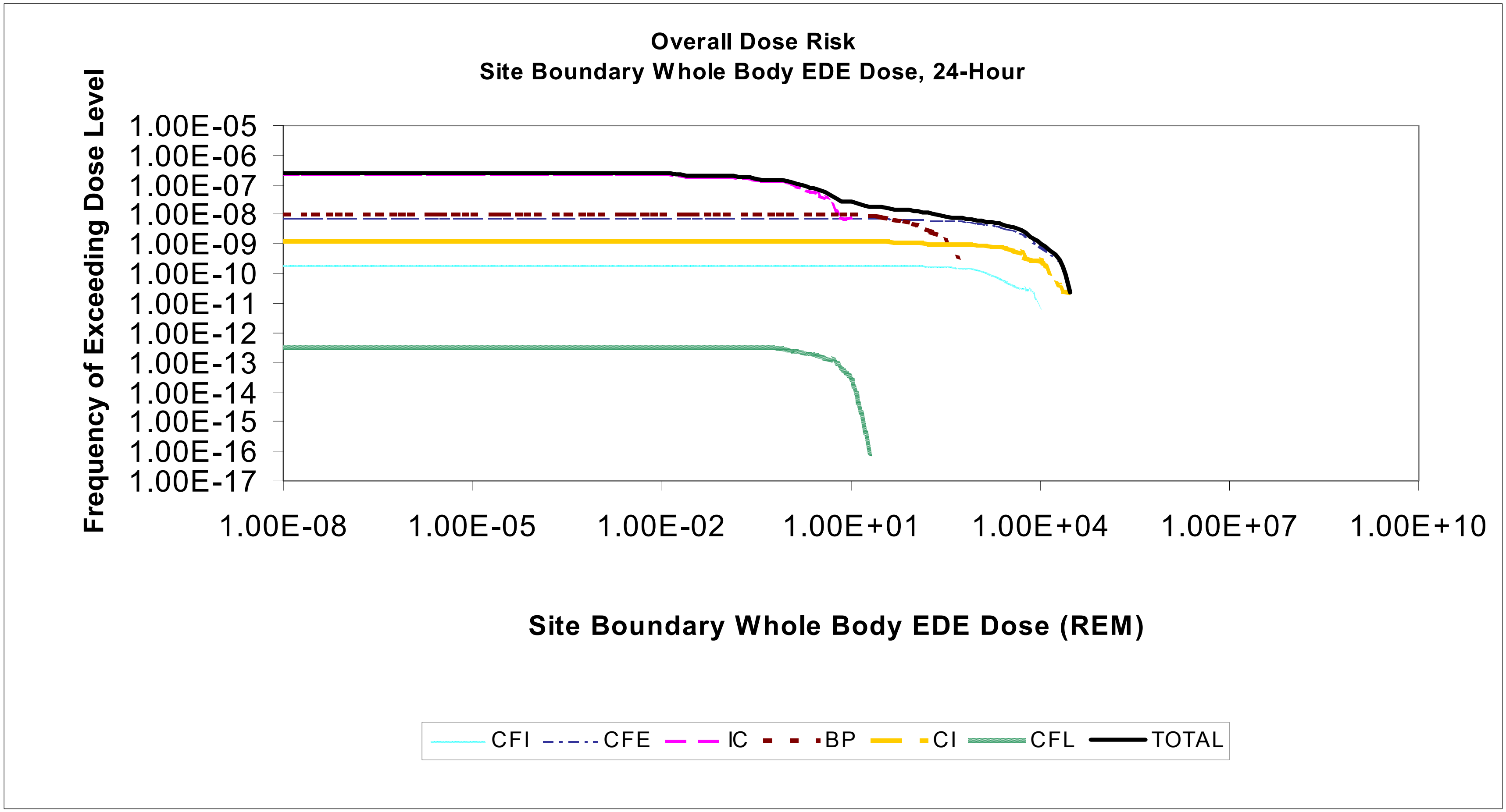

Figure 19.59-2

24-Hour Site Boundary Dose Cumulative Frequency Distribution

APPENDIX 19A THERMAL HYDRAULIC ANALYSIS TO SUPPORT SUCCESS CRITERIA

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APPENDIX 19B EX-VESSEL SEVERE ACCIDENT PHENOMENA

One of the key AP1000 severe accident design features is the capability to retain the core debris within the reactor vessel for a large number of severe accident sequences by flooding the reactor cavity and submerging the outer surface of the reactor vessel. The heat removal capability of the water on the external surface of the reactor vessel prevents the reactor vessel wall from reaching temperatures where failure of the reactor vessel could occur. This has been termed in-vessel retention (IVR) and is described in detail in Chapter 39 of the AP1000 Level 2 PRA. The primary benefit of in-vessel retention of the core is that ex-vessel severe accident phenomena associated with relocation of core debris to the containment, which can be a dominant containment failure mechanism, are physically prevented. Thus, retention of the core within the reactor vessel results in a significant reduction in the potential for large fission product releases to the environment for core damage accidents.

The probability of various levels of fission product releases (release categories) has been determined in the AP1000 Level 2 PRA, using a containment event tree which describes the various severe accident phenomena that can impact the fission product release quantities and probability of release. In the quantification of the AP1000 Level 2 PRA it was conservatively assumed that the containment would fail at the time of reactor vessel failure for all core damage sequences in which the core debris could not be retained within the reactor vessel. The two principle ways identified in the Level 2 PRA of retaining the core within the reactor vessel are reflooding the core with water before the core begins to relocate within the reactor vessel and submerging the outer surface of the reactor vessel to the reactor coolant loop nozzles. Using this approach, the regulatory and industry severe accident performance targets for the AP1000 design criteria were met. Therefore, it was considered unnecessary to investigate the consequences of reactor vessel failure on a realistic basis, including quantification of uncertainties.

The AP1000 design includes features to enhance the likelihood of retaining the core within the reactor vessel for severe accident sequences. These features include:

- Depressurization of the reactor coolant system (RCS) in the event of an accident by either automatic or manual actuation of the highly reliable automatic depressurization system (ADS)

- A containment layout wherein the water relieved from the reactor coolant system (either from the ADS discharge or a break in the RCS) accumulates in the reactor cavity region

- The capability to manually initiate flooding of the reactor cavity by gravity draining the in-containment refueling water storage tank (IRWST) into the reactor cavity

- The absence of in-core penetrations in the reactor vessel bottom head eliminates a possible reactor vessel failure mode

- The reactor cavity layout provides for rapid flooding of the reactor vessel to the reactor coolant loop nozzle elevation

- The reactor vessel insulation design promotes the two-phase natural circulation in the vessel cooling annulus

- The external reactor vessel surface treatment promotes wetability of the vessel

Some of the AP1000 design features to reduce the probability of a core damage accident and to enhance the likelihood of in-vessel retention of core debris in the event of a core damage accident are counter to the design philosophy that would be used to mitigate the consequences of ex-vessel severe accident phenomena. In particular, two of the design features are mutually exclusive between preventing ex-vessel phenomena and mitigating the consequences of ex-vessel phenomena. On balance, the AP1000 severe accident risk profile is substantially reduced by the features that prevent ex-vessel severe accident phenomena. Two of the more noteworthy features are:

- The large mass of the AP1000 core provides for a slower accident progression, which enhances the capability to prevent a core damage accident (i.e., a reduced core damage frequency). The larger mass of core materials may result in more severe consequences from some of the potential ex-vessel phenomena such as core debris coolability and core concrete interactions.

- The small reactor cavity floor area reduces the amount of water required to completely submerge the reactor vessel. The small cavity floor area also provides for a more rapid flooding of the cavity if manual initiation of IRWST draining to the reactor cavity is required to submerge the reactor vessel. The small reactor cavity floor area may result in more severe consequences from some of the severe accident ex-vessel phenomena such as core debris coolability and core concrete interactions.

The purpose of this section is to provide the results of a limited number of deterministic investigations of the consequences of ex-vessel severe accident phenomena for the AP1000 design. The results of these deterministic investigations show that the challenges to the integrity of the containment posed by ex-vessel severe accident phenomena are generally within the structural capability of the containment. From these investigations, the conclusion is the capability to prevent large fission product releases to the environment does not depend on the ability to retain the core within the reactor vessel for core damage accident sequences.

The limited deterministic investigations of ex-vessel severe accident phenomena described in this section includes: ex-vessel steam explosions, direct containment heating and core concrete interactions. These ex-vessel phenomena are strongly dependent on the assumptions made concerning the mode of reactor vessel failure for the AP1000 design. Therefore, the reactor vessel failure mode is described first, followed by a description of the ex-vessel phenomena investigations.

19B.1 Reactor Vessel Failure

The AP1000 reactor vessel has a main cylindrical section approximately 4 meters in diameter and a hemispherical bottom head. The bottom head is approximately 15 cm (6 inches) thick and is made of carbon steel with an inner cladding of stainless steel to prevent contact between reactor

coolant and carbon steel during normal plant operations. The bottom head of the reactor vessel does not contain any discontinuities or penetrations that could impact the mode of reactor vessel failure as the molten core material relocates to the bottom head.

Based on the similar vessel configurations of AP600 and AP1000, the possible failure modes for the AP600 reactor vessel, as documented in Reference 19B-1, are extended to the AP1000. The most likely failure mode is creep failure of the vessel wall due to heating of the vessel wall by the core debris that has relocated to the reactor vessel bottom head. Since creep failure is a strongly temperature-dependent phenomena, the location of the failure is predicted to be at the upper surface of the core debris pool that has relocated to the reactor vessel bottom head. For most severe accident sequences, this location is near the junction of the hemispherical bottom head and the cylindrical portion of the vessel.

As described in Reference 19B-2, the presence of water on the external surface of the reactor vessel, as in the case of a flooded reactor cavity, does not alter the conclusion that the highest heat fluxes to the reactor vessel walls will be at a point near the top of the in-vessel molten core pool. This would correspond to the region of the reactor vessel most susceptible to creep failure. However, reactor vessel failure will not occur for the case in which the reactor coolant system is depressurized and the reactor cavity is filled with water to the reactor coolant loop elevation.

For the case in which the outside of the reactor vessel is initially submerged but a sufficient in-flow of water to the reactor cavity cannot be maintained, the reactor vessel wall location experiencing the highest heat fluxes would uncover and lose its external cooling before other locations on the reactor vessel lower head. Thus, creep failure of the vessel would be expected to occur at the same location as the case with no water in the reactor cavity.

Two reactor vessel failure cases, as described below, are carried through the deterministic analyses of ex-vessel steam explosions and core concrete interactions. For the consideration of ex-vessel steam explosions and core concrete interactions, it is assumed that the reactor vessel is initially submerged in water but that gravity draining of water from the IRWST does not occur. As the water in the reactor cavity boils down, the outside of the reactor vessel at the elevation at the top of the in-vessel core pool will dry out and begin to heat up. As the vessel wall heats up, it undergoes thinning due to dissolution and melting until failure occurs. The manner in which the reactor vessel fails is treated in two separate scenarios described below.

In the first scenario, the formation of a localized opening occurs due to asymmetric heating around the circumference followed by the vessel tearing around nearly all of its circumference. This would result in the bottom part of the reactor vessel and the bottom head hinging such that the lower head swings downward and comes to rest on the cavity floor. This behavior is illustrated in Figure 19B-1. A hinging type of failure would result in an immediate pouring of core debris onto the cavity floor with metal flowing ahead of oxide. The relationship between the height of the reactor vessel above the floor is such that all but a minor part of the oxide melt would be free to flow immediately out of the head.

In the second scenario, the head and bottom part of the vessel do not hinge downward. In this scenario, the formation of a localized opening permits molten core debris to drain into the cavity lowering the in-vessel core debris depth and thereby decreasing the thermal load on the vessel

wall formerly adjacent to the melt. This type of failure is illustrated in Figure 19B-2. In this case, the continued boildown of water level is followed by the release of the core debris located above the water level after a delay interval during which heatup, thinning, and localized failure of the wall will occur. Over time, the elevation of the failure location moves downward over the vessel wall and lower head. This type of failure gives rise to a very slow release rate with the core debris first relocating downward through the water before collecting and spreading on the cavity floor.

19B.2 Direct Containment Heating

Direct containment heating (DCH) is defined as the rapid energy addition to the containment atmosphere as a result of several physical and chemical processes that can occur if the core debris is forcibly ejected from the reactor vessel. The prerequisites for direct containment heating are vessel failure occurs at a location where a substantial portion of the core debris that has relocated to the lower head is ejected into the reactor cavity before the RCS gases are discharged from the RCS and the RCS is at a high pressure (sometimes called high pressure melt ejection or HPME).

To preclude the potential for high-pressure core melt ejection leading to containment failure via DCH, SECY-93-087 (Reference 19B-4) directs passive light water reactor (LWR) designs to:

- Provide a reliable depressurization system

- Provide cavity design features to decrease the amount of ejected core debris that reaches the upper compartment

The AP1000 design incorporated design features that prevent high-pressure core melt. These features include the passive residual heat removal (PRHR) system and the ADS, both subsystems of the passive core cooling system (PXS). Depressurization of the AP1000 RCS in the event of an accident is provided by automatic or manual actuation of the ADS. Redundancy and diversity are included within the ADS design to ensure a highly reliable depressurization system. The ADS consists of four different valve stages that open sequentially to reduce reactor coolant system pressure in a controlled fashion. All four-valve stages are arranged into two identical groups. Different valve types/sizes are utilized within the ADS stages to provide diversity. Based on these ADS design features, a highly reliable depressurization system is provided which precludes the potential for high-pressure core melt ejection in the AP1000 design. The AP1000 PRHR and ADS subsystems are described in additional detail in Chapters 8 and 11 of the AP1000 PRA and in Section 6.3 of the *AP1000 Design Control Document* (DCD).

Even though high-pressure core melt ejection is not a likely scenario for the AP1000, SECY-93-087 directs passive LWR designs to include cavity design features to decrease the amount of ejected core debris from reaching the upper compartment. The AP1000 design includes design features to retain and quench the core debris within the reactor cavity in the unlikely event of core debris relocation outside the reactor vessel. These features include:

- A containment layout wherein the water accumulates in the reactor cavity region

- The capability to manually initiate flooding of the reactor cavity by gravity draining the IRWST into the reactor cavity

- The reactor cavity geometry is arranged to provide a torturous pathway from the reactor cavity to the loop compartment and no direct pathway for the impingement of debris on the containment shell

19B.3 Ex-Vessel Steam Explosions

The first level of defense for ex-vessel steam explosion is the in-vessel retention of the molten core debris. If molten debris does not relocate from the vessel to the containment, there are no conditions for ex-vessel steam explosion. In the event that the reactor cavity is not flooded and the vessel fails, the PRA containment event tree assumes that the containment fails in the early time frame.

An analysis of the structural response of the reactor cavity was performed for the AP600 (Reference 19B-3). As in the in-vessel steam explosion analysis, the results of this AP600 ex-vessel steam explosion analysis are extended to the AP1000. The vessel failure modes for AP600 and AP1000 are the same. The initial debris mass participating in the interaction, superheat and composition are assumed to be the same as for AP600. The mass assumption is conservative since the AP1000 reactor vessel lower head is closer to the cavity floor resulting in less debris mass participating in the interaction. The reactor cavity geometry and water depth prior to vessel failure are the same as AP600. Therefore, the results of the AP600 ex-vessel steam explosion analysis are considered to be appropriate for the AP1000.

19B.4 Core Concrete Interactions

If the reactor vessel fails when the RCS is at a low pressure, the molten core debris will pour from the reactor vessel onto the reactor cavity floor. If a steam explosion does not occur, the pour will spread over the cavity floor and begin to transfer heat to the concrete floor of the reactor cavity. Due to the predicted mode of reactor vessel failure and the shape of the AP600 reactor cavity, analyses of the possible spreading of the core debris over the cavity floor were conducted. The results were used as input to the MAAP4 code for analysis of core concrete interactions for AP1000.

An investigation of the spreading of core debris that pours into the reactor cavity was conducted for reactor vessel failure that occurs at low RCS pressure. The investigation considered the vessel failure mode and location, as well as the recognition that the oxide and metal components of the in-vessel core debris are predicted to be separated. Since the oxide and metal components of the core debris have very different physical characteristics (e.g., viscosity or heat capacity), the separated in-vessel layers influence the spreading of the core debris in the reactor cavity. The melt spreading analysis was conducted for two reactor vessel failure modes, hinged and localized failures.

For the hinged vessel failure case, the analysis results show that the core debris is spread relatively uniformly over the reactor cavity floor. However, the distribution of the metal and oxide components of the core debris are not uniformly distributed over the reactor cavity floor. In the region directly under the reactor vessel, the core debris consists primarily of the oxide component. At the opposite end of the reactor cavity, the core debris consists mainly of the metal component

of the core debris released from the reactor vessel. The core debris is still almost totally molten at the end of the spreading analysis.

A different behavior is predicted for the localized reactor vessel failure case. The analysis predicts that the core debris will accumulate at the reactor vessel end of the reactor cavity. The distribution of the metal and oxide components of the core debris are not uniformly distributed over the reactor cavity floor. In the region directly under the reactor vessel, the core debris consists primarily of the oxide component. At the opposite end of the reactor cavity, the core debris consists mainly of the metal component of the core debris released from the reactor vessel. The core debris is almost totally frozen at the end of the spreading analysis.

The core concrete interactions for the AP1000 design were analyzed for two concrete types: basaltic concrete and common limestone-sand concrete. The common limestone-sand concrete has a significantly higher noncondensable gas generation rate, compared to basaltic concrete and should therefore present a more severe containment pressurization transient. On the other hand, the basaltic concrete suffers higher ablation rate, due to its physical properties (mainly, its lower decomposition energy), and should therefore present a more severe basemat penetration failure mode, compared to common limestone-sand concrete. In all cases, a 3.5 m deep water pool is initially present in the cavity while debris is being released into it.

Based on analyses, it can be concluded that: a) the goal of protecting the containment fission product boundary during the first 24 hours of a core melt accident is met, b) it is not necessary to specify a concrete type for the containment basemat since credible containment basemat failure that could lead to fission product releases to the atmosphere are likely to occur at times well beyond 24 hours, and c) the reactor cavity sump is adequately protected such that it is not a weakness in containment basemat integrity during postulated accidents that lead to core concrete interactions.

19B.4.1 Containment Pressurization due to Core Concrete Interactions

The containment pressurization due to steam and noncondensable gas generation during the episodes of core concrete interactions described above was assessed to determine the effect of core concrete interactions on the containment integrity.

The indicator of a challenge to containment integrity for the containment pressurization due to the noncondensable gases produced from core concrete interactions is the Service Level “C” pressure, which is 91 psig (0.73 MPa). This is well below the 50 percent containment failure probability value of 135 psig (1.03 MPa).

The results also show that, in all cases the containment does not pressurize to Service Level “C” containment challenge indicator value prior to the time that the core debris completely penetrates the containment basemat. Thus, for these cases there is no potential challenge to containment integrity due to overpressurization since: a) there is no longer a source of mass and energy input to the containment after the core debris penetrates the entire basemat, and b) basemat penetration assures that the containment will be depressurized through the basemat failure.

Based on these analyses, it can be concluded that it is not necessary to specify a concrete type for the containment basemat since containment overpressure failure due to non-condensable gas generation from core concrete interactions is not likely for any credible severe accident scenarios.

19B.5 Conclusions

The results of the limited deterministic analyses of ex-vessel severe accident phenomena presented in this section show that early containment failure is not a certainty if the reactor vessel fails. Based on the deterministic analyses, direct containment heating that might ensue from a high pressure melt ejection would not challenge the integrity of the containment. Ex-vessel steam explosions, assessed on a very conservative basis would not produce impulse loads that would challenge the integrity of the containment due to localized failures of the reactor cavity floor and walls. In addition, these analyses indicate that the ex-vessel steam explosion loads are not strong enough to displace the reactor vessel from its location inside the biological shield. Thus, there is no challenge to any containment penetrations connected to the reactor vessel or to the reactor coolant loops. In the case of a vessel failure at a low RCS pressure, the core concrete interactions analyses indicate that the containment integrity would not be challenged in the first 24 hours of the event and thus no significant releases of fission products are predicted in that time frame.

Thus, it is concluded that prevention of large fission product releases to the environment is not dependent on the integrity of the reactor vessel. If reactor vessel failure occurs, there may be challenges to the containment integrity, but these challenges are highly uncertain and the most likely challenge (containment failure by core penetration of the cavity basemat) would not occur in the first 24 hours of the accident. Thus, the AP1000 assumption that reactor vessel failure always leads to containment failure is a conservatism in the AP1000 risk profile.

19B.6 References

19B-1 "AP600 Phenomenological Evaluation Summaries," WCAP-13388 (Proprietary) Rev. 0, June 1992 and WCAP-13389 (Nonproprietary), Rev. 1, 1994.

19B-2 Theofanous, T. G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

19B-3 "AP600 Probabilistic Risk Assessment," GW-GL-022, August 1998.

19B-4 "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Design," SECY-93-087, dated April 2, 1993.

TABLE 19B-1 NOT INCLUDED IN THE DCD.

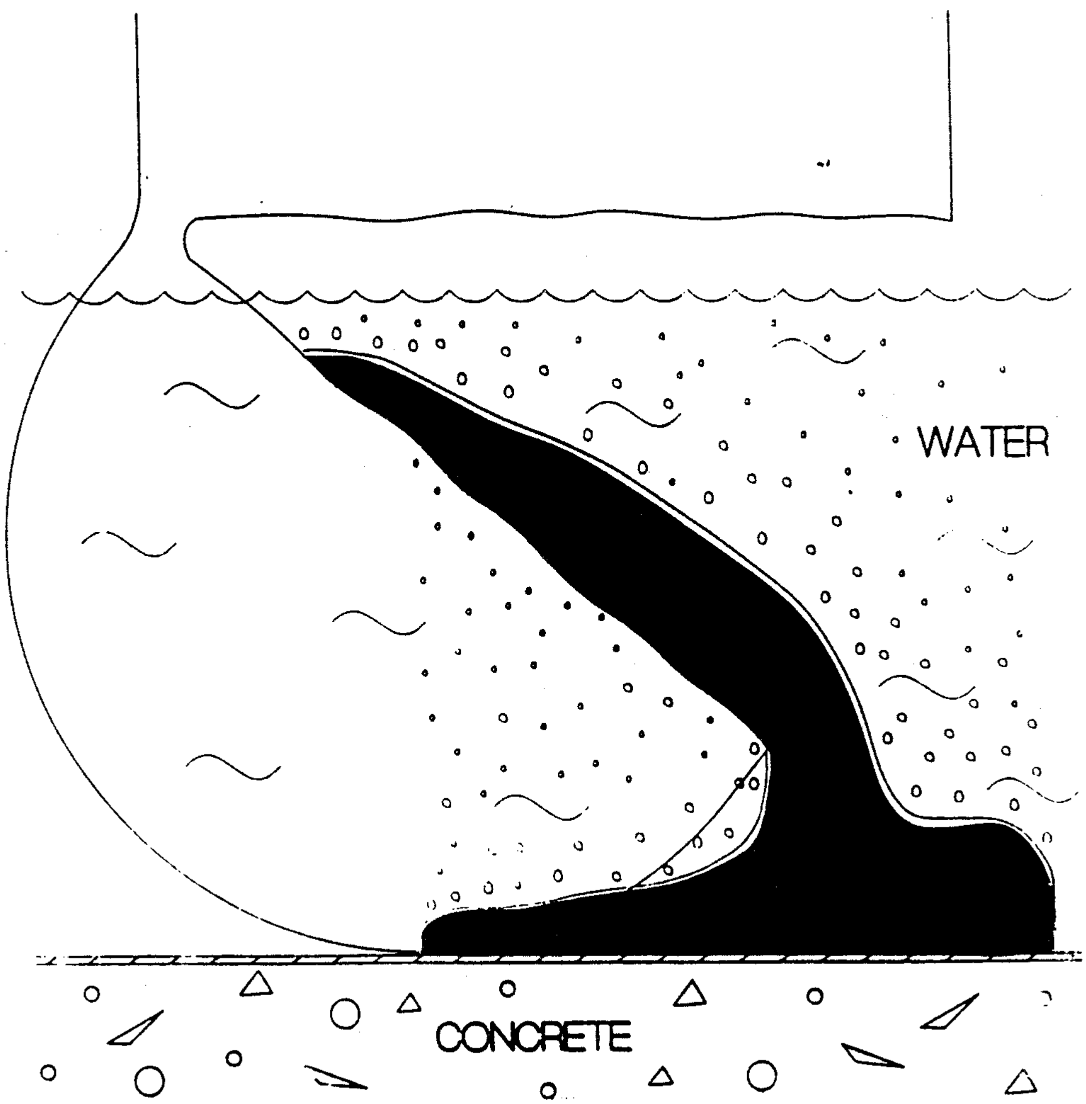

Figure 19B-1

Illustration of Hinging Type of Failure Resulting in Rapid Melt Release

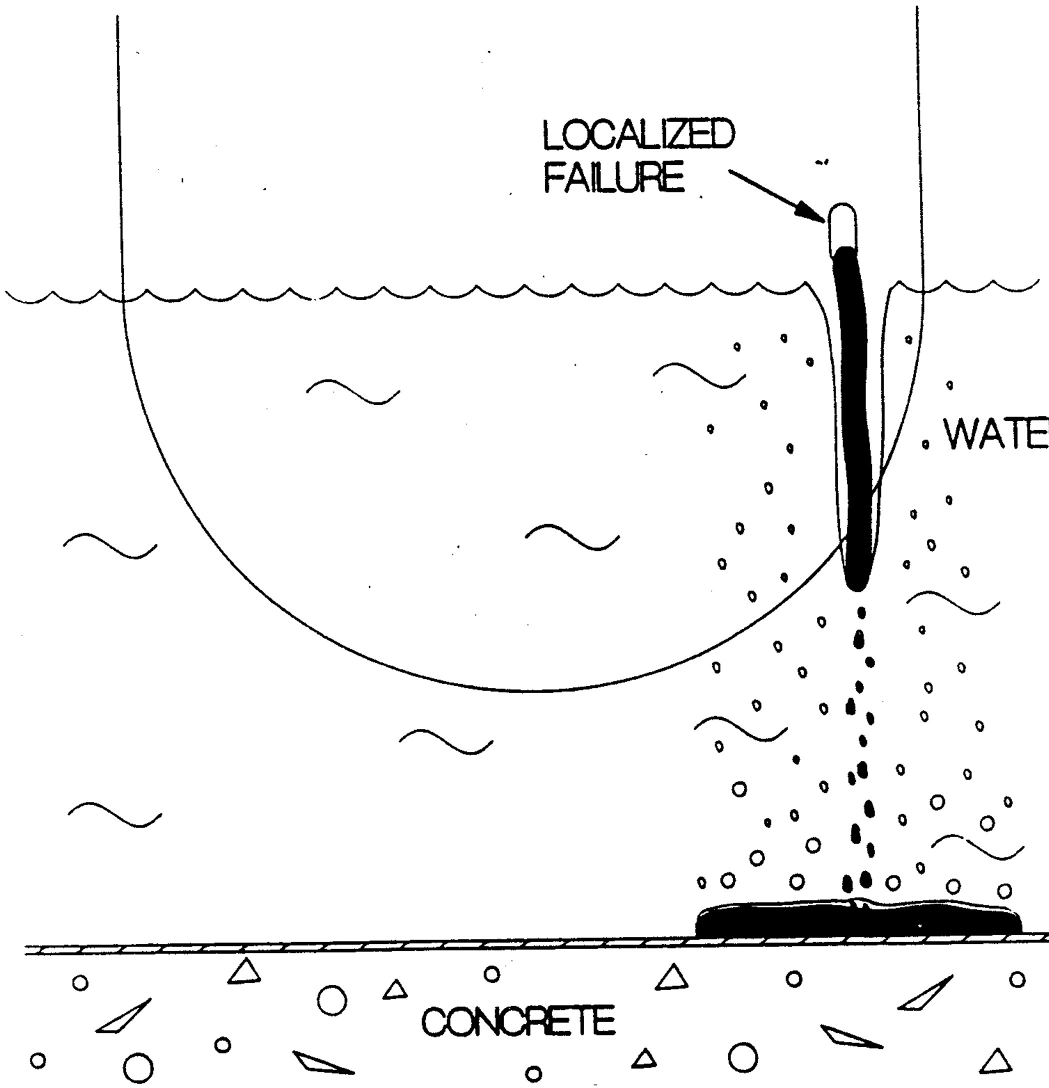

Figure 19B-2

Illustration of Localized Type of Failure Resulting in Slow Melt Release

FIGURES 19B-3 THROUGH 19B-8b NOT INCLUDED IN THE DCD.

APPENDIX 19C ADDITIONAL ASSESSMENT OF AP1000 DESIGN FEATURES

The AP1000 PRA model, like many other conventional PRA models, is an evolving model. It is revised, as needed, to keep up with design changes and to implement revisions identified by various reviews, applications, and related analyses. Due to the iterative nature of the interface between the PRA analysts and the plant designers, it is not always possible to incorporate all differences identified between the plant design and the PRA model in a timely manner. This appendix is intended to summarize known differences between the two, and identify any future changes planned to the current PRA model to address these differences.

Planned Revisions to AP1000 PRA Model

A review of the bus assignments by the AP1000 designers for the AP1000 PRA model identified that some bus assignments needed to be revised. A systematic investigation of the support system buses in the fault trees has been made and the fault trees are revised as needed. This also includes the replacement of the 4.16 KVAC bus with the 6.9 KVAC bus in fault trees. This revision is the basis for Revision 2 of the plant core damage frequency (CDF) for internal events at power. While this revision is being made, other revisions identified by either the PRA team or the AP1000 designers during the review of the AP1000 PRA sections is also incorporated into the plant CDF revision. These additional revisions are:

1. Containment isolation event trees.

2. Removal of AOV001B from the compressed air system fault trees.

3. Quantification of loss-of-offsite power (LOSP) event sequences with a lower cutoff probability to collect more cutsets for the station blackout (SBO) event (1.0E-14 cutoff by removal of the /m:25000 cutset restriction during LOSP quantification).

4. Correction of ADR fault tree top logic to reflect the success criteria (logic was conservative).

5. Addition of the third pump main feedwater pump to the main feedwater (MFW) fault trees.

6. The success criteria for medium LOCA (including CMT and DVI line breaks) will be modified to credit the PRHR heat exchanger for those instances when the accumulators are assumed to fail. The impact on the overall PRA results for this change is not expected to be significant.

Preliminary quantification shows that the plant CDF is not affected by this revision. The large release frequency (LRF) is not expected to be affected either. The next revision of the AP1000 PRA Report will incorporate these changes to the PRA model.

APPENDIX 19D EQUIPMENT SURVIVABILITY ASSESSMENT

19D.1 Introduction

The purpose of the equipment survivability assessment is to evaluate the availability of equipment and instrumentation used during a severe accident to achieve a controlled, stable state after core damage under the unique containment environments. Severe accident phenomena may create harsh, high temperature and pressure containment environments with a significant concentration of combustible gases. Local or global burning of the gases may occur, presenting additional challenges to the equipment. Analyses demonstrate that there is reasonable assurance that equipment used to mitigate and monitor severe accident progression is available at the time it is called upon to perform.

The methodology used to demonstrate equipment survivability is:

- Identify the high level actions used to achieve a controlled, stable state
- Define the accident time frames for each high level action
- Determine the equipment and instruments used to diagnose, perform and verify high level actions in each time frame
- Determine the bounding environment within each time frame
- Demonstrate reasonable assurance that the equipment will survive to perform its function within the severe environment.

19D.2 Applicable Regulations and Criteria

Equipment that is classified as safety-related must perform its function within the environmental conditions associated with design-bases accidents. The level of assurance provided by equipment required for design-bases events is “equipment qualification.”

The environmental conditions resulting from beyond design basis events may be more limiting than conditions from design-bases events. The NRC has established criteria to provide a reasonable level of assurance that necessary equipment will function in the severe accident environment within the time span it is required. This criterion is referred to as “equipment survivability.”

The applicable criteria for equipment, both mechanical and electrical, required for recovery from in-vessel severe accidents are provided in 10 CFR 50.34(f):

- Part 50.34(f)(2)(ix)(c) states that equipment necessary for achieving and maintaining safe shutdown of the plant and maintaining containment integrity will perform its safety function during and after being exposed to the environmental conditions attendant with the release of hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction including the environmental conditions created by activation of the hydrogen control system.

- Part 50.34(f)(2)(xvii) requires instrumentation to measure containment pressure, containment water level, containment hydrogen concentration, containment radiation intensity, and noble gas effluent.

- Part 50.34(f)(2)(xix) requires instrumentation adequate for monitoring plant conditions following an accident that includes core damage.

- Part 50.34(f)(3)(v) states that systems necessary to ensure containment integrity shall be demonstrated to perform their function under conditions associated with an accident that releases hydrogen generated from 100 percent fuel-clad metal-water reaction.

The applicable criteria for equipment, both electrical and mechanical, required to mitigate the consequences of ex-vessel severe accidents is discussed in Section III.F, “Equipment Survivability” of SECY-90-016. The NRC recommends in SECY-93-087 that equipment provided only for severe accident protection need not be subject to 10 CFR 50.49 equipment qualification requirements, the 10 CFR 50 Appendix B quality assurance requirements, or 10 CFR 50 Appendix A redundancy/diversity requirements. However, mitigation features must be designed to provide reasonable assurance they will operate in the severe accident environment for which they are intended and over the time span for which they are needed.

19D.3 Definition of Controlled, Stable State

The goal of accident management is to achieve a controlled, stable state following a beyond design basis accident. Establishment of a controlled, stable state protects the integrity of the containment pressure boundary. The conditions for a controlled, stable state are defined by WCAP-13914, the Framework for AP600 Severe Accident Management Guidance (SAMG) (Reference 19D-1) which is considered valid for AP1000.

For a controlled, stable core state:

- A process must be in place for transferring the energy being generated in the core to a long-term heat sink

- The core temperature must be well below the point where chemical or physical changes might occur

For a controlled, stable containment state:

- A process must be in place for transferring the energy that is released to the containment to a long-term heat sink

- The containment boundary must be protected

- The containment and reactor coolant system conditions must be well below the point where chemical or physical processes (severe accident phenomena) might result in a dynamic change in containment conditions or a failure of the containment boundary.

19D.4 Definition of Equipment Survivability Time Frames

The purpose of the equipment survivability time frames is to identify the time span in the severe accident in which specific equipment is required to perform its function. The phenomena and environment associated with that phase of the severe accident defines the environment which challenges the equipment survivability. The equipment survivability time frame definitions are summarized in Table 19D-1.

19D.4.1 Time Frame 0 - Pre-Core Uncovery

Time Frame 0 is defined as the period of time in the accident sequence after the accident initiation and prior to core uncovery. The fuel rods are cooled by the water/steam mixture in the reactor vessel. The accident has not yet progressed beyond the design basis of the plant, and hydrogen generation and the release of fission products from the core is negligible. Emergency response guidelines (ERGs) are designed to maintain or recover the borated water inventory and heat removal in the reactor coolant system to prevent core uncovery and establish a safe, stable state. Recovery within Time Frame 0 prevents the accident from becoming a severe accident. Equipment survivability in Time Frame 0 is covered under the design basis equipment qualification program.

19D.4.2 Time Frame 1 - Core Heatup

Time Frame 1 is defined as the period of time after core uncovery and prior to the onset of significant core damage as evidenced by the rapid oxidation of the core. This is the transition period from design basis to severe accident environment. The overall core geometry is intact and the uncovered portion of the core is overheating due to the lack of decay heat removal. Hydrogen releases are limited to relatively minor cladding oxidation and some noble gas and volatile fission products may be released from the fuel-clad gap. As the core-exit gas temperature increases, the ERGs transition to a red path indicating inadequate core cooling. The operators attempt to reduce the core temperature by depressurizing the RCS and re-establish the borated water inventory in the reactor coolant system. If these actions do not result in a decrease in core-exit temperature, the control room staff initiate actions to mitigate a severe accident by turning on the hydrogen igniters for hydrogen control and flooding the reactor cavity to prevent reactor pressure vessel failure. Recovery in Time Frame 1 prevents the accident from becoming a core melt. Equipment survivability in Time Frame 1 is evaluated to demonstrate it is within the equipment qualification envelope.

19D.4.3 Time Frame 2 - In-Vessel Severe Accident Phase

Time Frame 2 is the period of time in the severe accident after the accident progresses beyond the design basis of the plant and prior to the establishment of a controlled, stable state (end of in-vessel core relocation), or prior to reactor vessel failure. The onset of rapid oxidation of the fuel rod cladding and hydrogen generation defines the beginning of Time Frame 2. The heat of the exothermic reaction accelerates the degradation, melting and relocation of the core. Fission products are released from the fuel-clad gap as the cladding bursts and from the fuel matrix as the UO_2 pellets melt. Over the period of Time Frame 2, the initial, intact geometry of the core is lost as it melts and relocates downward. Severe accident management strategies exercised during Time

Frame 2 are designed to recover reactor coolant system inventory and heat removal, to maintain reactor vessel integrity and to maintain containment integrity. Recovery actions in Time Frame 2 may create environmental challenges by increasing the rate of hydrogen and steam generation.

19D.4.4 Time Frame 3 - Ex-Vessel Severe Accident Phase

Time Frame 3 is defined as the period of time after the reactor vessel fails until the establishment of a controlled, stable state. The AP1000 reliably provides the capability to flood the reactor vessel and prevent the vessel failure in a severe accident. This severe accident time phase 3 is of such low frequency, it is considered to be remote and speculative. Molten core debris is relocated from the reactor vessel onto the containment cavity floor which creates the potential for rapid steam generation, core-concrete interaction and non-condensible gas generation. Severe accident management strategies implemented in Time Frame 3 are designed to monitor the accident progression, maintain containment integrity and mitigate fission product releases to the environment.

19D.5 Definition of Active Operation Time

Equipment only needs to survive long enough to perform its function to protect the containment fission product boundary. In the case of some items, such as valves or motor-operators, once the equipment performs its function, it changes state and the function is completed. For other items, such as pumps, the equipment must operate continuously to perform its function. The time of active operation is the time during which the equipment must change state or receive power to perform its function.

19D.6 Equipment and Instrumentation for Severe Accident Management

The AP600 emergency response guidelines (Reference 19D-2) and severe accident management guidance (SAMG) framework (Reference 19D-1), which are considered valid for AP1000, define actions that accomplish the goals for achieving a controlled, stable state and terminating fission product releases in a severe accident. The high level actions from the accident management framework are summarized in Table 19D-2 and provide the basis for the actions considered for identifying equipment. The purpose of this section is to review ERG and SAMG actions within each of the time frames of the severe accident to determine the equipment and instrumentation and the active operation time in which they are needed to provide reasonable assurance of achieving a controlled, stable state. The AP600-specific accident management framework is used to identify the equipment for performing the high level actions. These high level actions are applicable to AP1000.

The Westinghouse Owners Group (WOG) SAMG (Reference 19D-3) provides the primary input to the selection of the instrumentation used for monitoring the actions. The instrument used to diagnose the need for the action and monitor the response are listed. Instruments to evaluate potential negative impacts are covered under other high level actions in the framework and therefore are also considered for survivability.

The equipment and instrumentation used in each time frame are summarized in Tables 19D-3 through 19D-5.

19D.6.1 Time Frames 0 and 1 - Accident Initiation, Core Uncovery and Heatup

Time Frame 0 represents the accident time prior to core uncovery. Time Frame 1 represents the time following core uncovery, prior to the rapid oxidation of the core. Aside from potential ballooning of the cladding, the core has not lost its initial intact geometry and is coolable.

During Time Frames 0 and 1, most of the equipment that is automatically actuated will receive a signal to start. However, given a severe accident sequence, some critical equipment does not actuate. From accident initiation until the time of core uncovery (Time Frame 0) the conditions are bounded by the design basis and covered under equipment qualification. During Time Frame 1, the environment is still within the design basis of the plant and the control room is operating within the Emergency Response Guidelines, but the conditions have the potential to degrade. To achieve a controlled, stable state, accident management, via the ERGs, is geared toward recovering the core cooling before the coolable geometry is lost. Failing that, the plant is configured to keep the core debris in the vessel, and mitigate the containment hydrogen that will be generated in Time Frame 2.

19D.6.1.1 Injection into the RCS

Failure of RCS injection is likely to be the reason the accident has proceeded to core uncovery. Successful injection into the RCS removes the sensible and decay heat from the core. Prior to the rapid oxidation of the cladding, successful RCS injection essentially recovers the accident before it progresses to substantial core melting and relocation and establishes a controlled, stable state. Failure to inject into the RCS at a sufficient rate allows the accident to proceed into Time Frame 2 and the SAMG.

The equipment and systems used to inject into the RCS are the core makeup tanks, accumulators and IRWST (which are part of the passive core cooling system (PXS)), the chemical and volume control system (CVS) pumps, and the normal residual heat removal (RNS) pumps. For non-LOCA and small LOCA sequences, depressurization of the RCS is required for successful injection.

The plant response is monitored using the system flowrates, RCS pressure, core exit temperature, or RCS temperature.

19D.6.1.2 Injection into Containment

The operator is instructed via the ERGs to inject water into the containment to submerge the reactor vessel and cool the external surface if injection to the RCS cannot be established. This action is performed at the end of Time Frame 1, immediately prior to entry into the SAMG. Successful cavity flooding prevents vessel failure in the event of molten core relocation to the vessel lower head. Failure of cavity flooding may allow the accident to proceed to vessel failure and molten core relocation into the containment (Time Frame 3) if timely injection into the reactor vessel cannot be established to cool the core and prevent substantial core relocation to the lower head.

The PXS motor-operated and squib recirculation valves are opened manually to drain the IRWST water into the containment.

The plant response is monitored by containment water level or IRWST water level indication.

19D.6.1.3 Decay Heat Removal

In the event of non-LOCA or small LOCA sequences, the RCS pressure is elevated above the secondary pressure. Failure of the PRHR may be the initiating event of such sequences. Recovery of the PRHR will provide decay heat removal. Failure of feedwater to the steam generators with the PRHR failed may also be the initiating event for such sequences and recovery of injection to the steam generators may be required. If the steam generators remain dry without PRHR recovery and the core is uncovered, the tube integrity or hot leg nozzle integrity will be threatened by creep rupture failure at the onset on rapid oxidation (entry into Time Frame 2). Injecting to the steam generators provides a heat sink to the RCS by boiling water on the secondary side, and protects the tubes by cooling them. Successful steam generator injection can establish a controlled, stable state if the losses from the RCS can be recovered and mitigated. Failure to inject to the steam generator requires depressurization of the RCS to prevent creep rupture failure of the tubes and loss of the containment integrity at the onset of rapid oxidation in Time Frame 2.

For accident sequences initiated by steam generator tube rupture, the procedures instruct the control room to isolate injection to the faulted steam generator, and to use injection to the intact steam generator in conjunction with steam generator depressurization and PRHR initiation to cooldown the reactor coolant system and isolate the break. In Time Frame 1, PRHR initiation or injection to the intact steam generators may be used to re-establish a primary heat sink to cooldown the RCS and a controlled, stable state if the losses from the RCS can be recovered and mitigated. Failure to recover the PRHR or to inject to the steam generator may lead to a continued loss of coolant to the faulted steam generator and progression to Time Frame 2.

The main feedwater and startup feedwater pumps are used to inject into a pressurized secondary system. If the secondary system can be depressurized sufficiently, condensate, fire water or service water can also be used to inject into the secondary side.

The plant response is monitored with the steam generator level and steamline pressure.

19D.6.1.4 Depressurize Reactor Coolant System

19D.6.1.4.1 Non-LOCA and Small LOCA Sequences

In the event of non-LOCA or a small LOCA sequences, the RCS pressure is above the secondary pressure. If the steam generators are dry and the core is uncovered, the hot leg nozzle or tube integrity is threatened by creep rupture failure at the onset of rapid cladding oxidation (beginning of Time Frame 2). Timely depressurization (prior to significant cladding oxidation) of the RCS mitigates the threat to the tubes, allows injection of the accumulators and IRWST water, and provides a long-term heat sink to establish a controlled, stable state. Failure to depressurize can result in the failure of the tubes and a loss of containment integrity when oxidation begins.

For steam generator tube rupture (SGTR) initiated sequences, depressurization of the RCS can be used to isolate the faulted steam generator, and re-establish core cooling via injection.

The automatic depressurization system (ADS) is required to fully depressurize the RCS to allow the PXS systems to inject. However, the recovery of passive residual heat removal (PRHR) or injection to the steam generators will provide a substantial heat sink to depressurize the RCS and mitigate the threat to the tubes. The auxiliary pressurizer sprays are not evaluated for survivability since the inclusion of several other safety-related systems which perform the same function provides reasonable assurance of RCS depressurization in the event of a non-LOCA or small LOCA severe accident.

The RCS pressure, core-exit temperature and RCS temperature can be used to monitor the plant response to the RCS depressurization.

19D.6.1.4.2 LOCA Sequences

LOCA sequences (other than small LOCA sequences) by definition are depressurized below the secondary system pressure by the initiating event and therefore, are not a threat to steam generator tube integrity upon the onset of rapid oxidation. Depressurization may be required for injection to establish a long-term heat sink. Medium LOCAs require additional depressurization to allow the injection of RNS or PXS. Large LOCAs are fully depressurized by the initiating event.

In LOCA sequences, only the ADS is effective in providing depressurization capability to allow injection to the RCS. Steam generator cooldown and auxiliary pressurizer sprays are not effective.

The RCS pressure, core-exit temperature and RCS temperature can be used to monitor the plant response to the RCS depressurization.

19D.6.1.4.3 Prevent Reactor Vessel Failure

Depressurization of the RCS, along with injecting into the containment is an accident management strategy to prevent vessel failure. The depressurization of the RCS reduces the stresses on the damaged vessel wall facilitating the in-vessel retention of core debris.

The ADS is used to depressurize the RCS to prevent reactor vessel failure.

The RCS pressure, core-exit temperature and RCS temperature can be used to monitor the plant response to the RCS depressurization.

19D.6.1.5 Depressurize Steam Generators

The steam generators are depressurized to facilitate low-pressure injection into the secondary system and to depressurize the RCS in non-LOCA and small LOCA sequences. Injection to the steam generator must be available to depressurize the secondary system to prevent creep rupture failure of the tubes.

The steam generator PORV and steam dump valves are used for depressurizing the steam generators.

Depressurization of the steam generators is outlined in the ERGs as a means to facilitate injection into the steam generators.

The steamline pressure and RCS pressure can be used to monitor the plant response.

19D.6.1.6 Containment Heat Removal

Containment heat removal is not explicitly listed as a high level action in the AP600 SAMG Framework, but it is implicit in the high level action "Depressurize Containment." Containment heat removal is provided by the passive containment cooling system (PCS). Water cooling of the shell is needed to establish a controlled, stable state with the containment depressurized. The actuation of PCS water is typically automatic in Time Frame 0.

PCS water is supplied to the external surface of the containment shell from the PCS water storage tank or the post-72 hour water tank. Alternative water sources can be provided via separate connections outside containment.

The containment heat removal can be monitored with the containment pressure and the PCS water flowrate or PCS water storage tank level.

19D.6.1.7 Containment Isolation

Containment isolation is not explicitly listed as a high level action in the AP600 SAMG Framework, but it is implicit as a requirement to protect the fission product barrier.

Containment isolation is provided by an intact containment shell and the containment isolation system which closes the isolation valve in lines penetrating the containment shell.

The containment isolation can be monitored by the containment pressure and the containment isolation system valve positions.

19D.6.1.8 Hydrogen Control

Maintaining the containment hydrogen concentration below a globally flammable limit is a requirement for a controlled, stable state. The containment can withstand the pressurization from a global deflagration, but potential flame acceleration can produce impulsive loads for which containment integrity is uncertain. While hydrogen is not generated in a significant quantity until Time Frame 2, provisions are provided in the ERGs within Time Frame 1 to turn on the igniters before hydrogen generation begins so that hydrogen can be burned as it is produced.

Severe accident hydrogen control in the AP1000 is provided by hydrogen igniters. The containment has passive auto-catalytic recombiners (PARs) as well, but they are not credited for severe accidents.

The igniters are manually actuated from the control room in the ERGs on high core-exit temperature. The intention is to actuate the igniters prior to the cladding oxidation (Time Frame 1). The containment hydrogen concentration is monitored prior to igniter actuation so that a globally flammable mixture is not unintentionally ignited by the hydrogen igniters.

The plant response to the igniter actuation can be monitored by containment hydrogen concentration using the hydrogen monitors or containment atmosphere sampling, which is part of

the primary sampling system. The containment pressure response can also be used to indicate hydrogen burning.

19D.6.1.9 Accident Monitoring

Accident monitoring is a post-TMI requirement as outlined in 10 CFR 50.34(f). Aside from the accident management purposes outlined above, monitoring the progression of the accident and radioactive releases provides input to emergency response and emergency action levels.

Accident monitoring is provided by the in-containment monitors for pressure, hydrogen concentration, water levels, and radiation.

19D.6.2 Time Frame 2 - In-Vessel Core Melting and Relocation

Time Frame 2 represents the period of core melting and relocation and the entry into the SAMG. The intact and coolable in-vessel core geometry is lost, and relocation of core debris into the lower head is likely. The in-vessel hydrogen generation and fission product releases from the fuel matrix occur during this time frame.

19D.6.2.1 Injection into the RCS

In Time Frame 2, the in-vessel core configuration loses its coolable geometry and it is likely that at least some of the core debris will migrate to the reactor vessel lower head. If the RCS is depressurized and the reactor vessel is submerged, the core debris will be retained in the reactor vessel. However, injection into the RCS to cover and cool the core debris is required to achieve a controlled, stable state. RCS injection is not required to protect the containment fission product boundary. Injection is successful if it is sufficient to quench the sensible heat from the core debris and maintained to remove decay heat.

RCS injection is outlined from SAMG (Reference 19D-3). Water can be injected into the RCS using the CVS or the RNS systems. The PXS is not credited in Time Frame 2 because automatic and manual activation of the system is attempted several times in Time Frame 1, and diverse pumped systems are credited to provide reasonable assurance of RCS injection survivability in this time frame. Post-core damage, the actions may be monitored with RCS pressure or temperature or containment pressure.

19D.6.2.2 Injection into Containment

The objective of injection to the containment prior to reactor vessel failure (Time Frame 3) is to cool the external surface of the reactor vessel to maintain the core debris in the vessel. Reasonable assurance of injecting to the containment for in-vessel retention is achieved by instructing the operator to drain the IRWST in the ERGs within Time Frame 1. After relocation of core debris to the lower head in Time Frame 2, the success of this action becomes uncertain. If the vessel fails, the accident progresses to Time Frame 3. Active operation for injection to containment is completed prior to Time Frame 2.

19D.6.2.3 Decay Heat Removal

In transients and small LOCAs, initiation of PRHR or injection into the steam generators is required to be recovered in Time Frame 1 to be successful. Steam generator tubes or the hot leg nozzles will fail when the cladding oxidation begins at the onset of Time Frame 2. Steam generator injection is not required for LOCAs which depressurize the RCS below the secondary system pressure.

Within Time Frame 2 SAMG, steam generator injection can be utilized in unisolated SGTR sequences to maintain the water level on the secondary side for mitigation of fission product releases. Injecting into the steam generators, along with depressurization of the RCS, is an accident management action to isolate containment or scrub fission products. Failure to inject to the faulted steam generator in Time Frame 2 can lead to continued breech of the containment fission product boundary and large offsite doses.

The main feedwater and startup feedwater pumps are used to inject into a pressurized secondary system. If the secondary system can be depressurized sufficiently, condensate, fire water or service water can also be used to inject into the secondary side.

Injection into the steam generators is covered in the WOG SAMG (Reference 19D-3). The plant response is monitored with the steam generator level and steamline pressure.

19D.6.2.4 Depressurize RCS

RCS depressurization is required within Time Frame 1 for facilitating in-vessel retention of core debris and for successfully preventing steam generator tube failure in high pressure severe accident sequences. The steam generator tubes or hot leg nozzles will fail due to creep rupture after the onset of rapid oxidation at the beginning of Time Frame 2. This action facilitates in-vessel retention of core debris in conjunction with injection into the containment to give time to recover pumped injection sources to establish a controlled, stable state. Reasonable assurance of successful RCS depressurization is provided by instructing the operator to depressurize the system in the ERGs in Time Frame 1. Active operation of RCS depressurization is completed prior to Time Frame 2.

19D.6.2.5 Depressurize Steam Generators

Active operation to depressurize the steam generators is used to cooldown the RCS prior to Time Frame 2. After the onset of core melting and relocation, depressurizing steam generators could threaten steam generator tube integrity. Depressurizing the steam generator in Time Frame 2 does not facilitate the establishment of a controlled, stable state.

19D.6.2.6 Containment Heat Removal

Reasonable assurance of successful containment heat removal is provided since automatic actuation of PCS water occurs in Time Frame 0. PCS flowrate and level are monitored to determine if additional water is needed. Alternate water sources can be provided by connections to the external PCS water tank which is outside the containment pressure boundary and not subjected to the harsh environment.

19D.6.2.7 Containment Isolation

Active operation of containment isolation valves is required in Time Frame 0 or 1 to establish the containment fission product barrier. Therefore, only the survivability of the containment pressure boundary, including penetrations, is required to maintain containment isolation after Time Frame 1.

19D.6.2.8 Hydrogen Control

The operator action to actuate the igniters occurs prior to the hydrogen generation at the onset of Time Frame 2. The igniters need to survive and receive power throughout the hydrogen release to maintain the hydrogen concentration below the lower flammability limit during the hydrogen generation in Time Frame 2.

19D.6.2.9 Mitigate Fission Product Releases

A nonsafety-related containment spray system is provided in AP1000 to wash aerosol fission products from the containment atmosphere. The spray system is manually actuated from the SAMG which is entered at the onset of Time Frame 2. Operating the spray involves opening an air-operated valve inside the containment and actuating valves and a pump outside the containment. Once open, the active operation of the valve inside the containment is completed.

19D.6.2.10 Accident Monitoring

During the initial core melting and relocation, containment hydrogen and radiation monitors are used for core damage assessment and verification of the hydrogen igniter operation. Steam generator radiation monitoring is used to determine steam generator tube integrity. In the longer term, containment atmosphere sampling can be used to monitor hydrogen and radiation. Containment pressure and temperature need to be monitored throughout Time Frame 2.

19D.6.3 Time Frame 3 - Ex-Vessel Core Relocation

Time Frame 3 represents the phase of the accident after vessel failure. The core debris is in the reactor cavity, and the IRWST water is not injected into the containment.

19D.6.3.1 Injection into the RCS

The RCS is failed. Injection to the RCS is no longer needed in Time Frame 3.

19D.6.3.2 Injection into Containment

Reasonable assurance of sufficient water coverage to the ex-vessel debris bed is passively provided by the containment design to drain water from the RCS, CMTs, and accumulators to the lower containment. Water condensing on the PCS shell is returned to the reactor cavity after filling the IRWST to the overflow. Without draining the IRWST water to the cavity, the CMT, accumulator and RCS water provides sufficient water return to the cavity to maintain water coverage over the ex-vessel debris bed.

19D.6.3.3 Decay Heat Removal

The RCS is failed. PRHR activation or injection into the steam generators is no longer needed in Time Frame 3. Injection to the steam generator for SGTR fission product scrubbing is not required to maintain the water level.

19D.6.3.4 Depressurize RCS

The RCS is depressurized by the vessel failure in Time Frame 3.

19D.6.3.5 Depressurize Steam Generators

The RCS is failed. Steam generator depressurization is not needed in Time Frame 3.

19D.6.3.6 Containment Heat Removal

Active initiation of PCS water is completed prior to Time Frame 3. PCS flowrate and level are monitored for post-72 hour activities.

19D.6.3.7 Containment Isolation and Venting

Continued operation of the containment shell as a pressure boundary is needed to maintain containment isolation in Time Frame 3.

In the event of containment pressurization above design pressure due to core concrete interaction non-condensable gas generation, the containment can be vented. Venting protects containment isolation by preventing an uncontrolled containment failure airborne release pathway. The vent can be opened and closed as required to maintain pressure in the containment below service Level C. Containment venting does not prevent or mitigate containment basemat failure due to core concrete interaction.

19D.6.3.8 Combustible Gas Control

The hydrogen igniters are used to control combustible gases. Active operation of igniters continues to control the release of combustible gases from the degradation of concrete in the reactor cavity.

19D.6.3.9 Mitigate Fission Product Releases

The nonsafety-related sprays are actuated in Time Frame 2. The operation of the nonsafety fire pump which provide containment spray continues, possibly into Time Frame 3, until the water from the source tank is depleted.

19D.6.3.10 Accident Monitoring

Containment pressure, temperature, and the containment atmosphere sampling function are sufficient to monitor the accident in the long-term.

19D.6.4 Summary of Equipment and Instrumentation

The equipment and instrumentation used in achieving a controlled, stable state following a severe accident, and the time it operates are summarized in Tables 19D-3 through 19D-5.

19D.7 Severe Accident Environments

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19D.8 Assessment of Equipment Survivability

Since severe accidents are very low probability events, the NRC recommends in SECY-93-087, that equipment desired to be available following a severe accident need not be subject to the qualification requirements of 10CFR50.49, the quality assurance requirements of 10CFR50 Appendix B, or the redundancy/diversity requirements of 10CFR50 Appendix A. It is satisfactory to provide reasonable assurance that the designated equipment will operate following a severe accident by comparing the AP1000 severe accident environments to design basis event/severe accident testing or by design practices.

19D.8.1 Approach to Equipment Survivability

The approach to survivability is by equipment type, equipment location, survival time required, and the use of design basis event qualification requirements and severe environment experimental data.

19D.8.1.1 Equipment Type

The various types of equipment needed to perform the activities discussed above are transmitters, thermocouples, resistance temperature detectors (RTDs), hydrogen and radiation monitors, valves, pumps, valve limit switches, containment penetration assemblies, igniters, and cables.

19D.8.1.2 Equipment Location

Some of the in-containment equipment, i.e., transmitters, have been deliberately located to avoid the most severe calculated environments. Other equipment is located outside containment. The performance of the equipment was judged based on the most severe postulated event for that location.

19D.8.1.3 Time Duration Required

Requirements are defined for each time frame, so the equipment evaluation only discusses performance during these periods. A limited amount of equipment has been designated for the long term (Time Frame 3) and these parameters can be monitored outside containment.

19D.8.1.4 Severe Environment Experiments

The primary source for performance expectations of similar equipment in severe accident environments is EPRI NP-4354, “Large Scale Hydrogen Burn Equipment Experiments.” This

information is supplemented by NUREG/CR-5334, "Severe Accident Testing of Electrical Penetration Assemblies." These programs tested equipment types that had previously been qualified for design basis event environmental conditions. The temperature in the chamber for the first program was in the 700 - 800°F range for ten to twenty minutes during the continuous hydrogen injection tests. Although the conditions at the equipment would be somewhat less severe, the chamber conditions envelop all of the longer duration profiles indicated for the AP1000 events. The equipment in this program was also exposed to significant hydrogen burn spikes that are also postulated for the AP1000. The same equipment was exposed to and survived several events, both pre-mixed and continuous hydrogen injection which provides confidence in its ability to survive a postulated severe accident. The second program tested containment penetrations to high temperatures for long durations. A penetration was tested under severe accident conditions simulated with steam up to 400°F and 75 psia for ten days. The results indicated that the electrical performance of the penetration would not lead to degraded equipment performance for the first four days. The mechanical performance did not degrade (no leaks) during the entire test.

19D.8.2 Equipment Located in Containment

The exposure to elevated temperatures as a direct result of the postulated severe accident or as a result of hydrogen burning is the primary parameter of interest. Pressure environments do not exceed the design basis event conditions for which the equipment has been qualified. Radiation environments also do not exceed the design basis event conditions throughout Time Frames 1 & 2.

19D.8.2.1 Differential Pressure and Pressure Transmitters

The functions defined for severe accident management that utilize in-containment transmitters are IRWST water level, reactor coolant system pressure, steam generator wide range water level and containment pressure. Most of these transmitters that provide this information are located in rooms where the environment is limited to short duration temperature transients. These transients exceed ambient design basis temperature conditions but should not impact the transmitter performance since the internal transmitter temperature do not increase significantly above that experienced during design basis testing. EPRI NP-4354 documents transmitter performance during several temperature transients with acceptable results. The IRWST water level transmitters are located in the maintenance floor and are only required during Time Frames 1 & 2. The environment during Time Frames 1 & 2 does not exceed the design basis qualification parameters of the transmitters. Reactor system pressure and steam generator wide range water level are required through the second time frame. The only long term application is the containment pressure transmitter which may eventually be impacted by the severe accident radiation dose. Containment pressure could also be measured outside containment if necessary.

19D.8.2.2 Thermocouples

The functions defined for severe accident management that utilize thermocouples are core exit temperature and containment water level. The core exit temperature is only required during Time Frame 1 and the containment water level is required through Time Frame 2. The temperatures to

which the thermocouples are exposed during the defined time frames do not exceed the thermocouple design.

19D.8.2.3 Resistance Temperature Detectors (RTDs)

Both hot and cold leg temperatures are defined as parameters for severe accident management in Time Frame 1. RTDs are utilized for these measurements and will perform until their temperature range is exceeded. The hot leg RTDs could fail as the temperature increases well above the design conditions of the RTDs but the cold leg RTDs should perform throughout Time Frame 1. RTDs are also utilized through Time Frame 3 for the containment temperature measurement and are exposed to temperature transients that exceed design basis qualification conditions. EPRI NP-4354 documents RTD performance during several temperature transients with acceptable results.

19D.8.2.4 Hydrogen Monitors

Containment hydrogen is defined as a parameter to be monitored throughout the severe accident scenarios. Early in the accident, the hydrogen is monitored by a device that operates on the basis of catalytic oxidation of hydrogen on a heated element. The hydrogen monitors are located in the main containment area. The design limits of this device may be exceeded after the first few hours of some of the postulated accidents and performance may be uncertain. If the device fails, hydrogen concentration is determined through the containment atmosphere sampling function.

19D.8.2.5 Radiation Monitors

Containment radiation is defined as a parameter to be monitored throughout the severe accident scenarios. The containment radiation monitors are located in the main containment area. Early in the accident, the design basis event qualified containment radiation monitor provides the necessary information until the environment exceeds the design limits of the monitor. If the device fails, containment radiation is determined through the containment atmosphere sampling function.

19D.8.2.6 Solenoid Valve

Qualified solenoid valves are used to vent air-operated valves (AOVs) to perform the function required. In Time Frame 1, the core makeup tank AOVs located in the accumulator room provide a path for RCS injection, the PRHR AOVs located in the maintenance floor provide a path for RCS heat removal and the containment is isolated by AOVs located in the maintenance floor and the PXS valve/accumulator room. The environment to which these solenoid valves may be exposed in Time Frame 1 is not significantly different than the design basis events to which the devices are qualified. In Time Frame 2, the RCS boundary AOV located in the maintenance floor is used for CVS injection into the RCS and the containment spray AOV located in the maintenance floor is used for control of fission product release. In addition, throughout Time Frame 3, access to the containment environment from the containment atmosphere sampling function is through solenoid valves located in the maintenance floor. During Time Frames 2 and 3, these valves may be exposed to transient conditions due to hydrogen burns that exceed design basis event qualification. Solenoid valves in an energized condition were included in the hydrogen burn experiments (EPRI NP-4354) and survived many transients. Shielding provided by the

location of the valves limits the severe accident radiation dose to the typical design basis qualification dose for these valves.

19D.8.2.7 Motor-Operated Valves

Motor-operated valves (MOVs) are utilized in several applications during the severe accident scenarios. MOVs in the accumulator and core makeup tank path are normally open and remain open. In Time Frame 1, the PXS recirculation MOVs located in the PXS valve/accumulator room are required for injection of water into the containment, MOVs for the first three stages of ADS located in a compartment above the pressurizer are required for RCS depressurization and the containment is isolated by MOVs located in the maintenance floor and the PXS valve/accumulator room. The environment to which these MOVs may be exposed in Time Frame 1 is not significantly different than the design basis events to which they are qualified. In Time Frame 2, the charging and injection MOV located in the maintenance floor provides a path from the CVS for RCS injection, an RNS MOV located in the PXS valve/accumulator room provides a path from the IRWST for RCS injection and an RNS MOV located in the WLS monitor tank room provides a path from the cask loading pit for RCS injection. In addition, throughout Time Frame 3, containment venting to the spent fuel pool is available through RNS hot leg suction line MOVs located in the RNS valve room. During Time Frames 2 and 3, these valves may be exposed to transient conditions due to hydrogen burns that exceed design basis event qualification. MOVs were included in the hydrogen burn experiments (EPRI NP-4354) and survived many transients. Shielding provided by the location of the valve limits the severe accident radiation dose to the typical design basis qualification dose for these valves.

19D.8.2.8 Squib Valves

Squib valves are only required in Time Frame 1 when the severe accident environment is not significantly different than the design basis environment for which these valves are qualified. IRWST and PXS recirculation squib valves located in the accumulator room are used for injection into the RCS and containment, respectively. For RCS depressurization, the fourth stage ADS squib valves are located in steam generator compartments 1 and 2.

19D.8.2.9 Position Sensors

Position sensors are required to monitor the position of containment isolation valves that could lead directly to an atmospheric release. These isolation valves actuate early in the transient, so verification is only required during Time Frame 1. The position sensors are located in the maintenance floor and the environment in this time frame does not exceed the design basis event qualification environment of the position sensors.

19D.8.2.10 Hydrogen Igniters

The hydrogen igniters are distributed throughout the containment and are designed to perform in environments similar to those postulated for severe accidents. The igniters' transformers are located outside containment. The successful results of glow plug testing through several hydrogen burns is documented in EPRI NP-4354 and provides confidence in the performance of these devices.

19D.8.2.11 Electrical Containment Penetration Assemblies

The electrical containment penetrations are located in the lower compartment and are required to perform both electrically and mechanically throughout the severe accident. The hydrogen burn equipment experiments documented by EPRI NP-4354 included penetrations qualified for nuclear plants. Electrical testing on the penetration cables after all the pre-mixed and continuous injection tests concluded that most of the cables passed the electrical tests while submerged in water. These tests consisted of ac (at rated voltage) and dc (at three times rated voltage) withstand tests and insulation resistance tests at 500 volts. The penetrations were also tested under simulated severe accident conditions at 400°F and 75 psia for about 10 days (NUREG/CR-5334). The results indicated that some degradation in instrumentation connected to the penetration may occur in four days under these severe conditions. The maintenance floor may experience short temperature transients above 400°F but stable temperatures are significantly less, so it is expected that the electrical performance would be maintained throughout the event. The only long term measurement utilizing these penetrations is containment pressure and this can be measured outside containment if necessary. There was no degradation of mechanical performance of the electrical penetrations (maintaining the seal) in either test program.

19D.8.2.12 Cables

The hydrogen burn equipment experiments documented by EPRI NP-4354 included twenty-four different cable types qualified for nuclear plants. Electrical testing on these cables after all the pre-mixed and continuous injection tests concluded that all (fifty two samples) of the cables passed the electrical tests while submerged. These tests consisted of ac (at rated voltage) and dc (at three times rated voltage) withstand tests and insulation resistance tests at 500 volts. Due to the exposure to many events, some cable samples had extensive damage in the form of charring, cracking and bulging of the outer jackets and still performed satisfactorily. The cables tested are representative of cables specified for the AP1000 and are only exposed to short single temperature transients in their respective locations. Proper performance can be expected. The only long term measurement utilizing cables is containment pressure, which can be measured outside containment if necessary.

19D.8.2.13 Assessment of Equipment for Sustained Burning

The equipment necessary for equipment survivability in sustained burning environments is defined in Tables 19D-3 through 19D-5. The equipment in Table 19D-3 includes equipment and instrumentation operation during Time Frame 1 - core uncovery and heatup, and is prior to the release of significant quantities of hydrogen. Therefore, it does not have to be qualified for sustained hydrogen burning. Table 19D-7 specifies the equipment and instrumentation used in Time Frames 2 and 3 to provide reasonable assurance of achieving a controlled stable state.

19D.8.3 Equipment Located Outside Containment

Other functions defined for severe accident management are performed outside containment and the equipment is not subjected to the harsh environment of the event. This equipment includes:

- The steamline radiation monitor,
- Transmitters for monitoring steamline pressure,

- The passive containment cooling system flow and tank level,
- The containment atmosphere sampling function,
- The CVS pumps and flow measurement,
- The RNS pumps and flow measurement,
- SFS MOV for injection to the IRWST,
- RNS MOV for injection from cask loading pit to RCS
- MFW pumps and valves,
- SFW pumps and valves and condensate,
- Fire water and service water to feed steam generators
- Steam generator PORVs and steam dump valves for depressurization,
- PCS valves and fire water pumps and valves for containment heat removal,
- Containment isolation valves (outside containment),
- Auxiliary building radiation monitor,
- MOV and manual valve from RNS hot leg suction lines to the spent fuel pool and
- Fire water, fire pumps, valves and flow measurement used to provide containment spray and containment cooling.

19D.9 Conclusions of Equipment Survivability Assessment

The equipment defined for severe accident management was reviewed for performance during the environments postulated for these events. Survivability of the equipment was evaluated based on design basis event qualification testing, severe accident testing, and the survival time required following the initiation of the severe accident. The equipment that is qualified for design basis events, has a high probability of surviving postulated severe accident events and performing satisfactorily for the time required.

AP1000 provides reasonable assurance that equipment, both electrical and mechanical, used to mitigate the consequences of severe accidents and achieve a controlled, stable state can perform over the time span for which they are needed.

19D.10 References

19D-1 "Framework for AP600 Severe Accident Management Guidance," WCAP-13914, Revision 3, January 1998.

19D-2 AP600 Emergency Response Guidelines.

19D-3 Westinghouse Owner's Group Severe Accident Management Guidance, June 1994.

Table 19D-1

DEFINITION OF EQUIPMENT SURVIVABILITY TIME FRAMES

Time Frame	Beginning Time	Ending Time	Comments
0	Accident initiation	safe, stable state or core uncovery	• Bounded by design basis equipment qualification environment
1	Core uncovery	controlled, stable state or rapid cladding oxidation	• Core uncovery and heatup • Bounded by design basis equipment qualification environment
2	Rapid cladding oxidation	controlled, stable state or vessel failure	• In-vessel core melting and relocation • Entry into SAMG
3	Vessel failure	controlled, stable state or containment failure	• Ex-vessel core relocation

Table 19D-2

AP1000 HIGH LEVEL ACTIONS RELATIVE TO ACCIDENT MANAGEMENT GOALS

(taken from Table 5-1, reference 19D-1)

Goal	Element	High Level Action*
Controlled, stable core	water inventory in RCS	• inject into RCS • depressurize RCS
	water inventory in containment	• inject into containment
	heat transfer to IRWST	• initiate PRHR
	heat transfer to SGs	• inject into RCS • inject into SGs • depressurize SGs
	heat transfer to containment	• inject into RCS • inject into containment • depressurize RCS • initiate PRHR
Controlled, stable containment	heat transfer from containment	• depressurize containment • vent containment • water on outside containment
	isolation of containment	• inject into SGs • depressurize RCS
	hydrogen prevention/control	• burn hydrogen • pressurize containment • depressurize RCS • inject into containment • vent containment • water on outside containment
	core concrete interaction prevention	• inject into containment
	high pressure melt ejection prevention	• inject into containment • depressurize RCS
	creep rupture prevention	• depressurize RCS • inject into SGs
	containment vacuum prevention	• pressurize containment
Terminate fission product release	isolation of containment	• inject into SGs • depressurize RCS
	reduce fission product inventory	• inject into containment • depressurize RCS
	reduce fission product driving force	• depressurize containment • water on outside containment

Note:

* See Tables 19D-3, 19D-4 and 19D-5

Table 19D-3 (Sheet 1 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION PRIOR TO END OF TIME FRAME 1 - CORE UNCOVERY AND HEATUP

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS	• PXS • CVS • RNS • IRWST	• core exit t/c's • RCS pressure • RCS RTDs • CVS flow • RNS flow • IRWST water level	• restore core cooling	• injection must often be recovered to be successful in severe accident
Inject Into Containment	• PXS recirc • SFS injection to refueling cavity • IRWST drains	• core-exit t/c's • containment water level • IRWST water level	• prevent vessel failure	• manual cavity flooding action in ERG
Decay heat removal	Initiate PRHR • High Pressure - MFW - SFW • Low Pressure - condensate - fire water - service water	• IRWST water level • SG WR water level • steamline pressure	• establish heat sink • make SGs available to depressurize RCS • prevent creep rupture	• injection source must often be recovered to be successful in severe accident
Depressurize RCS	• Pressurizer spray • ADS • PRHR HX • via SGs	• RCS pressure • core-exit t/c's • RCS RTDs • IRWST water level	• facilitate injection to RCS • long-term heat transfer path	• ADS often automatic
			• prevent creep rupture • containment integrity	• RCS depressurization required prior to cladding oxidation to prevent creep rupture
			• isolate break in SGTR	• uses intact SG or PRHR
			• prevent vessel failure	• requires injection to containment to be successful

Table 19D-3 (Sheet 2 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION PRIOR TO END OF TIME FRAME 1 - CORE UNCOVERY AND HEATUP

Action	Equipment	Instrumentation	Purpose	Comment
Depressurize SGs	• SG PORV • Steam dump	• steamline pressure • RCS pressure	• facilitate injection to SGs • depressurize RCS	• requires injection into SGs to prevent creep rupture
Containment Heat Removal	• PCS water • external water	• containment pressure • PCS flowrate • PCS tank level	• containment integrity • alleviate environmental challenge to equipment • long-term heat transfer path	• PCS water often automatic
Containment Isolation	• containment isolation system • containment shell • penetrations	• containment isolation system valve position • containment pressure	• containment integrity	• containment isolation system often automatic • manual action in ERG
Control Hydrogen	• igniters	• containment hydrogen concentration • containment pressure	• containment integrity	• manual igniter action in ERG
Accident Monitoring		• SG radiation • containment pressure • containment temperature • containment hydrogen concentration • containment water level • containment radiation	• accident management • emergency response • emergency action levels	• required by 10 CFR 50.34(f)

Table 19D-4 (Sheet 1 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION DURING TIME FRAME 2 - IN-VESSEL CORE MELTING AND RELOCATION

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS	• CVS • RNS	• RCS pressure • containment pressure • CVS flow • RNS flow	• cool core debris	• RCS injection needed to cool in-vessel debris for reasonable assurance of controlled, stable state
Inject Into Containment				• active operation completed in Time Frame 1
Decay heat removal	• PRHR HX • High Pressure - MFW - SFW • Low Pressure - Condensate - Fire Water - Service Water	• IRWST water level • SG WR water level • steamline pressure	• cool core debris • isolate containment in SGTR • scrub fission products	• also requires RCS depressurization for success of SG injection
Depressurize RCS				• active operation completed in Time Frame 1
Depressurize SGs				• active operation completed in Time Frame 1
Containment Heat Removal		• PCS flowrate • PCS tank level		• active operation completed in Time Frame 1
Containment Isolation	• containment shell • penetrations	• containment pressure	• containment integrity	• containment isolation system active operation completed in Time Frame 1
Control Hydrogen	• igniters	• containment hydrogen monitors • containment atmosphere sampling function	• containment integrity	• active operation continues in Time Frame 2 • monitors only required initially to verify hydrogen igniter operation

Table 19D-4 (Sheet 2 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION DURING TIME FRAME 2 - IN-VESSEL CORE MELTING AND RELOCATION

Action	Equipment	Instrumentation	Purpose	Comment
Control Fission Product Releases	• fire (spray) pump • spray valve	• spray flowrate • containment pressure	• scrub aerosols	• manual action within SAMG
Accident Monitoring		• containment pressure • containment temperature • containment atmosphere sampling function • aux bldg. radiation monitors • SG radiation monitors	• accident management • emergency response • emergency action levels	• active operation continues in Time Frame 2

Table 19D-5 (Sheet 1 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION DURING TIME FRAME 3 - EX-VESSEL CORE RELOCATION

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS				• not needed in Time Frame 3
Decay heat removal				• injection of CMTs and accumulators in Time Frame 1 provides reasonable assurance of water coverage to ex-vessel core debris
Inject into SGs				• not needed in Time Frame 3
Depressurize RCS				• not needed in Time Frame 3
Depressurize SGs				• not needed in Time Frame 3
Containment Heat Removal		• PCS flowrate • PCS tank level		• active operation completed in Time Frame 1
Containment Isolation	• containment shell • penetrations	• containment pressure	• containment integrity	• active operation of containment isolation system completed in Time Frame 1
	• RNS hot leg suction MOVs		• containment vent	• manual action within SAMG
Control Hydrogen	• igniters	• containment atmosphere sampling function	• containment integrity	• active operation continues in Time Frame 3

Table 19D-5 (Sheet 2 of 2)

EQUIPMENT AND INSTRUMENTATION OPERATION DURING TIME FRAME 3 - EX-VESSEL CORE RELOCATION

Action	Equipment	Instrumentation	Purpose	Comment
Control Fission Product Release	• spray pump	spray flowrate	• scrub fission products	• active operation continues
Accident Monitoring		• containment pressure • containment temperature • containment atmosphere sampling function • aux bldg. radiation monitors • SG radiation monitors	• accident management • emergency response • emergency action levels	• active operation continues in Time Frame 3

TABLE 19D-6 NOT INCLUDED IN THE DCD.

Table 19D-7 (Sheet 1 of 3)

SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Equipment	
PXS equipment (injection)	The PXS equipment utilized for introduction of cooling water includes component redundancy and is separated into two delivery flow paths. The two flow paths are physically separated into two trains such that if one train is disabled due to a sustained burn from DVI or other line break within that subsystem, the other subsystem will function.
CVS equipment (injection)	The equipment providing for CVS injection is located within the CVS compartment with the exception of the CVS makeup isolation valve. In accordance with the above, a sustained burn will not occur within the CVS compartment and, therefore, the equipment within this compartment utilized for CVS makeup will be operable. The CVS makeup isolation valve is normally in the correct position for severe accident scenario and is considered operable.
RNS equipment (injection)	Injection via the RNS is dependent only upon check valves within containment and, therefore, is not susceptible to sustained burning effects.
Main Feedwater (high pressure injection into the SG)	The operability of main feedwater system to inject high pressure feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Startup Feedwater (high pressure injection into the SG)	The operability of startup feedwater system to inject high pressure feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Condensate (low pressure injection into the SG)	The operability of the condensate system to provide makeup for low pressure feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Fire Water (low pressure injection into the SG), containment spray, and external containment vessel cooling	The operability of the fire water system to provide makeup for low pressure feedwater to steam generators, for containment spray and for external containment vessel cooling is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Service Water (low pressure injection into the SG)	The operability of the service water system to provide makeup for low pressure feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.

Table 19D-7 (Sheet 2 of 3)

SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Equipment	
Containment Shell	The operability of the containment shell during sustained burning is addressed by Reference 19D-5.
Igniters	Igniters are specified and designed to withstand the effects of sustained burning and, therefore, are considered operable for these events.
Instrumentation	
RCS Pressure	There are four RCS pressurizer pressure transmitters. Two transmitters are located at a distance greater than 75 feet from the vent from the PXS valve/accumulator room and are, therefore, beyond the distance that potentially causes operability concerns from a sustained flame. The other two transmitters are located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns.
Containment Pressure	There are three extended range containment pressure transmitters. The three transmitters are located such that they cannot all be exposed to a sustained flame from either of the vents from the PXS valve/accumulator room into the maintenance floor at the base of the CMTs. Therefore, continued operability of the containment pressure function is provided.
SG 1 Wide Range Level	There are four steam generator wide range levels for SG 1. Two of the transmitters are located at a distance of greater than 20 feet from a CMT and are, therefore, beyond the distance that could potentially cause operability concerns from a sustained flame from the vent from the PXS valve/accumulator room into the maintenance floor at the base of the CMT. The other two transmitters are located over 20 feet below the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns.
SG 2 Wide Range Level	Based on the layout of the four steam generator wide range levels for SG 2, at least two of the transmitters will not be exposed to a sustained flame from either of the vents from the PXS valve/accumulator room into the maintenance floor at the base of the CMTs. Therefore, continued operability of the SG 2 wide range level indication function is provided.

Table 19D-7 (Sheet 3 of 3)

SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Instrumentation	
Containment Hydrogen Monitors	There are 3 distributed containment hydrogen monitors. There are no sustained burns that could potentially affect the two sensors that are located at an elevation of 164 feet or the sensor located within the dome.
Containment Atmosphere Sampling Function	The capabilities to perform containment atmosphere sampling are discussed in Section 9.3.3.1.2.2 – Post-Accident Sampling. Successful containment atmosphere sampling is dependent on the availability of either of the hot leg sample source isolation valves and the containment isolation valves in series with the isolation valve. The sample isolation valve from reactor coolant hot leg number 1 is located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns. The sample isolation valve from reactor coolant hot leg number 2 is located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns. The containment isolation valves are located less than 20 feet from a CMT. However, a steel shroud around base of the CMT prevents a sustained flame existing on the containment side of that CMT and, therefore, affecting the operability of either of the containment isolation valves.

APPENDIX 19E SHUTDOWN EVALUATION

19E.1 Introduction

Westinghouse has considered shutdown operations in the design of the A1000 nuclear power plant. The AP1000 defense-in-depth design philosophy to provide normally operating active systems and passive safety-related systems gives the AP1000 a greater degree of safety during shutdown operations as well as normal power operation when compared to currently operating plants. This appendix presents and evaluates the AP1000 design features in the context of the specific shutdown issues identified by the Nuclear Regulatory Commission.

19E.1.1 Purpose

This appendix presents AP1000 design features that address the issues of shutdown risk and shutdown safety. This appendix further evaluates these design features with respect to their ability to reduce and or mitigate the consequences of events that can occur during shutdown.

19E.1.2 Scope

The scope of this appendix includes discussions of the following:

- Systems designed to operate during shutdown
- Shutdown operations – including maintenance insights, risk management, and Emergency Response Guidelines (ERGs) (Reference 1)
- Safety analyses and evaluations for shutdown operations
- Chapter 16, "Technical Specifications"
- Shutdown risk evaluations – including shutdown PRA results and insights and fire/flood risk
- Compliance with the guidance in NUREG-1449 (Reference 2)

19E.1.3 Background

The Diablo Canyon event of April 10, 1987, and the loss of ac power at the Vogtle plant on March 20, 1990, led the NRC staff to issue NUREG-1449, which provides an evaluation of the shutdown risk issue. During the AP600 Design Certification review, the NRC requested that Westinghouse perform a systematic assessment of the shutdown risk issue to address areas identified in NUREG-1449 as applicable to the AP600 design. The AP1000 design is based extensively on the AP600, and the systems, structures and components that are important in maintaining a low shutdown risk for AP600 are generally the same design and/or have the same design basis with respect to their role in reducing shutdown risk. Therefore, the conclusions from the assessment of the shutdown risk for the AP600 are applicable to the AP1000. This appendix summarizes the assessment of the shutdown risk issue for AP1000.

19E.2 Major Systems Designed to Operate During Shutdown

Westinghouse has considered shutdown modes, shutdown alignments, and industry issues related to shutdown in the design of the AP1000 safety-related and nonsafety-related systems designed to operate or be available during shutdown. This section provides descriptions of the important systems designed to operate during shutdown and includes specific design features that have been incorporated for shutdown operations with a discussion of their operating modes or alignment during shutdown.

In this appendix, references are made to the various AP1000 operating modes. The AP1000 operating modes have been defined in the Technical Specifications (Section 16.1, Table 1.1-1). The mode definitions for the AP1000 are similar to that of current Westinghouse pressurized water reactors (PWRs), with the difference being the definition of Mode 4, safe shutdown.

In the AP1000, Mode 4 has been redefined as safe shutdown and corresponds to the range of RCS temperature between 420°F and 200°F. The upper temperature limit corresponds to the RCS temperature that can be achieved by the passive safety-related systems 36 hours after shutdown. The ability of the passive safety-related systems to achieve Mode 4 within 36 hours is shown in subsection 4.10.2 of this appendix.

19E.2.1 Reactor Coolant System

19E.2.1.1 System Description

The reactor coolant system (RCS) is described in Chapter 5.

19E.2.1.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated design features that address issues related to shutdown operations. This subsection provides a discussion of the RCS design features that are incorporated to address shutdown operations or that are important to minimizing the risk to plant safety during shutdown.

19E.2.1.2.1 Loop Piping Offset

The RCS hot legs and cold legs are vertically offset. This permits draining of the steam generators for nozzle dam insertion with the hot leg level much higher than traditional designs. The RCS must be drained to a level sufficient to provide a vent path from the pressurizer to the steam generators. This loop piping offset also allows an RCP to be replaced without removing the full core.

19E.2.1.2.2 RCS Instrumentation

Instrumentation is provided to monitor the RCS process parameters as required by the PLS and PMS as discussed in Chapter 7. This subsection describes RCS instrumentation designed to accommodate shutdown operations.

RCS Hot Leg Level

There are two safety-related RCS hot leg level channels, one located in each hot leg. These level indicators are provided primarily to monitor the RCS water level during mid-loop operation following shutdown operations. These are totally independent of each other. One level tap is at the bottom of the hot leg, and the other tap is on the top of the hot leg close to the steam generator. The steam generator tap is located at the high point of the tubing run. The level tap for the instrument in the hot leg with the normal residual heat removal system (RNS) step-nozzle suction line connection is between the reactor vessel and the step-nozzle. Figure 19E.2-1 shows a simplified sketch of the RCS level instruments.

These channels provide signals for the following protection functions:

- Isolation of letdown on low level on a one-out-of-two basis
- Actuation of IRWST injection on low (empty) hot leg level on a two-out-of-two basis
- Actuation of fourth-stage ADS valves on low (empty) hot leg level on a two-out-of-two basis

These functions protect the plant during shutdown operations. Letdown isolation assists the operators when draining the RCS to a mid-loop level. If the operators fail to isolate letdown, these channels send a signal to close the letdown valves and stop the draining process.

In the event of a loss of the RNS during shutdown, coolant inventory could be boiled away. When the hot leg water level indicates that the loops are empty, IRWST injection and fourth-stage ADS are actuated 30 minutes after receipt of the empty hot leg level signal.

These channels also provide signals to the letdown flow control valve to control the drain rate of the RCS via the letdown line during the transition to mid-loop operation. When the hot legs are full, the drain rate can proceed at a high level. As the water level is reduced to the hot legs, the drain rate is automatically decreased to a rate of approximately 20 gpm.

These channels are also used to generate the alarms on low hot leg water level. The alarm setpoints are selected to give the operator sufficient time to take the manual actions necessary to prevent the automatic actuation described previously. Indication of these channels is retrievable in the main control room. This variable is used by the operator to monitor the status of RCS inventory following an accident and is, therefore, classified as a post-accident monitoring system (PAMS) variable as discussed in Section 7.5.

The accuracy and response time of the hot leg level instruments are consistent with the standard engineered safety features (ESF) actuation discussed in Section 7.3. Concerns related to potential problems of noncondensible gases in the hot leg level instrument lines that have been raised in NRC Information Notice 92-54, Level Instrumentation Inaccuracies Caused by Rapid Depressurization (Reference 3), have been addressed in the layout of the instrument lines. In addition, as the hot leg level instruments are provided primarily for shutdown operations, off-gassing due to sudden depressurization of the RCS in shutdown modes is not a concern.

In the AP1000, draining of the RCS to mid-loop conditions is achieved in a controlled manner as discussed in subsection 19E.2.1.2.4. Due to the low RCS drain rate, and the RCS step-nozzle

as discussed in subsection 19E.2.1.2.3, the amount of air-entrainment, and therefore RCS level perturbation during mid-loop, is negligible. Draining of the RCS is conducted in a quasi-steady-state, and the reliability of an accurate level reading is high.

Pressurizer Level

A fifth nonsafety-related independent pressurizer level transmitter, calibrated for low temperature conditions, provides water level indication during startup, shutdown, and refueling operations in the main control room and in the remote shutdown workstation. The upper level tap is connected to an ADS valve inlet header above the top of the pressurizer. The lower level tap is connected to the bottom of the hot leg. This provides level indication for the entire pressurizer and a continuous reading as the level in the pressurizer decreases to mid-loop levels during shutdown operations.

RCS Hot Leg Wide-Range Temperatures

The RCS contains two safety-related thermowell-mounted hot leg wide-range temperature detectors, one in each hot leg. The orientation of the resistance temperature detectors enables measurement of the reactor coolant fluid in the hot leg when in reduced inventory conditions. Their range is selected to accommodate the low RCS temperatures that can be attained during shutdown. In addition, at least two incore thermocouple channels are available to measure the core exit temperature during mid-loop RNS operation. These two thermocouple channels are associated with separate electrical divisions.

Pressurizer Surge Line Temperatures

There are three nonsafety-related temperature detectors located on the RCS pressurizer surge line. These instruments monitor the pressurizer surge line fluid temperature during plant normal operations to detect thermal stratification in the surge line. Two of the temperature detectors are on a moderately sloped run approximately midway between the RCS hot leg and the pressurizer. One detector is on the bottom of the pipe and the other detector on the top. The third detector is located on the pressurizer surge line close to the pressurizer nozzle. This detector is used to monitor cold water insurges to the pressurizer during transient operations.

The temperature is monitored at the three locations using strap-on resistance temperature detectors. Temperature indication is provided in the main control room. One low-temperature alarm is provided to alert the operator of thermal stratification in the surge line. This alarm is associated with the detector on the bottom of the pipe.

During shutdown operations, this temperature instrumentation will be monitored to detect possible surge line stratification. If stratification is detected, the operators can increase spray flow to increase the outsurge from the pressurizer and reduce stratification in the surge line.

19E.2.1.2.3 Step-nozzle Connection

The AP1000 RNS uses a step-nozzle connection to the RCS hot leg. The step-nozzle connection has two effects on mid-loop operation. One effect is to lower the RCS hot leg level at which a vortex occurs in the residual heat removal pump suction line due to the lower fluid velocity in the

hot leg nozzle. This increases the margin from the nominal mid-loop level to the level where air entrainment into the pump suction begins.

Another effect of the step-nozzle is that, if a vortex should occur, the maximum air entrainment into the pump suction as shown experimentally will be no greater than 5 percent (Reference 4). The RNS pumps can operate with 5% air-entrainment. As discussed in NUREG-0897 (Reference 5), low levels of air ingestion can be tolerated, and a pump inlet void fraction of 5% has been shown experimentally to reduce the pump head less than 15%. At this level of degradation, the RNS pumps would maintain decay heat removal. The step-nozzle thereby precludes air binding of the pump and will allow for RNS pump operation with low water levels in the hot leg.

19E.2.1.2.4 Improved RCS Draindown Method

During the cooldown operations, the RCS water level is drained to a mid-loop level to permit steam generator draining and maintenance activities. The AP1000 has improved the reliability of draindown operations by incorporating a dedicated drain path to be used to reduce the water level in the RCS controlled in the main control room. In current plants, various drain paths can be used either locally or remotely from the control room. These drain paths include the safety-related residual heat removal system, loop drain valves, and letdown. The result is that draining of the RCS can be difficult to control, and perturbations in water level can occur due to inadvertent system manipulations of which the operators are not always aware.

The AP1000 RCS drain path is via the CVS letdown line from the RNS cross-connect provided to maintain full RCS purification flow during shutdown. The letdown line flow control valve controls the letdown rate, which controls the RCS draindown rate. At the appropriate time during the cooldown, the operator initiates the draindown by placing the CVS letdown control valve into a refueling draindown mode. At this time, the makeup pumps are turned off and the letdown flow control valve controls the drain rate to the liquid radwaste system at the initial maximum rate of approximately 100 gpm. The rate is reduced once the level in the RCS is to the top of the hot leg. The letdown rate is manually controlled based upon the difference in flow instruments readings in the CVS letdown line and injection line. The letdown flow control valve as well as the letdown line containment isolation valve receives a signal to automatically close once the appropriate level is attained. Alarms actuate in the control room if the RCS level falls below the automatic letdown valve closure setpoint so that the operator is alerted to manually isolate the letdown line. Furthermore, an automatic isolation of the letdown line is actuated on low hot leg level. This draindown method provides a reliable means of attaining mid-loop conditions.

19E.2.1.2.5 ADS Valves

The ADS first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks (CMTs) are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent path to preclude pressurization of the RCS during shutdown conditions if decay heat removal is lost. This also allows the IRWST to automatically provide injection flow if it is actuated on a loss of decay heat removal. In addition, two of the four ADS fourth-stage valves are required to be available during reduced inventory operations to preclude surge line flooding following a loss of the RNS.

19E.2.1.2.6 Steam Generator Channel Head

The AP1000 steam generator is a vertical-shell U-tube evaporator with integral moisture separating equipment. The generator is discussed in subsection 5.4.2.

On the primary side, the reactor coolant flow enters the primary chamber via the hot leg nozzle. The lower portion of the primary chamber is hemispherical and merges into a cylindrical portion, which mates to the tubesheet. This arrangement provides enhanced access to all tubes, including those at the periphery of the bundle, with robotics equipment. This feature enhances the ability to inspect, replace, and repair portions of the AP1000 unit compared to the more hemispherical primary chamber of earlier designs. The channel head is divided into inlet and outlet chambers by a vertical divider plate extending from the apex of the head to the tubesheet.

The reactor coolant enters the inverted U-tubes, transferring heat to the secondary side during its traverse, and returns to the cold leg side of the primary chamber. The flow exits the steam generator via two cold leg nozzles to which the canned-motor RCPs are directly attached.

The AP1000 steam generator channel head has provisions to drain the head. For minimizing deposits of radioactive corrosion products on the channel head surfaces and for enhancing the decontamination of these surfaces, the channel head cladding is machined or electropolished for a smooth surface.

The steam generator is equipped with permanently mounted nozzle dam brackets, which are designed to support nozzle dams during refueling operations. The design pressure of the nozzle dam bracket and nozzle dam is selected to withstand the RCS pressures that can occur during a loss of shutdown cooling. The nozzle dam design pressure is at least 50 psia.

The AP1000 nozzle dams can be installed with the hot leg water level at the nominal water level for mid-loop operations. The nozzle dams can be inserted via the steam generator manway. The ADS valves connected to the pressurizer are open during all reduced inventory operations including nozzle dam installation, and provide a vent path to preclude pressurization of the reactor coolant system following a loss of decay heat removal when the nozzle dams are installed.

19E.2.2 Steam Generator and Feedwater Systems

19E.2.2.1 System Description

This section discusses the AP1000 steam generator system (SGS) and the main and startup feedwater system (FWS) designs as they relate to shutdown operations. These systems are discussed in Chapter 10.

19E.2.2.2 Design Features to Address Shutdown Safety

19E.2.2.2.1 Feedwater Control

The AP1000 provides improvements in feedwater control that minimizes the probability of loss of feedwater transients during low power and shutdown modes. The main feedwater pumps are capable of providing feedwater during all modes of operation, including plant startup and standby

conditions. In addition, the startup feedwater pumps are automatically started in the event that the main feedwater pumps are unable to continue to operate. The startup feedwater pumps are also automatically loaded on the diesels for operation following a loss of offsite power, during operating modes when the steam generators can be used for decay heat removal.

19E.2.2.2.2 Safety-Related Actuation in Shutdown Modes

The AP1000 has safety-related actuations associated with the SGS that are operable during shutdown modes. These include the PRHR HX actuation on low steam generator level during shutdown modes, and this is discussed in subsection 19E.2.3 of this appendix. Also included is the isolation of the main steam line on a high (large) negative rate of change in steam pressure. This safety-related signal is provided to address a steam line break that could occur in Mode 3. If actuated, this signal causes the MSIVs to close to terminate the blowdown of the SGS following a steam line break. This signal is placed into service below the setpoint that disables the low steam line pressure signal (P11) that actuates steam line isolation as discussed in Section 7.3. When the operator manually blocks the low steam line pressure signal, the steam line high pressure-negative rate signal is automatically enabled.

This signal is operable during Mode 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In Modes 4, 5, and 6, this function is not needed for accident detection and mitigation. Subsection 19E.4.2.3 discusses steam line break events that could occur in shutdown modes. Operability of this actuation logic is discussed in the AP1000 Technical Specifications (Section 16.1).

19E.2.2.2.3 Steam Generator Cooling in Shutdown Modes

The secondary side of the steam generators can be cooled during shutdown by recirculating their contents through the blowdown system heat exchanger. This feature reduces the challenges to low-temperature overpressure events. During RCS water-solid operation, heat input from the steam generators is capable of challenging the low-temperature relief valve. The Technical Specifications prevent the operators from starting an RCP with the steam generator secondary side temperature more than 50°F higher than the primary side, with the pressurizer water-solid. With the RCS water-solid, the heat input that could occur would cause the system to be pressurized to the setpoint of the low-temperature overpressure relief valve in the RNS.

When the RCPs are operating, the secondary side of the steam generator is cooled by steaming to the MSS. Once the RNS is aligned, and steaming to the MSS is decreased, the secondary side of the steam generators is cooled by operation of the RNS. However, once the RCPs are tripped, water does not circulate through the primary side of the tubes and the secondary side of the steam generators remains at elevated temperature. With the ability to cool the secondary side via the blowdown system, the AP1000 reduces the probability that an RCP would be started with the secondary side of the generator at elevated temperature. This cooling also makes the equipment available for maintenance at the earliest time in an outage.

The AP1000 has also incorporated steam generator fluid thermocouples to monitor the temperature of the fluid in the secondary side of the steam generator. This improves the ability of

the operators to monitor this temperature to prevent them from inadvertently starting an RCP with the secondary side at elevated temperatures.

19E.2.3 Passive Core Cooling System

19E.2.3.1 System Description

The passive core cooling system (PXS) is described in Section 6.3.

19E.2.3.2 Design Features to Address Shutdown Safety

A significant improvement in shutdown safety for the AP1000 is the availability of a dedicated safety-related system that can be automatically or manually actuated in response to an accident that can occur during shutdown. In current plants, the safety-related systems that mitigate the consequences of an accident are also the operating systems that are used for decay heat removal. In the AP1000, nonsafety-related active systems provide the first level of defense, while the passive safety-related systems are available during shutdown modes to mitigate the consequences of an accident. This design approach results in a significant improvement in the AP1000 shutdown risk.

19E.2.3.2.1 Core Makeup Tanks

The CMTs provide RCS makeup. During shutdown, the CMTs are available in Modes 3, 4, and 5, until the RCS pressure boundary is open and the pressurizer water level is reduced. During power operation, the CMTs are automatically actuated on various signals including a safeguards actuation signal (low RCS pressure, low RCS temperature, low steam line pressure, and high containment pressure) and on low pressurizer water level. See Chapter 7 for a description of the AP1000 PMS actuation logic. In shutdown modes, portions of the safeguards actuation signal are disabled to allow the RCS to be cooled and depressurized for shutdown. For instance, the low RCS pressure and temperature, and low steam line pressure signals are blocked in Mode 3 prior to cooling and depressurizing the RCS. Therefore, during shutdown Modes 3, 4, and 5, the primary signal that actuates the CMTs due to a loss of inventory is the pressurizer level signal. In Mode 5, with the RCS open (in preparation for reduced inventory operations), the low pressurizer level signal is blocked prior to draining the pressurizer. Therefore, in Mode 5 with the RCS open, the CMTs are not required to be available and the RCS makeup function is provided by the IRWST.

The CMTs also provide an emergency boration function for accidents such as steam line breaks. However, the signals that provide the primary protection for this function (low steam line pressure, low RCS pressure, and low RCS temperature) are blocked in Mode 3 as discussed above. Prior to blocking these signals in Mode 3, the Technical Specifications require that the RCS be sufficiently borated. For these events, the pressurizer level signal provides automatic actuation of the CMTs for a steam line break that might occur due to the RCS shrinkage that would occur.

19E.2.3.2.2 Accumulators

The PXS accumulators provide safety injection following a LOCA. In Mode 3, the accumulators must be isolated to prevent their operation when the RCS pressure is reduced to below their set

pressure. The accumulator isolation valves are closed when the RCS pressure is reduced to 1000 psig to block their injection when the RCS pressure is reduced to below the normal accumulator pressure.

19E.2.3.2.3 In-containment Refueling Water Storage Tank

The IRWST provides long-term RCS makeup. During shutdown, the IRWST is available until Mode 6, when the reactor vessel upper internals are removed and the refueling cavity flooded. At that time, the IRWST is not required, due to the large heat capacity of the water in the refueling cavity.

The IRWST injection paths are actuated on a low-2 CMT water level. This signal is available in shutdown Modes 3, 4, and 5, with the RCS intact. When the RCS is open to transition to reduced inventory operations, the CMT actuation logic on low pressurizer level is removed, and the CMTs can be taken out of service. For these modes, automatic actuation of the IRWST can be initiated (on a two-out-of-two basis) on low hot leg level.

19E.2.3.2.4 Passive Residual Heat Removal Heat Exchanger

The PRHR HX provides decay heat removal during power operation and is required to be available in shutdown Modes 3, 4, and 5, until the RCS is open. In these modes, the PRHR HX provides a passive decay heat removal path. It is automatically actuated on a CMT actuation signal, which would eventually be generated on a loss of shutdown decay heat removal, as shown in the analysis provided in Section 19E.4 of this appendix. In modes with the RCS open (portions of Mode 5 and Mode 6), decay heat removal is provided by “feeding” water from the IRWST and “bleeding” steam from the ADS.

19E.2.3.2.5 Reduced Challenges to Low-Temperature Overpressure Events

Another design feature of the PXS that reduces challenges to shutdown safety is the elimination of high-head safety injection pumps in causing low temperature overpressure events. In current plants, during water solid operations that may be necessary to perform shutdown maintenance, the high-head safety injection pumps are a major source of cold overpressure events. To address this, plants are required to lock out safety injection pumps to prevent them from inadvertently causing a cold overpressure event. This eliminates a potential source of safety injection for a loss of inventory event that could occur at shutdown. With the AP1000 PXS, the CMTs are not pressurized above RCS pressure and are, therefore, not capable of causing a cold overpressure event. Therefore, they are not isolated until the pressurizer is drained for mid-loop. Low-temperature overpressure events are discussed in subsection 19E.4.10.1.

19E.2.3.2.6 Discussion of Safe Shutdown for AP1000

The functional requirements for the PXS specify that the plant be brought to a stable condition using the PRHR HX for events not involving a loss of coolant. For these events, the PXS, in conjunction with the passive containment cooling system (PCS), has the capability to establish long-term safe shutdown conditions, cooling the RCS to less than 420°F within 36 hours, with or without the RCPs operating.

The CMTs automatically provide injection to the RCS as the temperature decreases and the pressurizer level decreases, actuating the CMTs. The PXS can maintain stable plant conditions for a long time in this mode of operation, depending on the reactor coolant leakage and the availability of ac power sources. For example, with a technical specification leak rate of 10 gpm, stable plant conditions can be maintained for at least 10 hours. With a smaller leak, a longer time is available. However, in scenarios when ac power sources are unavailable for as long as 24 hours, the ADS will automatically actuate.

For LOCAs and other postulated events where ac power sources are lost, or when the CMT levels reach the ADS actuation setpoint, the ADS initiates. This results in injection from the accumulators and subsequently from the in-containment refueling water storage tank, once the RCS is nearly depressurized. For these conditions, the RCS depressurizes to saturated conditions at about 240°F within 24 hours. The PXS can maintain this safe shutdown condition indefinitely.

The primary function of the PXS during a safe shutdown using only safety-related equipment is to provide a means for boration, injection, and core cooling. Analysis is provided in subsection 19E.4.10.2 of this appendix that verifies the ability of the AP1000 passive safety systems to meet the safe shutdown requirements.

19E.2.3.2.7 Containment Recirculation Screens

The PXS containment recirculation screens may have to function in the longer-term during a shutdown accident that results in ADS operation. Effective screen design, plant layout, and other factors prevent clogging of these screens by debris during such accident operations.

- Redundant screens are provided and are located in separate locations.
- A significant delay is provided between the accident/ADS stage opening and the initiation of recirculation (at least 2 hours).
- Deep flood up levels are provided post ADS operation (31 ft of water above the lowest level in containment and 25.5 ft above floors around screens).
- Bottom of screens are located well above the lowest containment level (13.5 feet) as well as the floors around them (2 feet).
- Top of screens are located well below the containment floodup level (~10 ft from top screens to minimum flood level).
- Screens have protective plates located no more than 1 foot above the top of the screens and extend at least 10 feet in front and 7 feet to the side of the screens.
- Screens have conservative flow areas to account for plugging. Operation of the nonsafety-related normal residual heat removal pumps with suction from the IRWST and the containment recirculation lines is considered in sizing screens. Note that adequate PXS performance can be supported by one screen with more than 90 percent of its surface area completely blocked.

- During recirculation operation, the velocity approaching the screens is very low, which limits the transport of debris.
- Each screen has a coarse and a fine screen.
- Technical Specifications require the screens to be inspected during each refueling outage.
- A COL commitment is made for a cleanliness program to limit the amount of foreign materials that might be left in the containment following refueling and maintenance outages and become debris during an accident.

19E.2.3.3 Shutdown Operations

Operation of the PXS during operating modes and during accident events including shutdown events is discussed in subsection 6.3.3. The following is a discussion of a loss of shutdown cooling during reduced inventory operations which can be a limiting shutdown event.

19E.2.3.3.1 Operation During Loss of Normal Residual Heat Removal Cooling During Mid-loop Events

During RCS maintenance, the most limiting shutdown condition anticipated is with the reactor coolant level reduced to the hot leg (mid-loop) level and the RCS pressure boundary opened. It is normal practice to open the steam generator channel head manway covers to install the hot leg and cold leg nozzle dams during a refueling outage. In this situation, the RNS is used to cool the RCS. The AP1000 incorporates features to reduce the probability of losing RNS. However, because the RNS is nonsafety-related, its failure has been considered.

In this situation, core cooling is provided by the safety-related PXS, using gravity injection from the IRWST, while venting through the ADS valves (and possibly through other openings in the RCS). Note that with the RCS depressurized and the pressure boundary opened, the PRHR HX is unable to remove the decay heat because the RCS cannot heat sufficiently above the IRWST temperature.

During plant shutdown, at 1000 psig, the accumulators are isolated to prevent inadvertent injection. Prior to draining the RCS inventory below the no-load pressurizer level, the CMTs are isolated by closing the inlet MOVs to preclude inadvertent draining into the RCS while preparing for mid-loop operation. Although these tanks are isolated from the RCS, the valves can be remotely opened by the operators to provide additional makeup water injection.

Prior to initiating the draindown of RCS to mid-loop level, the automatic depressurization first-, second-, and third-stage valves are opened. This alignment provides a sufficient RCS vent flow path to preclude system pressurization in the event of a loss of nonsafety-related decay heat removal during mid-loop operation. The ADS first- to third-stage valves are required to be opened before blocking the CMTs. They are required to remain open until either the RCS level is increased and the RCS is closed, or until the upper core internals are removed and the refueling cavity flooded. Note that the upper internals can restrict the vent flow path and prevent water in the refueling cavity from draining into the RCS unless ADS valves are open.

The IRWST injection squib valves and fourth stage ADS valves are automatically opened if the RCS hot leg level indication decreases below a low setpoint. A time delay is provided to provide time for the operators to restore nonsafety-related decay heat removal prior to actuating the PXS. The time delay with an alarm in the containment serves to protect maintenance personnel. Once the IRWST injection valves and fourth stage ADS valves open, the IRWST provides gravity-driven injection to cool the core. Containment recirculation flow would be automatically initiated when the IRWST level dropped to a low level to provide long-term core cooling.

Subsection 19E.4.8.3 provides the assessment of the loss of the RNS during mid-loop operations. Table 19E.2-1 provides the results of calculations performed to demonstrate the amount of time between a loss of RNS that could occur at mid-loop until core uncovery. This calculation is performed with the RCS water level at the nominal mid-loop water level and is performed with conservative, design basis assumptions for decay heat. As described previously and shown in Table 19E.2-1, the operators have a significant amount of time to actuate gravity injection before core uncovery. In addition, the PMS, on a two-out-of-two basis, provides a signal to actuate the IRWST when the hot legs empty.

This arrangement provides automatic core cooling protection, in mid-loop operation, while also providing protection (an evacuation alarm and sufficient time to evacuate) for maintenance personnel in containment during mid-loop operation.

Containment closure capability is required to be maintained during mid-loop operation, as discussed in subsection 19E.2.6.2 of this appendix. With the containment closed, containment recirculation can continue indefinitely with decay heat generating steam condensed on the containment vessel and drained back into the IRWST and/or the containment recirculation.

19E.2.4 Normal Residual Heat Removal System

19E.2.4.1 System Description

The normal residual heat removal system (RNS) is discussed in subsection 5.4.7.

19E.2.4.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated various design features to improve shutdown safety. The RNS features that have been incorporated to address shutdown safety are described in this subsection.

19E.2.4.2.1 RNS Pump Elevation and NPSH Characteristics

The AP1000 RNS pumps are located at the lowest elevation in the auxiliary building. This location provides the RNS pumps with a large available NPSH during all modes of operation including RCS mid-loop and reduced inventory operations. The large NPSH provides the pumps with the capability to operate during most mid-loop conditions without throttling the RNS flow. If the RCS is at mid-loop level and saturated conditions, some throttling of a flow control valve is necessary to maintain adequate net positive suction head for the RNS pumps. The RNS pumps can be restarted and operated with RCS conditions that might occur following a temporary loss of RNS cooling.

The plant piping configuration, piping elevations and routing, and the pump characteristics allow the RNS pumps to be started and operated at their full design flow rates in most conditions without the need to reduce RNS pump flow to meet pump NPSH requirements. This reduces the potential failure mechanism that exists in current PWRs, where failure of an air-operated control valve can result in pump runout and cavitation during mid-loop operations.

19E.2.4.2.2 Self-Venting Suction Line

The RNS pump suction line is sloped continuously upward from the pump to the RCS hot leg with no local high points. This eliminates potential problems with refilling the pump suction line if an RNS pump is stopped due to pump cavitation and/or excessive air entrainment. With the self-venting suction line, the line will refill and the pumps can be immediately restarted once an adequate level in the hot leg is re-established.

19E.2.4.2.3 IRWST Injection via the RNS Suction Line

During shutdown modes, initiating events such as the loss of the nonsafety-related RNS are postulated. Such events would require IRWST injection as discussed in subsection 19E.2.3 of this appendix, and as shown in the accident analyses provided in Section 19E.4. For initiating IRWST injection, the operation of PXS squib valves in the IRWST injection line is required. However, the operators can use the RNS pump suction line that connects to the IRWST to provide controlled IRWST injection. This flow path, shown in Figure 19E.2-2, connects the IRWST directly to the RCS via the RNS hot leg suction isolation valves and provides a diverse method for IRWST injection. In addition, it would be the preferred method of providing IRWST injection because the flow would be controllable by the operation of the IRWST suction line isolation valve. The RNS isolation valve is equipped with a throttle capability to provide the operators with the capability to control the injection flow via this path. The operator would monitor the RCS hot leg level while controlling flow through this valve. This path provides IRWST injection regardless of whether the RNS pumps are operating.

19E.2.4.2.4 Codes and Standards/Seismic Protection

The portions of the RNS located outside containment (that serve no active safety functions) are classified as AP1000 equipment Class C so that the design, manufacture, installation, and inspection of this pressure boundary is in accordance with the following industry codes and standards and regulatory requirements: 10 CFR 50, Appendix B (Reference 6); Regulatory Guide 1.26, quality group C (Reference 7); and ASME Boiler and Pressure Vessel Code, Section III, Class 3 (Reference 8). The pressure boundary is classified as seismic Category I.

19E.2.4.2.5 Increased Design Pressure

The portions of the RNS from the RCS to the containment isolation valves outside containment are designed to the operating pressure of the RCS. The portions of the system downstream of the suction line containment isolation valve and upstream of the discharge line containment isolation valve are designed so that its ultimate rupture strength is not less than the operating pressure of the RCS. The design pressure of the RNS is 900 psig, which is 40 percent of operating RCS pressure.

19E.2.4.2.6 Reactor Coolant System Isolation Valve

The RNS contains an isolation valve in the pump suction line from the RCS. This motor-operated containment isolation valve is designed to the RCS pressure. It provides an additional barrier between the RCS and lower pressure portions of the RNS.

19E.2.4.2.7 Normal Residual Heat Removal System Relief Valve

The inside containment RNS relief valve is connected to the residual heat removal pump suction line. This valve is designed to provide low-temperature, overpressure protection of the RCS as described in subsection 5.2.2. The valve, connected to the high-pressure portion of the pump suction line, reduces the risk of overpressurizing the low-pressure portions of the system.

19E.2.4.2.8 Features Preventing Inadvertent Opening of Isolation Valves

The RCS isolation valves are interlocked to prevent their opening at RCS pressures above 450 psig. Section 7.6 discusses this interlock. The power to these valves is administratively blocked during normal power operation.

In addition, these valves are interlocked with the RNS/IRWST isolation valves to prevent their opening with the RNS open to the IRWST. This precludes the blowdown of the RCS to the IRWST through the RNS upon system initiation.

19E.2.4.2.9 RCS Pressure Indication and High Alarm

The AP1000 RNS contains an instrumentation channel that indicates pressure in each normal residual heat removal pump suction line. A high-pressure alarm is provided in the main control room to alert the operator to a condition of rising RCS pressure that could eventually exceed the design pressure of the RNS.

19E.2.5 Component Cooling and Service Water Systems

The AP1000 service water system and component cooling water system are described in subsections 9.2.1 and 9.2.2 respectively.

19E.2.6 Containment Systems

19E.2.6.1 System Description

The containment systems are described in Section 6.2.

19E.2.6.2 Design Features to Address Shutdown Safety

The AP1000 has addressed the issue of containment closure at shutdown and incorporated the following requirements in the Technical Specifications (Chapter 16). In shutdown Modes 3 and 4, containment status is the same as at-power. Specifically, containment integrity is required, the major equipment hatches are closed and sealed, and containment air locks and isolation valves are operable.

In Modes 5 and 6, containment closure capability is required during shutdown operations when there is fuel inside containment. Containment closure is required to maintain, within containment, the cooling water inventory. Due to the large volume of the IRWST and the reduced sensible heat during shutdown, the loss of some of the water inventory can be accepted. Further, accident analyses provided in Section 19E.4 of this appendix show that containment closure capability is not required to meet offsite dose requirements. Therefore, containment does not need to be leak-tight as required for Modes 1 through 4.

In Modes 5 and 6, there is no potential for steam release into the containment immediately following an accident. Pressurization of the containment could occur only after heatup of the IRWST due to PRHR HX operation (Mode 5 with RCS intact), after heatup of the RCS with direct venting to the containment (Mode 5 with reduced RCS inventory or Mode 6 with the refueling cavity not fully flooded), or after heatup of the RCS and refueling cavity (Mode 6 with refueling cavity fully flooded). To limit the magnitude of cooling water inventory losses and because local manual action may be required to achieve containment closure, the containment hatches, air locks, and penetrations must be closed prior to steaming into containment.

The containment equipment hatches, which are part of the containment pressure boundary, provide a means for moving large equipment and components into and out of containment. If closed, the equipment hatch is held in place by at least four bolts. If open, each equipment hatch can be closed using a dedicated set of hardware, tools, and equipment. A self-contained power source is provided to drive each hoist while lowering the hatch into position. Large equipment and components may be moved through the hatches as long as they can be removed and the hatch closed prior to steaming into the containment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during Modes 1, 2, 3, and 4 unit operation. Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment operability is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Temporary equipment connections (for example, power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment.

Containment spare penetrations, which also provide a part of the containment boundary, provide for temporary support services (electrical, I&C, air, and water supplies) during Modes 5 and 6. Each penetration is flanged and normally closed. During periods of plant shutdown, temporary support systems may be routed through the penetrations; temporary equipment connections (for example, power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment.

The spare penetrations must be closed or, if open, capable of closure prior to reaching boiling conditions within reactor coolant inventory. Temporary containment penetrations that may be employed during shutdown modes must have a design pressure equal to the containment design pressure of 59 psig.

Containment penetrations, including purge system flow paths, that provide direct access from containment atmosphere to outside atmosphere must be isolated or isolatable on at least one side. Isolation may be achieved by an operable automatic isolation valve or by a manual isolation valve, blind flange, or equivalent.

The fuel transfer canal may be opened to provide for the transfer of new and spent fuel into and out of containment during Modes 5 and 6. At times when the canal is opened, it must be isolatable on at least one side by closure of the flange within containment or the gate valve outside containment.

19E.2.7 Chemical and Volume Control System

19E.2.7.1 System Description

The chemical and volume control system (CVS) is described in subsection 9.3.6.

19E.2.7.2 Design Features to Address Shutdown Safety

The AP1000 CVS is a nonsafety-related system. However, portions of the system are safety-related and perform safety-related functions, such as containment isolation, termination of inadvertent RCS boron dilution, RCS pressure boundary preservation, and isolation of excessive makeup.

Boron dilution events during low power modes can occur for a number of reasons, including malfunctions of the makeup control system. Regardless of the cause, the protection is the same. The CVS is designed to avoid and/or terminate boron dilution events by automatically closing either one of two series, safety-related valves in the demineralized water supply line to the makeup pump suction to isolate the dilution source. Additionally, the suction line for the CVS makeup pump is automatically realigned to draw borated water from the boric acid tank. The automatic boron dilution protection signal is safety-related and is generated upon any reactor trip signal, source-range flux multiplication signal, low input voltage to the Class 1E dc and uninterruptible power supply system battery chargers, or a safety injection signal.

The safety analysis of boron dilution accidents is provided in Chapter 15 and is discussed in subsection 19E.4.5 of this appendix. For dilution events that occur during shutdown, the source-range flux-doubling signal is used to isolate the line from the demineralized water system by closing the two safety-related remotely operated valves. The three-way pump suction control valve aligns the makeup pumps to take suction from the boric acid tank and, therefore, stops the dilution.

For refueling operations, administrative controls are used to prevent boron dilutions by verifying that the valves in the line from the demineralized water system are closed and locked. These valves block the flow paths that can allow unborated makeup water to reach the RCS. Makeup required during refueling uses borated water supplied from the boric acid tank by the CVS makeup pumps.

During refueling operations (Mode 6), two source-range neutron flux monitors are operable to monitor core reactivity. This is required by the plant Technical Specifications. The two operable

source-range neutron flux monitors provide a signal to alert the operator to unexpected changes in core reactivity. The potential for an uncontrolled boron dilution accident is precluded by isolating the unborated water sources. This is also required by the plant Technical Specifications.

19E.2.8 Spent Fuel Pool Cooling System

19E.2.8.1 System Description

The spent fuel pool cooling system (SFS) is discussed in subsection 9.1.3.

19E.2.8.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated various design features to improve shutdown safety. The SFS features that have been incorporated to address shutdown safety are described in this subsection.

19E.2.8.2.1 Seismic Design

The spent fuel pool, fuel transfer canal (FTC), cask loading pit (CLP), cask washdown pit (CWP), and gates from the spent fuel pool-CLP and FTC-spent fuel pool are all integral with the auxiliary building structure. The auxiliary building is seismic Class I design and is designed to retain its integrity when exposed to a safe shutdown earthquake (SSE). The suction and discharge connections between the spent fuel pool and RNS are safety Class C, which is also seismic Class I. The emergency makeup water line from the PCS water storage tank to the spent fuel pool actually connects with the RNS pump suction line. This emergency makeup line is also safety Class C and seismic Class I. The spent fuel pool level instruments connections to the spent fuel pool are safety Class C, seismic Class I, and have 3/8-inch flow restricting orifices at the pool wall to limit the amount of a leak from the pool if the instrument or its piping develops a leak.

The refueling cavity is integral with the containment internal structure, and as such, is seismic Class I, and is designed to retain its integrity when exposed to an SSE. In addition, the AP1000 has incorporated a permanently welded seal ring to provide the seal between the vessel flange and the refueling cavity floor. This refueling cavity seal is part of the refueling cavity and is seismic Class I. Figure 19E.2-3 is a simplified drawing of the AP1000 permanent reactor cavity seal. The cavity seal is designed to accommodate the thermal transients associated with the reactor vessel flange.

19E.2.9 Control and Protection Systems

The AP1000 control and protection systems support the operations necessary for the AP1000 to achieve shutdown. These systems consist of a nonsafety-related plant control system (PLS), a safety-related protection and safety monitoring system (PMS), and a nonsafety-related diverse actuation system (DAS). These systems are discussed in Chapter 7.

19E.3 Shutdown Maintenance Guidelines and Procedures

This section presents an overview discussion of AP1000 shutdown maintenance guidelines and procedures captured as part of the AP1000 design and design certification program. Shutdown maintenance requirements and guidelines have been identified in various licensing submittals,

such as the AP1000 Technical Specifications, (Section 16.1), and the design reliability assurance program, (Section 17.4).

Shutdown procedures were addressed in the AP600 design certification program by the submittal of the AP600 Emergency Response Guidelines (ERGs) (Reference 1), which include shutdown emergency procedures. These shutdown emergency procedures are applicable to the AP1000.

While ultimately the responsibility of shutdown maintenance and shutdown risk management is the responsibility of the combined operating license (COL) applicant, this section summarizes the major shutdown maintenance guidelines and procedures that have been identified.

19E.3.1 Maintenance Guidelines and Insights Important to Reducing Shutdown Risk

This section presents an overview of AP1000 shutdown maintenance guidelines and insights, which are either required for plant safety or are effective at reducing shutdown risk.

19E.3.1.1 Availability Requirements for Safety-Related Systems

Availability controls of the AP1000 safety-related systems are provided by the Technical Specifications. These availability requirements cover all modes of operation including shutdown.

19E.3.1.2 Availability Guidelines for Systems Important for Investment Protection

Availability guidelines for systems important for investment protection are discussed in the AP1000 Design Reliability Assurance Program, Section 17.4.

19E.3.1.3 Reactor Coolant System Precautions and Limitations at Shutdown

Precautions and limitations for RCS operation at shutdown are considered to minimize the risk to plant safety at shutdown. The most important of these are captured in the AP1000 Technical Specifications. However, other precautions and limitations associated with maintenance and operation at shutdown have been identified during the design of the AP1000. These are based on both the past operating experience of PWRs, as well as the designer's knowledge of the unique AP1000 design features. A summary of these precautions and limitations that apply to shutdown maintenance and operation is provided in this section.

19E.3.1.3.1 General Shutdown

Precautions and limitations for general shutdown are as follows:

- To provide mixing, at least one reactor coolant pump (RCP) or a normal residual heat removal pump should be in service while chemicals are being added to the system or the boron concentration is being changed. This requirement is included in the AP1000 Technical Specification 3.3.9.

- Reactor coolant samples must be taken at the regular intervals to check coolant chemistry, activity level, and boron concentration as specified in the appropriate Technical Specifications including 3.1.1, 3.4.11, and 3.1-1. In addition, during shutdown modes, more

frequent checks on RCS boron concentration should be made when changes in RCS boron concentration are being made.

- When the RNS is in operation, the reactor coolant temperature should not exceed 350°F. The reactor coolant pressure should be limited to avoid approaching the RNS relief valve setpoint.

- The maximum allowable heatup and cooldown rates for the RCS are provided in the Technical Specifications.

- During cooldown, the RCPs located in the loop containing the pressurizer spray line should be operated to provide adequate pressurizer spray.

- The accumulators must be isolated prior to reducing the RCS pressure to the accumulator pressure (637 to 769 psig).

19E.3.1.3.2 Water-Solid Operation

Precautions and limitations for water-solid operation are as follows:

- The RNS inlet line should not be isolated from the reactor coolant loop unless there is a steam bubble in the pressurizer or the makeup pumps are stopped. This precaution provides relief valve protection of the RCS when it is at low pressure and water-solid.

- Whenever the plant is water-solid and the reactor coolant pressure is being maintained by the letdown containment isolation outside-containment valve, the RNS should remain open to the reactor coolant loops to maintain sufficient letdown flow through the bypass line from the RNS to the letdown heat exchanger, until a steam bubble is formed in the pressurizer. During this mode of operation, the isolation valve in the bypass line from the RNS to the letdown heat exchanger should be in the full-open position and the letdown orifice bypass valve should also be open.

- If all RCPs are stopped and the reactor coolant temperature is greater than 200°F, the first pump should not be restarted until a steam bubble has formed in the pressurizer. This precaution will minimize the pressure transient when the first pump is started. The steam bubble will accommodate the resultant expansion.

- When the reactor coolant pressure is being maintained by the letdown containment isolation outside containment valve, changes to the flow rate through the RNS loop by throttling of valves or starting and stopping the RNS pumps will result in changes to the reactor coolant pressure.

- Whenever the reactor coolant temperature is above 160°F, at least one RCP should be in operation.

19E.3.1.3.3 Steam Generators

Precautions and limitations for steam generators are as follows:

- During cooldown, all steam generators should be connected to the steam header to provide uniform cooldown of the reactor coolant loops.

- During steam plant warmup and at hot standby, draw steam slowly and regulate feedwater additions carefully to avoid rapid cooling of the reactor coolant.

- During cooldown, once RNS is in operation, and after the RCPs have been tripped, actions should be taken to cool the contents of the steam generator secondary side, either by recirculation and cooling of this water or by draining the contents via the blowdown lines.

19E.3.1.3.4 Surge Line

During heatup and cooldowns, the temperature difference between the pressurizer and the hot legs should be less than 320°F. This prevents unacceptable stress levels in the surge line.

19E.3.1.3.5 Reduced-Inventory Operations

Precautions and limitations for reduced-inventory operations are as follows:

- The timing of the initiation of draindown is highly dependent of the scenario that requires the drained condition. However, in order to drain down to mid-loop conditions, the reactor coolant pumps must be tripped, and the RCS temperature must be less than saturation. Typically, the reactor coolant pumps operate until the RCS temperature is reduced to less than 160°F. For a refueling outage, the transition to reduced inventory conditions should typically begin about 3-4 days after shutdown. For a forced outage condition, reduced inventory operations should not begin until the RCS temperature is less than 160°F.

  The time after shutdown directly affects the time that the RCS would boil and the rate at which inventory would be depleted following a loss of cooling event. Table 19E.2-1 presents the time to reach saturation, and the time to core uncovery for a loss of heat sink event initiated from mid-loop conditions at 28 hours after shutdown. For loss of heat sink events initiated earlier, the time to reach saturation and the time to uncover the core would be slightly decreased. The performance of the IRWST injection, in conjunction with ADS, is sufficient to mitigate the consequences of the event.

  The time after shutdown impacts the requirements for containment closure during shutdown as discussed in subsection 19E.2.6.2 of this appendix (and captured in the Technical Specifications). For reduced inventory conditions, if the time to steaming (inside containment) following a loss of heat sink event is less than the time required to close the containment equipment hatches, then these hatches should be closed. If the time after shutdown is sufficiently long, such that steaming to containment would not occur prior to the containment hatches being able to be closed, then the equipment hatches could be open, with the ability to close them.

- As the RCS is drained, the rate of change in water level will vary non-linearly for a given drain rate due to the geometry of the RCS and the offset hot leg and cold leg piping. It is important to drain the RCS at a low rate to minimize the possibility of overdraining the system. Evaluations have been performed that indicate that a drain rate of 20 gpm is sufficient once the water level has been reduced to the top of the hot leg.

- After maintenance operations that result in draining the RCS, the system should be refilled with borated makeup water at the prevailing RCS boron concentration via the chemical and volume control system (CVS) makeup pumps. If the RCPs are drained, the pumps should be refilled with borated water via the pump drain line so that the pump is completely filled with borated water.

- After maintenance operations on the CVS purification loop (demineralizer, filters, and heat exchangers), the system should be purged, draining potential unborated water to the liquid radwaste system, and refilling it with borated water from the RCS. These operations should not be conducted at mid-loop or reduced inventory operations to avoid an inadvertent drop in RCS water level during mid-loop.

- The RCS hot leg level instruments should be operable and available prior to reduced inventory operations. Their automatic actuation functions are required to be operable in shutdown modes as described in Technical Specification 3.3.2.

19E.3.2 Shutdown Risk Management

This appendix contains insights of which Westinghouse is currently aware and which are related to AP1000 design certification.

19E.3.3 Shutdown Emergency Response Guidelines Overview

The AP600 ERGs (Reference 1) provide functional guidance for responding to accidents and transients that affect plant safety during shutdown modes of operation (operational Modes 5 and 6). The shutdown ERGs consist of a shutdown safety status tree for monitoring the critical safety functions and six shutdown guidelines for responding to the respective challenges to plant safety. The AP600 ERGs are applicable to AP1000 for the purpose of developing Emergency Operating Procedures.

The shutdown safety status tree provides a systematic method of determining the safety status of the plant. This status tree represents the critical safety functions that are of concern during plant shutdown conditions. Prior to this shutdown condition, the plant can be in any state ranging from heatup and pressurization (from 200°F to no-load temperature) to full power operation. Under these conditions (plant Modes 4 through 1), plant monitoring and response to a reactor trip or requirement for safety injection are covered by the optimal recovery guidelines, status trees, and function restoration guidelines of the at-power ERGs.

By using the shutdown status tree, plant conditions are monitored during plant shutdown after entering Mode 5 while normal operating procedures are in use for plant shutdown operations. The shutdown safety status tree is arranged so that the functions are checked in order of importance.

Core cooling during shutdown conditions is addressed first. During plant shutdown conditions, the RNS provides core cooling, which requires adequate RCS inventory to operate properly. RCS inventory checks are made first to show core cooling will not be interrupted because of inadequate RCS inventory and as an early symptom to a loss of shutdown core cooling. After adequate RCS inventory is checked, RNS operation is checked to verify shutdown core cooling is being provided by the RNS. After RNS operation is verified, containment radiation is checked so that an unexpected uncontrolled release will not occur because containment integrity may be breached during plant shutdown maintenance activities. Core reactivity is then checked by monitoring source range flux doubling as an early symptom of an unintended RCS boron dilution, which should occur at a slow enough rate to allow appropriate action to be taken to reestablish shutdown margin. RCS cold overpressure symptoms of RCS pressure and temperature are monitored for maintaining the RCS pressure boundary integrity safety function.

Lastly, RCS temperature change, aside from any normal expected RCS temperature change, is used as an early symptom for potential degradation of the core cooling safety function and the RCS pressure boundary integrity safety function. The shutdown safety status tree is considered to be satisfied when all status tree blocks have been satisfied. If a challenge is identified during the monitoring of the tree, the tree directs plant operators to one of the appropriate six shutdown guidelines for mitigating actions.

The format and arrangement of the shutdown ERG documentation is similar to the at-power ERGs consisting of guidelines and background documents. Implementation of the shutdown ERGs into plant procedures will also be similar to the at-power ERGs with the task allocation between the man and the computer for doing this to be decided when designing features of the man-machine interface system.

19E.4 Safety Analyses and Evaluations

19E.4.1 Introduction

This section reviews each of the design basis accidents (DBAs) and transients presented in Chapter 15, with respect to lower power and shutdown modes. In subsections 19E.4.2 through 19E.4.9, evaluations or analyses are performed for each case of the transient and LOCA analyses for events occurring at low power and shutdown operations, including the reduced reactor coolant system (RCS) inventory and refueling operations. The evaluations discuss the effects of key plant parameters (for example, plant control parameters, neutronic and thermal hydraulic parameters, and engineering safety features [ESFs]) on plant transient response (such as departure from nucleate boiling ratio [DNBR], peak pressure, and peak cladding temperature). The limiting case for each event category is identified. For those limiting cases bounded by the cases analyzed at power conditions, supporting rationales are provided.

For those events where analyses are presented in the shutdown modes, a discussion of the adequacy of the codes used is presented in subsection 19E.4.1.2.

In subsection 19E.4.10, additional analyses and evaluations demonstrate that the passive systems can bring the plant to a stable, safe condition and maintain this condition.

19E.4.1.1 Matrix of Chapter 15 Events

Table 19E.4.1-1 provides a list of Chapter 15 events. This table categorizes the events as "E" (requiring evaluation), "A" (requiring analysis), or "n/a" (not applicable). The "n/a" events are bounded by at-power analyses or current analyses.

The events denoted by an "n/a" in Table 19E.4.1-1 are as follows:

- Boron dilution design basis transient explained in subsection 15.4.6 because it explicitly considers all modes such that no analysis or evaluation is required for this appendix

- Rod cluster control assembly (RCCA) withdrawal at-power explained in subsection 15.4.2 because this event occurs only at-power

19E.4.2 Increase in Heat Removal from the Primary System

19E.4.2.1 Feedwater System Malfunctions Which Increase Heat Removal from the Primary System

Faults that decrease feedwater temperature or increase feedwater flow can be postulated in the feedwater system. These faults could increase heat removal from the primary system, which reduces RCS temperature. The reduction in RCS temperature could lead to an increase in core power generation (due to a negative moderator temperature coefficient) and result in a reduction in margin-to-core design limits. Unchecked, excessive feedwater flow could also result in overfilling the steam generators.

Discussions and analyses, initiated from Modes 1 and 2, of RCS cooldowns caused by feedwater system malfunctions are presented in subsections 15.1.1 and 15.1.2. Subsection 15.1.1 covers reductions in feedwater temperature, and subsection 15.1.2 covers increases in feedwater flow. Modes 1 and 2 are the limiting initial conditions for feedwater system induced RCS cooldown transients.

Protection against feedwater system induced cooldown transients is provided by the protection and safety monitoring system (PMS) through automatic functions that trip the reactor and isolate the feedwater system. The protection functions are available in all modes during which the feedwater system is in operation. Reactor trip includes overpower Δt, high power-range nuclear flux, high intermediate-range nuclear flux, or high source-range nuclear flux. The PMS closes the main feedwater control valves on low-1 RCS average temperature signal. The PMS also closes the main feedwater isolation valves and trips the booster/main feedwater pumps when RCS average temperature decreases below the low-2 RCS T_{avg} setpoint. These protection functions are arranged to detect symmetrical plant transients with a channel out of service and a single channel failure.

Additional PMS functions are provided to detect and protect against asymmetrical feedwater system malfunctions. Automatic reactor trip, closure of the main feedwater control and isolation valves, closure of the startup feedwater control and isolation valves, tripping of the booster/main feedwater pumps, and tripping of the startup feedwater pumps occur if the level in a single steam generator is above the high-2 water level setpoint. Similar actions occur if cold leg temperature in a single RCS loop decreases below the low T_{cold} setpoint. The high-2 steam generator level setpoint is active in Modes 1 through 4 unless the various feedwater valves are closed. This

ensures that the steam generators cannot inadvertently be overfilled. The low T_{cold} signal is available in Modes 1 through 3. In Mode 3 prior to blocking the low T_{cold} signal, the RCS must be borated to cold shutdown conditions. With the RCS borated, no feedwater malfunction can be postulated to cool the RCS such that a core power excursion would occur.

The feedwater malfunction associated with a drop in feedwater temperature is less severe as power level is decreased. Normal operating feedwater temperature decreases as plant power level decreases. Therefore, if a fault suddenly reduces the feedwater temperature, the maximum change in feedwater temperature will occur if the plant is operating at full power.

As discussed in subsection 19E.2.2 of this appendix, in Modes 2 and below, feedwater entering the steam generators is routed through the startup feedwater control valves. The maximum achievable flow rate through the startup feedwater path is much less than when flow is being controlled by the main feedwater control valves. Therefore, failure of a main feedwater control valve in Mode 2 and below is not likely. The assumption of a failed open startup feedwater control valve, in Mode 2 and below, will result in a relatively slow transient due to low feedwater flow rate.

The most severe RCS cooldowns caused by feed system malfunctions will occur in Modes 1 or 2. In Modes 3 or 4, RCS cooldowns due to feedwater malfunctions would be precluded, inconsequential, or less severe than in Modes 1 or 2. The analyses presented in Chapter 15 bound the consequences of this class of events initiated in the shutdown modes.

19E.4.2.2 Excessive Increase in Secondary Steam Flow

An excessive increase in secondary steam flow (excessive load increase) is caused by a rapid increase in steam flow that results in a power mismatch between the reactor core power and the steam generator load demand. The plant control system (PLS) is designed to accommodate a 10-percent step load increase in steam flow in the range of 25 to 100 percent of full power. Analyses results for a 10-percent step increase in steam flow are presented in subsection 15.1.3. The analyses are performed for Mode 1 from full-power initial conditions. Depending upon the plant and PMS characteristics (setpoint uncertainties), a reactor trip signal may or may not be generated for an excessive load increase from full power.

An excessive load increase in Mode 1 is considered limiting because an excessive load increase at full power will put the plant at the highest achievable power level. Load increases at less than full power, or during startup (Mode 2), will not reach as high a power level. The excessive load increase, in Mode 2, will not be as severe as the Mode 1 excessive load increase.

In Mode 3, the excessive load increase may be considered to be a simple steam release because there can be no load, per se, when the turbine is off-line and the core is subcritical. The Mode 3 load increase will be less limiting than the Mode 1 or Mode 2 case because the core is already subcritical. Automatic safeguards actuation signals may not be available if blocked by the operator (blocking is necessary to depressurize and cool down the RCS). However, the RCS must be borated to meet shutdown margin requirements at cold shutdown (200°F) prior to blocking automatic safeguards actuation signals to prevent a return to criticality in the event of a cooldown.

The Mode 4 situation is bounded by Mode 3 because pressure and temperature conditions in the primary and secondary systems are reduced. At some point in Mode 4, the RNS will be placed in service. In Modes 5 and 6, the RNS should be in operation. Any steam release will have little or no effect upon the core.

19E.4.2.3 Credible and Hypothetical Steamline Breaks

The spurious opening of a steam generator safety or relief valve is a Condition II event and referred to as a credible steam line break. This event affects the core like a load increase but the analysis assumptions that are applied are different. The credible steam line break is usually assumed to be an unisolatable, uncontrolled steam release, which causes a non-uniform core cooldown (typical of an open safety valve) during the period immediately following a reactor trip which inserts all but the most reactive rod cluster control assembly (RCCA). The resulting reactivity excursion may be large enough to overcome the shutdown margin and return the core to critical, especially when there is little or no decay heat (with power peaking in the region of the stuck RCCA). The credible steam line break is analyzed in Mode 2, and the results are presented in subsection 15.1.4. The assumptions used in the analysis lead to a more severe, post-trip transient than will result from a load increase initiated in Mode 1.

In Mode 1, prior to reactor trip, the transient characteristics of an inadvertent opening of a steam generator safety or relief valve are similar to the excessive load increase. A reactor trip signal, if needed, may result from overpower ΔT logic. After the reactor trip, the concern becomes a possible return to criticality with the most reactive RCCA stuck in the fully withdrawn position, leading to high local power levels. However, a post-trip return to criticality is less likely when this event occurs in Mode 1 than in Mode 2 because there will be more decay heat present, which tends to retard the cooldown.

In Mode 3, results are expected to be better than the Mode 2 case because pressure, temperature, and flow conditions will be less limiting. An occurrence in Mode 4 will be less severe than in Modes 2 or 3 due to the lower initial RCS temperature, and an effective decoupling of the secondary system from the primary system as the reactor coolant pumps (RCPs) are removed from service and the RNS is started. Automatic safeguards actuation signals are available through Mode 3, until the RCS is borated and the automatic safeguards signals are blocked (see excessive load increase discussion). Both CMTs continue to be available for automatic actuation on low-2 pressurizer level or manual actuation through Mode 4 with the RCS not being cooled by the RNS (see Technical Specification LCO 3.5.2). In Mode 4 with the RNS in operation and in Mode 5 with the RCS pressure boundary intact, one CMT is available for activation if needed.

Any cooldown in Modes 5 and 6 caused by depressurization of the secondary system is meaningless because the RCS is already cold, and the RNS system effectively decouples the steam generators from the core.

The steam line rupture is a Condition IV event, producing a greater uncontrolled steam release than the spurious opening of a steam generator safety valve (described above), but the relative effects in the various modes and requirements for protection equipment are the same. This is the most severe cooldown event.

19E.4.2.4 Inadvertent PRHR HX Operation

Inadvertent actuation of the PRHR HX causes an injection of relatively cold water into the RCS. This produces a reactivity insertion in the presence of a negative moderator temperature coefficient. Because the PRHR HX is connected to only one RCS loop, the cooldown resulting from its actuation is asymmetric with respect to the core. Inadvertent actuation of the PRHR HX could lead to an asymmetric power increase and a reduction in margin-to-core design limits.

A limiting analysis of an inadvertent actuation of the PRHR HX heat exchanger is presented in subsection 15.1.6. The analysis is initiated in Mode 1 from hot full-power conditions. This is the most limiting case.

The PRHR HX heat transfer rate is a function of the inlet temperature to the heat exchanger and the flow rate through the heat exchanger. PRHR HX heat transfer rate is higher with high flow rates and high inlet temperatures. Therefore, the maximum heat removal rate will occur when the plant is at full-power condition with forced RCS flow and a high hot leg temperature. At plant full-power conditions, the PRHR HX heat removal rate is approximately 10 percent of full power. At hot zero power (HZP) conditions with natural circulation, heat removal by the PRHR HX is approximately 1.5 percent to 2 percent of full power.

The heat sink for the PRHR HX is the in-containment refueling water storage tank (IRWST), in which the heat exchanger is submerged. Prior to actuation of the PRHR HX, the fluid within the heat exchanger is in thermal equilibrium with the fluid in the IRWST. Thus, the PRHR HX is initially filled with relatively cold fluid which is at containment ambient temperature. When the PRHR HX is actuated, the initial fluid outsurge is fluid at containment ambient temperature. Once the original fluid in the PRHR HX is purged, the out-flow temperature trend of the heat exchanger is set by the temperature entering the heat exchanger from the RCS hot leg minus the temperature drop through the heat exchanger. Thus, the outlet fluid temperature is limited by the cooling capacity of the PRHR HX.

If the reactor is at power (Mode 1 or 2) when the PRHR HX is inadvertently actuated, a cooldown induced increase in core power will occur. The transient response will have two parts. As the cold fluid from the PRHR HX, which is initially at the ambient IRWST temperature, enters the RCS, a large core power increase will occur. The magnitude of the power increase is proportional to the volume of the cold fluid in the PRHR HX. Once the original fluid is purged from the PRHR HX, the fluid temperature exiting the PRHR HX increases to a value limited by the cooling capacity of the PRHR HX. Core power will then decrease to a value higher than the initial core power, but in equilibrium with the heat removal capability of the steam generators plus the PRHR HX.

With the assumptions of a protection system channel out of service as allowed by the Technical Specifications, a failure of an additional protection system channel, and maximum instrument uncertainties, the asymmetric core power transient may not result in actuating any overpower reactor trips, such as high nuclear flux or overpower Δt. In this case, the core power transient is controlled only by the initial volume of cold water in the PRHR HX and the heat removal capability of the heat exchanger.

Higher initial core power will result in the largest achievable core power and in more severe consequences. Therefore, if the reactor is at-power, the full-power case produces the worst results.

In Mode 3, because the reactor is subcritical, inadvertent actuation of the PRHR HX produces a less severe power excursion than if the reactor is at power or at HZP with the reactor just critical. If in Mode 3 below no-load temperature, the cooldown caused by the actuation of the PRHR HX results in the cold leg temperature dropping below the low T_{cold} safeguards signal setpoint. This function actuates a reactor trip, initiates boration by the CMTs, and most importantly, trips all the RCPs. When the RCPs trip, natural circulation flow begins in the RCS and the PRHR HX loop. When natural circulation flow is initiated, the heat removal capability of the PRHR HX decreases to approximately 1.5 percent of full power and the severity of the transient is minimized. With the RCS in natural circulation, the cooldown rate of the RCS is also slowed. If criticality is obtained, boration by the CMTs will bring the core subcritical again.

The low T_{cold} safeguards signal may be blocked by the operator in Mode 3 to allow plant depressurization and cooldown to lower modes. However, prior to blocking the low T_{cold} safeguards signal, the RCS is borated to the shutdown margin requirements at cold shutdown (200°F). Therefore, in Mode 3 with safeguards signals blocked or in Mode 4, cooldown of the RCS by inadvertent actuation of the PRHR HX will not result in a reactivity excursion, which produces a power increase.

In Modes 5 and 6, the RCS will be borated such that a cooldown-induced power excursion could not be postulated. The RCS will be at 200°F or less, and with initial RCS temperatures this low, no significant cooling of the RCS by inadvertent actuation of the PRHR HX could be postulated.

19E.4.3 Decrease in Heat Removal by the Secondary System

19E.4.3.1 Loss of Load and Turbine Trip

Discussions and analyses of the consequences of loss of load, turbine trip, inadvertent closure of main steam isolation valves (MSIVs), or loss of condenser vacuum are presented in subsections 15.2.2 through 15.2.5. These events are characterized by a rapid reduction in steam flow from the steam generators. This results in an increase in steam pressure and a heatup of the primary side if the reactor power is not reduced. The effects of the primary to secondary power mismatch during these events are mitigated by tripping the reactor and opening secondary and primary side safety valves. The severity of these events is increased if the primary to secondary power mismatch is increased. Therefore, the most severe results occur if the plant is initially operating in Mode 1 at maximum-rated plant power conditions rather than lower power conditions. The turbine is off-line below Mode 1 and transients related to turbine-related faults cannot occur.

In Modes 2, 3, or 4, the plant may be removing decay heat by dumping steam to the condenser. In Mode 4 when the RCS is below 350°F, decay heat is removed using the RNS. In Modes 2, 3, or 4, the transient response to a loss of condenser vacuum or inadvertent MSIV closure is bounded by the turbine trip analysis from full power because the power mismatch is low. Decay heat removal can still be accomplished by the steam generators through atmospheric steam relief through power-operated relief valves (PORVs) if available or through steam generator safety valves, which

are available through Mode 4 (see Technical Specification LCO 3.7.1). Additionally, decay heat can be removed with the PRHR HX, which is available through Mode 5 with the RCS intact (see Technical Specifications LCO 3.5.4 and 3.5.5).

19E.4.3.2 Loss of ac Power

A discussion and an analysis of a loss of ac power event is provided in subsection 15.2.6. The loss of ac power results in the loss of forced primary coolant flow and the loss of main feedwater flow. This results in a heatup and pressurization of the RCS. If the reactor is at power, the event is mitigated by tripping the reactor. The reactor may be automatically tripped on low RCP speed, low RCS flow, low steam generator level, or several other primary side heatup signals. Also reactor trip may occur due to the loss of power to the control rod drive mechanisms.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on low steam generator level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for loss of ac power would be if the plant were at full rated power. This will result in the highest decay heat levels and stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized. In Modes 4 or 5 with the RNS in operation, the plant response to a loss of ac power is the same at the loss of RNS cooling as discussed in subsection 19E.4.8 of this appendix.

19E.4.3.3 Loss of Normal Feedwater

The main feedwater system is in operation during Modes 1 and 2. The startup feedwater system is used in Mode 2 below approximately 2 percent power, in Mode 3, and in Mode 4 before the RNS is aligned. In Mode 4 with the RNS aligned and in Modes 5 and 6, the feedwater system is not used, and therefore, loss of feedwater events are irrelevant.

A discussion and an analysis of a loss of normal feedwater event from rated full-power conditions are provided in subsection 15.2.7. The loss of normal feedwater flow results in a heatup and pressurization of the RCS. If the reactor is at-power, the event is mitigated by tripping the reactor on low steam generator level.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on low steam generator level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for a loss of normal feedwater is with the plant initially at full rated power. This case will have the highest decay heat levels and stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized. The analysis initiated from full power bounds cases initiated from the shutdown modes.

19E.4.3.4 Feedwater System Pipe Break

Depending upon the size of the break and plant operating conditions, the break could cause either an RCS heatup or an RCS cooldown. The cooldown aspects are less severe than a steam line break, which is discussed in subsection 19E.4.2.3 of this appendix and is not considered in the following discussion.

The main feedwater system is in operation during Modes 1 and 2. The startup feedwater system is used in Mode 2 below approximately 2 percent power, in Mode 3, and in Mode 4 before the RNS is aligned. In Mode 4 with the RNS aligned and in Modes 5 and 6, the feedwater system is not used, and therefore, a loss of feedwater caused by a feedwater system pipe break will not cause a heatup of the RCS.

A discussion and an analysis of feedwater system pipe break from rated full-power conditions are provided in subsection 15.2.8. A rupture of a feedwater system pipe results in a loss of feedwater flow causing a heatup and pressurization of the RCS. If the reactor is at-power, the event is mitigated by tripping the reactor on low steam generator level.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on low steam generator level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for a feedline break occurs with the plant at full rated power. This case will have the highest decay heat levels and the highest stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized.

19E.4.4 Decrease in Reactor Coolant Flow Rate

19E.4.4.1 Partial and Complete Loss of Forced RCS Flow

A partial loss of forced RCS flow may be caused by a mechanical or an electrical failure in an RCP or from a fault in the power supply to the pumps. An RCP failure will result in only the loss of a single RCP. A fault in the power supplies for the RCPs could result only in the loss of one, two, or all four RCPs.

The loss of one or more RCPs reduces the heat removal rate from the primary to the secondary coolant system and thereby causes a heatup in the RCS. The heatup of the RCS results in an increase in RCS pressure and a decrease in margin-to-core design limits (that is, departure from nucleate boiling [DNB]). An occurrence at full power will produce a greater and more rapid heatup than at part-power conditions or low-power conditions in Mode 2. Therefore, for evaluating the maximum RCS pressure or the minimum DNB ratio, analyses are performed at full-power conditions. Analyses for partial loss of forced RCS flow transients are presented in subsection 15.3.1. Analyses for a complete loss of flow are presented in subsection 15.3.2. These analyses bound loss of flow events initiated in other modes.

Protection for loss of forced RCS flow events is provided by tripping the reactor. This reduces reactor power and preserves margin-to-DNB limits. The AP1000 PMS includes a reactor trip on low RCS flow in any cold leg and a reactor trip on low RCP speed in any two of four RCPs. These two reactor trips are used to detect all possible partial and complete loss of RCS flow transients. Opening of the pressurizer safety valves in conjunction with the reactor trip prevents overpressurization of the RCS.

Below Mode 2, when the core is subcritical, forced RCS flow is not needed because margin-to-DNB is not an issue. It is common to have one or more RCPs out of service below Mode 2 because full RCS flow is no longer needed. In Modes 3 through 5, LCO 3.4.5 of the Technical Specifications requires that all four RCPs need to be operating if the reactor trip breakers are closed, to ensure that DNB limits are not exceeded, in the event RCCAs are inadvertently

withdrawn. If the trip breakers are open and RCCA withdrawal is precluded, no RCPs are required to be operating in Modes 3 through 5.

Following reactor trip in loss of forced RCS flow events, decay heat removal is required. The PRHR HX or the steam generators can be used for decay heat removal. In the event of a complete loss of forced RCS flow, RCS natural circulation is adequate to remove core decay heat. This is demonstrated by the loss of ac power analysis presented in subsection 15.2.6.

19E.4.4.2 Reactor Coolant Pump Shaft Seizure or Break

An RCP shaft seizure or break results in a partial loss of forced RCS flow. The results are similar to partial loss of flow events discussed in subsection 19E.4.4.2 of this appendix except that the rate of flow reduction is much more rapid if an RCP shaft breaks or seizes. Like the partial loss of flow, a locked or broken RCP shaft reduces the heat removal rate from the primary to secondary coolant system and thereby causes a heatup of the RCS. An occurrence at full power produces the most severe heatup transient. The discussion for the partial loss of flow with respect to limiting modes and protection is applicable to the RCP shaft seizures or breaks.

Analyses and evaluation of RCP shaft seizures and breaks for Mode 1, from full-power conditions, are provided in subsections 15.3.3 and 15.3.4. The analyses bound events initiated from the shutdown modes.

19E.4.5 Reactivity and Power Distribution Anomalies

19E.4.5.1 Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition

An uncontrolled RCCA bank withdrawal from a subcritical condition could cause a reactivity excursion, which if not terminated by a reactor trip, could result in DNB. Subsection 15.4.2 presents an analysis for the uncontrolled RCCA bank withdrawal from a subcritical condition in Mode 2. Assumptions are used that make the analysis bound an occurrence in Modes 2, 3, 4, or 5. Specific conservative assumptions are made for the number of RCPs operating, the reactor trip functions credited, initial RCS temperature, and the magnitude of the reactivity excursion.

A single failure in the rod control system could cause the withdrawal of only one bank, and its withdrawal rate would be expected to be slower than the maximum rod speed possible when in automatic rod control. The analysis assumes the simultaneous withdrawal of the combination of two sequential RCCA banks having the greatest combined worth at the maximum possible speed.

LCO 3.3.1 of the AP1000 Technical Specifications gives the operational requirements for reactor trips. The source-range high neutron flux trip must be in operation in Modes 3, 4, and 5 if the reactor trip breakers are closed. If the reactor trip breakers are open, then an RCCA withdrawal is precluded from occurring. The source-range high neutron flux trip is available in Mode 2 if power is below the P-6 interlock. In these instances, the source-range high neutron flux trip would be available to terminate the event, by tripping any withdrawn and withdrawing rods, before any significant power level could be attained. Therefore, DNB would be precluded. The intermediate-range high neutron flux reactor trip is also available in Mode 2. The analysis assumes that reactor trip does not occur until the power-range (low setting) high neutron flux setpoint is

reached. No credit is assumed in the analysis for the source-range high neutron flux reactor trip or the intermediate-range high neutron flux reactor trip.

LCOs 3.4.4 and 3.4.5 of the AP1000 Technical Specifications give the operation requirements for RCPs. LCO 3.4.4 specifies that all four RCPs must be operating whenever the reactor trip breakers are closed in Modes 1 through 5.

The RCS temperature is assumed to be at the HZP value in the analysis. This is more limiting than that of a lower initial system temperature for DNB and core kinetics feedback calculations.

These conservative assumptions result in the core returning to critical and generating power before reactor trip occurs. The analysis presented in Chapter 15 bounds the inadvertent RCCA bank withdrawal from a subcritical condition transient in Modes 2 through 5.

19E.4.5.2 Uncontrolled RCCA Bank Withdrawal at Power

This transient is defined only in Mode 1.

19E.4.5.3 RCCA Misalignment

RCCA misalignment events are analyzed in subsection 15.4.3. RCCA misalignment events include the following:

- One or more dropped RCCAs
- Statically misaligned RCCA
- Withdrawal of a single RCCA

This group of events may result in core radial power distribution perturbations, which may cause allowable design power peaking factors and DNB design limits to be exceeded. Therefore, these events are a concern only in the at-power modes, and the severity will be increased at high power. If the reactor is subcritical, DNB will not be a concern.

Following the dropping of one or more RCCAs while at-power, core power will immediately be reduced. The reduced core power and the continued steam demand to the turbine causes a reactor coolant temperature decrease. If the reactor is in manual control, the core power rises due to moderator feedback to the initial power level at a reduced core inlet temperature. If the reactor is in automatic control, the control system detects the drop in power and initiates withdrawal of a control bank. Power overshoot above the initial power level may occur as the control system withdraws a bank. Following dropping of one or more RCCAs, the most severe results occur when the control system overshoots the initial power level in conjunction with a perturbation in the radial power distribution. This is the most limiting case for this event, and the results are presented in Chapter 15. If the reactor is in any of the subcritical modes, dropping RCCAs will not result in any power transient.

As in the case of dropped RCCAs, statically misaligned RCCAs have no effect in the absence of a critical neutron flux and are not a concern below Mode 2. The most limiting case, and analysis, is for Mode 1 which also bounds Mode 2 operation.

The most limiting case for the withdrawal of a single RCCA is an occurrence while in Mode 1. An occurrence in any of the subcritical modes will have no effect. The shutdown margin requirements are specified in LCO 3.1.1 of the AP1000 Technical Specifications. The shutdown margin requirements are determined assuming the most reactive RCCA is fully withdrawn from the core. Therefore, no single RCCA withdrawal initiated from the subcritical modes will insert enough reactivity to attain criticality.

19E.4.5.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

This event is precluded from occurring during at-power modes by Technical Specifications. Startup of an inactive RCP while in any of the subcritical modes will have relatively little effect upon core temperature because there will be little or no temperature difference between the loops. Section 15.4.4 discusses the consequences of this event for the AP1000.

19E.4.5.5 Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant

Boron dilution analyses and evaluations for Modes 1 through 5 are provided in subsection 15.4.6. In Mode 6, administrative controls isolate the RCS from potential sources of unborated water by locking closed specified valves in the chemical and volume control system (CVS) and thereby precludes an uncontrolled boron dilution transient. Makeup needed during refueling is supplied from the boric acid tank which contains borated water.

19E.4.5.6 Inadvertent Loading of a Fuel Assembly in an Improper Position

Fuel loading errors – such as inadvertent loading of one or more fuel assemblies into improper positions, having a fuel rod with one or more pellets of the wrong enrichment, or having a fuel assembly with pellets of the wrong enrichment – may result in power shapes in excess of design values. Subsection 15.4.7 presents Mode 1 results for this event which bound the results for operation in Mode 2. This event is meaningful only if the reactor is at-power and, therefore, not applicable in the subcritical Modes of 3 through 6.

19E.4.5.7 RCCA Ejection

Analyses for RCCA ejections in Mode 1 and Mode 2 are presented in Tier 2 Information subsection 15.4.8. The cases analyzed in Chapter 15 are the most limiting cases. The shutdown margin requirements are specified in LCO 3.1.1 of the AP1000 Technical Specifications. The shutdown margin requirements are determined assuming the most reactive RCCA is fully withdrawn from the core. Therefore, the ejection of a single RCCA initiated from the subcritical modes would not insert enough reactivity to attain criticality.

19E.4.6 Increase in Reactor Coolant Inventory

An increase in RCS inventory could be caused by inadvertent actuation of the CMTs or by malfunctions in the CVS system. Analyses of events that increase the RCS inventory are provided in Section 15.5. Subsection 15.5.1 presents the analysis results for inadvertent actuation of the CMT. Subsection 15.5.2 contains results from the analysis of a CVS malfunction which increases RCS inventory. These events do not present a challenge to core design limits. If unchecked, these

events could lead to an overfill of the pressurizer and possible loss of reactor coolant from the system. The increase in pressurizer water volume is slow during these events and is controlled by the injection rate, core decay heat produced, and heat removal rate from the RCS. While the pressurizer safety valves may open, the steam relief from the pressurizer safety valves is low and no serious challenge to the RCS pressure boundary occurs (if the pressurizer does not fill).

The Chapter 15 analyses for these events are performed with the plant initially in Mode 1 at full-power conditions. This results in the maximum amount of stored energy in the plant and in the maximum core decay heat. If the plant was assumed to be at part power, or in the subcritical modes, the amount of stored energy and decay heat will be significantly reduced.

If a spurious "S" signal occurs causing the CMTs to be actuated, the reactor is also tripped and the PRHR HX is also actuated. The CMTs will begin injecting cold, borated fluid into the RCS. The injected fluid expands as it is heated in the RCS by decay heat. The expansion is counteracted by decay heat removal through the PRHR HX. The severity of the expansion is increased with higher decay heat levels.

Malfunctions in the CVS, which add excess inventory to the RCS, are protected against by the inclusion of automatic CVS isolation functions in the PMS. If a safeguards signal has occurred (which also would activate the CMTs), the CVS is automatically isolated if the pressurizer level exceeds the high-1 pressurizer level setpoint. Above the high-1 pressurizer level setpoint, there is a high-2 pressurizer level setpoint, which also isolates the CVS. The high-2 pressurizer level function is not interlocked with the safeguards signal. The high-2 function protects in situations where the reactor is at-power or a safeguards signal has not occurred. The high-2 pressurizer level function is available in Modes 1 through Mode 3 and in Mode 4 when the RNS is not operating. These functions effectively prevent overfilling of the pressurizer when the CVS acts alone or where CVS interacts to also cause the CMTs to be actuated.

Isolation of CVS on high-2 pressurizer level is available in Modes 1 through 4 until the plant is operating on RNS. There are applications where the RCS may be filled water-solid when the RNS is in operation. In Modes 4, 5, and 6 when the RNS is in operation, low-temperature overpressure protection (LTOP) of the RCS pressure boundary is provided by the RNS relief valve. A discussion of this is provided in subsection 19E.4.10.1 of this appendix.

19E.4.7 Decrease in Reactor Coolant Inventory

19E.4.7.1 Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the Automatic Depressurization System

Subsection 15.6.1 includes analyses and evaluations of the inadvertent opening of a pressurizer safety valve or the inadvertent operation of the automatic depressurization system (ADS).

When analyzed as depressurization events, inadvertent opening of primary side relief valves, if the reactor is at-power, could result in exceeding core design limits, specifically DNB criteria. Violation of DNB criteria is not a realistic concern if the reactor is in any of the subcritical modes. Therefore, these events are analyzed in Mode 1 at the maximum rated power and the analysis performed bounds cases initiated from Mode 2. These events bound events that can occur at shutdown.

The inadvertent ADS is analyzed as a loss-of-coolant accident in Mode 1 to demonstrate acceptance to the limits specified in 10 CFR 50.46. As described in subsection 15.6.5, this analysis is a “no-break” small-break LOCA calculation. The inadvertent opening of the 4-inch nominal size ADS Stage 1 valves is a situation that minimizes the venting capability of the RCS. Only the ADS valve vent area is available; no additional vent area exists due to a break. This case examines whether sufficient vent area is available to completely depressurize the RCS and achieve injection from the IRWST without core uncovery. The case analyzed at-power bounds the inadvertent ADS during shutdown because the lower decay heat levels at shutdown reduce the challenge to the ADS vent capacity. More limiting loss-of-coolant accidents at shutdown are analyzed as described in DCD subsection 19.E.4.8.

19E.4.7.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

This event is reported in subsection 15.6.2 as the rupture of a primary coolant sample line; the radiological consequences of this event are analyzed during Mode 1 because the coolant temperature and iodine concentrations bound those that would exist in the other modes. Concerning shutdown risk, the consequences of a sample line break during Modes 2, 3, 4, or 5 are no more severe than if the accident occurs during Mode 1 operation.

19E.4.7.3 Steam Generator Tube Rupture in Lower Modes

The steam generator tube rupture (SGTR) analysis presented in Chapter 15 is the limiting case with respect to offsite doses. The analysis was performed at full power because this results in the maximum offsite dose. The key inputs from the thermal-hydraulic SGTR analysis performed with the LOFTTR2 computer code to the offsite dose analysis are the amount of flashed primary to secondary break flow and the steam released from the faulted steam generator. Both of these will be significantly reduced at lower power levels and in lower modes of operation.

Margin to overfill analyses are not presented in Chapter 15, however an analysis is performed to demonstrate margin to steam generator overfill with no operator actions modeled. This is necessary because the dose analysis does not include consideration of water relief from the ruptured steam generator PORV/MSSV. This margin to steam generator overfill analysis was supported by the assertion that an analysis with operator actions modeled will also demonstrate margin to overfill. The overfill analysis with no operator actions discussed in Chapter 15 was initiated at full power. WCAP-10698-P-A (Reference 9) indicates that margin to overfill is reduced when the SGTR is initiated at zero power because of the higher initial steam generator secondary liquid inventory. WCAP-10698-P-A concludes that zero power and lower mode SGTR overfill analyses are not limiting, based primarily on more rapid operator responses expected in those conditions. This is discussed further in the Appendices to WCAP-10698-P-A. When operator actions are credited for AP1000 SGTR mitigation, the plant behaves in a manner comparable to a standard Westinghouse PWR and the conclusions of WCAP-10698-P-A apply.

When operator actions are not relied upon and only the AP1000 automatic RCS cooling and depressurization are credited, margin to overfill would still be maintained for SGTR events initiated at lower power levels despite the increased initial steam generator secondary side inventory corresponding to the lower initial power assumption. This is because the automatic protection system actions that prevent overfill are independent of the operator actions. For

operating plants, there is a set period of time from the start of the event until the operator can reverse the trend toward filling the steam generator. Therefore, the initial margin to overfill directly impacts the final margin. For the AP1000, the primary cooldown and depressurization occur automatically when the PRHR HX is actuated on a low pressurizer pressure "S" signal or low pressurizer level CMT actuation signal. The primary pressure may still be held up by the CVS, until it is isolated on a high steam generator level signal. For the AP1000, a higher initial steam generator water level results in the CVS flow being terminated earlier.

In lower modes, the PRHR HX actuation is provided only by the low pressurizer level signal. Although this results in delayed cooling and depressurization, margin to steam generator overfill is still maintained. The increase in mass in the secondary side of the ruptured steam generator is directly related to the reduction in pressurizer water level, because (once the CVS is isolated on high steam generator water level) there is no source of makeup to the RCS. The steam generator secondary side can accommodate the amount of fluid initially contained in the pressurizer and still retain a significant amount of margin to steam generator overfill. The PRHR HX will, therefore, be actuated on low pressurizer water level in sufficient time for the PRHR HX to cool and depressurize the primary and terminate break flow before steam generator overfill will occur.

19E.4.8 Loss-of-Coolant Accident Events in Shutdown Modes

The AP1000 DCD presents a spectrum of break sizes of the postulated LOCAs at the full-power operating condition. Other things being equal, the reduction in power to decay heat levels associated with shutdown mode operations will make all LOCA events less limiting than those analyzed at full power and reported in DCD subsection 15.6.5. However, as the plant proceeds through shutdown modes of operation, various PXS equipment are removed from service at identified points in time. One particularly significant action in the course of taking the AP1000 to cold shutdown, in the elimination of PXS equipment, is the isolation of the accumulators at 1000 psig. This procedural action reduces the capability of the PXS to mitigate LOCAs. For assessing the adequacy of the remaining PXS components to mitigate postulated LOCA events, the limiting double-ended cold-leg guillotine (DECLG) break, analyzed in DCD Chapter 15, is analyzed assuming it occurs immediately after the isolation of the accumulators. The analysis is performed using the AP1000 Large-Break LOCA WCOBRA-TRAC model used for the at-power Design Basis Accident analysis. Only safety-related systems are modeled in the analysis of this event.

Depressurization of the AP1000 primary system during shutdown operations will be performed with the same care taken to avoid the flashing of liquid in the core and upper head that is taken by current operating plants. Prudent plant operation dictates that subcooling margin be retained as pressure is reduced. Therefore, since the AP1000 shutdown operations will be conducted in a prudent, controlled manner, it is anticipated that the RCS temperature will be near the 420°F lower limit of Mode 3 when the accumulators are isolated.

For these analyses, the plant was assumed to be shut down in Mode 3 at steady-state conditions of 1000 psig and 425°F with the accumulators isolated. An initial pressure of 1000 psig is assumed because this is the highest pressure with the accumulators isolated and a hot-leg temperature of 425°F is the highest expected temperature when the pressure is 1000 psig. The decay heat level is determined at 2.78 hours after reactor shutdown based on the time estimate to cool down the plant

from full-power operation to 425°F at a cooldown rate of 50°F per hour. The low pressurizer pressure safeguards signal is also assumed to be disabled because the initial pressure is below the setpoint.

19E.4.8.1 Double-Ended Cold-Leg Guillotine

The DECLG break is analyzed using the WCOBRA/TRAC computer code and the AP1000-specific noding, which is based on the AP600 noding, presented in WCAP-14171, Revision 1 (Reference 10). Table 19E.4.8-1 summarizes the results.

This case models the double-ended rupture of one of the two cold legs in the RCS loop without the PRHR HX at a pressure of 1000 psig just after the accumulators are isolated. Only the core makeup tanks (CMTs) and IRWST are available to deliver PXS flow. This break evaluates the ability of the plant to withstand a large LOCA during shutdown with its conditions and equipment availability. The nominal discharge coefficient (1.0) is modeled. The analysis is performed with 10 CFR 50, Appendix K (Reference 11), required decay heat, and Technical Specification/Core Operating Limits Report maximum peaking factors.

The break is assumed to open instantaneously at 0.0 seconds. The subcooled discharge from the broken cold leg (Figure 19E.4.8-1) causes a rapid RCS depressurization (Figure 19E.4.8-2). In Figure 19E.4.8-1, the positive flow direction is the normal operation direction. The reversal of flow entering the vessel to flow out of the break is shown. Due to high-1 containment pressure, an “S” signal is generated at 2.2 seconds. Following a 2.0-second delay, the isolation valves on the CMT and PRHR HX outlet lines begin to open. The reactor coolant pumps trip at 8.2 seconds. The nominal discharge coefficient of 1.0, identified in full-power LOCA analyses, is assumed.

Within a few seconds, the collapsed liquid level drops within the upper plenum due to voiding (Figure 19E.4.8-3). The downcomer collapsed liquid level (Figure 19E.4.8-4) quickly falls below the elevation of the cold legs; the elevation of the top of the core is 20.47 feet. Because the RCS fluid enthalpy is lower than the full-power value, the RCS depressurization rate is decreased from the Tier 2 Information cases and more of the initial inventory is retained in the reactor vessel.

CMT injection from both tanks replenishes the RCS mass inventory. Injection from the CMTs as the RCS pressure declines terminates the peak cladding temperature (PCT) transient because the stable injection of water from the CMTs exceeds the break flow. The core collapsed level refills are as shown in Figure 19E.4.8-5. The pressure is low enough that the IRWST injection will begin once the CMTs drain to the low-2 level actuation setpoint. The maximum PCT value is approximately 1420°F for this bounding break size as shown in Figure 19E.4.8-6, and all the 10 CFR 50.46 (Reference 16) acceptance criteria are met.

19E.4.8.2 Loss of Normal Residual Heat Removal System Cooling in Mode 4 with Reactor Coolant System Intact

For this analysis, it is assumed that the RNS has just been placed in operation at 4 hours after reactor shutdown with the RCS at 350°F and 450 psig (464.7 psia). It is assumed that a loss of offsite power occurs, resulting in a loss of flow through the RNS, and thus, in a loss of RNS cooling. The MSS is assumed to be unavailable for heat removal although the steam generator secondary side is assumed to be at saturated conditions for 350°F with the normal water level.

Because the Mode 4 plant conditions assumed for the analysis are more limiting than Mode 5 conditions, this analysis is also applicable for a loss of RNS cooling in Mode 5 when the RCS is intact.

It is assumed that both CMTs are available for injection. Although the Technical Specifications permit one CMT to be taken out of service in Mode 4, there is a high probability that both CMTs will be available and, therefore, they were both assumed to operate. If only one CMT is available, the overall results should be similar although the timing of the event will be affected. Even though all of the fourth-stage ADS valves are available in Mode 4, the Technical Specifications permit one of the fourth-stage ADS valves to be out of service in Mode 5 when the RCS is intact. Thus, it was assumed that only three of the fourth-stage ADS valves are available for operation to bound the equipment availability in Mode 5. However, one of the three available fourth-stage ADS valves is assumed to fail to open on demand as the single failure, consistent with the single failure assumption used for the small-break LOCA analyses for shutdown conditions.

Two cases were analyzed. The first allowed for automatic safety system actuation on a low pressurizer level signal late in event. During this time, the only mechanism for removing decay heat is boiling off the RCS inventory and venting through the RNS relief valve. The second calculation assumes operator action 1800 seconds after the loss of RNS cooling.

Automatic Safety Injection Actuation Case

The accident analyzed is a loss of RNS cooling, which is assumed to result in a complete loss of heat removal for the RCS. The sequence of events for this analysis is presented in Table 19E.4.8-2.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS. The core decay heat generation causes the reactor coolant temperature and pressure to increase. Although the MSS is assumed to be unavailable for heat removal, the steam generators represent a heat sink that slows the rate of heatup of the reactor coolant. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-7. The reactor coolant heatup causes the system pressure to increase, as shown in Figure 19E.4.8-8, until the pressure reaches the RNS relief valve setpoint of 500 psig (514.7 psia) at approximately 400 seconds. The normal relieving capacity of the RNS relief valve is 850 gpm, and the pressure is maintained at the relief valve setpoint as the temperature continues to increase and reactor coolant is discharged from the relief valve. Flow out the relief valve is shown in Figure 19E.4.8-9. The expansion of the water due to the coolant temperature increase also causes the pressurizer level to increase slightly as shown in Figure 19E.4.8-10.

The loss of reactor coolant through the relief valve is not sufficient to remove the core decay heat, and the reactor coolant temperature continues to increase until the core outlet temperature reaches saturation at the relief valve setpoint at approximately 3200 seconds. The generation of steam in the core causes the system pressure to increase above the RNS relief valve setpoint and the pressurizer level to continue to increase. A mixture level begins to form in the upper plenum at approximately 3800 seconds and drops to the top of the hot-leg elevation as shown in Figure 19E.4.8-11. At about 4100 seconds, enough mass has been discharged such that a mixture level also forms in the downcomer (Figure 19E.4.8-12) and the downcomer two-phase level begins to decrease. As the boiling front moves lower and lower into the core, more steam

generation occurs and the pressure continues to increase. Once the entire core length is boiling, the upper plenum mixture level is within the hot-leg perimeter. At approximately 7000 seconds, when steam begins to flow through the relief valve along with liquid, the pressure begins to decrease. The pressurizer level also begins to decrease as water drains from the pressurizer into the reactor coolant system hot leg. However, the voiding in the RCS increases as the pressure decreases, and flashing begins to occur in the pressurizer at approximately 7300 seconds. This additional steam generation causes the pressure to begin to increase, and the relief valve flow becomes solely liquid again. The steam voiding in the pressurizer not only causes the pressure increase, but also facilitates draining, and the pressurizer level continues to decrease.

As the pressurizer level decreases, a CMT actuation signal is generated automatically on low pressurizer level. Following a 1.2-second delay, the isolation valves on the available CMT tank delivery lines open and CMT injection flow is initiated at approximately 7910 seconds as shown in Figure 19E.4.8-13. The opening of the PRHR HX isolation valve on a CMT actuation signal starts the flow through the heat exchanger. The CMT injection causes the reactor coolant pressure to decrease below the RNS relief valve setpoint, and the loss of reactor coolant is terminated at approximately 8100 seconds. As the CMT level decreases (Figure 19E.4.8-14), the first-stage ADS setpoint at 67.5 percent is reached at 9348 seconds. The second-stage and third-stage ADS valves also open following the timer delays for the actuation of the second-stage and third-stage ADS valves. The vapor and liquid flow through the ADS valves (Figures 19E.4.8-15 and 19E.4.8-16) results in a rapid depressurization of the reactor coolant system. The CMT reaches the fourth-stage ADS setpoint of 20 percent, and two of the four fourth-stage paths open at 10,225 seconds. As noted previously, it is assumed that one of the fourth-stage paths is out of service and one path is assumed to fail as the single active failure. The vapor and liquid flow through the fourth-stage ADS paths (Figures 19E.4.8-17 and 19E.4.8-18) further reduces the pressure to the point where IRWST injection begins at approximately 10,700 seconds (Figure 19E.4.8-19).

The CMT and IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-11 and 19E.4.8-12, respectively. As shown in Figure 19E.4.8-11, the core stack mixture level is maintained above the elevation of the top of the core active fuel (20.34 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to within the hot-leg perimeter and the downcomer mixture level has been restored to the DVI nozzle elevation. The fluid temperature at the core outlet has also been reduced and is being maintained at less than 250ºF. As shown in Figure 19E.4.8-20, the reactor coolant mass inventory twice reaches a minimum of approximately 110,000 pounds when the CMT and IRWST injection then increase the inventory. The reactor coolant mass inventory is greater than 200,000 pounds and is slowly increasing at the end of the transient. Thus, it is concluded that the consequences of a loss of RNS in Modes 4 and 5 with the RCS intact are acceptable.

Manual Safety Actuation

If operator action occurs after 1800 seconds, the CMT and PRHR isolation valves would open. Initially, the decay heat is greater than the PRHR capacity and the RCS pressure increases to the RNS safety valve setpoint (Figure 19E.4.8-21). At this time, RCS inventory is vented through the valve (Figure 19E.4.8-22). Eventually, the decay heat matches the PRHR capacity

(Figure 19E.4.8-42) and the RCS pressure decreases slowly to the valve setpoint. For this case, the ADS is not actuated. The sequence of events for this case is also shown in Table 19E.4.8-2.

19E.4.8.3 Loss of Normal Residual Heat Removal System Cooling in Mode 5 with Reactor Coolant System Open

For this analysis, it is assumed that the RNS is in operation in Mode 5 at 24 hours after reactor shutdown with the ADS Stage 1, 2, and 3 valves open and the RCS vented to the IRWST. The reactor coolant temperature is assumed to be at 160°F, and the pressurizer pressure is assumed to be at atmospheric pressure plus the elevation head in the IRWST, or 18.2 psia. The steam generator secondary side is assumed to be drained, and thus, there is no secondary heat sink for this case. It is assumed that the CMTs and the PRHR are not available because the Technical Specifications permit them to be taken out of service when the RCS is open in Mode 5. It is also assumed that only two of the fourth-stage ADS valves are available for potential use by the operators because the Technical Specifications permit two of the fourth-stage ADS valves to be out of service in Mode 5 when the RCS is open. In addition, one of the two available fourth-stage ADS valves is assumed to fail to open on demand as the single failure. The Technical Specifications also permit one of the two IRWST injection paths to be out of service in Mode 5 with the RCS open, and thus, only one of the IRWST injection paths is assumed to be available.

It is assumed that a loss of offsite power occurs, resulting in a loss of RNS flow, and thus a loss of RNS cooling. The sequence of events for this analysis is presented in Table 19E.4.8-3.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS and the core decay heat generation results in an increase in the reactor coolant temperature. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-24. The core outlet fluid temperature increases steadily until approximately 3000 seconds when saturation temperature is reached and voiding is initiated in the core. Because the RCS is vented to the IRWST via ADS Stages 1, 2, and 3, the pressure initially remains constant until approximately 3200 seconds as shown in Figure 19E.4.8-25. As the void generation in the system increases, the vapor flow through ADS Stages 1, 2, and 3 is not sufficient to maintain the pressure. The pressure increases to approximately 44.0 psia, and then begins to decrease. As shown in Figure 19E.4.8-26, the pressurizer level also increases as the reactor coolant temperature increases. The level subsequently reaches the top of the pressurizer as a result of the steam generation in the system. As shown in Figures 19E.4.8-27 and 19E.4.8-28, a mixture of steam and water is discharged via ADS Stages 1, 2, and 3 after the pressurizer fills.

The continued loss of reactor coolant through ADS Stages 1, 2, and 3 causes the pressure to begin to decrease after approximately 4600 seconds. The core outlet temperature is at saturation and also begins to decrease as the pressure decreases. A mixture level begins to form in the upper plenum at approximately 3550 seconds, and the level begins to decrease, as shown in Figure 19.4.8-29, as the voiding continues in the system. At about 4050 seconds, enough mass has been discharged that a mixture level forms in the downcomer (Figure 19.4.8-30) and the downcomer level also begins to decrease. The pressurizer level does not decrease significantly due an increasing void fraction in the pressurizer.

As the voiding in the core continues, the core stack mixture level continues to decrease as shown in Figure 19E.4.8-29. The void fraction in the hot legs also increases, and the mixture level in the hot leg begins to decrease after 3250 seconds. The hot leg is empty at approximately 4800 seconds as shown in Figure 19E.4.8-31. This is the normal signal for opening the fourth-stage ADS valves and to initiate IRWST injection when the systems are aligned for automatic actuation. Thus, it is assumed that the operator will initiate manual action at 4800 seconds to open the fourth-stage ADS valves and to open the IRWST flow path to permit IRWST injection when the downcomer pressure is sufficiently low. Discharge through one of the fourth-stage ADS valves is initiated at 4890 seconds as shown in Figures 19E.4.8-32 and 19E.4.8-33. As noted previously, one of the two available fourth-stage ADS paths is assumed to fail to open as the single active failure. The flow through the fourth-stage ADS path results in a further reduction in the pressurizer pressure and a rapid decrease in the pressurizer level. The downcomer pressure is also reduced to the point where IRWST injection is initiated at approximately 5500 seconds (Figure 19E.4.8-34). However, the pressurizer level increases due to subsequent additional void formation at the lower pressure and the downcomer pressure increases slightly. This temporarily terminates the IRWST flow. The downcomer pressure then drops slowly, resulting in sustained IRWST injection.

The IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-30 and 19E.4.8-31, respectively. As shown in Figure 19E.4.8-30, the core stack mixture level is maintained well above the elevation of the top of the core active fuel (20.43 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to above the middle of the hot-leg elevation and the downcomer mixture level is above the DVI nozzle elevation. The fluid temperature at the core outlet has also been reduced to approximately 250°F. As shown in Figure 19E.4.8-35, the reactor coolant mass inventory reaches a minimum of approximately 135,000 pounds and then begins to increase as a result of the IRWST injection. Thus, it is concluded that when the appropriate operator action is performed, one ADS Stage 4 valve is effective in reducing system pressure so that the consequences of a loss of RNS in Mode 5 with the RCS vented are acceptable.

The analysis presented here is a conservative analysis of a loss of RNS cooling during reduced inventory conditions. During Mode 5, prior to draining to mid-loop conditions, the operator manually opens the ADS Stages 1 through 3 paths to the IRWST. With the RCS “open,” the operator then proceeds to slowly drain the RCS to “mid-loop” conditions for performing steam generator maintenance or other maintenance that requires a reduced RCS water level. At this moment, it is postulated that a loss of decay heat removal via the nonsafety-related RNS occurs. A loss of RNS cooling at this time is selected because it is the earliest time the RCS could be placed into a reduced inventory (that is, RCS open) condition. In addition, the backpressure on the reactor vessel, due to the presence of water in the pressurizer, is higher at this time. This presents the most challenging condition for the ADS to depressurize the RCS to IRWST cut-in pressure. This transient represents the most limiting “surge line flooding” scenario, a term commonly used for operating plants to refer to the phenomenon associated with water in the pressurizer and surge line causing a high backpressure in the RCS. This potentially challenges the ability of the low head safety injection systems to inject properly. In addition, this scenario can potentially challenge the design pressure of temporary nozzle dams placed in the steam generators to facilitate maintenance of the RCS during refueling.

For a loss of the RNS during mid-loop operations, calculations have been performed to determine the time until core uncovery would occur. The results of these calculations are presented in Table 19E.2-1. The progression of events following a loss of RNS cooling during mid-loop results in a heatup of the RCS to saturation, followed by a boiling off of the coolant to the IRWST via the ADS Stages 1, 2, and 3 valves. Eventually, the operator actuates the IRWST upon a loss of RCS subcooling, followed by the loss of RCS inventory. The conditions in the RCS following IRWST and fourth-stage ADS actuation are similar to those in this evaluation. As shown in Table 19E.2-1, the operator has at least 100 minutes from the loss of RNS cooling until the onset of core uncovery to manually actuate the IRWST and ADS Stage 4. In general, the results of a loss of RNS during mid-loop conditions are similar, but slightly less severe to those presented in this evaluation due to the lower levels of decay heat and to the absence of the initial water inventory in the pressurizer. This serves to reduce the surge line flooding phenomenon that degrades the depressurization capability of the ADS Stages 1 through 3 vent paths.

19E.4.9 Radiological Consequences

This section presents evaluations that confirm that the radioactive material releases from the AP600 events postulated to be initiated in a shutdown mode have acceptable consequences.

- The Standard Review Plan (Reference 12) no longer includes the atmospheric releases from radioactive gas waste system failure and radioactive liquid waste system leak or failure events as part of the review. As discussed in subsections 15.7.1 and 15.7.2, no analysis for these events is provided.

- Release of radioactivity to the environment due to a liquid tank failure is addressed in subsection 15.7.3 and is not mode dependent.

- The fuel handling accident described in subsection 15.7.4, while not mode dependent, is analyzed in the applicable and bounding mode and accounts for spent fuel pool boiling. This accident analysis bounds radioactivity releases from other Chapter 15 events during low power and shutdown operations. The LOCA analysis results show PCT remains below 2200°F, and there are no fuel cladding failures.

- The spent fuel cask drop accident described in subsection 15.7.5 is not mode dependent.

- Appendix 15A contains the evaluation models and parameters that form the basis of the radiological consequences analyses for the various postulated accidents. This methodology applies in all modes of operation.

In summary, there are no shutdown risks associated with the radiological consequences methodology or parameters, or the postulated or applicable events, which need to be considered outside the scope of what is already analyzed for Section 15.7.

19E.4.10 Other Evaluations and Analyses

19E.4.10.1 Low Temperature Overpressure Protection

For the AP1000, the normal residual heat removal system (RNS) suction relief valve is located immediately downstream of the RCS suction isolation valves. This relief valve protects the RNS from overpressurization and provides low temperature overpressure protection (LTOP) for the RCS components when the RNS is aligned to the RCS to provide decay heat removal during plant shutdown and startup operations. The RNS relief valve is sized to provide LTOP by limiting the RCS and RNS pressure to less than the 10 CFR 50 Appendix G (Reference 13) steady-state pressure limit. Subsection 5.2.2 provides a discussion of the AP1000 low temperature overpressure protection design bases.

19E.4.10.2 Shutdown Temperature Evaluation

In SECY-94-084, Item C, Safe Shutdown (Reference 14), the NRC staff recommended the Commission's approval of 420°F or below, rather than cold shutdown condition as a safe stable condition, which the PRHR HX must be capable of achieving and maintaining following non-LOCA events, predicated on acceptable passive safety system performance and an acceptable resolution of the regulatory treatment of nonsafety systems (RTNSS) issue. The NRC requested a safety analysis to demonstrate that the passive systems can bring the plant to a stable safe condition and maintain this condition so that no transients will result in the specified acceptable fuel design limit and pressure boundary design limit being violated and that no high-energy piping failure being initiated from this condition results in 10 CFR 50.46 (Reference 15) criteria.

As discussed in subsection 7.4.1.1, the PRHR HX operates to reduce the RCS temperature to the safe shutdown condition following an event. An analysis of the loss of ac power event demonstrates that the passive systems can bring the plant to a stable safe condition following postulated transients. The results of this analysis are presented in Figures 19E.4.10-1 through 19E.4.10-4. The progression of this event is outlined in Table 19E.4.10-1.

Summarizing this transient, the loss of normal ac power occurs, followed by the reactor trip. The PRHR heat exchanger is actuated on the low steam generator narrow range level coincident with low startup feed water flow rate signal. Eventually a safeguards actuation signal is actuated on Low cold leg temperature and the CMTs are actuated.

Once actuated, at about 600 seconds, the CMTs operate in recirculation mode, injecting cold borated water into the RCS. In the first part of their operation, due to the cold flow rate, the CMTs operate in conjunction with the PRHR to reduce RCS temperature. Due to the primary system cooldown, the PRHR heat transfer capability drops below the decay heat and the RCS cooldown is essentially driven by the CMT cold injection flow. However, at about 3,500 seconds, the CMT cooling effect decreases and the RCS starts heating up again (Figure 19.E.4.10-1). The RCS temperature increases until the PRHR HX can match decay heat. At about 31,000 seconds, the PRHR heat transfer matches decay heat and it continues to operate to reduce the RCS temperature to below 420°F within 36 hours. As seen from Figure 19E.4.10-1 the cold leg temperature in the loop with the PRHR is reduced to 420°F at 82,600 seconds, while the core average temperature reaches 420°F in 123,600 seconds (approximately 34 hours).

As discussed in subsection 7.4.1.1, this mode of operation can last for up to 72 hours. However, in about 22 hours after the event, if no ac power is available, or if condensate return is not available, then the operator is instructed to actuate the ADS. Operation of the ADS in conjunction with the CMTs, accumulators, and IRWST reduces the RCS pressure and temperature to below 420°F.

19E.5 Technical Specifications

While the Technical Specification guidance provided in NUREG-1449 (Reference 2) relates to existing plant shutdown operation concerns, the underlying concerns relating to causes of events and recovery from those events during shutdown operations are applicable to the AP1000. Section 19E.5.1 summarizes the shutdown Technical Specifications. Section 19E.5.2 summarizes the AP1000's compliance with SECY-93-190 (Reference 16).

19E.5.1 Summary of Shutdown Technical Specifications

The content of the AP1000 Technical Specifications meets the requirements of 10 CFR 50.36 (Reference 17) and is consistent with the guidance provided in NUREG-1431 (Reference 18). For the AP1000, passive systems are used to safely shut down the plant. Because this design feature is different from existing plants, and because NUREG-1449 provides a reasonable basis for creating shutdown Technical Specifications, the AP1000 Technical Specifications are improved to include specifications for these systems in the shutdown modes. These shutdown specifications are summarized in AP1000 Technical Specification Table B 3.0-1 (Section 16.1), which provides the passive systems shutdown mode matrix of system versus limiting conditions for operation (LCO), mode applicability, and required end state.

19E.6 Shutdown Risk Evaluation

The "AP1000 Probabilistic Risk Assessment (PRA)" (Chapter 19) provides an assessment of the plant risk associated with events at shutdown.

19E.7 Compliance with NUREG-1449

The Diablo Canyon event of April 10, 1987, and the loss of ac power event at the Vogtle plant on March 20, 1990, led the Nuclear Regulatory Commission (NRC) staff to issue NUREG-1449, "Shutdown and Low Power Operation at Commercial Nuclear Power Plants in the United States" (Reference 2), to provide an evaluation of the shutdown risk issue. The scope of NUREG-1449 includes subjects such as operating experiences as documented in generic letters, operator training, technical specifications, residual heat removal capacity, temporary reactor coolant boundaries, rapid boron dilution, containment capacity, fire protection, outage planning and control, and instrumentation.

The NRC requested Westinghouse to assess the compliance of AP600 with NUREG-1449. It was recognized that some of the issues discussed in NUREG-1449 are the responsibility of the plant owners because they relate to operation, maintenance, and refueling plans, procedures, and risk management. However, the NRC believed that the level of defense-in-depth against shutdown events would be improved if clear guidance is provided to the areas discussed above by the plant designer. The NRC requested that Westinghouse perform a systematic assessment of the shutdown

risk issue to address areas identified in NUREG-1449 as they are applicable to the AP1000 design and document the results.

This Appendix provides the systematic assessment of the shutdown risk issue to address areas identified in NUREG-1449. This assessment includes design basis evaluations of events that can occur during shutdown and a probabilistic assessment of plant risk at shutdown. The design of the AP1000 builds on the lessons-learned from the industry with regard to shutdown safety, including the guidance provided in NUREG-1449.

19E.8 Conclusion

This AP1000 Shutdown Evaluation provides a systematic evaluation of the AP1000 during shutdown operations. As demonstrated in this appendix, the AP1000 is designed to mitigate events that can occur during shutdown modes. In addition, the risk of core damage as a result of an accident that may occur during shutdown has been demonstrated to be acceptably low.

19E.9 References

1. Letter, Westinghouse to NRC, DCP/NRC1385, AP600 Emergency Response Guidelines.

2. NUREG-1449, "Shutdown and Low Power Operations at Commercial Nuclear Power Plants in the United States," September 1993.

3. NRC Information Notice 92-54, "Level Instrumentation Inaccuracies Caused by Rapid Depressurization," July 24, 1992.

4. Letter, Westinghouse to NRC, DCP/NRC0124, APWR-0452, "AP600 Vortex Mitigator Development Test for RCS Mid-loop Operation," July 6, 1994.

5. NUREG-0897, Rev. 1, "Containment Emergency Sump Performance," October 1985.

6. Title 10, Code of Federal Regulations, Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants."

7. NRC Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," Revision 3, February 1976.

8. American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, 1988 with 1989 Addenda.

9. Lewis, R. N., Huang, P., Behnke, D. H., Fittante, R. L., and Gelman, A., WCAP-10698-P-A (Proprietary) and WCAP-10750-A (Non-Proprietary), "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August 1987.

10. WCAP-14171, Revision 2 (Proprietary) and WCAP-14172, Revision 2 (Non-Proprietary), "WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident," March 1998.

11. Title 10, Code of Federal Regulations, Part 50, Appendix K, "ECCS Evaluation Model."

12. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Revision 1, July 1981.

13. Title 10, Code of Federal Regulations, Part 50, Appendix G, "Fracture Toughness Requirements."

14. SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," March 28, 1994.

15. Title 10, Code of Federal Regulations, Part 50, (10 CFR 50.46).

16. NRC letter, SECY-93-190, "Regulatory Approach to Shutdown and Low-Power Operations," July 12, 1993.

17. Title 10, Code of Federal Regulations, Part 50.36, "Technical Specifications."

18. NUREG-1431, "Standard Technical Specifications – Westinghouse Plants," April 1995.

Table 19E.2-1

EVALUATION OF A LOSS OF RNS AT MID-LOOP WITH NO IRWST INJECTION

Time After Shutdown	Time to Boiling	Time to Empty Hot Leg	Time to Core Uncovery
28 hours	10 minutes	22 minutes	40 minutes

Table 19E.4.1-1 (Sheet 1 of 2)

AP1000 ACCIDENTS REQUIRING SHUTDOWN EVALUATION OR ANALYSIS

Tier 2 Section	Titles	Evaluation or Analysis Required
15.1	Increase in Heat Removal from the Primary System	
15.1.1	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature	E
15.1.2	Feedwater System Malfunctions that Result in an Increase in Feedwater Flow	E
15.1.3	Excessive Increase in Secondary Steam Flow	E
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	E
15.1.5	Steam System Piping Failure	E
15.1.6	Inadvertent Operation of the Passive Residual Heat Removal Heat Exchanger	E
15.2	Decrease in Heat Removal by the Secondary System	
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	E
15.2.2	Loss of External Electrical Load	E
15.2.3	Turbine Trip	E
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	E
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	E
15.2.6	Loss of ac Power to the Plant Auxiliaries	E
15.2.7	Loss of Normal Feedwater Flow	E
15.2.8	Feedwater System Pipe Break	E
15.3	Decrease in Reactor Coolant System Flow Rate	
15.3.1	Partial Loss of Forced Reactor Coolant Flow	E
15.3.2	Complete Loss of Forced Reactor Coolant Flow	E
15.3.3	Reactor Coolant Pump Shaft Seizure (Locked Rotor)	E
15.3.4	Reactor Coolant Pump Shaft Break	E
15.4	Reactivity and Power Distribution Anomalies	
15.4.1	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-Power Startup Condition	E
15.4.2	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	n/a
15.4.3	Rod Cluster Control Assembly Misalignment (System Malfunction or Operator Error)	E
15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	E

Table 19E.4.1-1 (Sheet 2 of 2)

AP1000 ACCIDENTS REQUIRING SHUTDOWN EVALUATION OR ANALYSIS

Tier 2 Section	Titles	Evaluation or Analysis Required
15.4.6	Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant	n/a
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	E
15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents	
15.5	Increase in Reactor Coolant Inventory	
15.5.1	Inadvertent Operation of the Core Makeup Tanks (CMT) During Power Operation	E
15.5.2	Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory	E
15.6	Decrease in Reactor Coolant Inventory	
15.6.1	Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the ADS	E
15.6.2	Failure of Small Lines Carrying Primary Coolant Outside Containment	E
15.6.3	Steam Generator Tube Rupture	E
15.6.5	Loss of Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary	E/A
15.7	Radioactive Release From a Subsystem or Component	E

Table 19E.4.8-1

DOUBLE-ENDED COLD-LEG GUILLOTINE BREAK – SEQUENCE OF EVENTS

Event	Time (seconds)
Break open	0.0
"S" signal receipt	4.2
RCPs start to coast down	8.2
CMT draindown begins	5
Lower plenum refilled	200

Table 19E.4.8-2

LOSS OF NORMAL RESIDUAL HEAT REMOVAL SYSTEM COOLING IN MODE 4 WITH REACTOR COOLANT SYSTEM INTACT – SEQUENCE OF EVENTS

Event	Automatic Actuation Time (seconds)	Manual Actuation Time (seconds)
Loss of RNS cooling	0	0
RNS relief valve flow starts	250	250
CMT and PRHR actuated	7910	1800
RNS relief valve flow terminated	8100	<1 lbm/s @ 25,000
ADS Stage 1 flow starts	9348	–
ADS Stage 2 flow starts	9418	–
ADS Stage 3 flow starts	9538	–
ADS Stage 4 flow starts	10,225	–
IRWST injection starts	10,700	–

Table 19E.4.8-3

LOSS OF NORMAL RESIDUAL HEAT REMOVAL SYSTEM COOLING IN MODE 5 WITH REACTOR COOLANT SYSTEM OPEN – SEQUENCE OF EVENTS

Event	Time (seconds)
Loss of RNS cooling	0
Hot leg empty	4800
ADS Stage 4 flow initiated	4890
IRWST injection starts	5500

Tables 19E.4.8-4 and 19E.4.8-5 not used.

Table 19E.4.10-1

SEQUENCE OF EVENTS FOLLOWING A LOSS OF AC POWER FLOW WITH CONDENSATE FROM THE CONTAINMENT SHELL BEING RETURNED TO THE IRWST

Event	Time (seconds)
Feedwater is Lost	10.0
Low Steam Generator Water Level (Narrow-Range) Reactor Trip Setpoint Reached	72.4
Rods Begin to Drop	74.4
PRHR HX Actuation on Low Steam Generator Water Level (Wide-Range)	129.4
Low T_{cold} Setpoint Reached	599.0
Steamline Isolation on Low T_{cold} Signal	611.0
CMTs Actuated on Low T_{cold} Signal	617.0
IRWST Reaches Saturation Temperature	17,600
Heat Extracted by PRHR HX Matches Core Decay Heat	31,000
CMTs Stop Recirculating	43,500
Cold Leg Temperature Reaches 420°F (loop with PRHR)	82,600
Hot Leg Temperature Reaches 420°F (loop with PRHR)	123,600

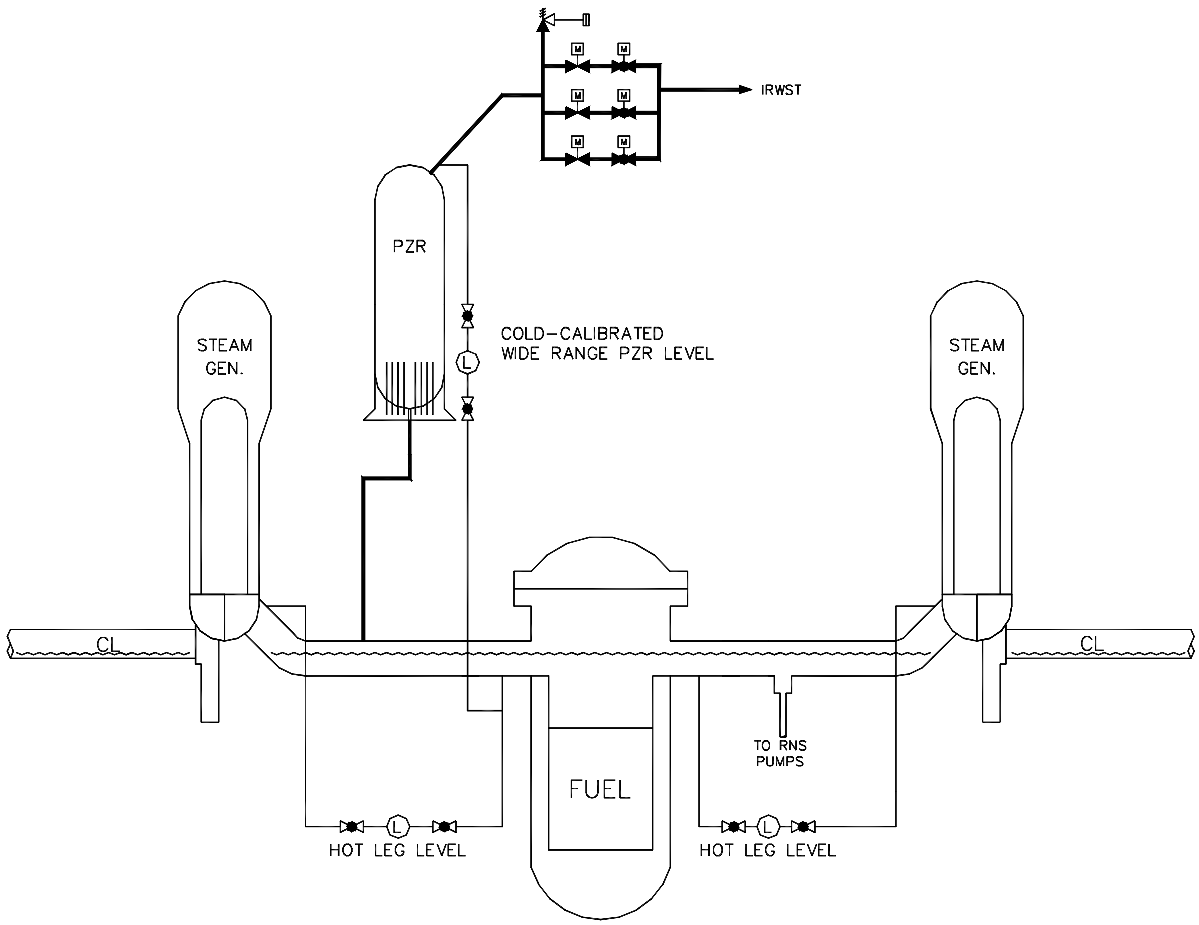

Figure 19E.2-1

Reactor Coolant System Level Instruments Used During Shutdown

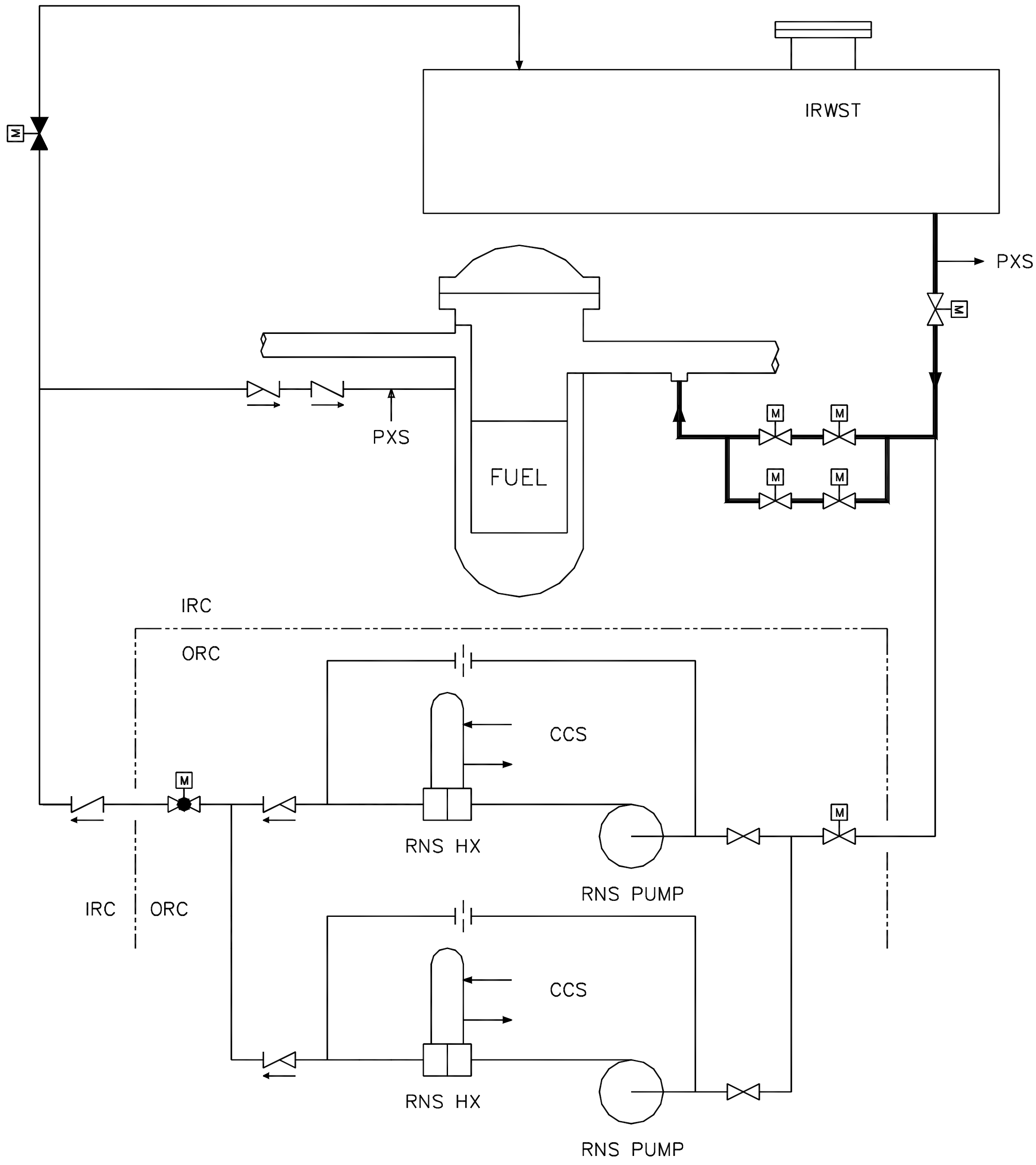

Figure 19E.2-2

IRWST Injection Flow Path

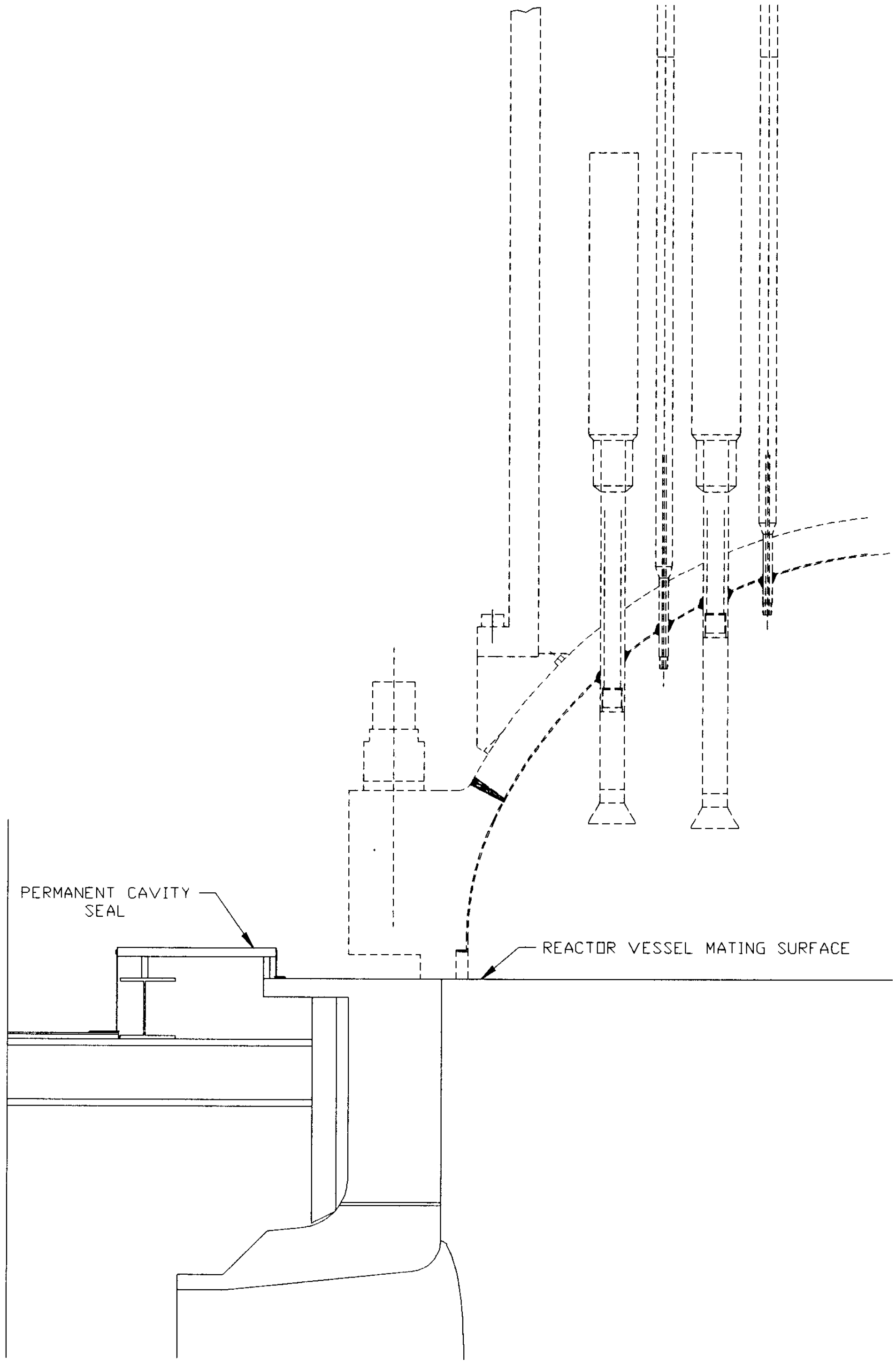

Figure 19E.2-3

AP1000 Permanent Reactor Cavity Seal

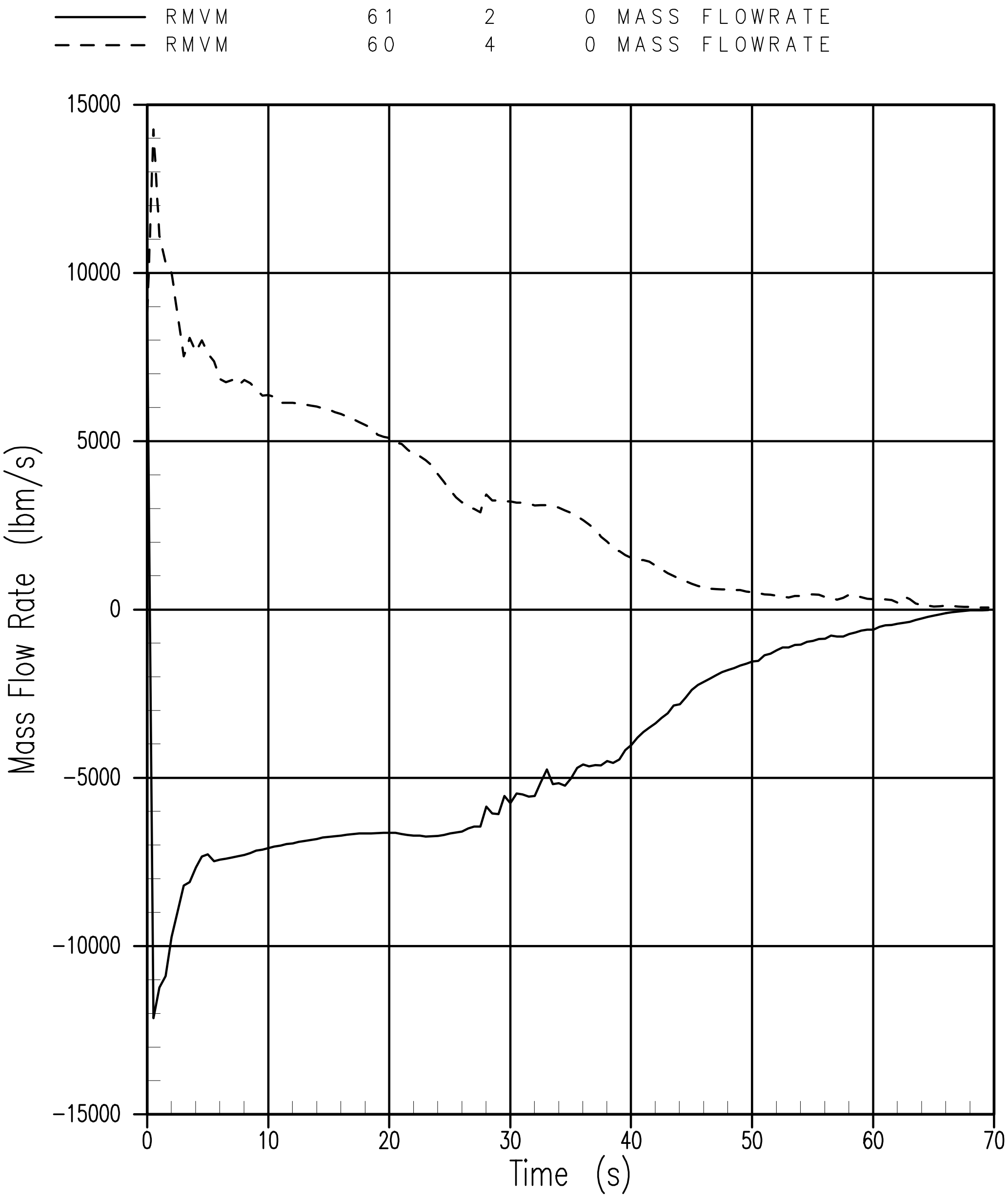

Figure 19E.4.8-1

Mode 3 DECLG Break, Break Flow Rates, Vessel and RCP Sides

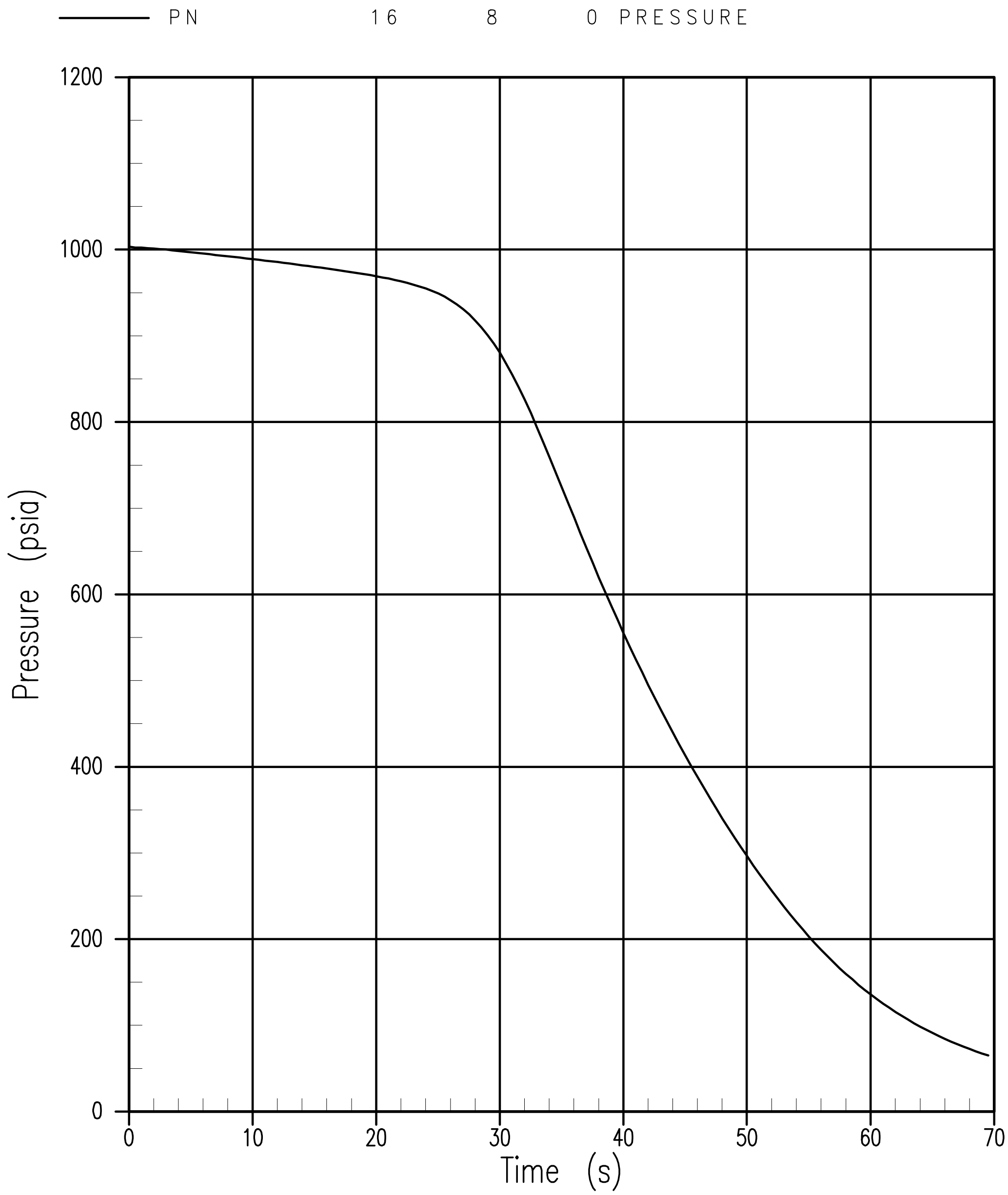

Figure 19E.4.8-2

Mode 3 DECLG Break, Pressurizer Pressure

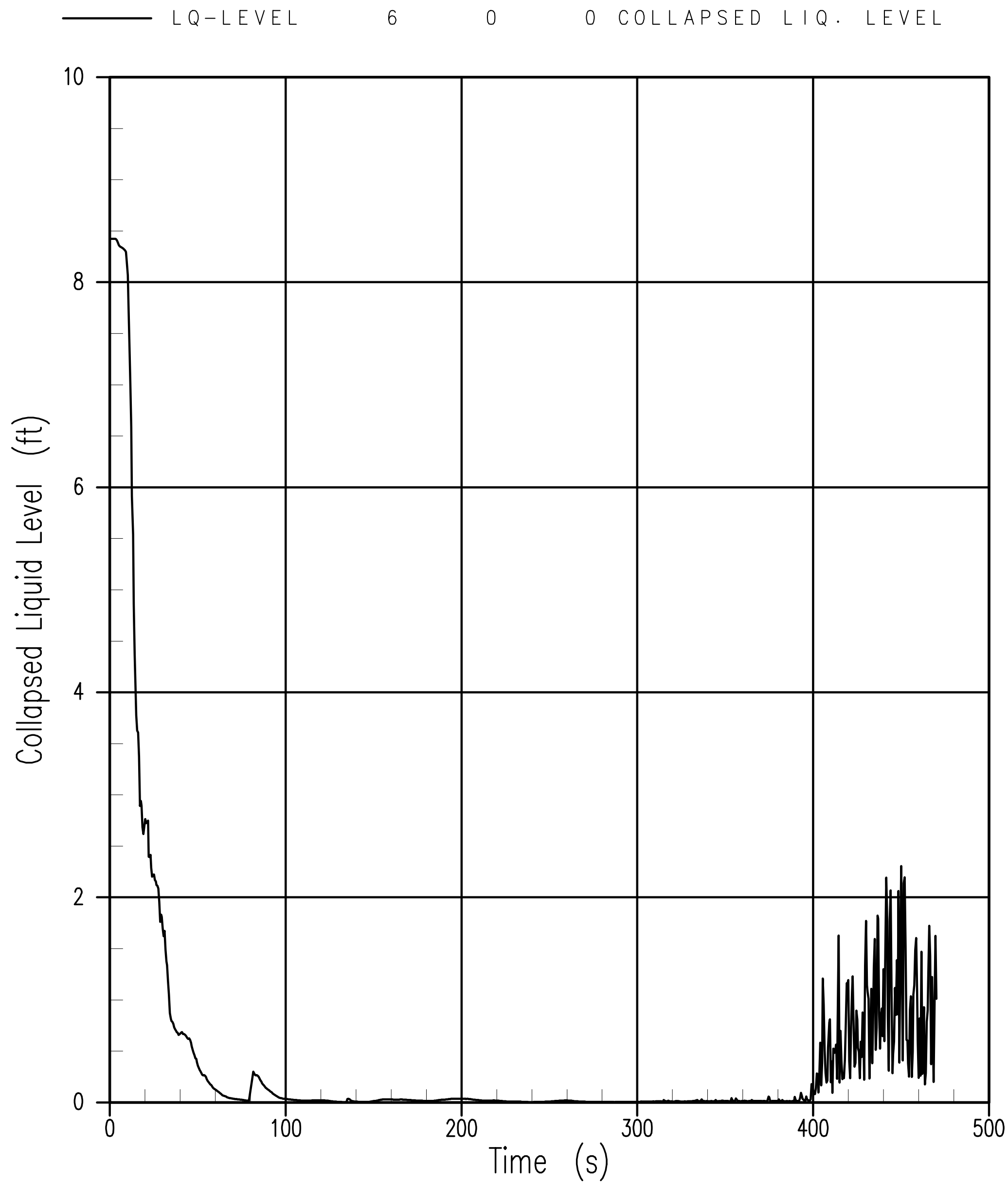

Figure 19E.4.8-3

Mode 3 DECLG Break, Upper Plenum Collapsed Liquid Level

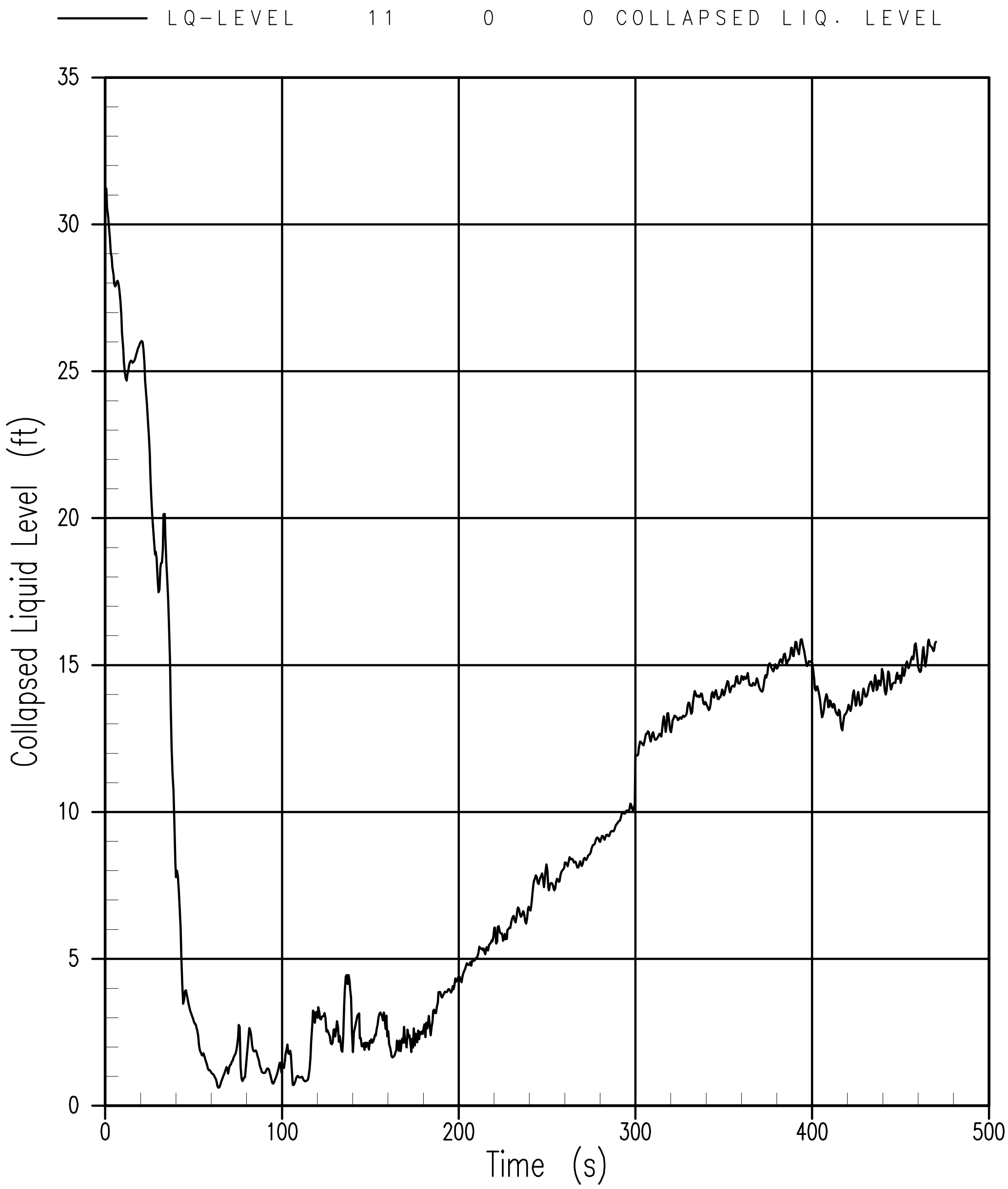

Figure 19E.4.8-4

Mode 3 DECLG Break, Downcomer Collapsed Liquid Level

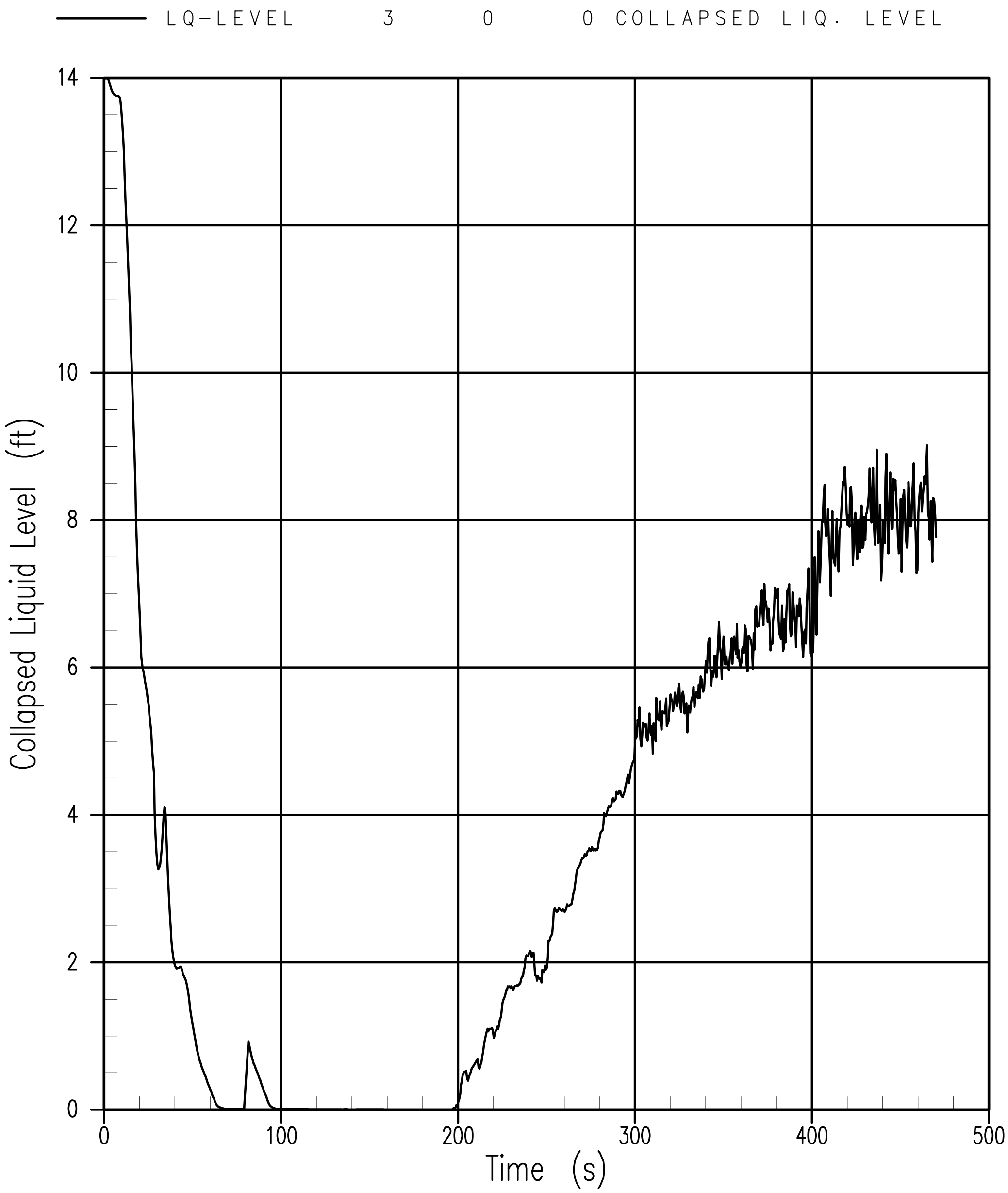

Figure 19E.4.8-5

Mode 3 DECLG Break, Core Collapsed Liquid Level

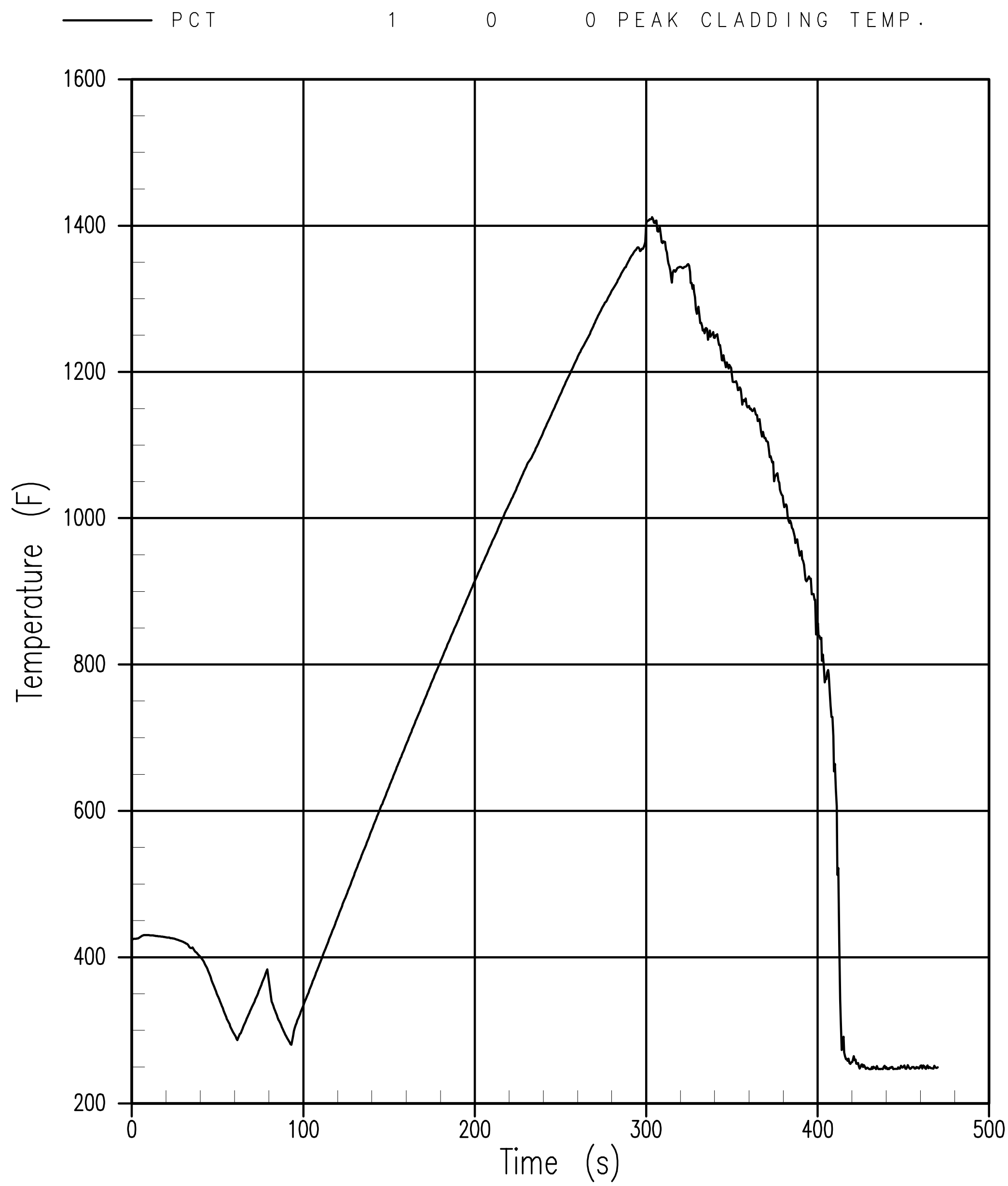

Figure 19E.4.8-6

Mode 3 DECLG Break, Peak Cladding Temperature

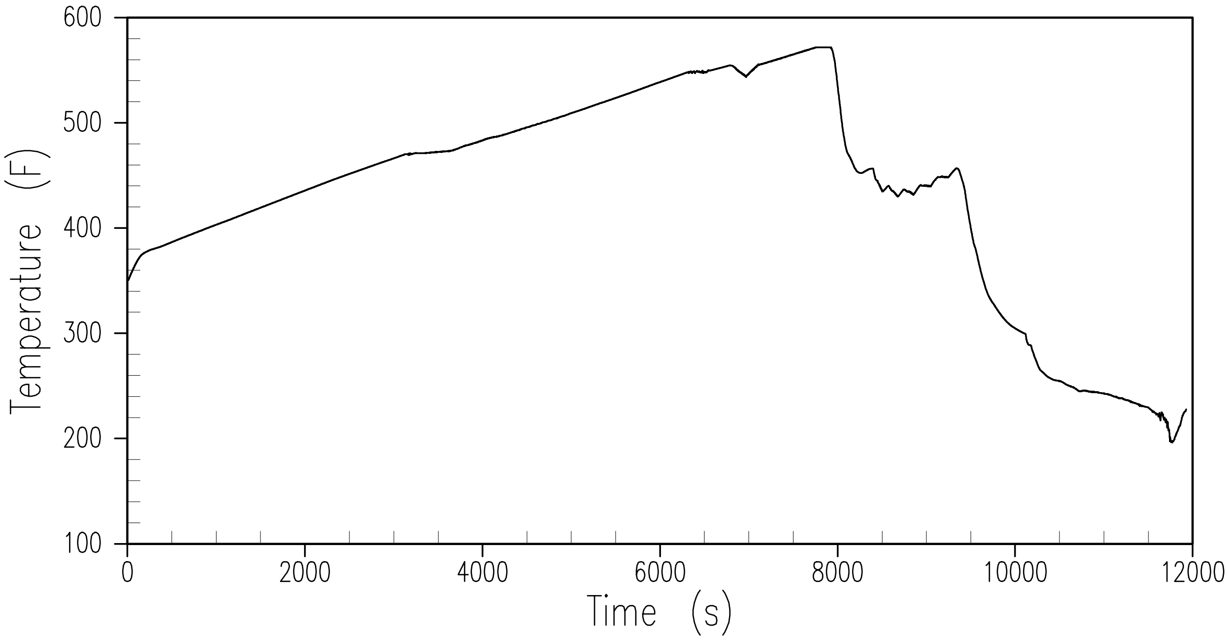

Figure 19E.4.8-7

Core Outlet Temperature, Loss of RNS in Mode 4 with RCS Intact

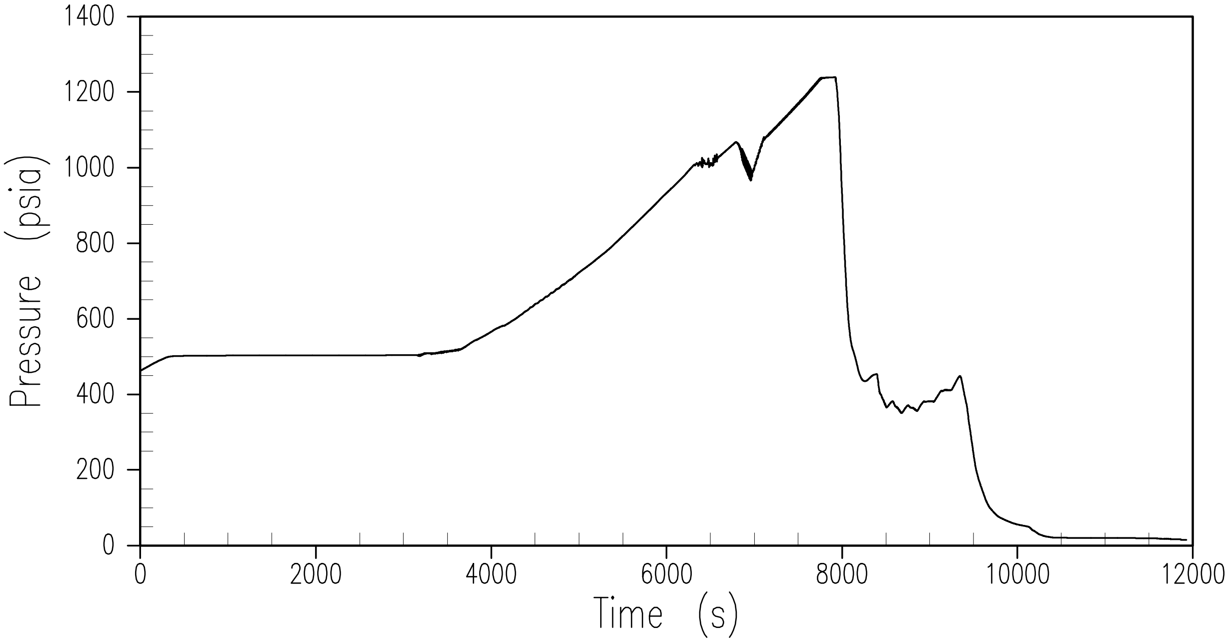

Figure 19E.4.8-8

Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact

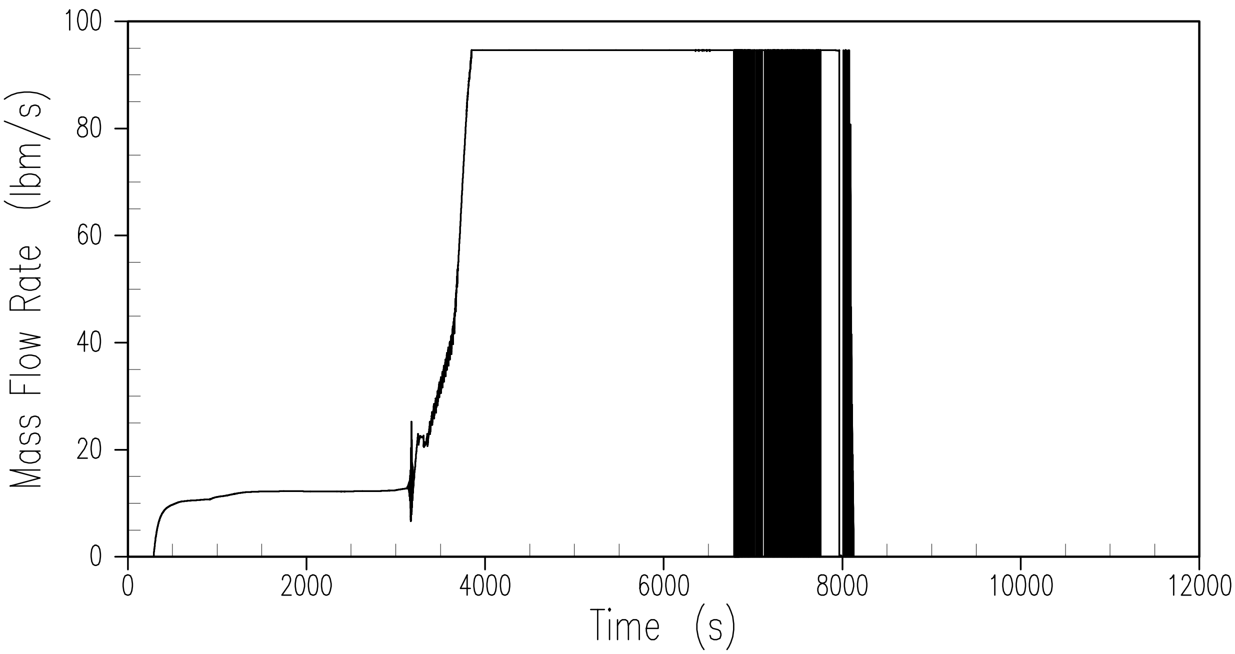

Figure 19E.4.8-9

RNS Relief Valve Flow, Loss of RNS in Mode 4 with RCS Intact

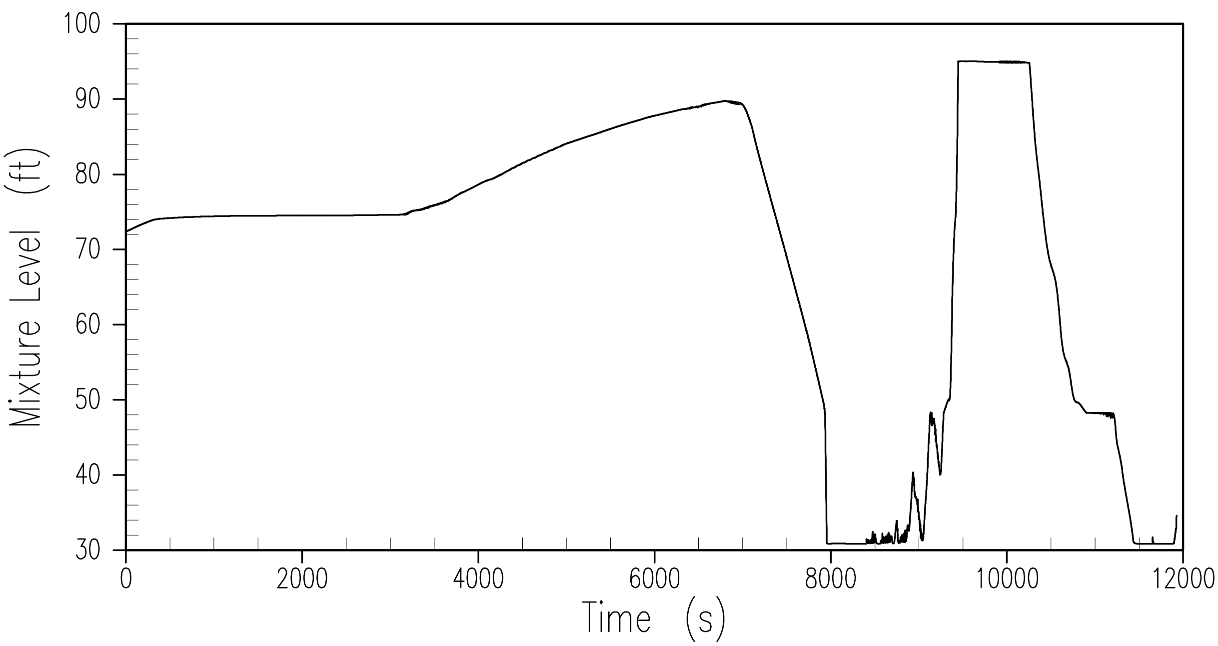

Figure 19E.4.8-10

Pressurizer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

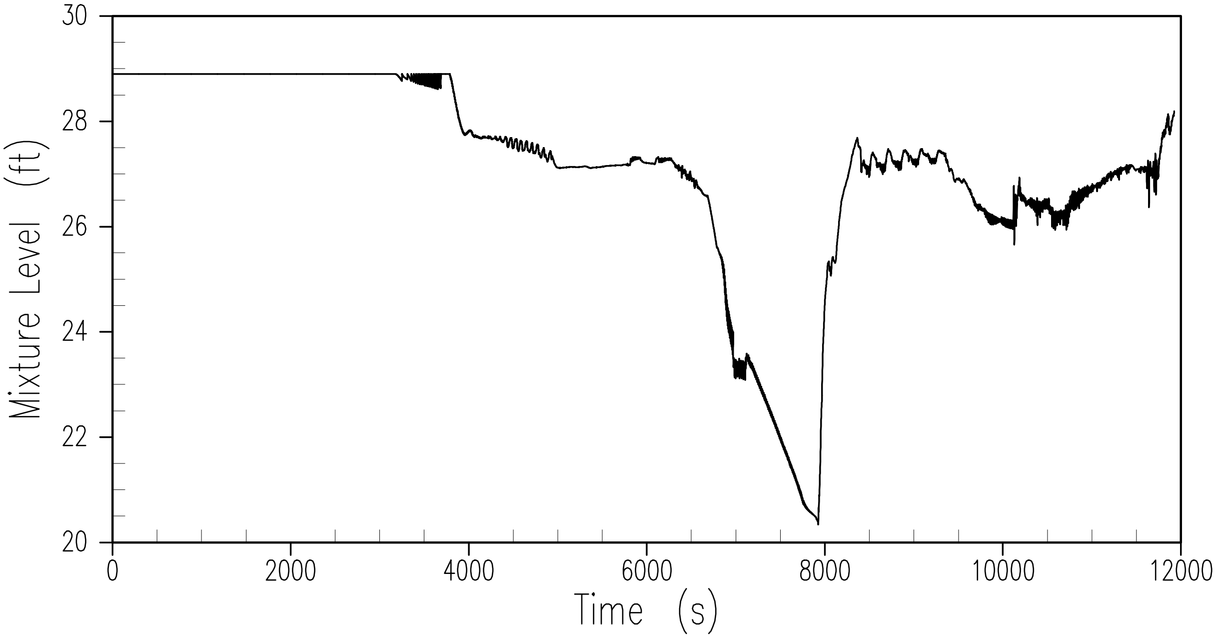

Figure 19E.4.8-11

Core Stack Mixture Level, Loss of RNS in Mode 4 with RCS Intact

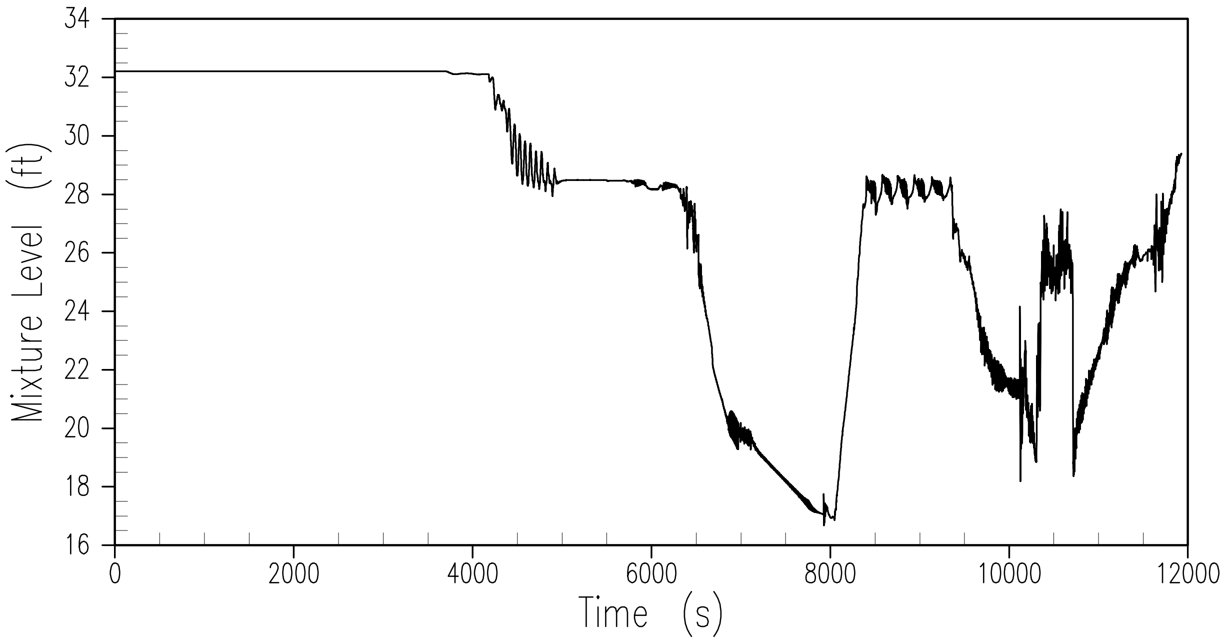

Figure 19E.4.8-12

Downcomer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

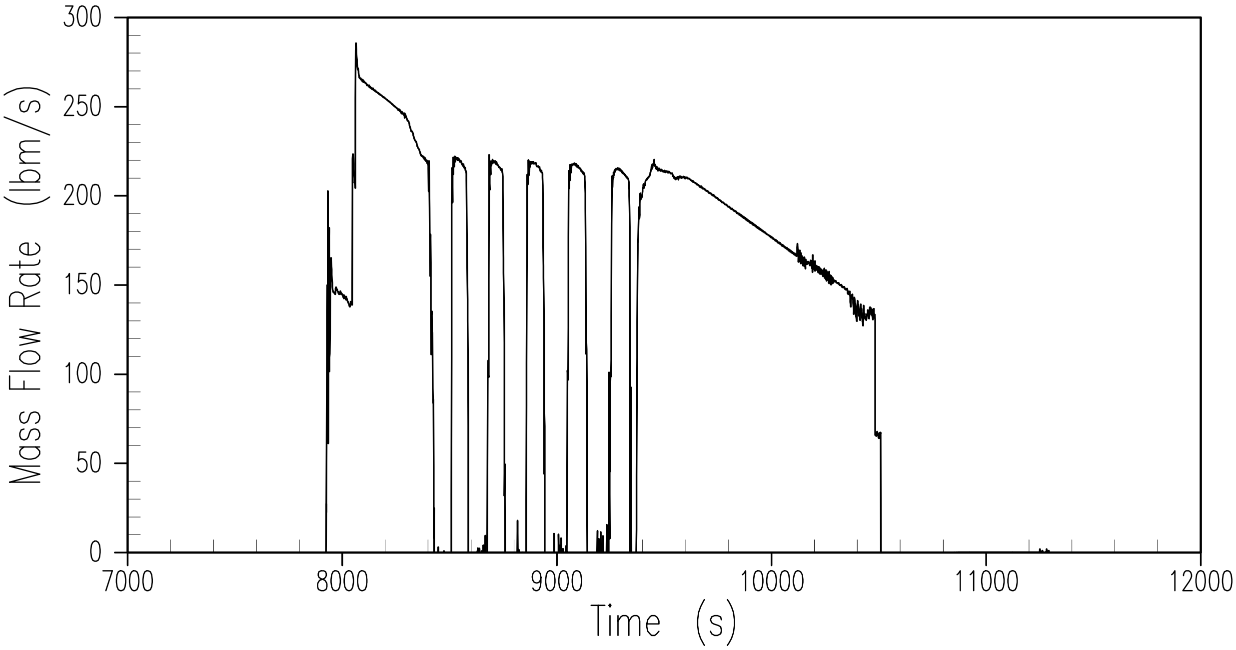

Figure 19E.4.8-13

CMT to DVI Flow, Loss of RNS in Mode 4 with RCS Intact

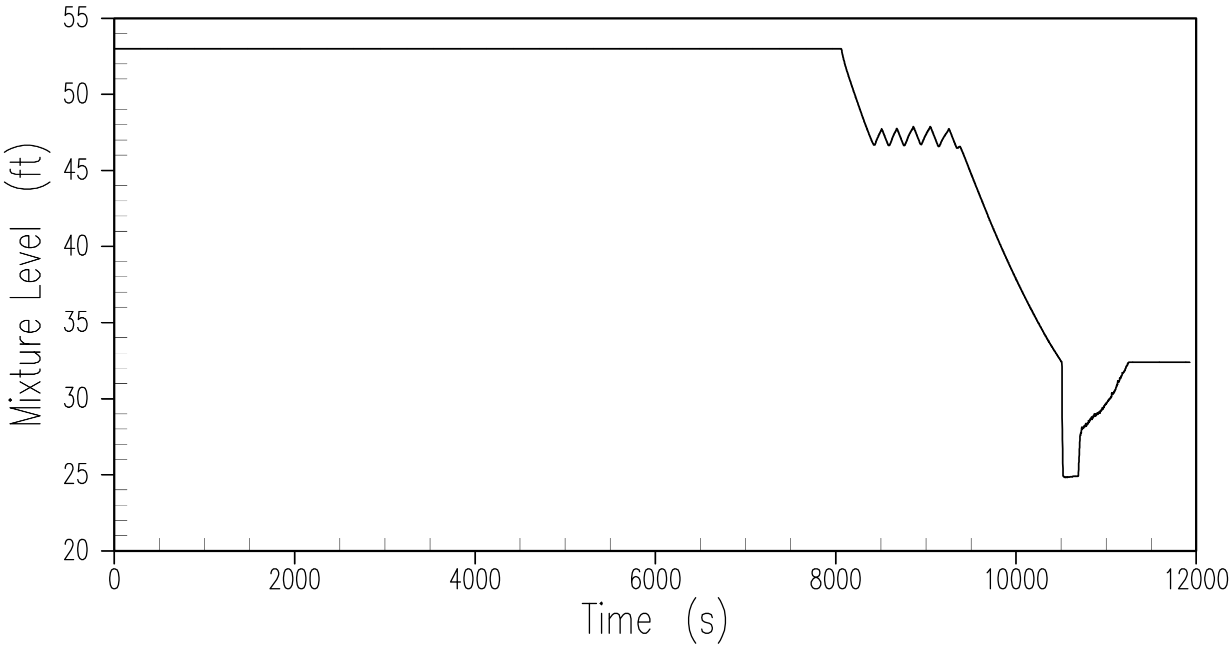

Figure 19E.4.8-14

CMT Mixture Level, Loss of RNS in Mode 4 with RCS Intact

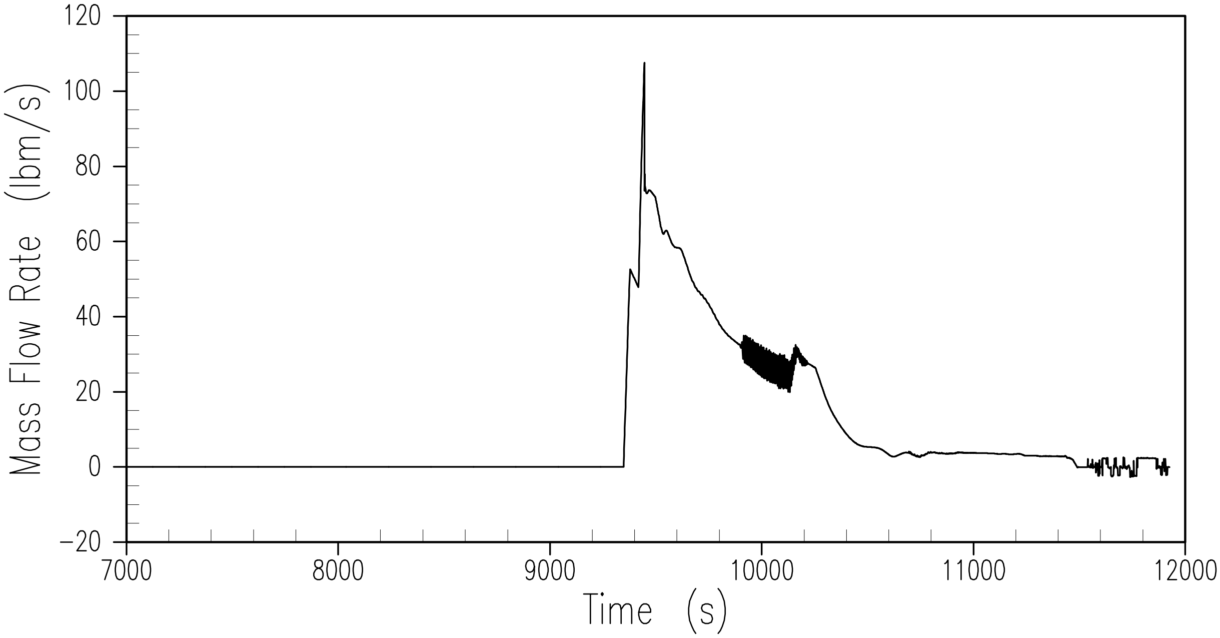

Figure 19E.4.8-15

ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 4 with RCS Intact

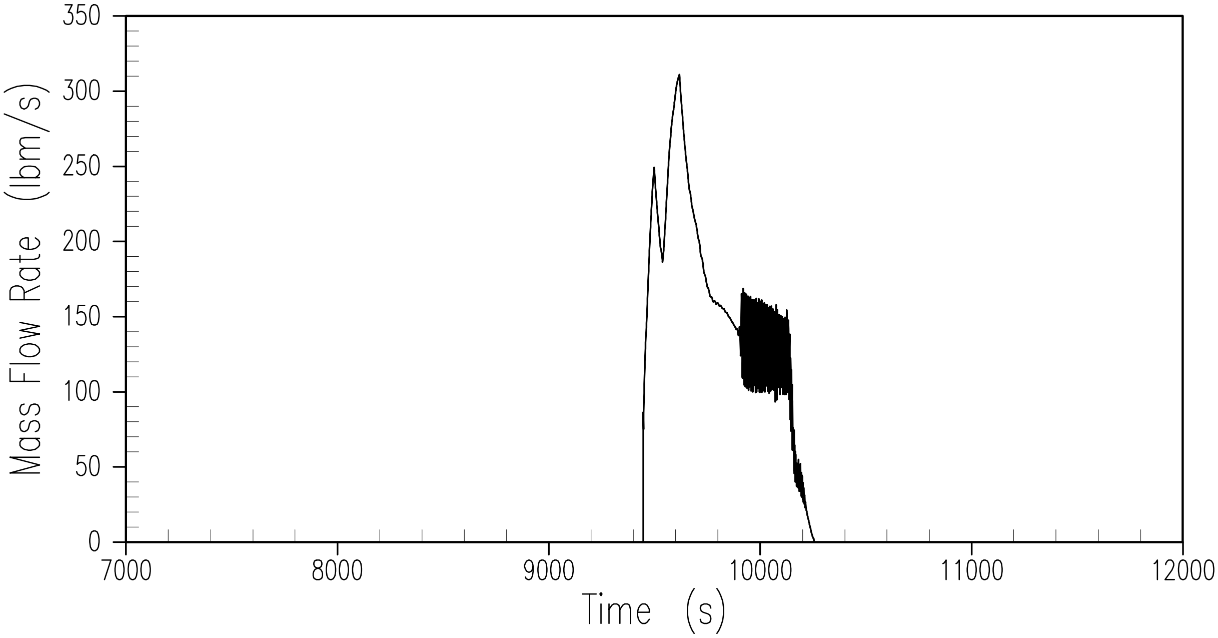

Figure 19E.4.8-16

ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

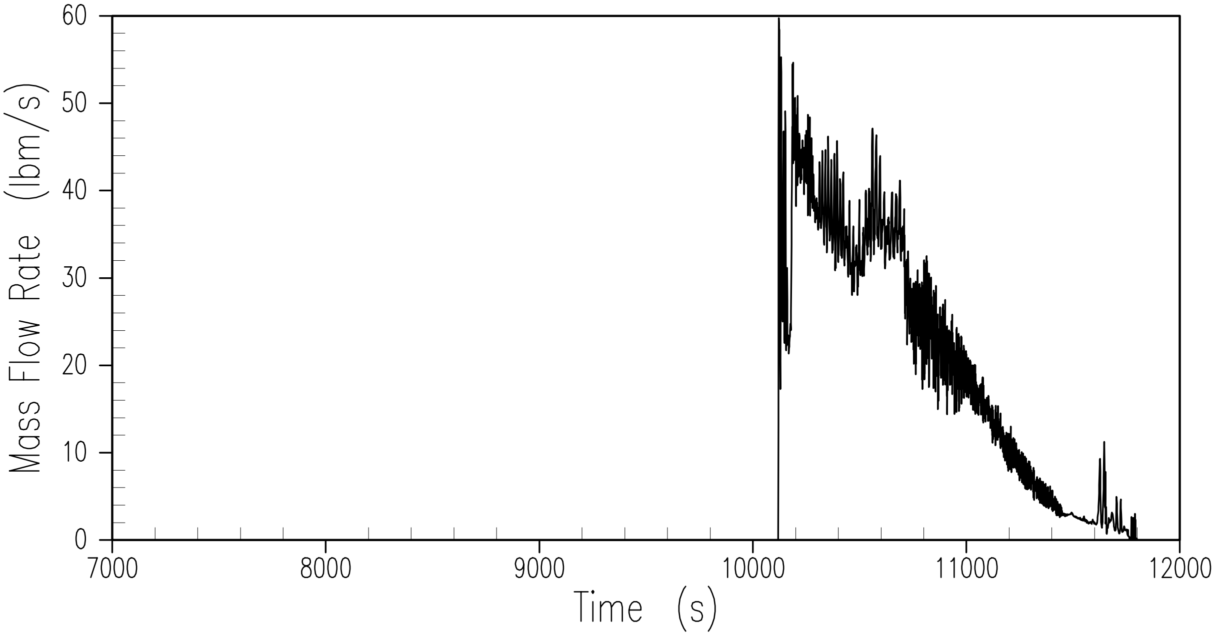

Figure 19E.4.8-17

ADS Stage 4 Vapor Flow, Loss of RNS in Mode 4 with RCS Intact

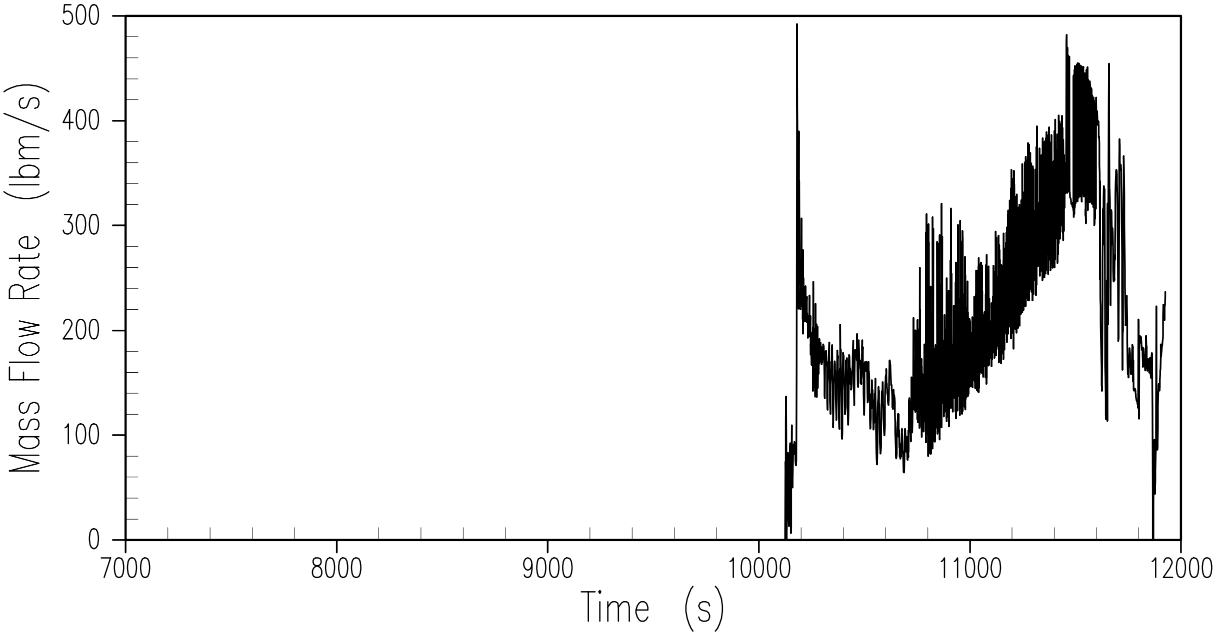

Figure 19E.4.8-18

ADS Stage 4 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

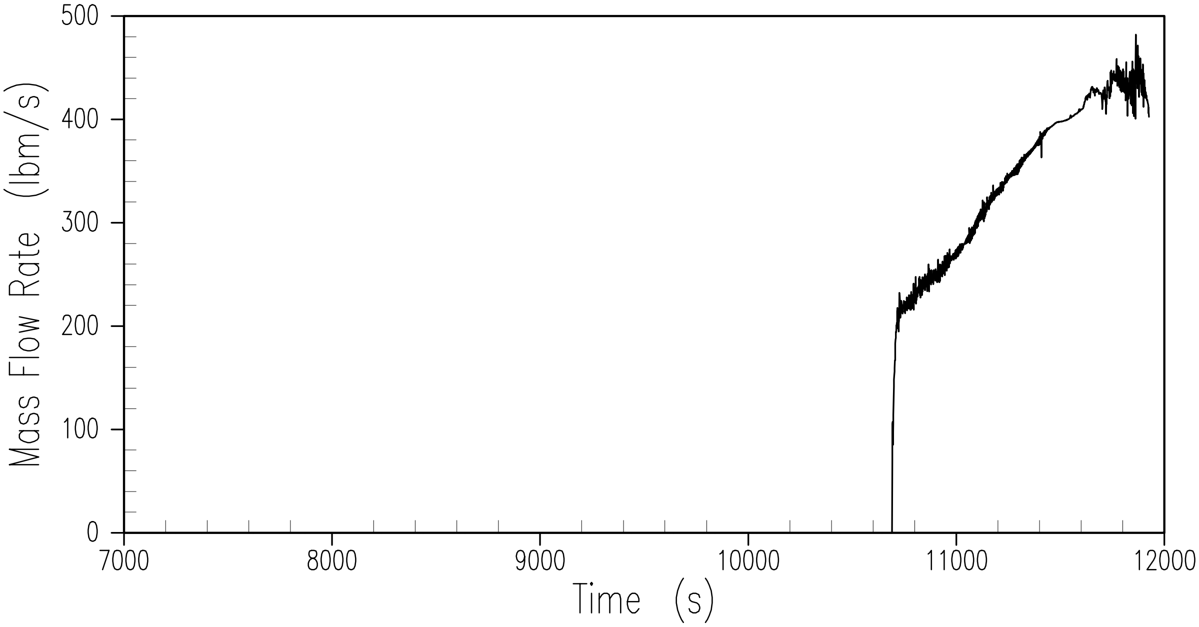

Figure 19E.4.8-19

Loop 1 IRWST Injection Flow, Loss of RNS in Mode 4 with RCS Intact

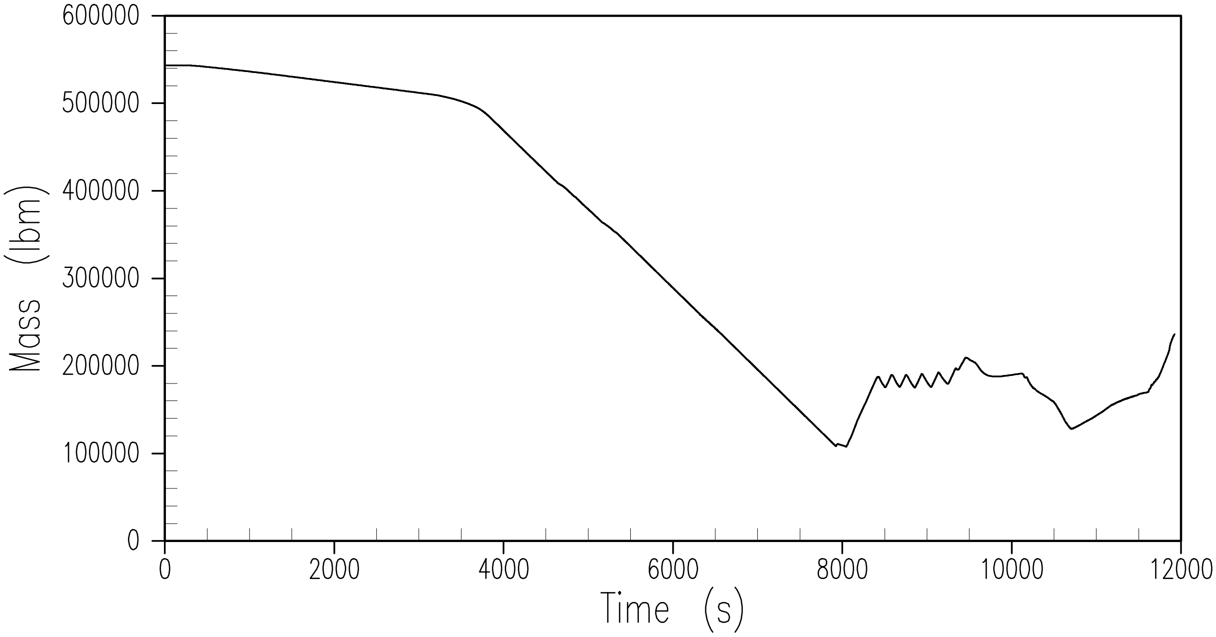

Figure 19E.4.8-20

Primary Mass Inventory, Loss of RNS in Mode 4 with RCS Intact

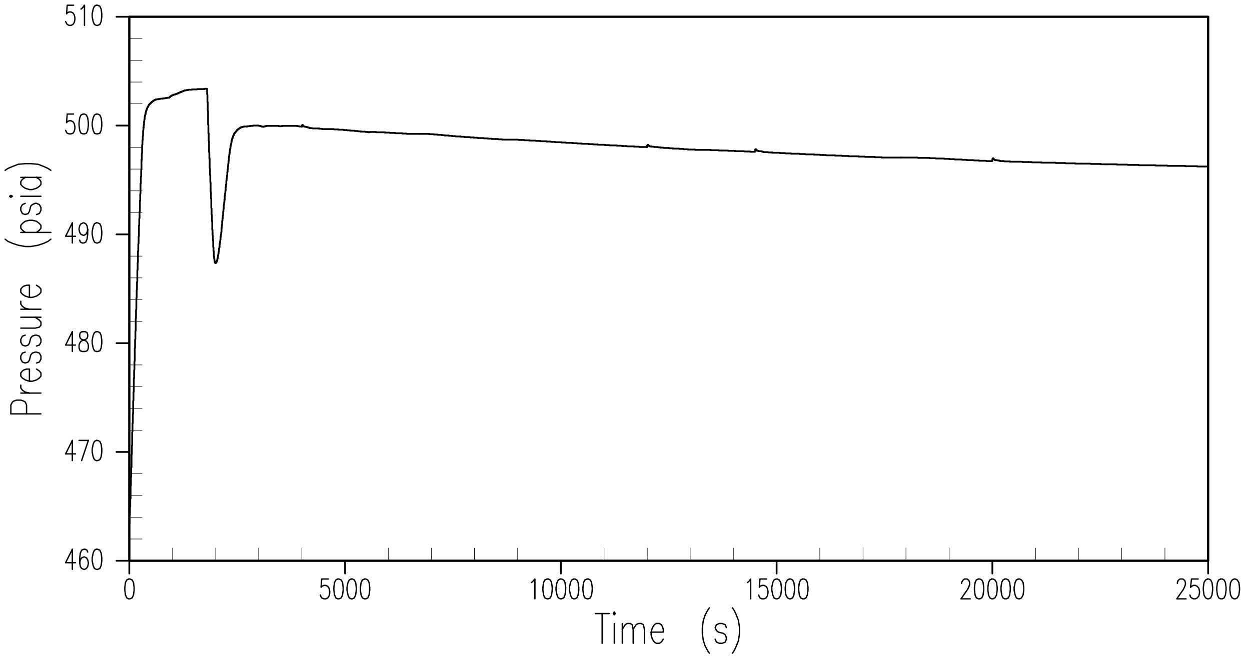

Figure 19E.4.8-21

Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

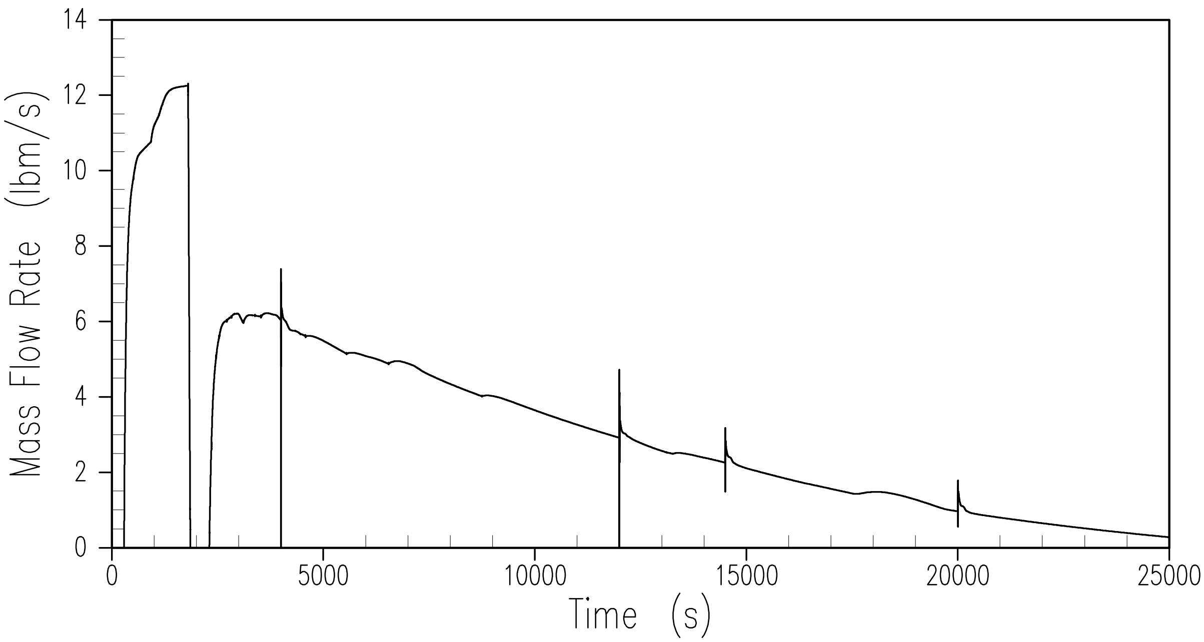

Figure 19E.4.8-22

RNS Safety Valve Flow, Loss of RNS in Mode 4 RCS Intact, Manual Safety System Actuation at 1800 Seconds

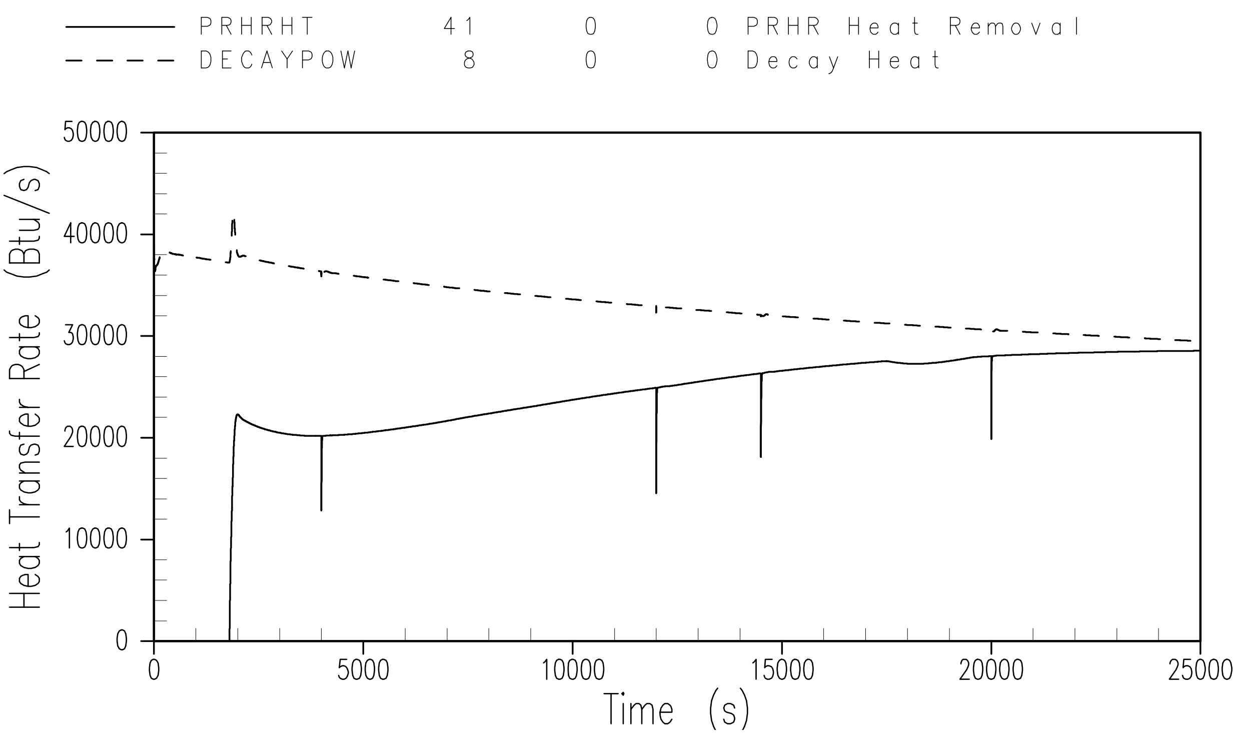

Figure 19E.4.8-23

Decay Heat and PRHR Heat Removal, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

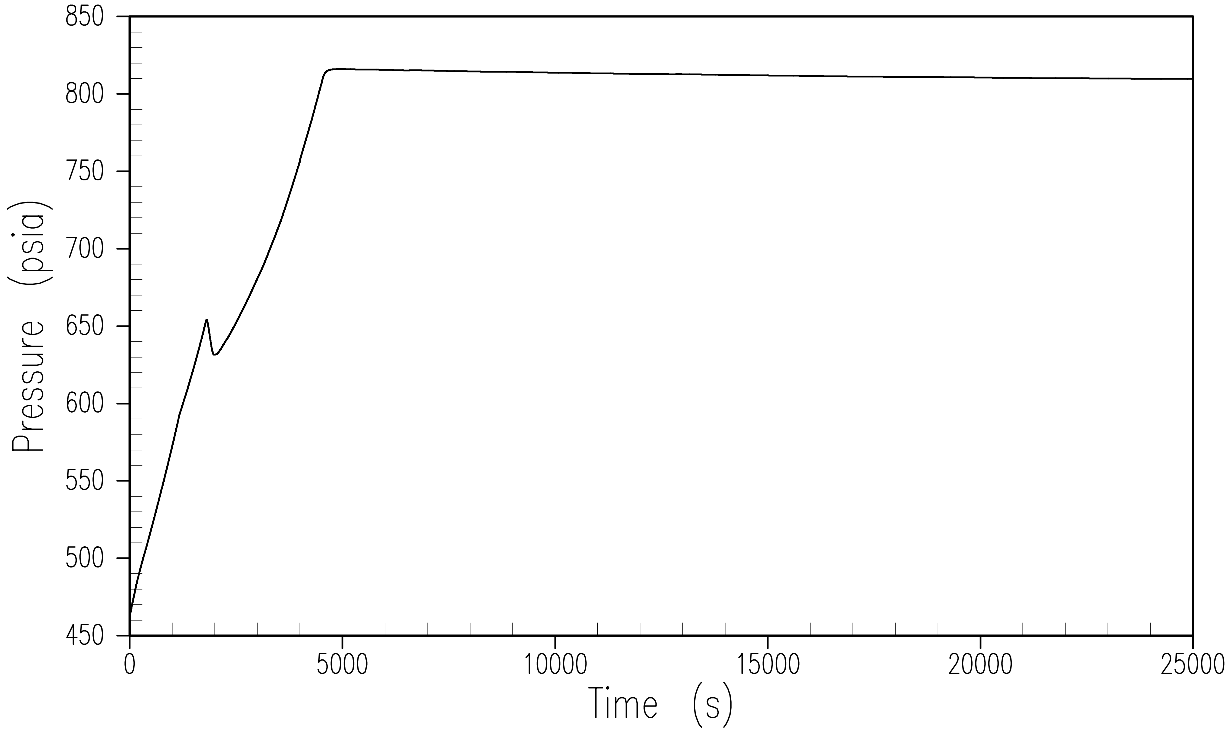

Figure 19E.4.8-24

Core Outlet Fluid Temperature, Loss of RNS in Mode 5 with RCS Open

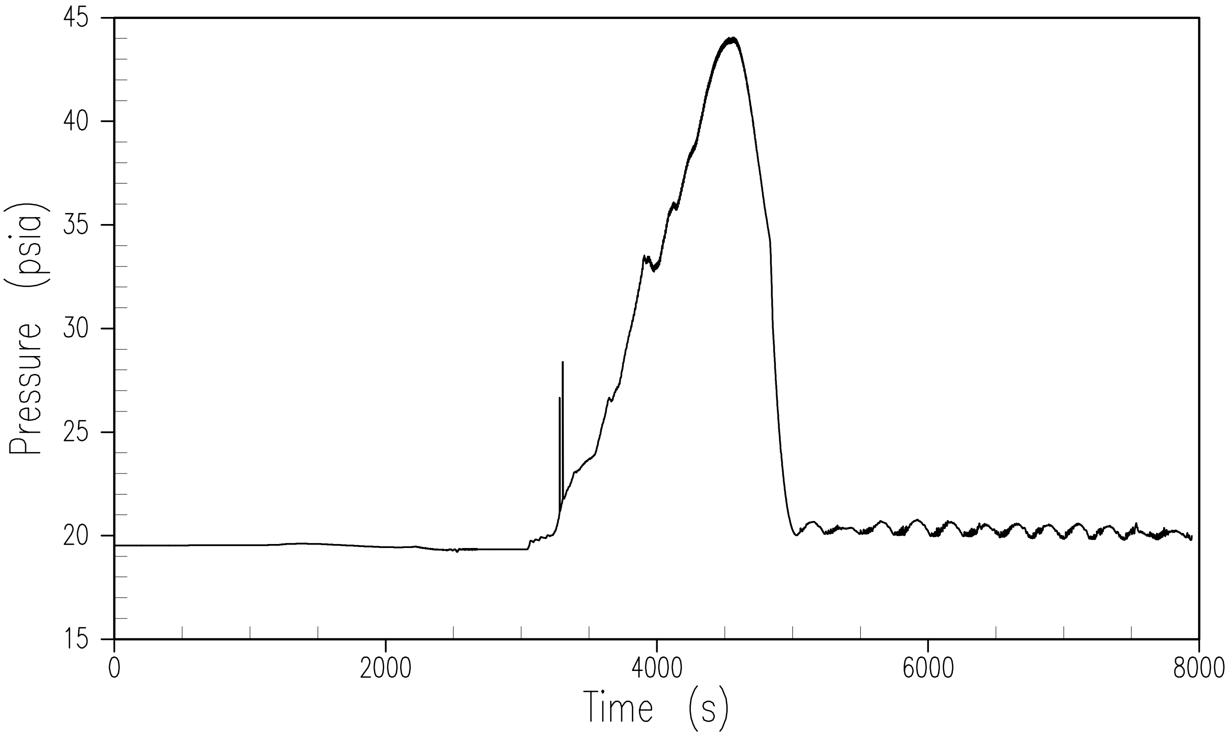

Figure 19E.4.8-25

Pressurizer Pressure, Loss of RNS in Mode 5 with RCS Open

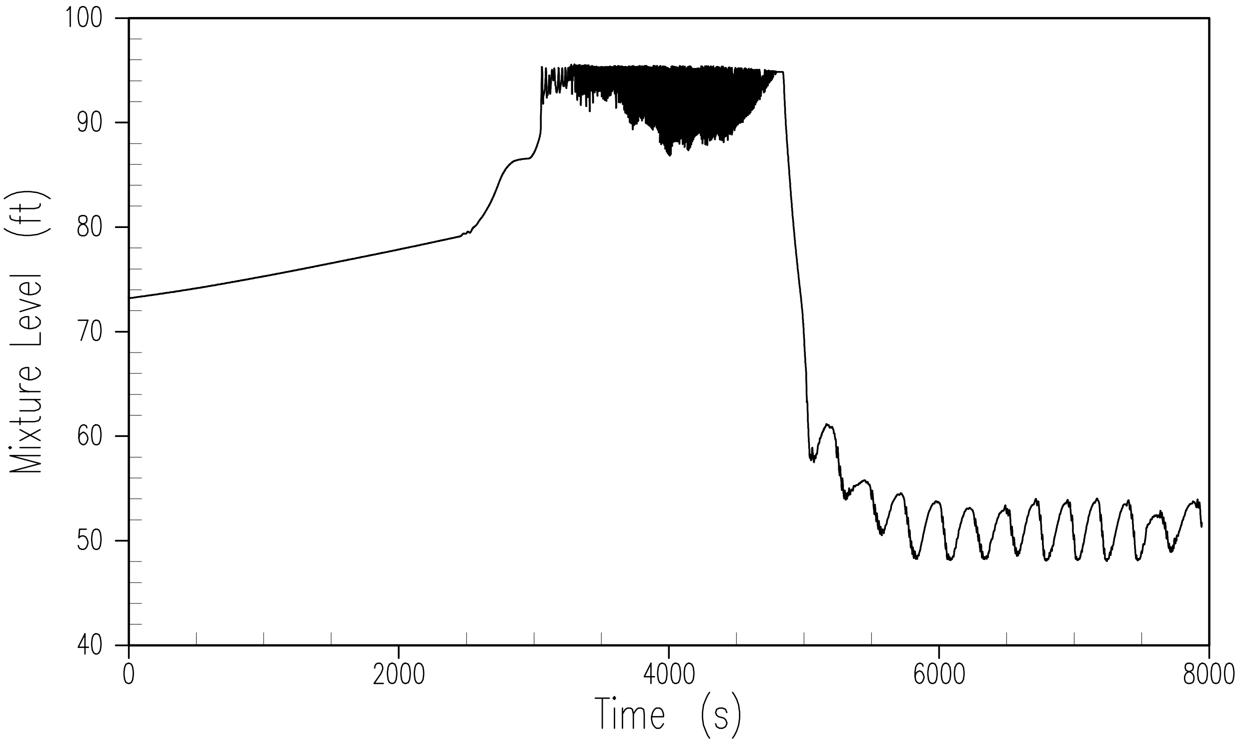

Figure 19E.4.8-26

Pressurizer Mixture Level, Loss of RNS in Mode 5 with RCS Open

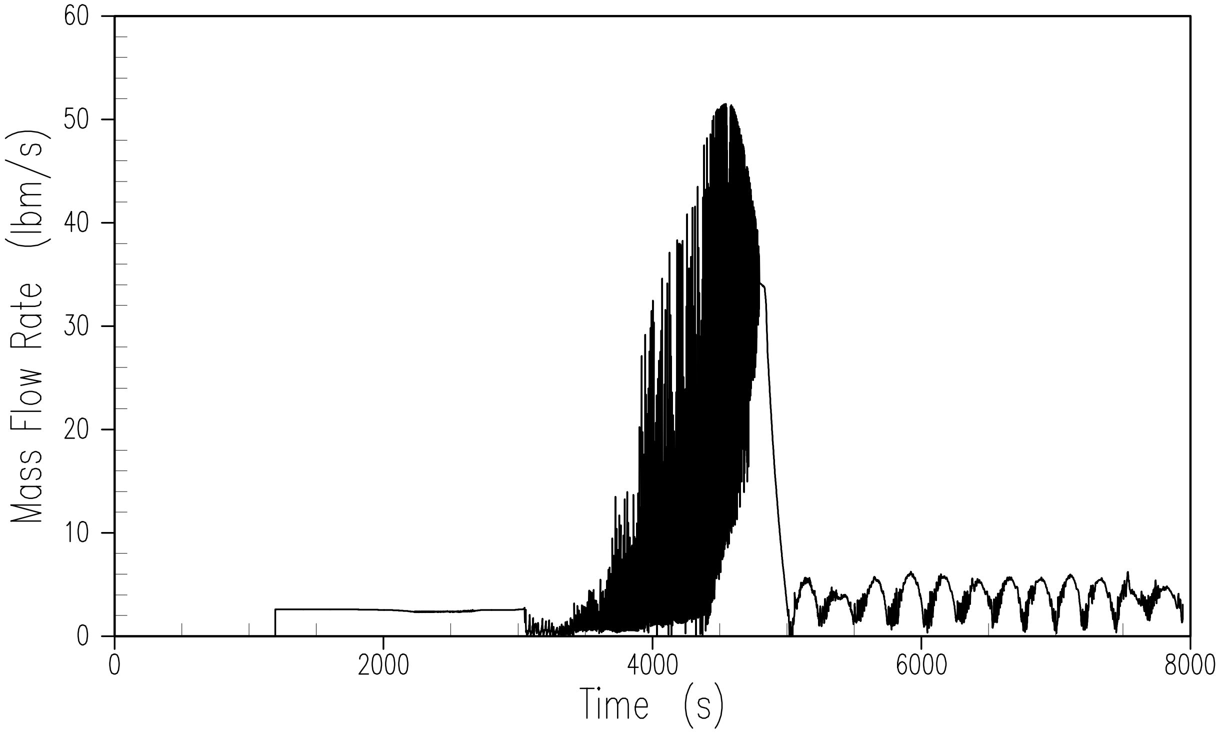

Figure 19E.4.8-27

ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

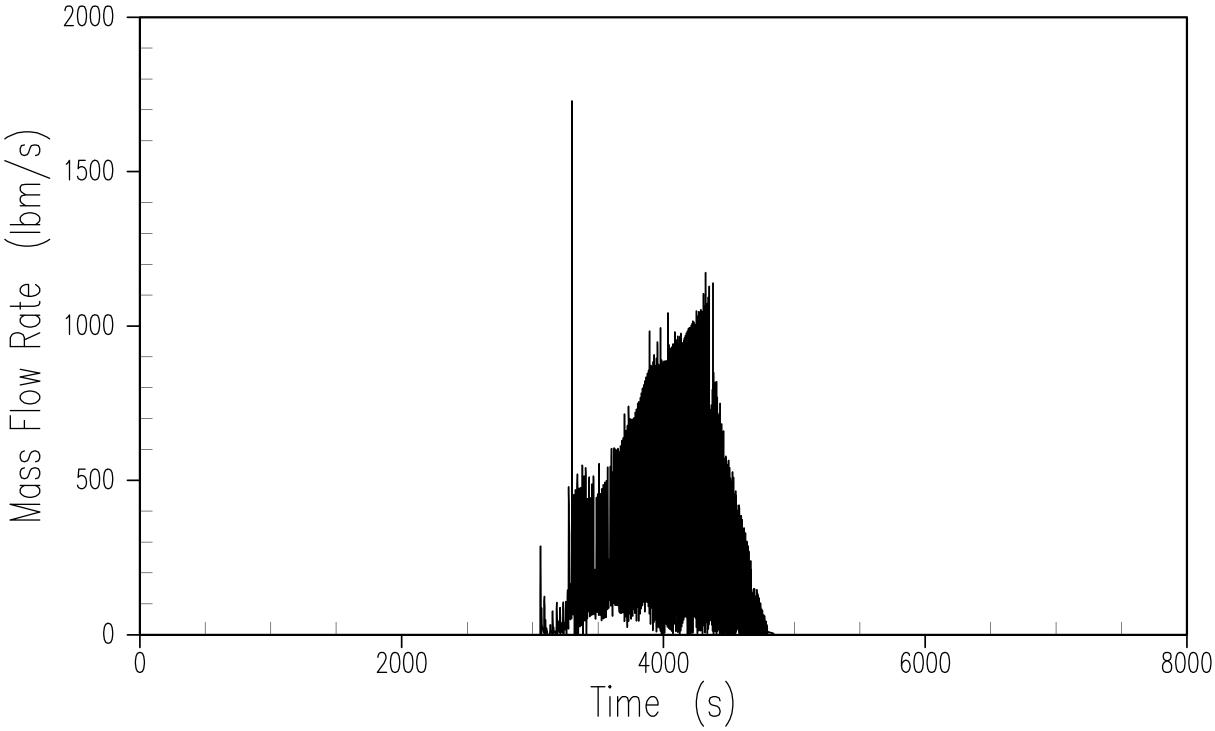

Figure 19E.4.8-28

ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

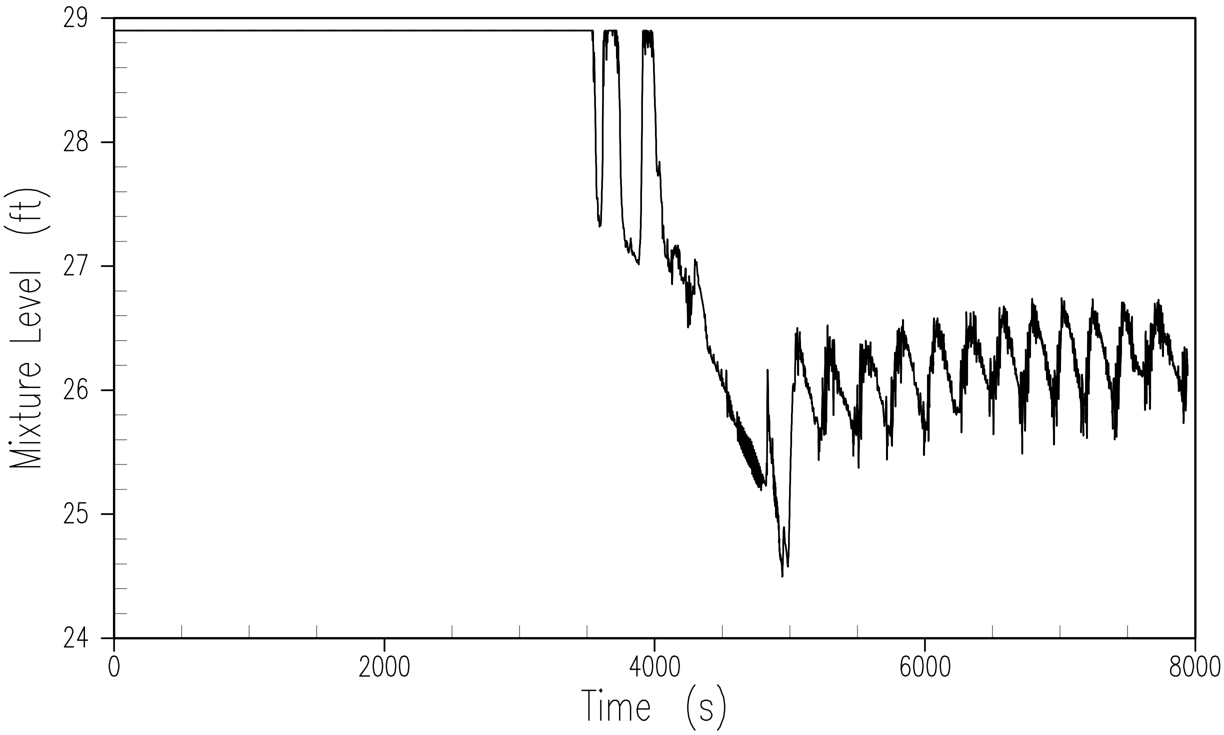

Figure 19E.4.8-29

Core Stack Mixture Level, Loss of RNS in Mode 5 with RCS Open

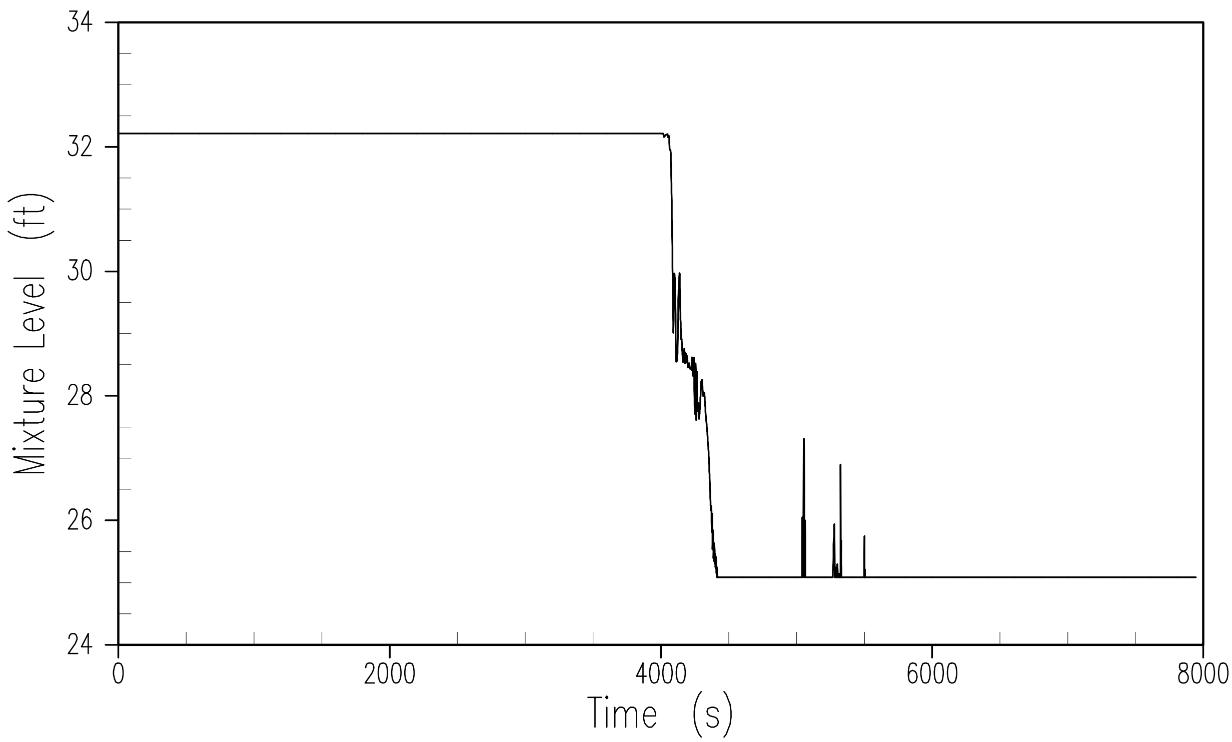

Figure 19E.4.8-30

Downcomer Mixture Level, Loss of RNS in Mode 5 with RCS Open

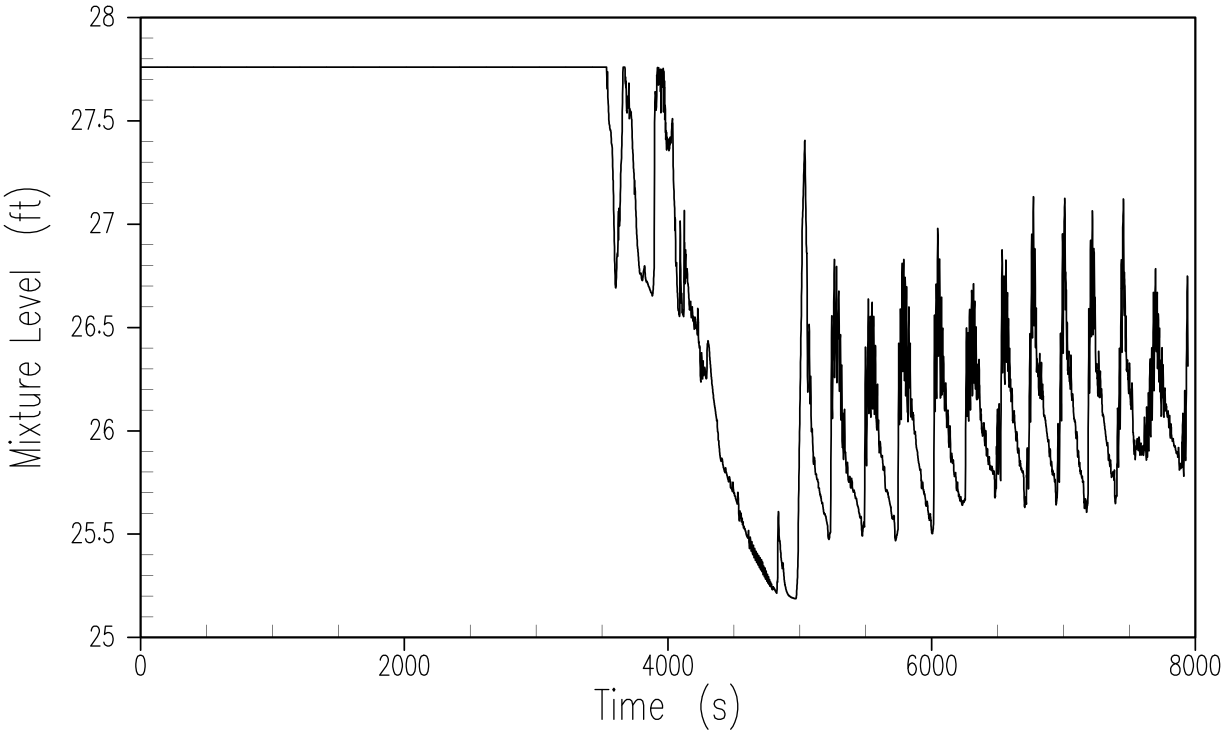

Figure 19E.4.8-31

Loop 1 Hot-Leg Mixture Level, Loss of RNS in Mode 5 with RCS Open

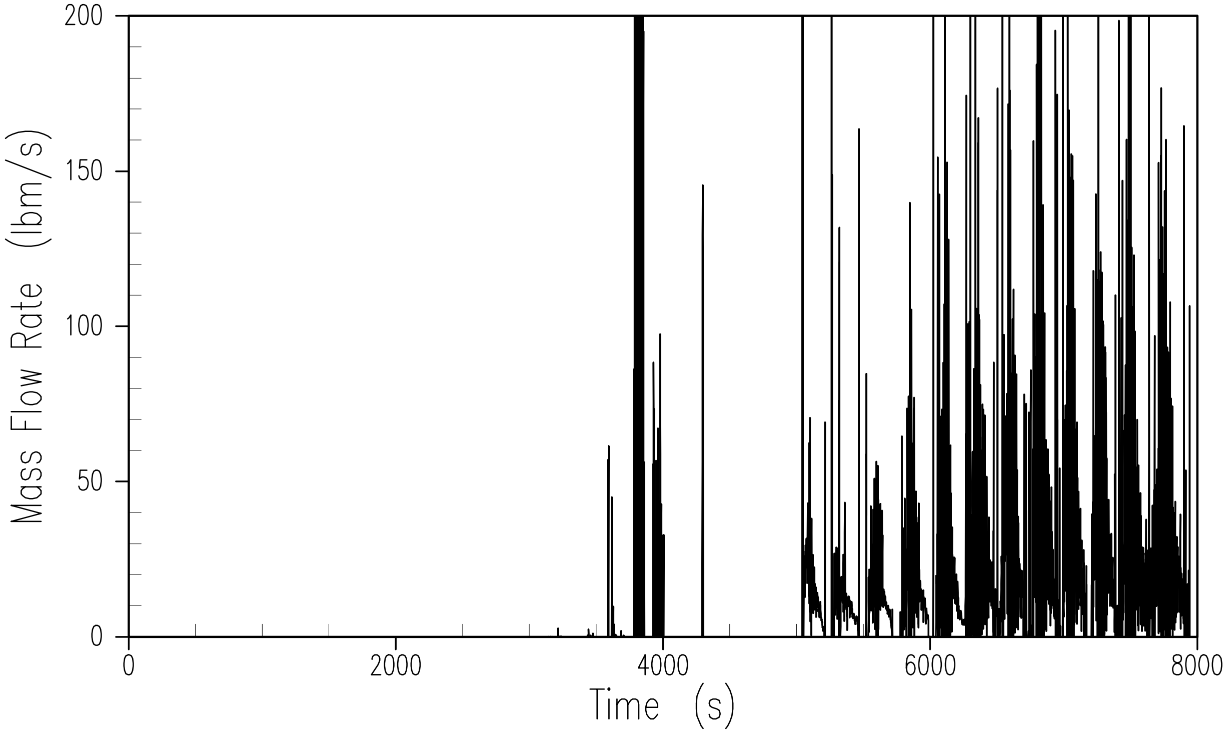

Figure 19E.4.8-32

ADS Stage 4 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

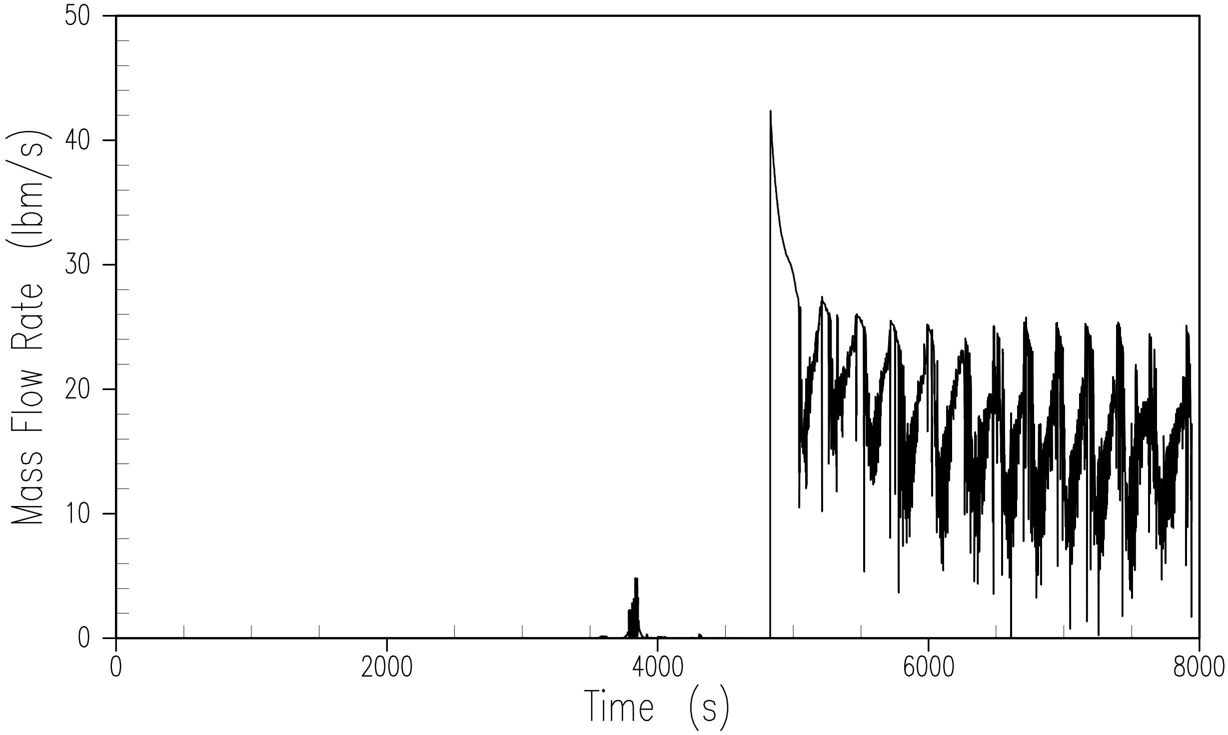

Figure 19E.4.8-33

ADS Stage 4 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

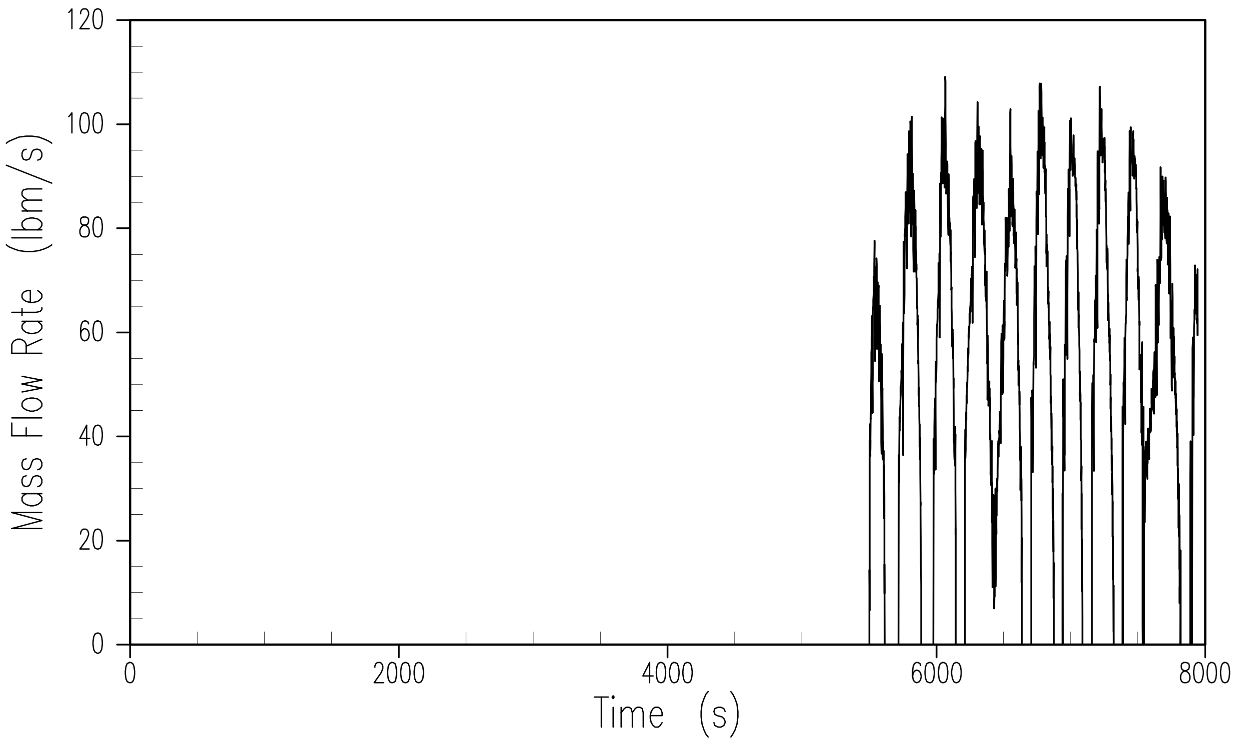

Figure 19E.4.8-34

IRWST Injection Flow, Loss of RNS in Mode 5 with RCS Open

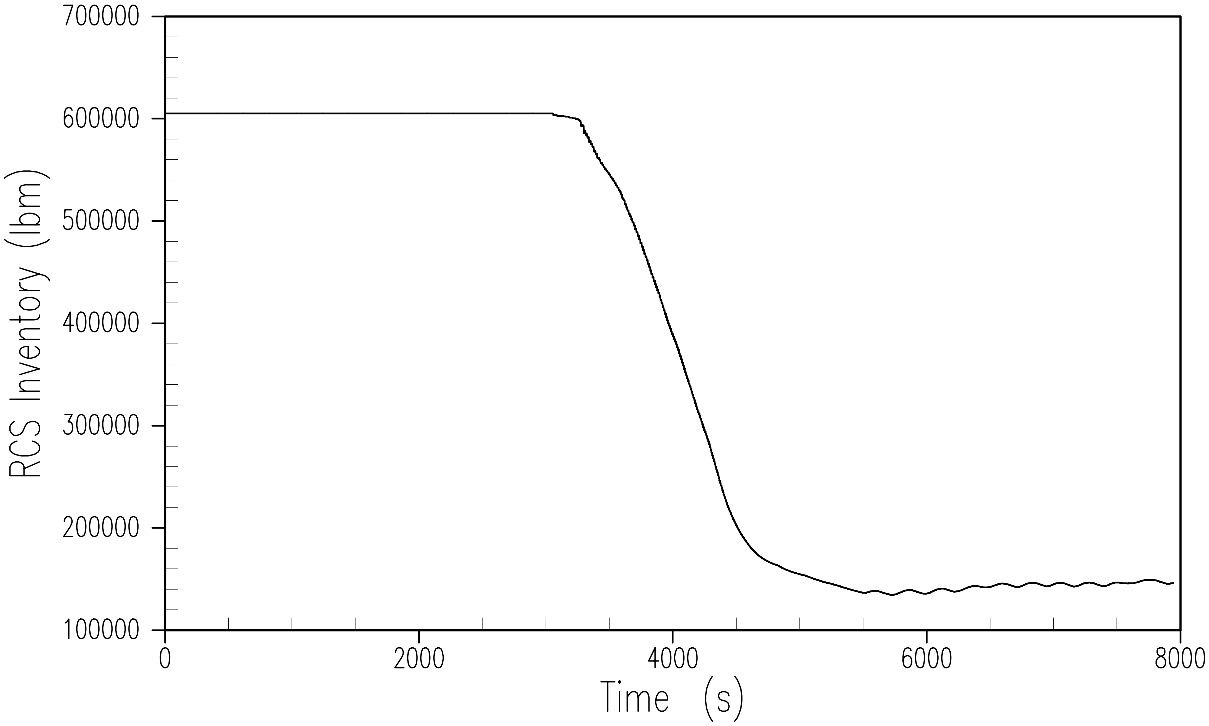

Figure 19E.4.8-35

Primary Mass Inventory, Loss of RNS in Mode 5 with RCS Open

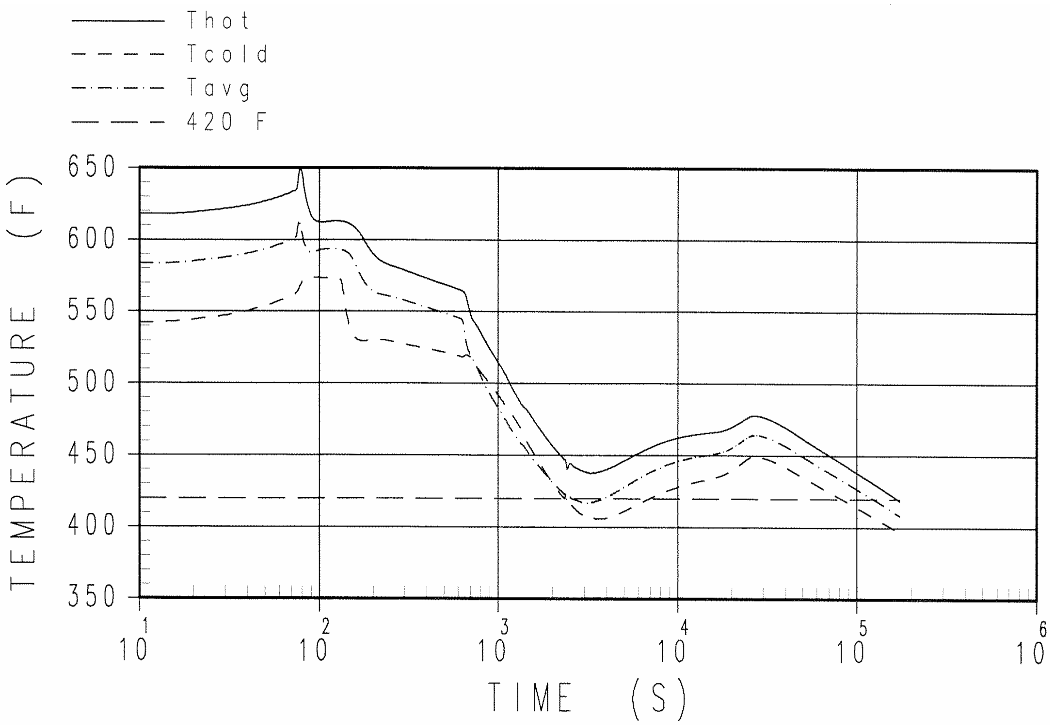

Figure 19E.4.10-1

Shutdown Temperature Evaluation, RCS Temperature

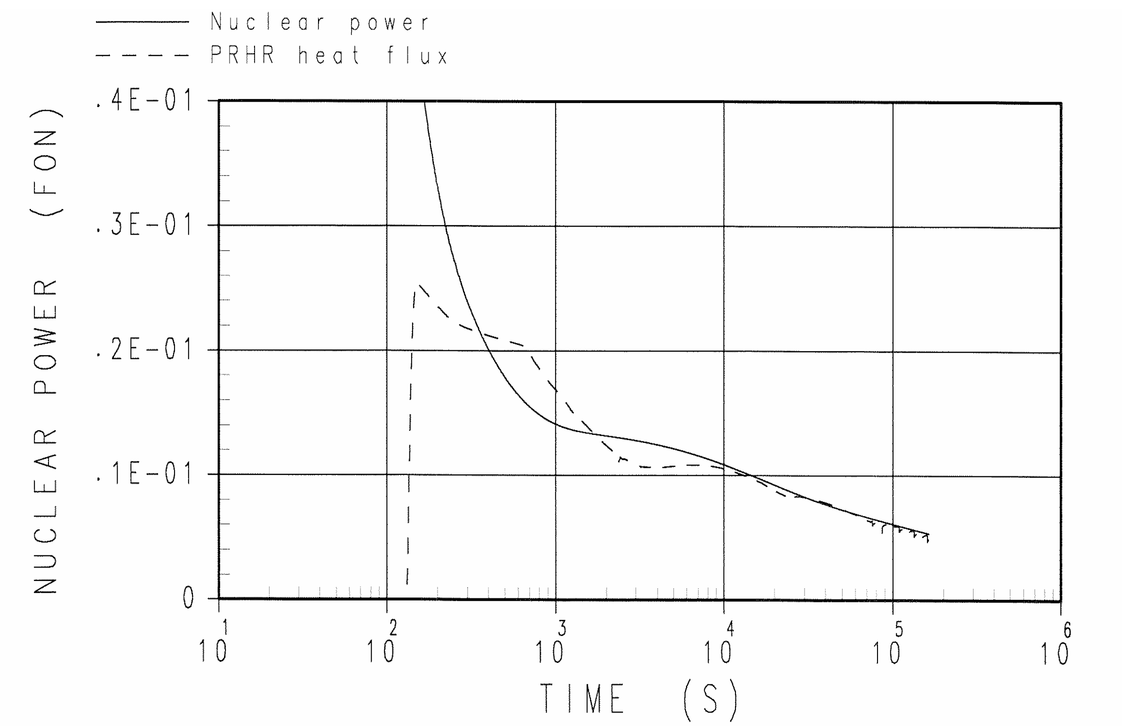

Figure 19E.4.10-2

Shutdown Temperature Evaluation, PRHR Heat Transfer

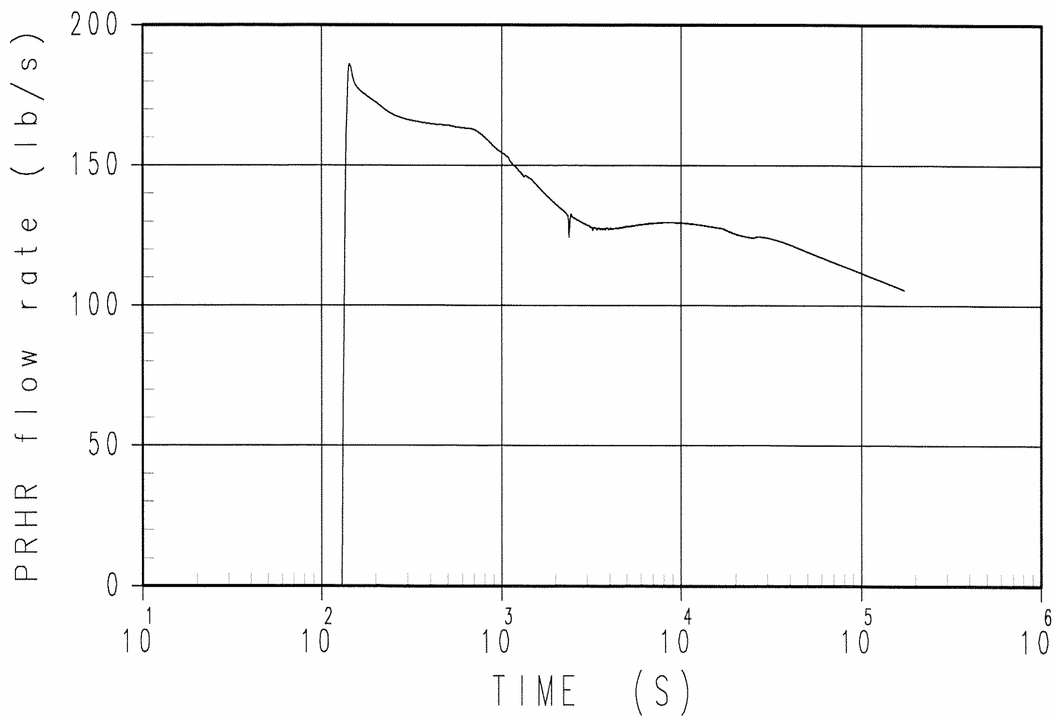

Figure 19E.4.10-3

Shutdown Temperature Evaluation, PRHR Flow Rate

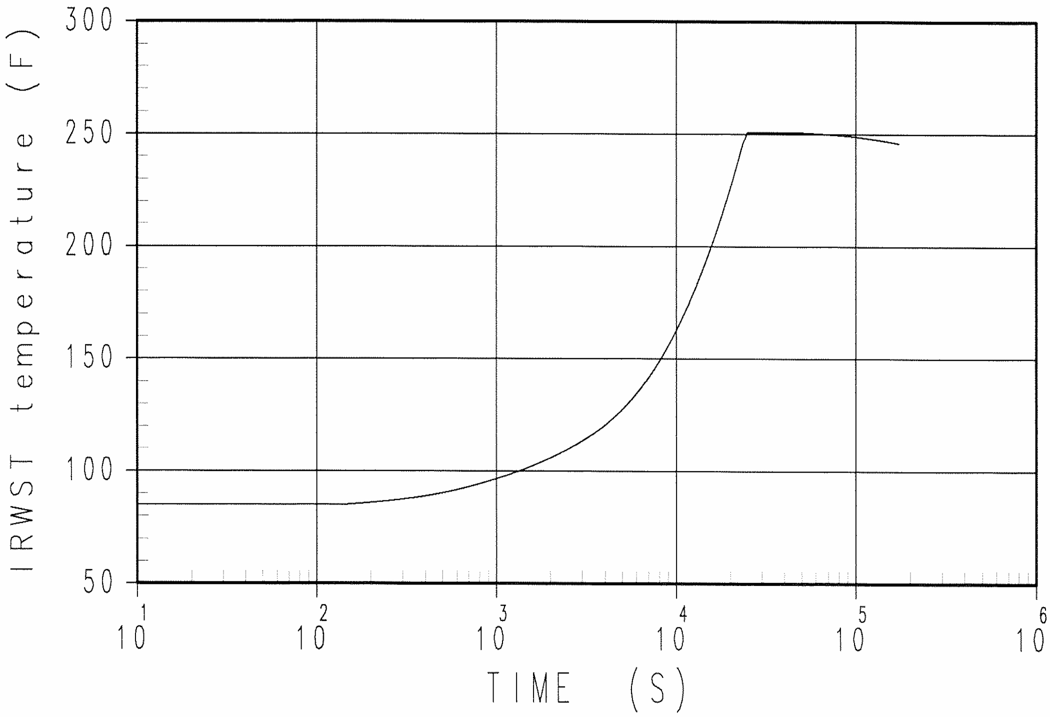

Figure 19E.4.10-4

Shutdown Temperature Evaluation, IRWST Heatup