8.0 ELECTRIC POWER

8.1 INTRODUCTION

8.1.1 UTILITY GRID DESCRIPTION

The Georgia Power Company (GPC) is a member of the Southern electric system whose other members are Alabama Power Company, Gulf Power Company, Mississippi Power Company, Savannah Electric and Power Company, and Southern Electric Generating Company. The Southern electric system is interconnected with Duke Power Company, Florida Peninsula Systems, Middle South Utilities, South Carolina Electric and Gas Company, and the Tennessee Valley Authority. The GPC grid system consists of interconnected hydro plants, fossil-fueled plants, and nuclear plants supplying electric energy over a transmission system consisting of various voltages up to 500 kV as shown in figure 8.2-2.

8.1.2 SOURCES OF POWER FOR AUXILIARY SYSTEMS

The sources of power for the unit auxiliary power system include four auxiliary transformers (two unit auxiliary and two startup auxiliary), three diesel generators (includes one shared diesel), and two station batteries. These sources supply highly reliable sources of electric power to the auxiliary systems.

Primary station distribution voltage is 4160 V and is supplied through the auxiliary transformers to seven 4160-V buses. During normal operation, 4160-V buses 2A, 2B, 2C, and 2D are supplied through the two-unit auxiliary transformers. Additionally, one of the startup transformers provides the normal source of power to the 4160-V essential buses 2E, 2F, and 2G. Power for buses 2E, 2F, and 2G can be supplied from the transmission system through one of the two startup auxiliary transformers or from three diesel generators.

The normal station dc power supply is from the station battery chargers with the station batteries floating online on continuous charge. These station batteries supply essential dc power.

Electric power required during startup or shutdown is drawn from the transmission system through the startup auxiliary transformers.

8.1.3 SAFETY- AND NONSAFETY-RELATED LOADS

Safety- and nonsafety-related loads on each 4160-V bus are shown in table 8.3-1. All essential equipment is supplied from 4160-V buses 2E, 2F, and 2G.

Tables 8.3-4 and 8.3-6 show the standby diesel generator system emergency loads and the load distribution on the essential buses during a loss-of-coolant accident.

8.1.4 DESIGN BASES

A. Electric power from the transmission network to the onsite electric distribution system is supplied by two physically independent circuits designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating, postulated accident, and environmental conditions. Two physically independent 230-kV circuits are provided from the switchyard to startup auxiliary transformers 2C and 2D.

B. For transmission line protection, each line is protected with one primary and one secondary system of protective relaying. These two systems are completely redundant and are supplied by two independent 125-V batteries located in the substation switch house.

C. In order to provide two sources of power to the essential buses, the essential buses are normally connected to startup auxiliary transformer 2D and backed up by startup auxiliary transformer 2C. Each of these two transformers has a rating capable of feeding essential loads under all situations.

D. The electrically powered safety loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed. Essential loads are divided between the three essential 4160-V buses 2E, 2F, and 2G. Availability of any two of these buses is sufficient to meet any accident conditions. There are five diesel generators furnishing essential loads of both HNP-1 and HNP-2. Any four out of five diesel generators are adequate to supply the engineered safety features (ESF) loads of one unit concurrent with the emergency shutdown loads of the other unit.

E. The 125/250-V-dc system is designed so that no single component failure will prevent the system from providing power to a sufficient number of essential dc loads necessary for safe shutdown of the plant. Two separate plant batteries are furnished, each with its own set of battery chargers.

F. Cables, raceway system, and routing are designed to survive the design basis events and prevent a loss of function of any safeguard system due to a cable failure.

G. The Class 1E auxiliary power system is designed so that a single failure will not prevent or impair the operation of essential unit safety functions.

H. The design of the offsite power system and the onsite Class 1E electrical system is generally in accordance with the following general design criteria, regulatory guides, and standards. Conformance with and exceptions to these and other general design criteria (GDC), regulatory guides, and industry standards are discussed in paragraphs 8.3.1.2 and 8.3.2.2

I. General Design Criteria for Nuclear Power Plants, Appendix A of 10 CFR 50:

a. GDC 17 - Electric Power System

b. GDC 18 - Inspection and Testing of Electric Power System

2. Nuclear Regulatory Commission Regulatory Guides for Power Reactors:

a. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," 1971

b. Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," 1971

c. Regulatory Guide 1.22, February 1971[a]

With respect to the periodic testing of the safety-related electric systems, provisions were incorporated into the design of the systems in accordance with the requirements of GDC 18, as described in section 3.1, whose requirements parallel those of Regulatory Guide 1.22, including Branch Technical Position EICSB 22.

d. Regulatory Guide 1.29, August 1973[a]

The seismic design classification of the electric power systems and their conformance to the recommendations of Regulatory Guide 1.29 are presented in subsection 3.2.1.

e. Regulatory Guide 1.40, March 1973[a]

The degree of conformance of this guide is discussed in appendix A.

f. Regulatory Guide 1.47, May 1973[a]

During the review of the construction permit application, a commitment was made to provide a manually operated light board in the main control room to indicate bypassed ESF. This was described in Amendment 12 to the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) Preliminary Safety Analysis Report (PSAR), which was submitted in November 1971. After review of the commitment in the PSAR, the Atomic Energy Commission staff concluded it was acceptable and referred to it in paragraph 3.6.2.5 of the Safety Evaluation Report. The system was designed in accordance

a. See footnote on page 8.1-4.

with the approved PSAR commitment; however, it was later modified to accommodate additional system inoperable indications. The provision for the status indication of the bypassed and inoperable portions of the safety systems and the degree of conformance of the status indication to the recommendations provided in Branch Technical Position EICSB 21 are provided in appendix A.

The status indication for the supporting system (Class 1E electric power systems) is included in the design of the circuitry.

g. Regulatory Guide 1.53, June 1973[a]

With regard to the design of the electric power systems, the intent of this guide is met by providing the required separation and redundancy in accordance with GDC 17 as described in paragraph 8.3.1.4 and section 3.1.

h. Regulatory Guide 1.62, October 1973[a]

The design of Class 1E electric systems supporting the protection systems is in conformance with the recommendations of this guide.

i. Regulatory Guide 1.73, January 1974[a]

This regulatory guide is not applicable to the design of the safety-related electric systems since the guide describes the acceptable method for qualifying electric valve operators installed inside the containment.

3. Institute of Electrical and Electronics Engineers (IEEE) Standards

a. IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations"

The design of the safety-related electric systems includes separation and redundancy requirements as required by GDC 17 and satisfies the requirements of Section 4.2 of IEEE 279-1971. These provisions are described in paragraph 8.3.1.4 and section 3.1.

a. This regulatory guide was issued after the design of the HNP-2 electric power systems was formulated. As a result, these guides were not used in the design of the electric power systems. However, the degree to which the electric power systems conform to these guides is presented herein.

b. IEEE 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

c. IEEE 338-1971, "Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems"

The provisions for the periodic testing of safety-related electric systems are designed in accordance with GDC 18, as described in section 3.1, whose requirements parallel those of IEEE 338-1971.

d. IEEE 379-1972, "Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems"

The design of the safety-related electric systems incorporates the separation and redundancy requirements of GDC 17 and satisfies the requirements of Section 4.2 of IEEE 279-1971. These provisions are described in paragraph 8.3.1.4 and section 3.1.

8.2 OFFSITE POWER SYSTEM

8.2.1 SYSTEM DESCRIPTION (HNP-1 AND HNP-2)

The Southern electric system transmission network supplies offsite ac energy for operating the essential buses as well as startup and shutdown of the Edwin I. Hatch Nuclear Plant (HNP).

The network interconnections at HNP consist of four 500-kV transmission lines and four 230-kV transmission lines. A 500/230-kV autotransformer connects the 500-kV switchyard to the 230-kV switchyard. The Hatch-Duval and the Hatch-Thalmann 500-kV lines have a 150-MVAR shunt reactor bank connected to each line. A 117-MVAR capacitor bank is connected to the 230-kV switchyard Bus 2, and an 85-MVAR capacitor bank is connected to the 230-kV switchyard Bus 1. These 500-kV and 230-kV connections are shown on figure 8.2-1 and connect the HNP with the transmission system as shown on figure 8.2-2.

The voltage level and length of each transmission line from the site to the first major substation that connects the line to the grid are as follows:

Major Substation	Voltage Level (kV)	Length (miles)
Vidalia	230	23
Eastman	230	57
South Hazlehurst	230	16
Offerman	230	38
Bonaire	500	89
N. Tifton	500	82
Duval (white)[a]	500	128
Thalmann (black)	500	65

The eight transmission lines converge on the substations as shown on drawing no. H-13867. The Bonaire and Tifton 500-kV lines cross over the Douglas and Offerman 230-kV lines. The transmission line structures are designed to withstand light loading conditions of 0-in. ice and 9 lb/ft^2-horizontal wind loading as defined for the Hatch site geographical area by the American National Standards Institute C2, National Electric Safety Code. The support structures for the buses in the 24-kV, low-voltage substation are designed to withstand a wind loading of 105 mph. Cable buses running from the startup transformers to the emergency buses are completely enclosed in metal ducts and separated by ~ 2 ft. (See figure 8.2-4.)

A ring bus switching scheme is used for the 500-kV switchyard, and a breaker-and-a-half scheme is utilized for the 230-kV switchyard. Three physically independent 230-kV circuits are provided from the switchyard to startup auxiliary transformers 1C, 1D, 2C, and 2D. (See drawing nos. H-13850 and H-20192.)

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a. Florida Power and Light Company substation.

Two independent 125-V batteries are provided in the switchyard switch house. Refer to figure 8.2-3 for a typical one-line diagram of the battery systems. Each transmission line is protected with two protective relaying systems: one primary system and one secondary system. Each power circuit breaker is equipped with two separate trip coils, primary and secondary. These components are connected so that each protective function is redundant, and the loss of any component in one relaying protective scheme, including loss of its battery, in no way affects the proper functioning of the other protective scheme. Each transmission line and both switchyards are equipped with overhead static wires as a designed lightning protection system.

The 230-kV and 500-kV breakers, with the exception of 230-kV breakers 179380 and 179590, are controlled from the main control room. Breaker 179380 and 179590 are controlled from the Georgia Power Company (GPC) control center.

The normal offsite system operating voltage range for HNP-1 and HNP-2 is 101.3 to 104.9% of 230 kV. This range was determined by transmission system studies using the expected maximum plant loading to establish the minimum offsite voltage level and using minimum plant loading to establish the maximum offsite voltage level. It has been shown that, with an offsite voltage level as low as 101.3%, the plant safety systems will have adequate voltage levels to perform their safety functions for mitigating the consequences of a loss-of-coolant accident.

8.2.2 ANALYSIS

8.2.2.1 <u>Electrical Power Systems</u>

The eight transmission lines supply power to the onsite electric power system via the 230-kV and 500-kV switchyard and three electrically and physically separated 230-kV circuits from the switchyard to the startup auxiliary transformers. Physical separation, the ring bus, breaker-and-a-half switching schemes, redundant switchyard protection systems, and transmission system design based on load flow and stability studies minimize simultaneous failure of all offsite power sources in compliance with GDC 17.

Regulatory Guide 1.32 (1972) is discussed in paragraph 8.3.1.2.1.b.

8.2.2.2 <u>Inspection and Testing of Electrical Power Systems</u>

The 230-kV and 500-kV breakers and the transmission line protective relaying system are inspected and tested on a routine basis without removing the generators, transformers, and most transmission lines from service. This testing complies with GDC 18.

8.2.2.3 <u>Analysis of Grid Power Supply</u>

Steady-state load flow and transient stability studies were made of the grid for Southern electric system 1990 peak and valley load conditions. The results of these studies demonstrate that:

A. The integrity of the grid can be maintained for the loss of either HNP-1 or HNP-2, plus one other element (i.e., line, transformer, or unit) out of service in the power grid.

   This is a generally accepted criterion and poses no significant problems to grid stability.

B. Grid stability is maintained for any three-phase fault at Plant Hatch.

   The postulated worst case concerning the 230-kV bus would be a three-phase fault during valley load conditions at the 230-kV terminals of the 500/230-kV auto transformer. Grid stability is maintained for such an improbable occurrence.

   The postulated worst case concerning the 500-kV bus would be a three-phase fault during valley load conditions on the HNP-Duval (white) 500-kV circuit. In this case, the backup protective scheme also takes the HNP-North Tifton 500-kV circuit out of service. Again, grid stability is maintained for such an improbable occurrence.

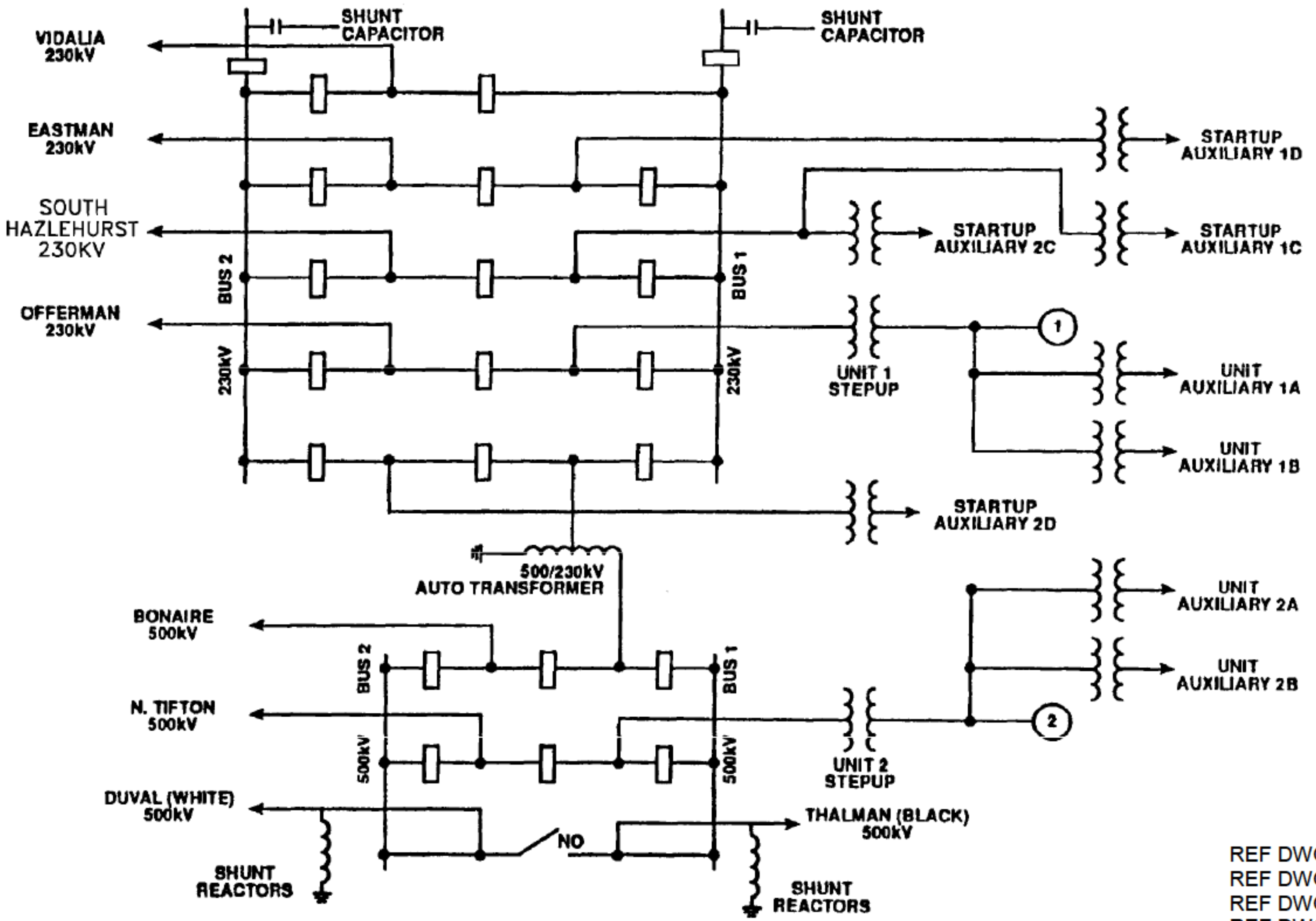
C. Grid stability is maintained for any three-phase fault at substations remote to HNP.

   This fault condition was considered for all remote substations (one bus away) and was found to be less severe than any fault condition described in B above.

   For any three-phase fault, the tripping of a unit is not required to maintain grid stability.

   There are situations where faults involving breaker failure on either the 230-kV bus or the 500-kV bus would result in the tripping of a unit by the backup protective scheme. These situations are less severe than those described in B above. In these situations, the tripping of a unit will serve to improve grid stability.

It should be noted from the foregoing discussion of grid stability that no significant problems are encountered in maintaining the integrity of the grid and that no special methods are employed or necessary to maintain grid reliability.



REF DWG H-10209 REV 5
REF DWG H-13950 REV 22
REF DWG H-23900 REV 10
REF DWG H-23901 REV 12

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UNIT 2

SINGLE-LINE DIAGRAM PLANT SWITCHYARD CONNECTIONS

FIGURE 8.2-1

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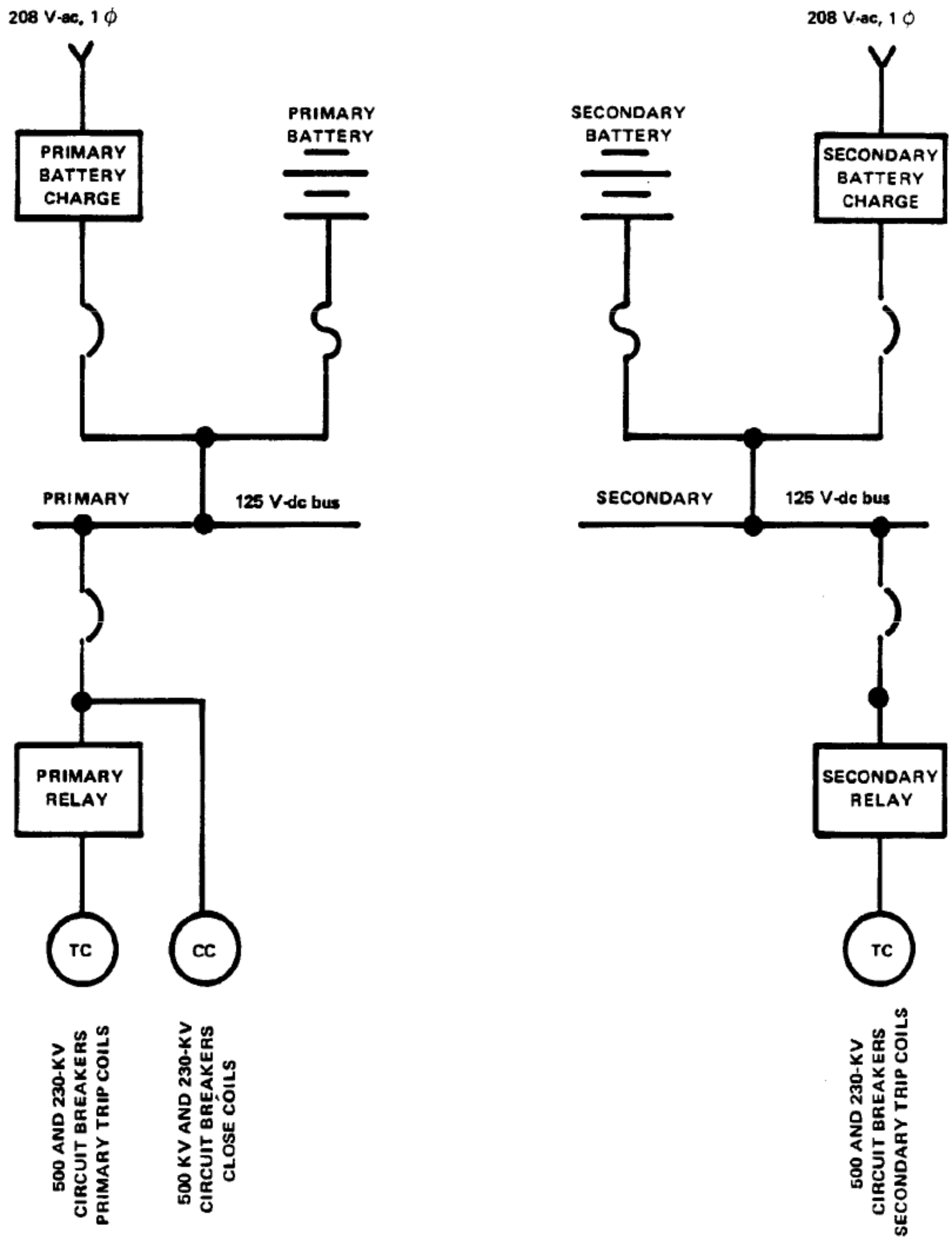
GPC GENERATION, TRANSMISSION AND PRIMARY DISTRIBUTION SYSTEM

FIGURE 8.2-2



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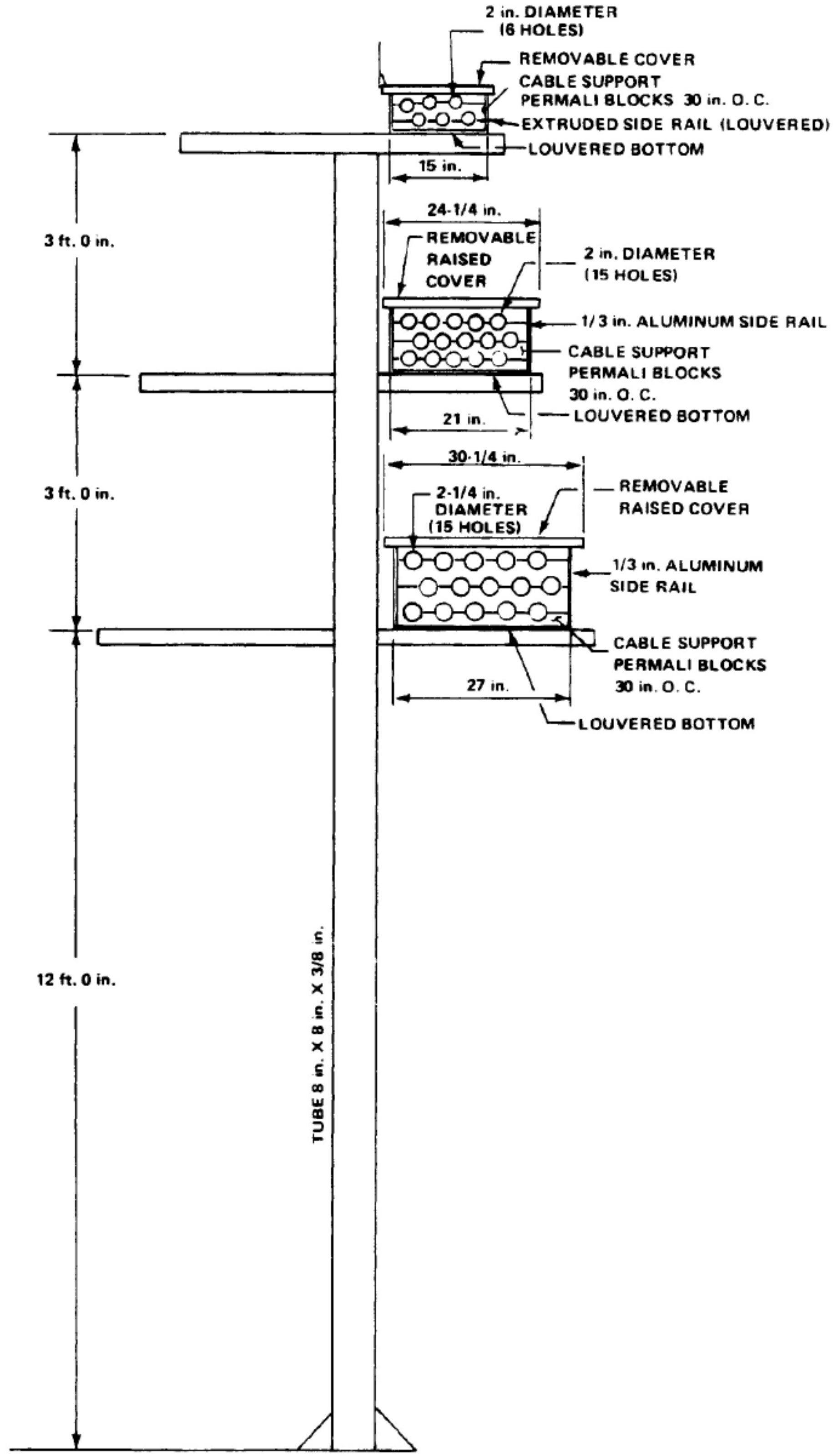
UNIT 2

SWITCHYARD/SUBSTATION
dc ONE-LINE DIAGRAMS
(TYPICAL)

FIGURE 8.2-3



ACAD 2080204

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

24-kV SWITCHYARD BUS SUPPORT STRUCTURE

FIGURE 8.2-4

8.3 ONSITE POWER SYSTEM

8.3.1 THE ac POWER SYSTEM

8.3.1.1 Description

8.3.1.1.1 Sources of ac Power

The onsite ac power system has the following sources of power:

A. Four station service transformers (two unit auxiliary and two startup auxiliary transformers) are available.

   The four station service transformers are sized to carry the station service loads. Each is an oil-filled, triple-rated transformer, 55°C rise with a 65°C rise supplementary rating (with the exception of unit auxiliary transformer 2A, which has a 65°C rating only with no supplementary rating). The two unit auxiliary transformers are connected delta-wye with the neutral grounded through a resistor. The two startup auxiliary transformers are wye-wye connected with a delta tertiary. The high-side neutral is solidly grounded while the low-side neutral is grounded through a resistor.

   The descriptions of the station service transformer are as follows:

   - Unit Auxiliary Transformer 2A

     Type ONAN/ONAF/ONAF, oil immersed, three phase, three winding, rated 21/28/35 MVA primary and 10.5/14/17.5 - 10.5/14/17.5 MVA secondary, 24,000-V delta to 4160-V wye-wye at 65°C rise.

   - Unit Auxiliary Transformer 2B

     Type OA/FA/FOA, oil immersed, three phase, two winding, rated 15/20/25 MVA, 24,000-V delta to 4160-V wye. 65°C supplementary rating is 28 MVA.

   - Startup Auxiliary Transformer 2C

     Type OA/FA/FOA, oil immersed, three phase, two winding, rated 15/20/25 MVA, 230,000-V wye to 4160-V wye with delta tertiary. 65°C supplementary rating is 28 MVA.

- Startup Auxiliary Transformer 2D

  Type OA/FA/FOA, oil immersed, three phase, three winding, rated 18/24/30 MVA primary and 9/12/15 - 9/12/15 secondary, 230,000-V wye to 4160-V wye-wye with delta tertiary. 65°C supplementary rating is 33.6 MVA for primary and 16.8 MVA for secondary windings.

B. Three diesel generator units (2A, 1B, and 2C) are available.

Diesel generators 2A and 2C have the following ratings:

2850 kW - continuous
3100 kW - 2000 h
3250 kW - 300 h
3500 kW - 30 min

Diesel generator 1B is shared between HNP-1 and HNP-2. It has the following ratings:

2850 kW - 1000 h
3250 kW - 168 h

The diesel generators are rated at 4160 V, three-phase, 60 Hz, and are capable of attaining rated frequency and voltage within 12 s after receipt of a start signal.

8.3.1.1.2 The ac Distribution System

The principal elements of the onsite ac power system are shown on figures 8.2-1, 8.3-1, 8.3-3, and 8.3-8.

A. Primary Distribution

The primary distribution is at 4160 V. There are seven 4160-V buses (2A, 2B, 2C, 2D, 2E, 2F, and 2G) in the station auxiliary power distribution system. (See figure 8.3-1.) Buses 2A and 2B supply power to large motors and are designated as normal buses. Buses 2C and 2D are also normal buses and supply power to other station auxiliaries requiring ac power during planned operations. The normal buses are located in the turbine building. The three essential buses are 2E, 2F, and 2G. These buses are located in separate rooms in the diesel building and supply power to essential loads required during planned operations and during anticipated operational occurrences and accidents.

The 4160-V buses 2A and 2B are rated at 350 MVA; the remaining buses are rated at 250 MVA. All of the 4160-V switchgear is the metal-clad indoor type with breakers of the electrically operated, three-pole, stored-energy, closing-mechanism type. Control power for the 4160-V breakers is supplied from the 125- to 250-V-dc

batteries described in subsection 8.3.2. See table 8.3-1 for loads connected to the 4160-V buses.

Power is distributed to the normal 4160-V auxiliary buses during planned operation from either the unit auxiliary transformers 2A and 2B or from the startup auxiliary transformers 2C and 2D. The startup transformers are used to supply the 4160-V buses during normal startup, maintenance outage, and shutdown. After the main generator was synchronized to the system and a minimum stable load established, each 4160-V normal bus is manually transferred from the startup auxiliary transformer to the unit auxiliary transformer. The transfer is a hot transfer following synchronization checks. This type of transfer results in the momentary interconnection of the startup and unit transformer through a single 4160-V auxiliary bus.

Startup transformer 2C is the alternate supply for normal buses 2A and 2B. It is also the alternate supply for essential buses 2E, 2F, and 2G. It is conservatively sized at 28 MVA to supply either the total connected load of buses 2A and 2B or the total connected load of buses 2E, 2F, and 2G. During normal plant running operations, buses 2A and 2B are supplied from unit auxiliary transformer 2B, which is conservatively sized at 28 MVA. In the event transformer 2B fails, a fast transfer scheme will automatically switch the load on buses 2A and 2B to startup transformer 2C.

During startup, shutdown, or normal plant operation buses 2E, 2F, and 2G are supplied from startup transformer 2D. In the event transformer 2D fails, a transformer scheme will automatically switch the load of buses 2E, 2F, and 2G to transformer 2C.

In the unlikely event unit auxiliary transformer 2B and startup transformer 2D both fail, emergency buses 2E, 2F, and 2G will transfer to startup transformer 2C as noted above; but normal buses will not transfer and, in fact, will be disconnected from transformer 2C, if previously connected.

Unit auxiliary transformer 2A is the normal supply for 4160-V buses 2C and 2D. In the event that the unit auxiliary transformer 2A fails, fast transfer scheme will automatically switch the load on 4160-V buses 2C and 2D to startup auxiliary transformer 2D, if available.

The maximum operating load on the essential buses fed by startup transformer 2D is within the transformer rating. In the event unit auxiliary transformer 2A fails, the loads on 4160-V buses 2C and 2D will be transferred to startup transformer 2D. The expected maximum load on transformer 2D (which under these circumstances will be supplying 4160-V buses 2C, 2D, 2E, 2F, and 2G) will also be within the transformer 2D rating of 33.6 MVA at 65°C rise forced oil and air (FOA), continuous.

Maximum loadings on the startup transformers 2C and 2D are verified in the Offsite Source Voltage Study, which is updated on a frequency approximately corresponding to the refueling frequency.

B. Secondary Distribution

The secondary plant distribution is at 600 V. This system is shown on figure 8.3-2. The 600-V distribution system consists of 12 buses: 4 normal-service buses (2A, 2AA, 2B, and 2BB), 2 essential buses (2C and 2D), and 6 cooling tower buses (2E, 2F, 2G, 2H, 2J, and 2K, not shown on figure 8.3-2).

All the 600-V switchgear is metal-enclosed indoor type, rated 22,000-A symmetrical. Each bus is supplied by a close-coupled, oil-filled transformer, 55°C rise, 4160-600-V, delta-delta connected, rated at 1190/1368 kVA for transformers 2C, 2D, and 2CD; 1190/1368 kVA for transformers 2A, 2AA, 2B, 2BB, and 2AB; and 850/978 kVA for transformers 2E, 2F, 2G, 2H, 2J, and 2K. The breakers are electrically operated with stored-energy closing mechanisms operated from the 125- to 250-V-dc station batteries described in paragraph 8.3.2.1.1.

The four normal-service 600-V buses are supplied from 4160-V buses 2C and 2D. One spare 4160- to 600-V transformer (2AB) is provided as an alternate source for the normal 600-V buses. A manual transfer to this spare transformer is required. The 600-V normal buses supply power to the 600-V auxiliaries required during planned operation.

The two essential 600-V buses, 2C and 2D, are normally supplied from separate 4160-V buses 2E and 2G through their own transformers. One spare 4160- to 600-V transformer (2CD), supplied from 4160-V essential bus 2F, is provided as a spare source for either essential 600-V bus. The 600-V essential buses are located in separate rooms in the control building.

Under normal conditions, electrical interlocks prevent closing both main breakers on each 600-V essential bus. Electrical interlocks also prevent both supply breakers from the 2CD transformer being closed at the same time. The feeder breaker from the 4160-V bus 2F to transformer 2CD is normally open, and one of the disconnect links is open. Thus, as a minimum, a failure of one interlock concurrent with two operator errors is required to parallel feed the 2C or 2D 600-V bus (i.e., to concurrently feed a single 600-V bus from two 4160-V buses). Paralleling the two buses, i.e., to concurrently feed both 600-V essential buses from a single 4160-V bus, requires a failure of one electrical interlock and four operator errors under normal operating conditions. Refer to figures 8.3-2 and 8.3-8 for electrical system diagrams.

Transformer 2CD, supplied from 4160-V essential bus 2F, is provided as a spare source for either essential 600-V bus. When transformer 2CD is being utilized, the electrical interlocks mentioned above are operational, the feeder breakers to the out-of-service transformer are open, and at least one of the disconnect links on the 600-V side of the 2CD transformer is open. Thus, as a minimum, to parallel feed

(i.e., to concurrently feed a single 600-V bus from two 4160-V buses) an essential 600-V bus requires a failure of one interlock concurrent with two operator actions in closing the out-of-service transformer feeder breaker and the 600-V bus supply breaker. Paralleling the two buses, i.e., to concurrently feed both 600-V essential buses from a single 4160-V bus, would require two operator errors and failure of one electrical interlock. The normally open 600-V breakers with the electrical interlock between them are redundant and physical separation and/or barriers are provided.

Switchgear on HNP-2 contains stationary-type breaker auxiliary contacts; i.e., removing a breaker from its operating position does not break the continuity of the interlocking circuits. The control circuits of safety-related equipment have been checked to ensure interlocking circuits utilize these stationary-type breaker auxiliary contacts. The results of this check show that no other redundant components would be inadvertently rendered inoperable by the disabling or failure of a component during normal or emergency operation, test, or out-of-service condition.

The six cooling tower buses supply power to the cooling tower fans. The buses are supplied through 4160-600-V transformers from 4160-V buses 2C and 2D. Control power for the cooling tower breakers is supplied from the cooling tower battery.

AC motor control centers (MCCs) 2R24-S018A and B provide power to the following low pressure coolant injection (LPCI) motor-operated valves (MOVs):

- LPCI injection valves.
- LPCI pump minimum flow valves.
- Reactor recirculation pump suction valves.
- Reactor recirculation pump discharge valves.

Normal power is supplied from 4160-V buses 1E and 1G (HNP-1-FSAR figure 8.5-1) via the HNP-1 emergency 600-V buses 1C and 1D to MCCs 2R24-S018A and B. In the event of a loss of offsite power, backup power for the 4160-V buses 1E and 1G is supplied by dedicated HNP-1 diesel generators 1A and 1C. Alternate power for one LPCI MOV load center is supplied from 4160-V bus 2F via 600-V bus 2D via manual transfer switch 2R26-M107 to MCC 2R24-S018A or B. Backup power for 4160-V bus 2F is supplied by swing diesel generator 1B.

All ac MCCs except two are normally fed from the 600-V switchgear. MCCs 2R24-S026 and 2R24-S048 are fed from the 4160-V bus through 4160-600-V transformers. MCCs are NEMA Class 1. The branch breakers are molded-case, manually operated. All breakers are provided with magnetic short-circuit protection on all poles. MCC motor starters have provisions for thermal overload protection on poles 1 and 3 and provisions for thermal overload alarms on pole 2. The control

contact of the thermal overload protection relay is bypassed during normal plant operation for MCC motor starters feeding essential motor operated valves (MOVs), essential motors, and other safety-related MOVs, where appropriate. Essential MOVs and motors are those used for ECCSs, containment isolation function, or 10 CFR 50.49 applications.

For Class 1E starters, where the thermal overload protection is bypassed, protection was operative from starter installation date until completion of preoperational testing before core load. After testing, the thermal overload relay contacts used for control of these starters are permanently bypassed with shorting straps. The thermal overload relays on pole 2 are still reserved for annunciation. These overload relays are periodically checked to ensure operability.

All essential switchgears and MCCs are designed to Class 1E requirements.

8.3.1.1.3 Standby ac Power

A. Introduction

The onsite standby ac power supply for HNP-1 and HNP-2 consists of five diesel generator units, which supply standby power to 4160-V essential buses 1E, 1F, 1G, 2E, 2F, and 2G. Diesel generators 1A and 1C supply Unit 1 essential buses 1E and 1G, respectively. Diesel generators 2A and 2C supply Unit 2 essential buses 2E and 2G, respectively. Diesel generator 1B is a shared facility and can supply either Unit 1 essential bus 1F or Unit 2 essential bus 2F.

B. Starting Initiation

Automatic starting of the diesel generator units supplying Unit 2 is initiated by any of the following conditions:

- Loss-of-coolant accident (LOCA) signal.
- Reactor low-water level signal.
- High drywell pressure signal.
- Undervoltage on essential buses 2E, 2F, and 2G, as a result of a complete loss-of-offsite power (LOSP), a sustained degraded voltage condition, or a failure in any of the redundant instrument trains sensing voltage will start the diesel associated with that individual bus.

C. Starting Mechanism and System

The starting mechanism and system are described in subsection 9.5.6.

D. Interlocks and Permissives

1. For starting the diesel generator:

Each diesel generator has a MODE SELECT switch in the main control room (MCR) and a local switch on the diesel control panel in the diesel building. The diesel generator MODE SELECT switch is a key-locked switch and has two positions - NORM and TEST. When this switch is in the NORM position, the diesel is on automatic start; i.e., the diesel will start upon receipt of a start signal. When this switch is in the TEST position, the diesel may be started from the MCR for test purposes. During testing, the diesel generator is synchronized to its associated 4160-V essential bus and, consequently, to the offsite power system.

Additionally, only one diesel generator at a time is synchronized to the offsite power system during testing. Each diesel generator is equipped with the keylocked MODE SELECT switch that must be set in the TEST position before the generator can be synchronized and connected to the offsite power system. The mode-switch key is removable in the NORM position only.

The test position circuitry is designed so that the occurrence of a LOCA or undervoltage on startup transformer 2C automatically drops the diesel generator from the test mode and initiates the normal autostart circuitry.

The diesel generator local switch also has two positions - REMOTE and CONTROL AT ENGINE. When the local switch is in the REMOTE position, the diesel generator is controlled from the MCR. When the local switch is in the CONTROL AT ENGINE position, all automatic starting circuits are disengaged. In this position, diesel generator maintenance can be performed without the possibility of the diesel receiving a start signal. The diesel generator can be started only by a switch located on the diesel generator control panel when the switch is in the CONTROL AT ENGINE position. Annunciation is provided in the MCR when the local switch is in this position.

2. For connection of the diesel generator to its associated 4160-V bus, the following conditions are necessary to initiate the closing of the diesel generator breaker:

- Diesel generator at rated voltage and speed.
- LOSP lockout relay for the associated 4160-V bus tripped.
- The supply breakers between startup auxiliary transformers 2C and 2D on the associated essential 4160-V bus are tripped.

When the last condition above is met, the possibility of one diesel generator operating in parallel with any other diesel generator is precluded.

E. Load Shedding

When the diesel generator breaker closes, the following load shedding has already taken place:

The 4160-V loads and most nonessential 600-V loads are tripped, but the feeder breakers to the 4160-600-V station service transformers supplying the essential 600-V load centers and their associated MCCs remain closed. This ensures power continuity to vital 600-V auxiliaries such as the generator seal oil pumps and instrumentation transformers even when a reactor trip does not accompany loss of normal power.

F. Sequential Loading

The diesel generator loading sequence is shown in table 8.3-3. Emergency loads are shown in tables 8.3-4, 8.3-5, and 8.3-6.

Timing devices are provided to sequentially start the motors for each essential load. The engineered safety feature (ESF) loads are applied automatically in sequence at ~ 10-s intervals to minimize the initial voltage drop due to starting the induction motor-driven pumps. This method of starting motors provides flexibility in timing adjustment and independence of control. The tabulation of tables 8.3-3 through 8.3-6 assumes three diesel generators are available.

At time t-plus-30 s after a LOCA with all three essential buses available, four residual heat removal (RHR) and two core spray (CS) pumps would be in operation. Full flow injection or spray may still be prohibited by flow- or pressure-sensing ESF interlocks. Failure of any one diesel or diesel battery and its buses cannot prevent attainment of minimum safe shutdown requirement regardless of which bus fails. The plant operator can manually drop off any excess pumping capacity at any time t-plus-30 s but prior to proceeding into the second phase of accident control. This occurs at approximately time t-plus-10 min when reactor water level is stabilized and containment cooling begins.

The automatic starting and load sequencing times in the current design are more restrictive than the timing assumptions made in the SAFER/GESTR-LOCA analysis. The LOCA analysis supports a 31-s response time for CS and a 64-s response time for LPCI.

At time t-plus-10 min, all diesel generator loading can be controlled by the plant operator. The plant operator makes decisions as to which emergency loads may be manually connected or disconnected following a LOCA after time t-plus 10 min. An operating procedure provides directions to the operator. The procedure is

based on the information contained in tables 8.3-11 through 8.3-16 and 8.3-18 through 8.3-20.

G. Diesel Engine and Generator Protection

Each diesel engine and generator is protected by various devices listed in tables 8.3-9 and 8.3-10. However, only the following signals shut down the diesel engine when the MODE SELECT switch is in the NORM position:

- Engine overspeed.
- Low lube oil pressure.[a]
- Generator differential relaying.

Should a diesel fail to start within 7 s, its starter air supply and the fuel are cut off, and an alarm is sounded.

With the MODE SELECT switch in the NORM position, all other protective devices will not trip the engine but will annunciate as indicated by table 8.3-7. Table 8.3-8 lists the generator alarms.

Each generator will be grounded through a high resistance. A ground-detector circuit will annunciate a ground condition in the MCR. The neutral ground-fault relays are not designed to trip the emergency diesel generators.

H. Fuel Oil Supply, Storage, and Transfer

The fuel oil supply, storage, and transfer system is described in subsection 9.5.4.

I. Diesel Engine and Generator Control

1. Each diesel generator unit has a floor-mounted control panel located in the diesel building complete with the following equipment:

    - Ammeter with selector switch.
    - Voltmeter with selector switch.
    - Frequency meter.
    - dc ammeter with shunt for generator field current.
    - Watthour meter and associated pulse initiator.

a. Two lube oil pressure switches have been installed and wired in series so that two signals are necessary to trip.

- Voltage regulator with raise-lower switch.
- Field rheostat.
- Governor control switch.
- Motor-operated device for remote control of generator voltage following failure of automatic voltage regulator.
- Potential transformers and current transformers.
- Field ground detection relay for annunciator alarm.
- 20-window annunciator, operated on 120-V-ac supplied by an inverter from the 125-V-dc diesel battery.
- Alarm contacts, provided for remote annunciation in the MCR.

In addition to the diesel generator control panel, a diesel engine control panel located in the diesel building is also provided. This panel has the following equipment:

- Running time meter.
- Engine gauges (water temperature, oil pressure, oil temperature, etc.) and throttle control.
- Indicating lights.
- Starting controls.

Each diesel generator has a separate annunciator panel located on the generator control panel in the diesel building. In addition, annunciation is also supplied for each diesel generator in the MCR. Table 8.3-7 lists all alarms and points of annunciation for the diesel engine. Table 8.3-8 lists all alarms associated with the diesel generator.

Power for each diesel generator unit controls is supplied by a 125-V-dc battery system. Each battery has its own normal static-type battery charger and bus. A standby battery charger permits servicing a charger. These features allow loss of no more than one diesel generator set of controls due to a single failure.

2. The shared diesel generator 1B is identical in all respects to the other four diesel generators. The requirements of Section C of Regulatory Guide 1.81 are met in the following fashion:

a. The features unique to the engine and generators, independent of their application, are either automatically or locally controlled within the generator set perimeter.

b. The features of diesel 1B, such as load testing, electric bus control, and annunciation, are duplicated identically for HNP-1 and HNP-2.

c. Positive selection, indication, and isolation are provided so the shared diesel will automatically fulfill LOCA and LOSP duties on either unit.

Figure 8.3-7 shows the motor control centers that supply the diesel generator 1B auxiliaries and the environmental controls for generator room 1B.

J. Diesel Engine Cooling

The diesel engine cooling system is described in subsection 9.5.5.

K. Diesel Building

The diesel generators are housed in a reinforced concrete Seismic Category I structure, which provides protection against natural phenomena such as tornado missiles, tornadoes, floods, lightning, rain, ice, or snow. Each unit is completely enclosed in its own concrete cell and is isolated from other units. The walls separating the diesel generators are 18-in. reinforced-concrete structural walls with a fire rating of 3 h. Automatic fire detection and extinguishing systems are provided. A potential missile, the crankcase door, could be generated from a postulated crankcase explosion. This missile would be contained by the reinforced concrete wall.

L. Diesel Building Ventilation

The diesel building ventilation system is described in subsection 9.4.5.

M. Testing

Tests of the diesel generators are conducted to check for equipment failures and deterioration. Testing is conducted at equilibrium operating conditions to demonstrate proper operation at these conditions. Each diesel is manually started, synchronized to the bus, and the load is applied. The diesels are loaded to at least 50% of rated load to prevent fouling of the engines. In addition, during the test when the generator is synchronized to the bus, it is also synchronized to the offsite power source and thus is not completely independent of this source. A test is performed at least monthly to verify optimum performance.

At the end of the load test of the diesel generators, the fuel oil transfer pumps are operated to refill the day tank and to check the operation of these pumps.

The test of the emergency generators during a refueling outage is more comprehensive in that it functionally tests the system; i.e., it checks diesel starting, closure of diesel breaker, and sequencing of loads on the diesel. The diesels are started by simulation of a LOCA. In addition, an undervoltage condition is imposed to simulate an LOSP. The timing sequence is checked to ensure proper loading in the required time. The inspections will detect any signs of wear long before failure.

The diesel generator sets are Fairbanks-Morse Model 38TD8 1/8, which were previously qualified by at least two other utilities.

Both used the 100 prototype starting tests, conducted by Fairbanks-Morse in September 1968, with no failure. These tests are discussed in Institute of Electrical and Electronics Engineers (IEEE) Conference Paper 69-CP-177-PWR, presented in January 1969 to the 1969 IEEE winter power meeting.

More than 200 starting tests were performed at the Duane Arnold Energy Center by Iowa Electric Light and Power between October 6 and 13, 1973. There were no failures to start and assume load within 10 s. These tests were conducted during their preoperational testing program, and the actual test logs are available at the site.

Northern States Power conducted 202 successful starting tests during the Prairie Island preoperational and startup testing program, which were reported to the Atomic Energy Commission (AEC) in a report entitled "Diesel Generator and Diesel Driven Pump Reliability Tests and Diesel Tests for Two Unit Operation." This report was submitted to the AEC with a letter from B. O. Mayer to J. F. O'Leary on March 15, 1974.

In all, more than 500 starting tests were conducted on this model diesel with no failures.

N. Diesel Seismic Qualification

The diesel generator vendor performed a dynamic analysis on the diesel generators, employing a modal analysis with lumped-mass modeling using the response spectrum technique and the floor response spectrum developed for the diesel generator building foundation. Appropriate damping factors were used.

The horizontal and vertical forces were added simultaneously to the normal loads in a way to create the most critical loading. Overturning moments, shear and tensile stresses on anchor bolts, and stresses in support brackets and weldments were checked for these loadings.

All safety-related electrical interlocks were analyzed and found satisfactory.

The diesel fuel oil system, including storage tanks, transfer pumps, piping, and day tanks are designed to Seismic Category I criteria.

Analysis and tests show that the diesel generator units, including component parts and associated systems, will function during a seismic event.

Seismic verification of the diesel generators associated with replacement of modification activities is consistent with the methodology developed by the Seismic Qualification Utility Group (SQUG) which utilizes earthquake experience and generic test data to verify the seismic adequacy of all classes of mechanical and electrical equipment.

This methodology is documented in the Generic Implementation Procedure (GIP) which was evaluated and approved by the NRC as documented in Supplement 2 to the Safety Evaluation Report associated with the GIP.

8.3.1.1.4 Instrument Power Supply

Figure 8.3-9 shows the ac instrument power supply system. This system consists of the following:

A. 120-208-V-ac Instrument Power System

This is an essential power system supplied from the 600-V essential buses 2C and 2D through two 112.5-kVA, three-phase essential transformers to essential cabinets 2A and 2B. The essential cabinets supply essential and nonessential loads. Failure of a nonessential load will not affect the ability of this system to supply the essential loads.

All essential equipment involved in this system is designed to Class 1E requirements.

For essential loads, see distribution cabinets 2B and 2C shown in figure 8.3-9.

B. 120-V Reactor Protection System (RPS) Power Supply (not a Class 1E system except for motor-generator (M-G) set protective relaying described below)

Control power for the RPS is normally supplied from two M-G sets powered from 600-V essential buses 2C and 2D. The M-G sets feed RPS buses 2A and 2B. The RPS buses supply the following loads:

- RPS trip system.
- Power range neutron monitoring (PRNM) system.
- Process radiation monitors for main steam lines and off-gas system.
- Nuclear steam supply shutoff valves (inboard and outboard).

- Primary containment isolation system (PCIS).
- Analog transmitter trip system (ATTS) panels.

Each M-G set supplies 120 V-ac (+ 10%), 60 Hz (+ 5%) power to its respective RPS bus via two series-connected Class 1E circuit breakers.

To ensure that all electrical components connected to the RPS bus are protected from a malfunction of the M-G set, the output voltage and frequency of each M-G set are monitored by two separate sets of protective relaying. Each set of protective relaying is associated with one of the two Class 1E circuit breakers.

The Class 1E protective relaying consists of an undervoltage relay set at 110 V-ac, an overvoltage relay set at 129 V-ac, an underfrequency relay set at 57.2 Hz, and a time delay relay set at 3.5 s. If the output of one M-G set exceeds these limits for 3.5 s, its circuit breaker will trip via an undervoltage release mechanism.

The two sets of Class 1E relaying and circuit breakers per M-G set ensure that RPS equipment is protected from voltage and frequency ranges outside their capabilities. Furthermore, the two sets are entirely redundant, satisfying the single-failure criterion. A manual transfer scheme is provided, which allows any one of the two RPS buses to be supplied from the 120-208-V-ac power system described in 8.3.1.1.4.A. This arrangement permits the energization of both RPS buses even though one of the M-G sets may be out of service. The protective relaying scheme on their alternate source of power is identical to the two Class 1E protective schemes on the M-G sets.

C. 120-240-V Uninterruptible ac Power System (not a Class 1E system)

Power for this system is normally supplied from 600-V essential bus 2D through a battery charger and static inverter combination to the uninterruptible ac power cabinet.

Two standby sources exist for this system. A 240-V-dc battery is one standby source.

The battery charger called out above is of sufficient size to simultaneously supply full inverter load and to recharge the battery from a discharge condition. The other alternate source of power for this system is a standby transformer supplied from 600-V essential bus 2C. The uninterruptible ac load is automatically transferred from the preferred source to the standby source by means of a static transfer switch. A local transfer switch is provided for isolation for maintenance purposes. The manual transfer switch is of the make-before-break type.

The 120-240-V-ac uninterruptible power system provides power for vital service for which power interruption should be avoided. These vital services are necessary for the operation of the plant but are not required for plant safety.

For loads on the uninterruptible ac power cabinet, see distribution cabinet 2A shown in figure 8.3-9.

D. 120 VAC Critical Instrument Bus

This is an essential power system supplied from the safety related 125/250VDC system via a safety related, seismically qualified 7.5 kVA, 250 VDC/120 VAC Inverter.

Like the essential 120/208 VAC instrument buses, the critical instrument buses supply both essential and non-essential loads. They provide AC power from the safety related DC sources to loads critical for the mitigation of events when AC power is not available from offsite sources or from the on-site emergency AC system.

Failure of a non-essential load will not affect the ability of the system to supply the essential loads.

Back-up power is available to the inverter via the existing essential cabinets. The back-up power will ensure power is not lost to the critical instrumentation during DC system maintenance.

8.3.1.2 Analysis of ac Systems

8.3.1.2.1 Compliance with General Design Criteria, Nuclear Regulatory Commission (NRC) Regulatory Guides, and Industry Standards

In this section an analysis of the ac systems describes the degree of compliance with the following:

A. General Design Criteria for Nuclear Power Plants, Appendix A of 10 CFR 50

Compliance with the following general design criteria is discussed in section 3.1:

- GDC 17 - Electric Power System
- GDC 18 - Inspection and Testing of Electric Power System

B. NRC Regulatory Guides for Power Reactors

The construction permit for HNP-2 was issued in December 1972. Since the issuance of the construction permit, a number of new regulatory guides were issued that were not available for incorporation into the original design; however, many requirements of the following regulatory guides are met and discussed below:

Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Supplies and Between Their Distribution Systems," 1971

The Class 1E ac system is divided into redundant load groups so that loss of any one group will not prevent the minimum safety functions from being performed.

Each ac load group has connections to two preferred (offsite) power supplies and to a single diesel generator. Each diesel generator is exclusively connected to a single 4160-V load group. Figure 8.3-1 shows this arrangement.
The diesel generator of one load group cannot be automatically paralleled with the diesel generator of the redundant load group.

No provisions exist for connecting one load group to the redundant load group when operating from the diesel generators.

No provisions exist for automatic transfer of ac loads between redundant onsite power supplies.

Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," 1971

Diesel generators 2A and 2C have a 2000-h rating of 3100 kW and a 30-min rating of 3500 kW. Ninety percent of 3500 kW is 3150 kW. The lower of the two figures is the 2000-h rating of 3100 kW. Table 8.3-6 shows automatically connected loads on the diesel generators do not exceed 3100 kW. The loading beyond 10 min is based on the operator manually switching loads in accordance with minimum system requirements. Tables 8.3-11 through 8.3-16 and 8.3-18 through 8.3-20 show that possible load distribution on emergency buses beyond 10 min is within the ratings of the diesel generators. The predicted loads shall be verified during preoperational testing. When diesel generator 1B was purchased, the diesel generator manufacturer did not have a 2000-h rating procedure; however, diesel generator 1B is identical in design and capability to diesel generators 2A and 2C. For diesel generator ratings, see paragraph 8.3.1.1.1.B.

Diesel generators have the capability of starting and accelerating all ESF and safe shutdown loads to rated speed in the time frame and sequence shown in table 8.3-3. The voltage does not drop to < 75% of nominal voltage at the starting of any motor with the exception of the CS pump motor and RHR service water (RHRSW) pump drive motors, in which case the voltage drops to ~ 72% of rated voltage.

Since the CS pump motor is the first equipment to be started in the initial 10 s of the loading sequence (table 8.3-3), no other equipment is affected by the voltage dip that occurs when the motor is started. In case of the RHRSW pump drive motors, the voltage returns to ~ 90% of rated voltage within 2.6 s. The RHRSW pump motors accelerate to full rated speed in ~ 5 s under the above-listed conditions. The frequency does not decrease to < 95% of nominal value. The diesel generators are, during the loading sequence, capable of maintaining the

frequency and voltage above a level that degrades the performance of any of the loads below their minimum requirements.

For Class 1E motors not supplied with the nuclear steam supply system (NSSS), the specified minimum voltage required at the motor terminals to successfully accelerate the safety loads within the required period of time is 75% of the rated nameplate voltage.

For Class 1E motors supplied by General Electric (GE), the minimum voltage required at the motor to successfully accelerate the pump load within the required period is 3000 V for the RHR and CS motors and 440 V for the standby liquid control (SLC) pump motor. One of the RHR pump drive motors is manufactured and supplied by Reliance Electric Limited and meets the above criteria.

The sequencing of the safety system loads is in accordance with regulatory position C.4 of Regulatory Guide 1.9 (March 1971). Sequential loading of the safety system loads is described in paragraph 8.3.1.1.3.F.

The minimum margin of motor torque allowed over the pump load torque during the accelerating period is 10%. For motors not certified by the manufacturer to accelerate under a low-voltage condition, analyses were performed to determine the actual minimum value of motor torque available over pump torque that would adequately accelerate the pump to full load rpm within the required period without excessive motor heating. This value was determined to be ~ 10%.

The minimum motor torque margin is 17% for the RHR pump motor, 19% for the CS pump motor, and 12% for the SLC pump motor. The Reliance Electric Limited RHR motor provides wider torque margins than the original GE motor.

There are no features provided to monitor the temperature rise in large horsepower motor components not supplied with the NSSS when a motor fails to accelerate its load within the allowable number of starts.

The diesel generators are capable of recovering from transients caused by step-load increases or resulting from the disconnection of full load so that the speed does not cause damage to moving parts. The overspeed trip device is set sufficiently high to guarantee that the unit does not trip on full-load rejection. The units are capable of running at 110% speed without damage or loss of function. The loading takes place at sufficiently timed intervals to ensure recovery of voltage and frequency.

The suitability of each diesel generator set is confirmed by prototype qualification test data and was verified by preoperational tests.

Regulatory Guide 1.30, "Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment," 1972

Regulatory Guide 1.30 is discussed in paragraph 8.3.1.3.

Regulatory Guide 1.32, "Use of IEEE Standard 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," 1972

Compliance with Regulatory Position C(a) of this guide concerning ac systems is as follows: Two completely independent transmission lines are available to the plant, providing immediate access to the transmission network.
Additionally, compliance with IEEE Standard 308-1971 as applied to ac systems, as discussed in paragraph 8.3.1.2.1C.

Regulatory Guide 1.41, "Preoperational Testing of Redundant Onsite Electric Power Systems To Verify Proper Load Group Assignments," 1973

The onsite electric power systems, designed in accordance with Regulatory Guides 1.6 and 1.32, were tested as part of the preoperational testing program. The tests were performed in accordance with the procedures outlined in chapter 14. These tests verified the independence between the redundant onsite power sources and their load groups.
The Class 1E ac power system was functionally tested, one load group at a time, by allowing one load group to be powered only by its associated diesel generator. The redundant load group remained completely disconnected from its associated diesel generator.

A LOCA signal was simulated to start each diesel generator and initiate automatic sequencing.

Design of the Class 1E ac load groups and buses is such that no electrical connections exist between the buses except through a normally open breaker, thereby ensuring an absence of voltage on the buses and loads not under test due to the load group under test. Consequently, voltage on the buses not under test will not be monitored.

Regulatory Guide 1.63, "Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants," 1973

The electrical penetration assemblies conform to Regulatory Guide 1.63 except as discussed below.

The electrical penetration assemblies are not incorporated with self-fusing characteristics. They are designed to withstand, without loss of mechanical integrity, the maximum possible fault-current-versus-time conditions, which could occur because of single random failures of circuit overload protection devices, within the two leads of any one single-phase circuit or the three leads of any one three-phase circuit. The operating time of the backup protection on the faulty circuit is taken as the minimum permissible time for the maximum fault or overload current to flow without causing any physical damage that affects the mechanical integrity of the electric penetrations.

Regulatory Guide 1.75, "Physical Independence of Electric Systems," 1975

The construction permit for HNP-2 was issued in December 1972. The implementation date given in Section D of Regulatory Guide 1.75 (1975) is February 1974. For this reason, the recommendations of Regulatory Guide 1.75 (1975) are not required to be met on HNP-2. Physical independence of electric systems is discussed in paragraphs 8.3.1.4.1.1 and 8.3.1.4.1.2.

Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Plant," 1974

The onsite ac power system has one shared diesel generator unit. The design and installation of this shared unit are in accordance with NRC Regulatory Guide 1.81. For further explanation see paragraph 8.3.1.1.3.I.2.

Regulatory Guide 1.89, "Qualification of Class 1E Equipment for Nuclear Power Plants," 1974

Regulatory Guide 1.89 refers to IEEE Standards 323-1974 and 344-1971. Compliance with these standards is discussed in chapter 7 and section 3.10, respectively.

C. IEEE Standards

The construction permit for HNP-2 was issued in December 1972. Since the issuance of the construction permit, a number of new IEEE standards were issued that were not available for incorporation into the original design; however, many requirements of the following IEEE standards are met and discussed below:

IEEE 308-1971, "IEEE Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

The Class 1E ac power systems are designed to ensure that any design basis event, as listed in Table 1 of IEEE 308, does not cause either loss of electric power to more than one load group, surveillance devices, or protection system devices sufficient to jeopardize the safety of the unit or loss of electric power to equipment that could result in a reactor power transient capable of causing significant damage to the fuel or to the reactor coolant system.

The Class 1E system is capable of performing its function when subjected to the effects of any of the design basis events. The Class 1E loads are designed to perform their functions adequately for the design variations of voltage and frequency in the Class 1E system.

Controls and indicators for the Class 1E 4160-V bus supply breakers are provided in the MCR. Controls and indicators for the diesel generator power supplies are provided in the MCR and in the diesel generator rooms.

Class 1E equipment and associated circuits are distinctly identified as described in paragraph 8.3.1.5.

Each type of Class 1E equipment is qualified by analysis, by successful use under previous similar conditions, or by actual test to demonstrate its ability to perform its function under applicable design basis events.

Supplementary design criteria of IEEE 308 are addressed in the applicable sections describing specific Class 1E equipment.

The surveillance requirements of IEEE 308 are followed in the design, installation, and operation of Class 1E systems and consist of the following:

1. Preoperational equipment tests and inspections are performed in accordance with the procedures described in chapter 14 with all components installed. These tests and inspections demonstrate that:

    a. All components are correct and are properly mounted.
    b. All connections are correct and the circuits are continuous.

    c. All components are operational.

    d. All metering and protective devices are properly calibrated and adjusted.

2. Initial system tests are performed in accordance with the procedure described in chapter 14 with all components installed. These tests demonstrate that the equipment operates within design limits, that the system is operational within design limits, and that the system is operational and meets its performance specifications. These tests also demonstrate that:

    a. The Class 1E loads can operate on the preferred power supply.

    b. The loss of the preferred power supply can be detected.

    c. The standby power supply can be started and can accept design load in the sequence and time duration shown in table 8.3-3.

    d. The standby power supply is independent of the preferred power supply.

3. Periodic equipment tests are performed at the scheduled intervals to detect deterioration of the system toward an unacceptable condition and to demonstrate that the standby power equipment and other components that are not exercised during normal operation of the station are operable.

4. Initial system tests referred to in item 2 above are performed at scheduled intervals to demonstrate the operational readiness of the system.

With regard to Section 7 of IEEE 308, the Technical Specifications contain operating requirements for periods of operation with degraded Class 1E ac system conditions.

With regard to Section 8 of IEEE 308, the following discussion applies:

HNP-1 and HNP-2 do not share preferred power supplies (offsite) between the two units; however, startup auxiliary transformers 1C and 2C share a common link with the 230-kV switchyard. For the standby onsite power source, there are five diesel generators, two each for HNP-1 and HNP-2 and one shared between the two units. Four diesel generators are sufficient to operate the ESFs for a design basis accident (DBA) on one unit and those systems required for a concurrent safe shutdown on the other unit. (See table 8.3-4.)

<u>IEEE 317-1972</u>, "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear-Fueled Power Generating Stations"

The mechanical design, materials, fabrication, inspection, and testing of the pressure-retaining boundary of the electric penetration assembly, excluding electric compounds and gaskets, is in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Subsection NE, for Class MC components. The electric penetration assembly is designed to meet all the electrical requirements for the specified service environment without dielectric breakdown or overheating.

The design and installation is such as to facilitate periodic individual penetration assembly leakage testing after installation including both aperture and conductor seals.

The penetration assembly design is qualified for the intended service within the service environmental by testing.

<u>IEEE 323-1971</u>, "General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations"

The qualification methods and documentation requirements of IEEE 323 are followed for Class 1E electric equipment. All Class 1E equipment and its associated design, operation, and maintenance documents are identified and, equipment specifications adequate for the application are prepared. The tests, analysis, or operating experience demonstrate that the equipment is capable of meeting performance specifications under the service conditions. Documentation is prepared in a manner that permits independent evaluation of the equipment qualification.

<u>IEEE 336-1971</u>, "IEEE Standard - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations"

IEEE 336-1971 is discussed in paragraph 8.3.1.3.

IEEE 344-1971, "Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations"

Seismic qualification of Class 1E electric equipment and the extent of compliance with IEEE 344 are discussed in section 3.10.

IEEE 383-1974, "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations"

Samples of all cables were successfully tested in accordance with IEEE Standard 383-1974. The tests included temperature- and moisture-resistance tests, long-term physical aging tests, and thermal and flame tests.

The cables that must remain functional during and after a LOCA were also successfully tested in accordance with IEEE Standard 383-1974 and applicable sections of IEEE Standard 323-1971.

The manufacturers' final test report describes these tests and the ability of the cables to perform under specified service conditions.

Samples of splices were successfully tested by the cable manufacturer. Thermal blocks used in the primary penetrations were successfully tested by the penetration vendor.

IEEE 384-1974, "IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits"

This standard is referred to in Regulatory Guide 1.75. See discussion of Regulatory Guide 1.75 (paragraph 8.3.1.2.1.B).

IEEE 387-1972, "Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations"

The following paragraphs analyze compliance with the design criteria of IEEE 387.

Adequate cooling and ventilation equipment is provided to maintain an acceptable service environment within the diesel generator rooms during and after any design basis event even without support from the preferred power supply.

The diesel generator is capable of starting, accelerating, and accepting load as described in paragraph 8.3.1.1.3. The diesel generator automatically energizes its cooling equipment within an acceptable time after starting.

Frequency and voltage limits and the basis of the continuous rating of the diesel generator are included in the discussion of NRC Regulatory Guide 1.9.

Discussion of NRC Regulatory Guide 1.6 contains a description of the independence provided between the redundant Class 1E ac load groups. Mechanical and electric systems are designed so that a single failure affects the operation of only a single diesel generator.

Design conditions such as vibration, torsional vibration, and overspeed are considered in accordance with the requirements of IEEE 387.

Each diesel generator is provided with control systems permitting automatic and manual control. The automatic start signal is functional except when the diesel generator local switch (located on the diesel generator control panel in the diesel building) is in the CONTROL AT ENGINE position. Provision is made for controlling the diesel generator from the MCR and from the diesel generator room. Paragraph 8.3.3.1.1.3 provides further description of the control systems.

Voltage, current, frequency, and output-power metering are provided in the MCR to permit assessment of the operating condition of each diesel generator. Surveillance instrumentation is provided in accordance with IEEE 387.

Tests as listed in chapter 14 are conducted on each diesel generator in accordance with IEEE 387.

8.3.1.2.2 Safety-Related Equipment Exposed to Hostile Environment

The detailed information on all Class 1E equipment that must operate in a hostile environment during and/or subsequent to an accident is furnished in section 3.11, chapter 15, and supplement 15A.

8.3.1.3 Conformance With Quality Assurance Standards

The quality assurance (QA) program applicable to operation-phase activities is described in the SNC Quality Assurance Topical Report (QATR). The program includes a comprehensive system to ensure that the purchased material, manufacture, fabrication, testing, and quality control (QC) of the equipment in the emergency electric power system conform to the evaluation of the emergency electric power system equipment vendor QA programs and preparation of procurement specifications incorporating QA requirements. The administrative responsibility and control to be provided are described in the QATR.

These QA requirements include an appropriate vendor QA program and organization, purchaser surveillance as required, vendor preparation and maintenance of appropriate test and inspection records, certificates and other QA documentation, and vendor submittal of QC records considered necessary for purchaser retention to verify quality of completed work.
The procedures for the installation, inspection, and testing of instrumentation and electric equipment conform to ASME NQA-1-1994 and IEEE 336-1985, as described in the QATR.

8.3.1.4 Independence of Redundant Systems

The physical arrangement of the redundant Class 1E electric load groups and their associated raceway systems ensures that a single failure in one Class 1E electric system does not affect the redundant system.

8.3.1.4.1 Separation Criteria

To preserve the independence of redundant Class 1E electric systems, the design of the associated raceway systems located in the different plant areas and cable routing are in accordance with the following separation criteria.

8.3.1.4.1.1 Raceway System Installation. Wherever possible, cable trays of the same division are arranged from top to bottom, with trays containing the cables with the highest voltage classification at the top and trays containing the cables with the lowest voltage classification at the bottom. A cable tray designated for cables with a particular voltage classification contains only those cables of the same voltage classification.

Voltage classifications are as follows:

- 4.16-kV power.
- 600-V-, 480-V-, and 208-V-ac power.
- 250-V-dc power.
- ac and dc control, 208-120-V-ac unarmored power, communication 24-48-V-dc and 125-V-dc power.
- Low-level instrumentation circuits, including process instrumentation and control, thermocouple, resistance thermometer, and other signals that are noise sensitive but not noise productive.

In the absence of confirming analysis to support less stringent requirements, the following rules apply:

A. General Plant Areas

   1. Vertically stacked trays of the same division are installed with a minimum vertical separation of 12 in. between the top of the lower tray and the bottom of the upper tray. The horizontal separation between trays of the same division is a minimum of 6 in. between the interior sides of the trays.

2. The vertical separation between two stacks of trays of different divisions is 5 ft from the top of the topmost tray of the lower stack to the bottom of the lowest tray of the upper stack. In areas where this requirement is not attainable, the lower tray must have either a solid metal cover or 1 in. of Kaowool laid in. The upper tray must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 5 ft separation between trays is achieved or to the wall.

3. The horizontal separation between trays of different divisions is a minimum of 3 ft between the interior sides of the trays of both divisions. In areas where this requirement is not attainable, the trays must have either a solid metal cover or 1 in. of Kaowool laid in on the top. The trays must also have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 3-ft separation is achieved or to the wall or floor.

4. When stacks of trays of different divisions cross each other, the vertical separation is 5 ft from the top of the topmost tray of the lower stack to the bottom of the lowest tray of the upper stack. In areas where this requirement is not attainable, the lower tray must have either a solid metal cover or 1 in. of Kaowool laid in. The upper tray must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool shall extend 3 ft from each side of the intersection or to the wall or floor.

5. Where conduits of one division cross over or run parallel above a cable tray of the opposite division, there is a minimum vertical separation of 5 ft. In areas where this requirement is not attainable, the tray must have either a solid metal cover or 1 in. of Kaowool laid in, or the conduit must be wrapped with 1 in. of Kaowool. For crossovers, this cover or Kaowool shall extend 3 ft from each side of the intersection or to the wall. For parallel runs this cover or Kaowool must be installed to a distance where the 5-ft separation is achieved or to the wall.

B. Cable Spreading Room

1. The vertical separation between trays of different divisions is 3 ft from the top of the lower tray to the bottom of the upper tray. In areas where this requirement is not attainable, the lower tray must have either a solid metal cover or 1 in. of Kaowool laid in. The upper tray must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 3-ft separation between trays is achieved or to the wall.

2. The horizontal separation between trays of different divisions is a minimum of 1 ft between the interior sides of the trays of both divisions. In areas where this requirement is not attainable, the trays must have either a solid metal cover or 1 in. of Kaowool laid in on the top. The trays must also have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 1-ft separation is achieved or to the wall or floor.

3. Where trays of different divisions cross each other, the vertical separation is 3 ft from the top of the lower tray to the bottom of the upper tray. In areas where this requirement is not attainable, the lower tray must have either a solid metal cover or 1 in. of Kaowool laid in. The upper tray must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool shall extend 1 ft from each side of the intersection or to the wall or floor.

4. Where cables of different divisions approach the same or adjacent panels with spacing less than the minimum specified above, at least one of the cables (or group of cables) shall be run in metal (rigid or flexible) conduit to a point where the required separation exists.

5. Where conduits of one division cross over or run parallel above a cable tray of the opposite division, there is a minimum vertical separation of 3 ft. In areas where this requirement is not attainable, the tray must have either a solid metal cover or 1 in. of Kaowool laid in, or the conduit must be wrapped with 1 in. of Kaowool. For crossovers this cover or Kaowool shall extend 1 ft from each side of the intersection or to the wall. For parallel runs this cover or Kaowool must be installed to a distance where the 3-ft separation is achieved or to the wall.

C. Yard Area

Cables of the same voltage classification are routed in individual ducts of the underground duct bank systems. Barriers are provided in pull boxes to maintain physical separation. The underground concrete duct bank system for Class 1E cables is designed to:

- Meet the quality standards as required by GDC 1 and described in paragraph 8.3.1.3.

- Meet the Seismic Category I requirements as required by GDC 2 and described in section 3.10.

- Minimize the probability and effects of fires as required by GDC 3 and described in paragraph 8.3.1.4.3.

- Accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents as required by GDC 4 and described in section 3.11.

- Meet the separation and redundancy requirements of GDC 17.

- Meet the requirements of IEEE 308-1971 as described in paragraph 8.3.1.2.1.

Safety-related cable ducts passing under roadways are designed to:

- Sustain the heaviest load for which the roadways are designed.

- Withstand the effects of the design basis earthquake (DBE) and remain functional during normal and accident conditions. The safety-related cable ducts were analyzed in accordance with supplement 3.7A.B.

- Meet the requirements for duct banks of American Association of State Highway Officials (AASHO) H.20 truck loading. HNP-2 Class 1E underground electrical duct banks were considered to act as continuous beams on an elastic foundation.

Safety-related cable ducts that leave one Seismic Category I structure and enter another Seismic Category I structure are designed to:

- Withstand the effects of the DBE and remain functional during normal and accident conditions.

- Meet the design provision that the cable ducts are able to withstand the interactions between the ducts and the Seismic Category I structures. Expansion joints are installed in the cable ducts.

Some ductbank pullboxes have submersible sump pumps installed to manage the ground/rainwater seepage that enters them in an effort to prevent submerged/wetted cables from occurring. All other pullboxes are manually pumped on a PM schedule. In addition, gaskets and covers are provided to limit rainwater from entering.

D. Primary Containment Penetration Areas

The primary containment penetration assemblies of one division are separated from the assemblies of the other division as shown in primary and secondary containment electrical layout drawings.

E. Intake Structure

All HNP-2 cables in the intake structure are routed in conduits. Cables of different divisions are routed in separate conduits and do not mix with any HNP-1 cables in conduit or tray.

The Seismic Category I raceway supports are designed in accordance with the requirements specified in paragraph 3.10.2.1.1.

8.3.1.4.1.2 **Cable Installation**. Class 1E cables of one division are routed in a raceway system of the same division.

Non-Class 1E cables associated with Class 1E cables of a division are routed in a raceway system of the same division. The associated cables are subject to requirements placed on Class 1E cables, such as cable derating, environmental qualification, flame retardance, splicing restriction, and raceway fill.

A. Cable Derating

Ampacity rating of cables is established as published in Insulated Power Cable Engineers Association (IPCEA) P-46-426 and in accordance with the manufacturer's standards. To this basic rating, a grouping derating factor, also in accordance with IPCEA P-46-426, was applied. Whenever applicable, a load-diversity factor was taken into consideration. As a minimum, all power cables were selected using a 100% load factor and continuously rated at 125% of the full-load current.

B. Cable Tray Fill

As a minimum requirement, cable trays for power cables are limited to a 40% fill by cross section. The trays for control and instrumentation cables are limited to 50% fill by cross section. Where these fills are exceeded, each case is reviewed for the adequacy of the design for both physical fill and derating, using higher fill percentages.

C. Conduit Fill

Cables are installed in conduit in accordance with the allowable percentage of conduit fill listed below.

- Conduit containing one cable - 53%.
- Conduit containing two cables - 31%.
- Conduit containing three or more cables - 40%.[a]

D. Separation of Electrical Equipment

This section defines the requirements for the separation of wiring and components within an electrical enclosure, such as a panel, and between two redundant pieces of electrical equipment. In the absence of confirming analysis to support less stringent criteria, the following rules apply:

1. Separation of RPS and primary containment isolation system (PCIS) Circuits and Components

    a. PRS, PCIS, and diesel generator 1B circuits and components are not mixed with any essential division circuits and components.

a. Where these fills are exceeded, each case is reviewed for the adequacy of the design for both physical fill and derating, using higher fill percentages.

    b. The four reactor protection scram solenoid group circuits prefixed RPG1, RPG2, RPG3, and RPG4 are not mixed with each other or any other RPS, PCIS, or essential division circuit.

    c. The RPS and PCIS circuits and components within a single piece of electrical equipment are allowed to mix as follows:

Group A	Group B
RP1A	RP2A
RP1B	RP2B
PC1A	PC2A
PC1B	PC2B
RP3A	RP3B

    Mixing of Group A with Group B is not allowed.

    d. Where the above criteria cannot be met there is a minimum of 6 in. of separation between circuits and components that are not allowed to mix or, if there is < 6 in. of separation, the circuits and components are separated by a metal barrier or the circuits are enclosed in metal conduit.

    Instrumentation and control cables (≤ 125 V) not subject to harsh environments may be wrapped with an approved barrier material to provide thermal and electrical insulation.

2. Separation of engineering safeguard system (ESS) Circuits and Components

    a. ESS 1, ESS 2, and diesel generator 1B circuits and components are not mixed with each other or with any RPS or PCIS circuits or components.

b. Where the above criteria cannot be met, there is a minimum of 6 in. of separation between circuits and components of the different divisions or, if there is < 6 in. of separation, the circuits and components are separated by a metal barrier or the circuits are enclosed in metal conduit.

   Instrumentation and control cables (≤ 125 V) not subject to harsh environments may be wrapped with an approved barrier material to provide thermal and electrical insulation.

3. Nonessential Associated Circuits

   a. In the case where nonessential circuits associated with one division terminate in the same equipment as the essential (including diesel generator 1B) wiring of the other division, the nonessential cables are to be treated as essential and separation provided as delineated above.

   b. No separation is required where nonessential associated circuits of one division terminate in the same equipment as nonessential associated circuits of another division.

4. If two pieces of redundant electrical equipment are < 3 ft apart, there is a steel barrier between them. Panel ends closed by metal end plates are considered to be acceptable barriers.

8.3.1.4.2 Cable and Raceway Markings

Cables and raceways are marked with the divisional colors in accordance with paragraph 8.3.1.5.

8.3.1.4.3 Administrative Responsibilities and Controls for Ensuring Separation Criteria

The cable and raceway channel identification described in paragraph 8.3.1.5 facilitates and ensures the maintenance of separation in the routing of cables and the connection of control boards and panels. At the time of the cable routing assignment during design, personnel responsible for cable and raceway scheduling check to make sure that the division separation designation on the scheme to be routed is compatible with a load group division separation designation and other schemes previously routed. Extensive use of computer facilities assists in ensuring separation. Each cable and raceway is identified in the computer program and the identification includes the applicable division separation designation. Auxiliary programs are made available specifically to ensure that cables of a particular division separation are routed through the appropriate raceways. The routing is also confirmed by QC personnel during installation to be consistent with the design document. Color identification of equipment and cabling (discussed in paragraph 8.3.1.5) assists field personnel in this effort.

8.3.1.5 Physical Identification of Safety-Related Equipment

A. Class 1E electric equipment is provided with nameplates engraved with master parts list number and equipment description for identification.

B. Trays are identified by "EZ" code markers at intervals not exceeding 15 ft. Each marker has the tray number annotated on the divisional color background. All conduits have numbers written in black ink with felt tip pens at both ends and/or both sides of penetrations. RPS and PCIS cables are routed in conduits which are marked with red tapes at an interval not exceeding 15 ft in addition to the conduit numbers marked in black ink adjacent to the tape.

C. Class 1E and associated circuits installed in exposed Class 1E raceways are painted with divisional colors in a manner of sufficient durability at intervals not to exceed 10 ft, except for RPS and PCIS cables which will have red tags at terminating points. All Class 1E and associated circuits are permanently identified at their terminal points.

D. Color codes for cables and raceways are shown in table 8.3-17.

E. The tray numbering system identifies the division to which a particular tray belongs, the function of each tray, tray run designation, and other information. The exception to the tray numbering system is that for diesel generator B and control rod position indication, which are unique as indicated below.

Diesel Generator B Tray Number

```
2 DSB8  01
¦  ¦    ¦
¦  ¦    +-------Section of the tray
¦  +-----------Diesel generator B tray run designation
+--------------Plant unit designation
```

An example of the numbering system for a typical tray follows:

Typical Tray Number

```
2  R  A  A  5  09
¦  ¦  ¦  ¦  ¦  ¦
¦  ¦  ¦  ¦  ¦  +-----Tray section number
¦  ¦  ¦  ¦  +---------Division separation designation and function
¦  ¦  ¦  +------------Tray branch designation
¦  ¦  +---------------Main tray run designation
¦  +------------------Tray location area code
+---------------------Plant unit designation
```

An example of the control rod drive (CRD) position indication tray follows:

```
2  CRDP  01
¦   ¦     ¦
¦   ¦     +-----Section of the tray
¦   +-------------CRD position indication cable
+-------------------Plant unit designation
```

Explanatory Notes:

1. Division Separation Designation and Function

For Nonessential and Diesel 1B Cable Numbering Only	Div I	Div II	Function
A	1	2	4.15-kV power
B	3	4	600, 480, and 208-V-ac power
C	5	6	250-V-dc power
D	7	8	ac and dc control, 208 to 120-V-ac unarmored power, communication 24 to 48 and 125-V-dc power
E	9	0	Low-level Instrumentation circuits, including process instrumentation and control, thermocouple, resistance thermometer, and other signals that are noise sensitive but not noise productive

2. Area Designation for Cable Trays

Plant Area Code	Plant Area Description
A	West and south cableway - el 112 ft 0 in.
B	Control building - el 112 ft 0 in.
C	Control building - el 130 ft 0 in.
D	Control building - el 147 ft 0 in.
E	Control building - el 164 ft 0 in.
F	Turbine building - el 112 ft 0 in.
G	Turbine building - el 130 ft 0 in.
H	Turbine building - el 147 ft 0 in.
J	Turbine building - el 164 ft 0 in.
K	Cooling towers
L	Diesel generator building
N	Miscellaneous areas - small buildings
P	Intake structure
R	Reactor and radwaste buildings

F. Conduit Numbering System

1. All conduits used for power, control, and instrumentation cables are numbered for systems or groups of systems as follows:

   a. RPS system - requiring four- or six-channel separation.

   b. PCIS system - requiring four-channel separation.

   c. ESS - requiring two-division separation.

   d. Emergency diesel generator 1B.

   e. All other systems which do not require mandatory separation, i.e., balance of plant.

2. Conduits are numbered on the drawings and tagged in the field in five groups, based on the above as shown below:

RPS

Turbine Building (Main Steam Pipe Chase)	Reactor Building
2R1A001 to 499	2R1A500 to 999
2R1B001 to 499	2R1B500 to 999
2R2A001 to 499	2R2A500 to 999
2R2B001 to 499	2R2B500 to 999
2R3A001 to 499	2R3A500 to 999
2R3B001 to 499	2R3B500 to 999

PCIS

Turbine Building (Main Steam Pipe Chase)	Reactor Building
2P1A001 to 499	2P1A500 to 999
2P1B001 to 499	2P1B500 to 999
2P2A001 to 499	2P2A500 to 999
2P2B001 to 499	2P2B500 to 999

ESSs

All Other Buildings	Reactor Building
2E10001 to 2E14999	2E15000 to 2E19999
2E20001 to 2E24999	2E25000 to 2E29999

<u>Emergency Diesel Generator 1B</u>

2ESB001 and up	There will be 2ESB circuits to swing diesel 1B.

<u>All Other Systems Not Requiring Mandatory Separation</u>

a. 2MR0001 to 2MR8999 for reactor/radwaste building.

b. 2MR9000 to 2MR9999 for communication circuits - reactor/radwaste buildings.

c. 2MT0001 to 2MT8999 for turbine building.

d. 2MT9000 to 2MT9999 for communications circuits - turbine building.

e. 2MB0001 to 2MB8999 for all other buildings.

f. 2MB9000 to 2MB9999 for communication circuits - all other buildings.

g. 2MS0001 to 2MS7999 for emergency response facilities (TSC and meteorological tower).

h. 2MS8000 to 2MS9999 for communication circuits emergency response facilities (TSC, EOF, and meteorological tower).

where:

2 - Hatch Unit 2
M - Miscellaneous circuits
R - Reactor/Radwaste buildings
T - Turbine buildings
B - All other buildings
S - Emergency response facilities

G. The cable numbering system identifies the system and division or channel separation designations, function number, and other information indicated in the following example:

Typical Cable Number

```
EA   E1   01   M19
¦    ¦    ¦    ¦
¦    ¦    ¦    +-----Function number
¦    ¦    +------------Scheme number
¦    +------------------Separation designations
+--------------------------System code
```

Explanatory Notes:

1. Function Number

   The function number indicates the cable number and its associated device or function as listed below:

A	Ammeter
C	Control
D	Metering cable test (CT) circuit
E	Relaying CT circuit
F	Relaying and metering CT circuit
G	Grounding
H	Heaters
M	Power feeder (to motors, transformers, panels, etc.)
P	Potential - station service, etc.
S	Synchroscope
V	Voltmeter

2. Scheme Number

   The scheme number indicates the schematic diagram containing the associated cable as indicated by the function number.

3. Separation Designations

   - ESS Division Separation Designation

     E1,3,5,7,9 - Division I
     E2,4,6,8,0 - Division II
     EA,B,C,D,E - Diesel generator B

   - Channel Separation Designation

     1A - Channel 1
     1B - Channel 2
     2A - Channel 3
     2B - Channel 4

- Associated Circuit Separation Designation

  X1,3,5,7,9 - Circuit associated with Division I
  X2,4,6,8,0 - Circuit associated with Division II
  XA,B,C,D,E - Circuit associated with diesel generator B

4. Table of System Codes

System Description	MPL Code	System Code	System Status
Nuclear Steam Supply Shutoff System	A71B	AA[(a)] or PC	ESS and PCIS
Analog Transmitter Trip System	A70	AB,[(a)] RP or PC	ESS, RPS & PCIS
Nuclear Boiler Process Instrumentation System	B21A	BA	ESS
Steam Leak Detection System	B21B	BB	ESS
Autodepressurization System	B21C	BC	ESS
Reactor Vessel Temp. Monitoring System	B21D	BD	Non ESS
Jet Pump Instrumentation System	B21E	BE	Non ESS
Rod Worth Minimizer System	B21F	BF	Non ESS
Reactor Recirc. Pump & ASD A System	B31A	BG	ESS
Reactor Recirc. Pump & ASD B System	B31B	BH	ESS
Reactor Manual Control System	C11A	CA	Non ESS
Control Rod Drive Hydraulic Instrum. System	C11B	CB	Non ESS
Feedwater Control System	C32	CC	Non ESS
Standby Liquid Control System	C41	CD	Non ESS
Startup Range Neutron Mon. Sys.	C51A	CE* or RP	Non ESS & RPS
Power Range Neutron Mon. Sys.	C51B	CF* or RP	Non ESS & RPS
Startup Range Detector Drive Cont. System	C51C	CG	ESS
Traversing Incore Probe Calibration System	C51D	CH	Non ESS
Primary Cont. Isolation System	C61	CJ* or PC	ESS & PCIS
Remote Shutdown System	C82	CK	ESS
Reactor Protection M/G Set Control System	C71B	CL	Non ESS
Reactor Protection System	C71A	CM*, RP or RG	ESS, RPS & RPG
Nuclear Steam Supply Computer	C91	CN	Non ESS
Mini Computer Tie In	C91A	CR	Non ESS

a. Systems that are called ESS do not necessarily contain only essential cables. Circuits do not require 4/6 channel separation.

System Description	MPL Code	System Code	System Status
Process Computer			Non ESS
Replacement System	C95	CS	Non ESS
Process Radiation Mon. System	D11	DA* or RP	ESS and RPS
Area Radiation Mon. System	D21	DB	Non ESS
Residual Heat Removal System	E11	EA	ESS
Core Spray System	E21A	EB	ESS
Core Spray Jockey Pump System	E21B	EC	ESS
High Pressure Coolant Injection System	E41	ED	ESS
Reactor Core Isolation Cooling System	E51A	EE	ESS
RHR Service Water System	E11A	EF	ESS
Startrec System	F41	FA	Non ESS
Radwaste System	G11A	GA	Non ESS
Radwaste Filter System	G11B	GB	Non ESS
Radwaste Conveyor System	G11C	GC	Non ESS
Radwaste Bldg. Support System	G11D	GD	Non ESS
Reactor Water Cleanup System	G31A	GE	Non ESS
Reactor Water Cleanup Demin. System	G31B	GF	Non ESS
Fuel Pool Cooling System	G41A	GG	Non ESS
Fuel Pool Filter/Demin. System	G41B	GH	Non ESS
Radwaste Solidification System	G12	GJ	Non ESS
Heat Tracing for Piping System	G13	GK	Non ESS
Torus Drainage & Purification System	G51	GL	Non ESS
Nuclear Instrumentation Grounding System	R35	GR	Non ESS
Excess Flow Check Valves	L50	LA	Non ESS
Seismic Measurement Equipment System	L51	LB	Non ESS
Miscellaneous Hoists	L45	LC	Non ESS
Main Steam System	N11	NA	Non ESS
Condensate & Feedwater System	N21	NB	Non ESS

System Description	MPL Code	System Code	System Status
Feedwater Heater Drain System	N22	NC	Non ESS
Electro Hydraulic Control Cabinet	N32	NE	Non ESS
Steam Seal System	N33	NF	Non ESS
Lube Oil System	N34	NG	Non ESS
Condensate Vacuum System	N22A	NI	Non ESS
Reheat System	N38	NK	Non ESS
Turning Gear System	N39	NL	Non ESS
Generator System	N41	NM	Non ESS
Generator Hydrogen Seal Oil System	N42	NN	Non ESS
Isolated Phase Buses	N44	NP	Non ESS
Gland Seal System	N33A	NQ	Non ESS
Main Condenser System	N61	NR	Non ESS
Off Gas System	N62A	NS	Non ESS
Waste Gas Treatment Bldg. Support System	N62C	NT	Non ESS
Off Gas Support System	N62B	NU	Non ESS
Waste Gas Treatment Vent System	N62D	NV	Non ESS
Circulation Water & Cond. Equip. & Aux. System	N71	NW	Non ESS
Extraction Steam System	N36	NX	Non ESS
Generator Auxiliary Equip. System	N43	NY	Non ESS
Alterrex Excitation	N51	NZ	Non ESS
Reactor & Radwaste Build. Condensate Storage & Transfer System	P11	PA	Non ESS
Process Sampling System	P33A	PB	Non ESS
H_2O_2 Analyzer System	P33B	PD	ESS
React. Bldg. Service Water System	P41A	PE	ESS
React. Bldg. Closed Cooling Water System	P42	PF	ESS
Plant Heating System	P44	PG	ESS
Plant Service Air System	P51	PH	Non ESS
Plant Inst. Air System	P52	PJ	Non ESS

System Description	MPL Code	System Code	System Status
Heating & Process Steam System	P61	PK	Non ESS
Turbine Bldg. Chilled Water System	P63	PL	Non ESS
Drywell Pneumatic System	P70	PM	ESS
Reactor Bldg. Chilled Water System	P64	PP	ESS
Reactor & Radwaste Chilled Water System	P65	PR	Non ESS
Reactor & Radwaste Bldg. Service Air System	P51A	PS	Non ESS
Reactor & Radwaste Bldgs. Inst. Air System	P52A	PT	ESS
Control Building Chilled Water System	P67	PY	Non ESS
Hydrogen Water Chemistry System	P73	PY	Non ESS
Zinc Injection Passivation System	P85	PZ	Non ESS
Plant Service Water System	P41	PU	ESS and Diesel 1B
Demineralized Water System	P21	PV	Non ESS
Turbine Water Analysis System	P33C	PW	Non ESS
Post Accident Sampling System	P33D	PX	ESS
125 V Cooling Tower Batteries	R42C	RA	Non ESS
Normal Station Service 4 kV System	R20B	RC	Non ESS & DSL 1B
Normal Station Service 600 V System	R20C	RD	Non ESS
Normal Station Service 120/208 V System	R20D	RE	Non ESS
Plant Lighting 480/277 V Supply System	R20E	RF	Non ESS
Emergency Station Service Transf. (2C & 2D)	R20K	RG	Non ESS
Emergency Station Service 4 kV System	R20L	RH	ESS and Diesel 1B
Emergency Station Service 600 V	R20M	RI	ESS and Diesel 1B
125 V Diesel Generator Batteries	R42B	RJ	ESS
120/208 V Essential & Emergency Station Service	R20N	RK	ESS
120/240 V Vital ac System	R20P	RL	Non ESS
125/250 V Station Battery	R42A	RN	ESS
24/48 V Instrumentation Battery System	R42E	RR	Non ESS
Diesel Generator 2A	R43A	RS	ESS

System Description	MPL Code	System Code	System Status
Diesel Generator 1B	R43B	RT	Dsl. Gen. 1B
Diesel Generator 2C	R43C	RU	ESS
Public Address System Radwaste Bldg.	R51A	RV	Non ESS
Public Address System Reactor Bldg.	R51B	RW	Non ESS
250 V dc Inverter System	R44	RX	ESS
Public Address System Control & Turbine Building	R51D	RY	Non ESS
Public Address Systems for Other Buildings	R51F	RZ	Non ESS
Main Auxiliary Service & Startup Transformer	S11	SA	Non ESS
Generator & Main Transformer Protective Relaying & Metering	S32	SD	Non ESS
Auxiliary Transformers 2A & 2B Metering and Relaying System	S32A	SE	Non ESS
Auxiliaries (Welding Outlets & Misc. Equipment)	S30	SF	Non ESS
500 & 230 kV Switchyard Interlock System	S40	SG	Non ESS
Annunciator Arrangements & Designation System	S15	SH	Annunciation
Spare Cables	SPAR	SP	Spare
Safeguard Equipment Cooling System	T41B	TB	ESS
Reactor Bldg. Ventilation System	T41C	TC	ESS
Leak Detection System	T45	TD	Non ESS
Standby Gas Treatment System	T46	TE	ESS
Drywell Cooling System	T47	TF	ESS
Containment Atmos. Dilution System	T48A	TG	ESS
Primary Cont. Purge and Inerting System	T48B	TH	ESS
Nitrogen Inerting & Makeup System	T48C	TJ	Non ESS
Reactor Building Fire Protection System	T43	TL	Non ESS
Integrated Leak Rate Test System	T23	TM	Non ESS
Drywell to Torus Diff. Pressure System	T48D	TP	ESS

System Description	MPL Code	System Code	System Status
Torus Temperature Monitoring System	T48E	TR	ESS
Turbine Bldg. Ventilation System	U41	UB	Non ESS
Turbine Bldg. Fire Protection System	U43	UC	Non ESS
Turbine Bldg. Leak Detection System	U61	UD* or PC	Non ESS & PCIS
Radwaste Bldg. Vent System	V41	VA	Non ESS
Radwaste Bldg. Fire Protection System	V43	VB	Non ESS
Chlorination System	W23	WA	Non ESS
Cooling Towers No. 4, 5, and 6	W24	WB	Non ESS
Screen Wash System	W32	WC	Non ESS
Circ. Water Screens & Trash	W33	WD	Non ESS
Circ. Water Structure Fire Protection System	W43	WF	Non ESS
Diesel Generators 2A, 1B, & 2C and Cooling Towers Heating & Vent System	X41A	XA	ESS and Dsl. 1B
Hot Machine Shop HVAC Equipment System	X41G	XC	Non ESS
Hot Machine Shop Fire Protection System	X43G	XD	Non ESS
Hot Machine Shop Sump Pumps	X45G	XE	Non ESS
Diesel Build. Fire Protection System	X43B	XF	Non ESS
Intake Structure Sump Pump System	X45	XG	Non ESS
Fire Prot. Valve Houses Heating System	X41H	XH	Non ESS
Service Bldg. Annex Fire Prot. System	X43L	XL	Non ESS
High/Low Voltage Switchyard Fire Protection System	X43E	XM	Non ESS
TSC HVAC System	X75B	XP	Non ESS
TSC 600/480 V Power Supply	R20U	XR	Non ESS
TSC 480/208/120 V Power Supply	R20V	XS	Non ESS
TSC Uninterruptible Power Supply	R20W	XT	Non ESS
ERF Digital System	X75A	XU	ESS
SPDS Analog System	X75C	XV	Non ESS
ERF, TSC, SPDS, & NRC ERDS Computer Power System	X75F	XZ	Non ESS

System Description	MPL Code	System Code	System Status
Oil, Chemical, Etc., Transfer & Storage	Y34A	YA	Non ESS
Tornado Roof Vents	Y34B	YB	Non ESS
Cooling Tower Fire Prot. System	Y43	YC	Non ESS
Deep Well Pump System	Y42	YD	Non ESS
Controlled Access System	Y34	YE	Non ESS
Controlled Access System	Y43A	YF	Non ESS
Meteorological Data Collection System	Y33	YG	Non ESS
Controlled Access System	R43D	YH	Non ESS
Controlled Access System	R20R	YI	Non ESS
Controlled Access System	R20S	YJ	Non ESS
Controlled Access System	R20T	YK	Non ESS
Controlled Access System	Y34	YM	Non ESS
Controlled Access System	X41J	YN	Non ESS
Controlled Access System	Y34	YP	Non ESS
Controlled Access System	Y34	YT	Non ESS
Controlled Access System	Y34	YX	Non ESS
Control Bldg. Ventilation System	Z41	ZA	ESS
Control Bldg. Fire Prot. System	Z43	ZG	Non ESS
Control Bldg. Equip. Floor Drains	Z45	ZH	Non ESS

8.3.2 THE dc POWER SYSTEM

8.3.2.1 Description

The dc power system is composed of the following subsystems:

- 125-250-V-dc station battery power system (Class 1E).
- 125-V-dc diesel auxiliary power system (Class 1E).
- 24/48-V-dc power system.
- 125-V-dc cooling tower battery system.

8.3.2.1.1 125/250-V-dc Station Battery Power System

The 125/250-V-dc power system (figure 8.3-4) is an ungrounded system equipped with ground-detection circuitry, which will give annunciation and meter indication in the MCR when a ground fault is present on the 125/250-V-dc power system. Multiple grounds on this system are not probable since the first ground would be located and removed as soon as possible after alarming in the MCR. This system is composed of the following:

A. Two independent plant service batteries 2A and 2B: Batteries 2A and 2B are 120-cell lead-calcium type, with a continuous discharge rating of 1254 Ah and 1513 Ah, respectively, for 2 h at 77°F to 1.75 V/cell average. Plant battery operating voltage is 125/250 V, and each battery has adequate storage capacity to carry the required load for ~ 2 h without recharging.

   Batteries 2A and 2B are located in separate rooms in the control building at el 112 ft. A Class 1 ventilation system in each battery room prevents the buildup of combustible gases and ensures operation during emergency conditions. Fire dampers are installed in the ventilation duct system to prevent fire from spreading from one battery room to the other. The batteries are mounted in racks, which are secured to pads located 5 ft above the floor. Both the batteries and the racks are designed to Class 1E requirements.

B. Six static-type battery chargers 2A through 2F: All six battery chargers are full-wave, silicon-controlled rectifier type rated at 400 A, with a voltage regulation of ± 0.75% from no load to 2% load and ± 0.5% from 2% load to full load, with an ac supply variation of ± 10% in voltage and ± 5% in frequency. Each battery charger is capable of recharging a battery from the minimum discharge condition in 24 h while supplying a normal steady-state dc load.

   The battery chargers are located in the control building at el 130 ft. Battery chargers 2A, 2B, and 2C are located in the dc switchgear 2A room, and battery chargers 2D, 2E, and 2F are located in the dc switchgear 2B room. The chargers are designed to Class 1E requirements.

C. Two independent and redundant 125/250-V-dc metal-clad switchgear buses 2A and 2B: These buses supply essential loads as shown on figure 8.3-4 and are supplied as follows:

   1. Bus 2A is normally supplied by 125-V battery chargers 2A and 2B with charger 2C as a standby source. Battery chargers 2A, 2B, and 2C are fed from 600-V essential bus 2C. Emergency dc power for 125/250-V-dc bus 2A is supplied by station battery 2A.

   2. Bus 2B is normally supplied by 125-V battery chargers 2D and 2E with charger 2F as a standby source. Battery chargers 2D, 2E, and 2F are fed from 600-V essential bus 2D. Emergency dc power for 125/250-V-dc bus 2B is supplied by station battery 2B.

The interrupting capacity of the air circuit breakers used on dc buses 2A and 2B is 25,000 A-dc. The loads supplied by these dc buses include dc motor control centers; dc cabinets 2A, 2B, 2C, 2D, and 2E; and 125/250-V-dc switchgear buses 2C and 2D. Cabinets 2A, 2B, 2D, and 2E are essential cabinets with cabinets 2A and 2D supplying Division I essential loads and cabinets 2B and 2E supplying Division II essential loads. Cabinet 2C and switchgear buses 2C and 2D are nonessential. The loads supplied by switchgear buses 2C and 2D include bearing emergency oil pumps for the main turbine and the reactor feed pump turbines. Cabinet 2C supplies control power for plant switchgear and certain nonessential systems.

Switchgear assemblies 2A and 2B are located in separate rooms in the control building at el 130 ft and are designed to Class 1E requirements.

Switchgear assemblies 2C and 2D are located in the turbine building at el 164 ft and 147 ft, respectively, and are not designed to Class 1E requirements.

8.3.2.1.2 125-V-dc Diesel Auxiliary Power System

The 125-V-dc diesel auxiliary power system is shown on figure 8.3-5. This system is ungrounded and is composed of 125-V batteries 2A, 1B, and 2C, and 125-V battery chargers 2G, 1H, and 2J. Standby battery chargers 2H, 1N, and 2N will be used in the event of a normal battery charger failure.

Batteries 1B, 2A, and 2C are 60-cell, lead-calcium type with a discharge rating of 495 Ah for battery 1B and 410 Ah for batteries 2A and 2C for 8 h to 1.75 V/cell average at 77°F. Each battery has adequate storage capacity to carry the required load for ~ 2 h without recharging.

The 125-V-dc chargers are full-wave, silicon-controlled, rectifier type rated at 100 A with a voltage regulation of ± 0.75% from no-load to 2% load and ± 0.5% from 2% load to full-load with an ac supply variation of ± 10% in voltage and ± 5% in frequency.

This system is designed to supply separate control power for diesel generators 2A, 1B (shared unit), and 2C, the diesel generator feeder breakers, and the 4160-V switchgear bus feeder associated with a particular diesel generator. The control power for the diesel generators is normally supplied by the battery chargers. Battery charger 2G is a Division I source that is supplied from a Division I essential panel. Battery charger 2J is a Division II source supplied from a Division II essential panel. Battery charger 1H supplies control power for the shared diesel. It is supplied through an essential MCC from 4160-V essential bus 2F when the diesel is aligned to HNP-2. In the event of a charger failure, the batteries will supply the dc power.

The batteries and the battery chargers are located in separate rooms in the diesel building and are designed to Class 1E requirements.

The diesel building ventilation system (including the diesel battery room ventilation system) is described in paragraph 9.4.5.

8.3.2.1.3 24/48-V-dc Power System

The 24/48-V-dc power system is shown on drawing no. H-23635. This is a nonessential system consisting of two center-point-grounded 48-V batteries, 2A and 2B; six battery chargers, 2A, 2B, 2AB, 2C, 2D, and 2CD; and two independent 24/48-V buses. Each 24/48-V system is provided with an undervoltage relay that alarms a low-voltage condition in the MCR.

The batteries are 24-cell, lead-antimony type with a continuous discharge rating of 75 Ah for 8 h at 77°F to 1.75 V/cell average.

The battery chargers are full-wave, silicon-controlled, rectifier-type rated 25 A and 0.5% voltage regulation with supply variation of ± 10% in voltage and ± 0.5% in frequency. The battery chargers have adequate capacity to recharge the batteries to a full charge from a discharged condition in 8 h.

The battery chargers are the normal source of power for this system. Although this is a nonessential system, power for the battery chargers is supplied from 120/208-V-ac essential cabinets 2A and 2B. This system will not adversely affect the integrity of the essential cabinets. In the event of a battery charger failure, the batteries will supply power for this system.

The 24/48-V-dc buses supply power to startup range NMS and process radiation monitoring system (PRMS) instrumentation.

8.3.2.1.4 125-V Cooling Tower Battery System

This is a nonessential system composed of one 125-V battery and two 125-V battery chargers, one normal and one standby.

The battery is a 60-cell, lead-calcium type with a discharge rating of 100 Ah for 8 h to 1.75 V/cell average at 77°F.

The 125-V-dc battery chargers are full-wave, silicon-rectified saturable reactor type rated at 15 A and ± 1% voltage regulation with an ac supply variation of 10% in voltage.

The battery chargers, both normal and standby, are fed through a 120/208-V cooling tower distribution panel from a 600-208/120-V transformer. This transformer has two possible feeds, from either cooling tower bus 2G or 2H. Upon failure of the battery charger or its ac supply, dc power will be supplied from the 125-V cooling tower battery. This system supplies control power for the cooling tower fan circuit breakers.

8.3.2.2 Analysis of dc Systems

8.3.2.2.1 Compliance with General Design Criteria, NRC Regulatory Guides, and Industry Standards

In this section an analysis of the 125/250-V-dc power system describes the degree of compliance with the following:

A. General Design Criteria for Nuclear Power Plants, Appendix A of 10 CFR 50.

Compliance with the following general design criteria is discussed in section 3.1:

GDC 17 - Electric Power System

GDC 18 - Inspection and Testing of Electric Power System

B. NRC Regulatory Guides for Power Reactors

The construction permit for HNP-2 was issued in December 1972. Since the issuance of the construction permit, a number of new regulatory guides have been issued that were not available for incorporation into the original design; however, many requirements of the following regulatory guides are met and discussed below:

Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Supplies and Between Their Distribution Centers," 1971

Separate Class 1E 125-250-V-dc subsystems supply control power for each of the Class 1E ac load groups. Complete loss of either one of these subsystems does not prevent the minimum safety functions from being performed.

Each dc subsystem is energized by one 125-250-V battery and three 125-V battery chargers (two normal chargers and one spare charger). Each battery is exclusively associated with a single 125-250-V-dc bus. Each set of battery chargers is supplied by one ac load group only. The battery and the battery chargers exclusively associated with on 125-250-V-dc subsystem cannot be interconnected with any other 125-250-V-dc subsystem. The normal and backup chargers are supplied from the same ac load group for which the associated dc subsystem supplies the control power. The loads between the redundant 125-250-V-dc subsystem are not transferable except for the autodepressurization system where the redundant logic circuits and the valves are normally fed from the Division I dc system. If the Division I dc system fails, one logic circuit and the valves are transferred to the Division II dc system by the action of a normally energized voltage-sensing relay. On loss of power, the relay deenergizes, transferring the redundant logic and valve power supply to a redundant onsite power supply. The logic in which these relays appear is fused, and the relay contacts involved are a

break-before-make type. This provides reliable separation between redundant power sources.

Sufficient independence and redundancy exist between the 125-250-V-dc subsystems to ensure performance of minimum safety functions assuming a single failure.

<u>Regulatory Guide 1.30</u>, "Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment," 1972

Regulatory Guide 1.30 is discussed in paragraph 8.3.2.3.

<u>Regulatory Guide 1.32</u>, "Use of IEEE Standard 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," 1972

Compliance with Regulatory Position C(b) of this guide concerning dc systems is as follows:

1. The battery chargers are capable of supplying the normal steady-state dc loads while completely recharging their associated battery from a minimum discharge condition.

2. Additionally, compliance with IEEE Standard 308-1971, as applies to dc systems, is discussed in paragraph 8.3.2.2.1.C.

<u>Regulatory Guide 1.41</u>, "Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignment"

Testing of the dc power system, including battery acceptance test, is performed prior to unit operation and after major modifications or repairs in accordance with the procedures described in chapter 14.

The charger, battery connections, and charger supply are checked for proper assignment of ac load group.

Design of the Class 1E dc load groups and buses is such that no electrical connections exist between the buses, thereby ensuring an absence of voltage on the buses and loads not under test due to the load group under test. Consequently, voltage on the buses not under test will not be monitored.

<u>Regulatory Guide 1.75</u>, "Physical Independence of Electric Systems"

The construction permit for HNP-2 was issued in December 1972. The implementation date given in Section D of Regulatory Guide 1.75 (1975) is February 1974. For this reason, the recommendations of Regulatory Guide 1.75 (1975) are not required to be met on HNP-2. Physical independence of electric systems is discussed in paragraphs 8.3.1.4.1.1 and 8.3.1.4.1.2.

Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Power Plants," 1974

The plant dc systems are not shared between the two units.

C. IEEE Standards

The construction permit for HNP-2 was issued in December 1972. Since the issuance of the construction permit, a number of new IEEE standards were issued that were not available for incorporation into the original design; however, many requirements of the following IEEE standards are met and discussed below:

IEEE 308-1971, "IEEE Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

The Class 1E dc system provides dc electric power to the Class 1E dc loads and for control and switching of the Class 1E systems. Physical separation, electrical isolation, and redundancy are provided to prevent the occurrence of common mode failures. The design of the Class 1E dc system includes the following:

1. The 125/250-V-dc subsystem is separated into two divisions.

2. The safety actions by each group of loads are independent of the safety actions provided by its redundant counterpart.

3. Each dc subsystem includes power supplies that consist of one battery and three battery chargers.

4. The batteries are not interconnected.

5. The Class 1E battery supplies are not shared between the two units.

Each Class 1E distribution circuit is capable of transmitting sufficient energy to start and operate all required loads in that circuit. Distribution circuits to redundant equipment are independent of each other. The distribution system is monitored to the extent that it is shown to be ready to perform its intended function. The dc auxiliary devices required to operate equipment of a specific ac load group are supplied from the same load group.

When nonsafety-related circuits are supplied from the safety-related buses, the circuits are treated as safety related.

Each battery supply is continuously available both during normal operations and, following the loss of power from the ac system, to start and operate all required loads.

MCR instrumentation and alarms provided to monitor the status of the battery supply include:

- Battery ammeters.
- Battery voltmeter.
- Battery low-voltage alarm.
- Battery ground-fault alarm.

The batteries are maintained in a fully charged condition and have sufficient stored energy to operate all necessary circuit breakers and to provide an adequate amount of energy for all required emergency loads for approximately a 2-h period after loss of ac power.

Each Class 1E battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully charged state while supplying the maximum demand of the steady-state loads. The battery charger of one subsystem is independent of the battery charger for the redundant subsystem. Instrumentation and alarms provided on the battery charger to monitor its status include:

- Ammeter.
- Voltmeter.
- ac input fail.
- dc output low.
- dc output high.
- Overtemp.
- Blocked air filter.
- Both fans fail.
- dc ground fault (for diesel battery only).

Each battery charger has an input ac and output dc circuit breaker for isolation of the charger. Each battery charger power supply is designed to prevent the ac supply from becoming a load on the battery due to a power feedback as the result of the loss of ac power to the chargers.

Each Class 1E battery charger is subjected to a periodic surveillance test to verify its ability to deliver a minimum of 100% of its rated output current at the nominal float voltage for the battery it supplies.

The Class 1E 125/250-V-dc subsystem is designed to meet Seismic Category I requirements as stated in section 3.10. The batteries, battery chargers, dc buses, switchgear, inverters, and other components of the dc subsystem are housed in the control building, which is a Seismic Category I structure.

IEEE 336, "IEEE Standard, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During Construction of Nuclear Power Generating Stations"

IEEE 336-1971 is discussed in paragraph 8.3.2.3.

IEEE 344, "IEEE Guide for Seismic Qualifications of Class 1 Electric Equipment for Nuclear Power Generating Stations"

Seismic qualification of Class 1E electric equipment and the extent of compliance with IEEE 344 are discussed in section 3.10.

IEEE 384, "IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits"

This standard is referred to in Regulatory Guide 1.75. See discussion of Regulatory Guide 1.75 (paragraph 8.3.2.2.1.B).

IEEE 450-1987, "Recommended Practice for Maintenance, Testing, Replacement of Large Stationary-Type Power Plant and Substation Lead Storage Batteries"

The following recommended practices of IEEE 450 for maintenance, testing, and replacement of batteries are followed for the Class 1E batteries.

1. Maintenance and inspections are carried out on a regularly scheduled basis to comply with the requirements of IEEE 450-1987.

2. The procedure for battery capacity tests is in accordance with Section 5 of IEEE 450-1987.

3. The battery capacity test schedule is as follows:

    a. An acceptance test is performed at the factory to determine whether it meets the specified discharge rate.

    b. Performance discharge tests are performed in accordance with IEEE 450-1987.

    c. A battery service test is performed at the frequency specified in the Technical Specifications.

4. Records of the data obtained from inspections and tests are kept along with test procedures to comply with the requirements.

8.3.2.3 Conformance with Appropriate QA Standards

A planned QA program is described in chapter 17, which includes a comprehensive system to ensure that the purchased material, manufacture, fabrication, testing, and QC of the equipment in the emergency electric power system conforms to the evaluation of the emergency electric power system equipment vendor QA programs and preparation of procurement specifications incorporating QA requirements. The administrative responsibility and control to be provided are described in chapter 17.

These QA requirements include an appropriate vendor QA program and organization, purchaser surveillance as required, vendor preparation and maintenance of appropriate test and inspection records, certificates and other QA documentation, and vendor submittal of QC records considered necessary for purchaser retention to verify quality of completed work.

The procedures for installation, inspection, and testing of instrumentation and electric equipment conform to Regulatory Guide 1.30 (1972) and IEEE 336-1971.

8.3.2.4 Independence of Redundant Systems

The general considerations for the independence of Class 1E dc power subsystems are described in paragraph 8.3.1.4.

8.3.2.5 Physical Identification of Safety-Related Equipment

Physical identification of Class 1E equipment is discussed in paragraph 8.3.1.5.

TABLE 8.3-1 (SHEET 1 OF 2)

TABLATION OF LOADS ON 4160-V BUSES

4160-V Bus 2A	Load
Recirculation pump 2A ASD	6665 kVA
Circulating water pump 2A	5000 hp
4160-V Bus 2B	
Recirculation pump 2B ASD	6665 kVA
Circulating water pump 2B	5500 hp
4160-V Bus 2C	
Condensate pump 2C	1250 hp
Condensate booster pump 2C	3000 hp
Cooling tower feeders	3000 hp
Turbine building refrigerator unit 2A	1000 hp
4160-600-V station service transformer 2A	1368 kVA
4160-600-V station service transformer 2AA	1368 kVA
4160-600-V station service transformer 2BB	1368 kVA
4160-480/277-V lighting and miscellaneous power switchgear transformer	425 kVA
4160-600-V standby transformer 2AB[a]	1368 kVA
4160-V Bus 2D	
Condensate pump 2A	1250 hp
Condensate pump 2B	1250 hp
Condensate booster pump 2A	3000 hp
Condensate booster pump 2B	3000 hp
Cooling tower feeders	3000 hp
Turbine building refrigerator unit 2B	900 hp
4160-600-V station service transformer 2B	1368 kVA
4160-480/277-V lighting and miscellaneous power switchgear transformer[a]	425 kVA
4160-600-V switchyard transformer	600 kVA
4160-600-V standby transformer 2AB[a]	1368 kVA
4160-480/277-V lighting and miscellaneous power hot machine shop	500 kVA

TABLE 8.3-1 (SHEET 2 OF 2)

4160-V Bus 2E (Essential)	Load
CS pump 2A	1000 hp
RHR pump 2A	1000 hp
RHRSW pump 2A	1250 hp
CRD pump 2A	250 hp
Plant service water (PSW) pump 2A	700 hp
Drywell chiller unit 2A	600 hp
4160-600-V station service transformer 2C	1368 kVA
4160-V Bus 2F (Essential)	
RHR pump 2C	1000 hp
RHR pump 2D	1000 hp
RHRSW pump 2C	1250 hp
CRD pump 2B	250 hp
PSW pump 2C	700 hp
PSW pump 2D	700 hp
4160-600-V transformer 2F1	225 kVA
4160-600-V transformer 2F2	75 kVA
4160-600-V standby transformer 2CD[a]	1368 kVA
4160-V Bus 2G (Essential)	
RHR pump 2B	1060 hp
RHRSW pump 2B	1250 hp
RHRSW pump 2D	1250 hp
CS pump 2B	1000 hp
PSW pump 2B	700 hp
Drywell chiller unit 2B	600 hp
4160-600-V station service transformer 2D	1368 kVA

a. Standby loads only.

TABLE 8.3-3

SEQUENCE FOR AUTOMATICALLY CONNECTING EMERGENCY ac LOADS ON LOCA/LOSP[a,c]

Event	Time (s)	Action/Comments
Low reactor pressure vessel (RPV) water level or high drywell pressure.	0	Signal standby ac power supply to start.
Standby ac system is ready for loading.	12	Apply power to 600-V emergency load centers and motor-operated isolation valves. Start standby gas treatment system (SGTS). Energize emergency lighting. Power available to CS injection valves. Start both CS pumps. Start on RHR pump
RPV depressurizes, allowing pressure permissive logic for LOCA valves to be satisfied.[c] One RHR pump and both CS pumps are operating.	20-23	RHR and CS injectionvalves begin to open. Start three RHR pumps. Recirculation loop discharge valves begin to close.
All RHR pumps are operating.	30	Start two PSW pumps.[b] CS injection valves are open. LOCA analysis supports a 31-s response time for CS.
Recirculation line discharge valve is fully closed. RHR injection valve is sufficiently open for full LPCI flow.	60-64	This assumes a 41-s recirculation discharge valve stroke time and a 63-s RHR isolation valve stroke time. LOCA analysis supports a 64-s response time.

a. The sequence for automatic connection of ac loads is based upon operation of all three emergency buses and diesel generator units.
b. PSW pumps are tripped on an LOSP or a LOCA/LOSP, but not on a LOCA alone.
c. Times are supported by the SAFER/GESTR-LOCA analysis described in subsection 6.3.3. Valve stroke times are design values and are also supported by the LOCA analysis.

TABLE 8.3-4

STANDBY DIESEL GENERATOR SYSTEM EMERGENCY LOADS[a]

Loads	Total No. of Motors	Motor Rating (hp)	0-10 min: Minimum Required	0-10 min: No. of Pumps Running	0-10 min: Demand[d] (hp/kW)	10-60 min: No. of Pumps Running	10-60 min: Demand[d] (hp/kW)	60 min and Beyond: No. of Pumps Running	60 min and Beyond: Demand[d] (hp/kW)
HNP-2 DBA									
CS pumps	2	1000	1	2	2000/1596	1	1000/798	1	1000/798
RHR pumps	4	1000[e]	2	4	4320/3448	1	1080/862	1	1080/862
RHRSW pumps	4	1250	0	0	0/0	2	2450/1954	2	2450/1954
PSW pumps	4	700	1	2	1200/974	2	1200/974	2	1200/974
600-V loads[b]	-	-		-	-/ ≤ 1193[f]	-	-/ ≤ 1869[f]	-	-/ ≤ 1869[f]
					≤ 7211[f]		≤ 6457[f]		≤ 6457[f]
HNP-1 Emergency Shutdown					hp		hp		hp
PSW pumps	4	700		2	1200	2	1200	2	1200
RHR pumps	4	1000		0	0	1	1080	1	1080
RHRSW pumps	4	1250		0	0	2	2440	2	2440
CRD water pumps	2	250		0	0	0	0	1	260
Emergency ac lighting	-	90[c]		-	120	-	120	-	120
Battery charger	2	25[c]		2	70	2	70	2	70
Other 600-V loads					1651		1536		1566
Subtotal demand (hp)					3041		6446		6736
Subtotal demand (kW) (90% efficiency assumed)					2521		5343		5583

a. The LOCA signal will initiate the starting of both CS pumps and all four RHR pumps. The 0- to 10-min loading of the accident unit is based on the operation of all three essential buses and diesel generator units. The loading beyond 10 min is based on the operator manually switching loads in accordance with minimum system requirements. The Minimum Required column of this table demonstrates that four of five 2850-kW diesel generator units are adequate to supply the ESF loads of one unit concurrent with the emergency shutdown loads of the other.
b. See table 8.3-5.
c. In kW.
d. The hp/kW load considered is for the maximum hp/kW load on the pumps, except for the PSW pumps where the load is considered with the turbine building isolated.
e. Three of the motors are rated at 1000 hp; one is rated at 1060 hp.
f. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-5

LOADS ON 600-V ESSENTIAL BUSES

Loads	Total No. of Motors	Motor Rating
Drywell cooling units	4	75 hp
Drywell cooling units	2	25 hp
CS and RHR pump room cooling units	4	25 hp
Reactor core isolation cooling pump room cooling units	2	5 hp
High pressure coolant injection pump room cooling units	2	7.5 hp
Intake structure essential loads	-	15 hp
SGTS exhaust fans	2	25 hp
SLC tank startup heaters	1	35 kW
SGTS heaters	2	24 kW
SLC tank heaters	1	10 kW
Diesel generator room fans	6	5 hp
Diesel generator water jacket heaters	3	15 kW
Diesel generator lube oil heaters	3	15 kW
Diesel generator room heaters	9	12.5 kW
Switchgear room heaters	9	7.5 kW
600/208-V essential small fan and pump motors, miscellaneous loads[a]	-	--
Battery chargers	4	67.22 kW
Battery chargers	2	16.46 kW
Service air compressors	2	125 hp
Air blowers - outboard	2	5 hp
Air blowers - inboard	1	5 hp
Air compressor for diesels A and C	4	5 hp
Motor-operated valves - intermittent	-	--
Emergency lighting	-	--
Diesel service water pump	1	60 hp
Drywell return air fans	2	30 hp
Chilled water recirc pumps	2	50 hp
CS jockey pumps	2	10 hp
CRD pump room cooling units	2	15 hp
Reactor bldg floor drain sump pump	4	7.5 hp
SSAC closed cooling system pump/fans	5	23 hp

a. Loads below 5 hp are considered miscellaneous loads.

TABLE 8.3-6

LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP AND 0-10 min POST-LOCA)

	Bus 2E			Bus 2F			Bus 2G		
Pump Services	No	hp[a] /	kW[b]	No	hp[a] /	kW[b]	No.	hp[a] /	kW[b]
CS	2A	1000 /	798		-		2B	1000 /	798
RHR	2A	1080 /	862	2C	1080 /	862	2B	1080 /	862
				2D	1080 /	862			
PSW	2A	600 /	487		-		2B	600 /	487
600-V loads[c]		/	≤ 484[d]			≤ 254[d]			≤ 455[d]
TOTAL kW			≤ 2631[d]			≤ 1978[d]			≤ 2602[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-7

DIESEL ENGINE ALARMS

Alarm Condition	Sensor	Annunicated Diesel Building	Annunicated MCR	Remarks
Lube oil temperature low	Temperature switch	Yes	Yes	
Lube oil temperature high	Temperature switch	Yes	Yes	
Jacket coolant temperature low	Temperature switch	Yes	Yes	
Jacket coolant temperature high	Temperature switch	Yes	Yes	
Lube oil pressure low	Pressure switch	Yes	Yes	These four alarms are qualified by time delay to allow pressure buildup after starting.
Fuel oil pressure low	Pressure switch	Yes	Yes	
Raw water pressure low	Pressure switch	Yes	Yes	
Jacket coolant pressure low	Pressure switch	Yes	Yes	
Start Failure	Time Delay	Yes	Yes	
Engine overspeed	Speed switch	Yes	Yes	
High crankcase pressure	Pressure switch	Yes	Yes	Time delay on start
Control at engine	Mode switch	Yes	Yes	
Day tank fuel oil level low	Level switch	Yes	Yes	
Day tank fuel oil level high	Level switch	Yes	Yes	
Expiration tank jacket cool level low	Level switch	Yes	Yes	
No. 1 air reserve pressure low	Pressure switch	Yes	Yes	
No. 2 air reserve pressure low	Pressure switch	Yes	Yes	
Emergency engine shutdown	LO relay	No	Yes	

TABLE 8.3-8

DIESEL GENERATOR ALARMS

Alarm Condition	Sensor	Annunciated: Diesel Building	Annunciated: MCR	Remarks
Generator winding temperature high	Temperature monitor	No	Yes	
Generator bearings temperature high	Temperature monitor	No	Yes	
Generator neutral overcurrent	IAC relay	No	Yes	
Generator differential operation	CFDs and HEA	No	Yes	Relay target in diesel building.
Generator overcurrent, volt restraint	IJCVs relay	No	Yes	Relay target in diesel building.
Generator overvoltage	IAV relay	No	Yes	
Generator loss of excitation	CEH relay	No	Yes	Functions only in TEST mode.
Generator reverse power	ICW relay	No	Yes	Functions only in TEST mode.
Generator field ground	DGF relay	No	Yes	

TABLE 8.3-9

DIESEL ENGINE PROTECTION

Abnormal Condition	Protective Device	Protective Function Versus Mode Select Switch Position: NORMAL	TEST	Remarks
Starting failure[a]	T-D relay	Yes	Yes	
Engine overspeed	Speed switch	Yes	Yes	
Lube oil temperature high	Temperature switch	No	Yes	
Jacket coolant temperature high	Temperature switch	No	Yes	
Lube oil pressure low	Pressure switch	Yes	Yes	T-D on start to allow pressure buildup.
Jacket coolant pressure low	Pressure switch	No	Yes	T-D on start to allow pressure buildup.
Crankcase pressure high	Pressure switch	No	Yes	T-D on start.

a. The start-failure relay operates to interrupt the starting of the diesel generator if the diesel engine fails to start in 7 s. The start-failure relay timer is deenergized by one of the following signals:

- Lube oil pressure is established.
- Predetermined speed is reached.

TABLE 8.3-10

DIESEL GENERATOR PROTECTION

Abnormal Condition	Protective Device	Protective Function Versus Mode Select Switch Position NORMAL	Protective Function Versus Mode Select Switch Position TEST	Remarks
Generator differential	CFD and HEA	Yes	Yes	Trips LO relay and voltage regulator.
Generator overcurrent, volt restraint[a]	IJCV and ACB	Yes	Yes	Trips generator ACB only.
Generator loss of excitation	CEH and HEA	No	Yes	Trips LO relay and voltage regulator.
Generator reverse power	ICW and HEA	No	Yes	Trips LO relay and voltage regulator.

a. The generator overcurrent voltage restraint is retained for tripping the 4160-V diesel breaker when the mode selector switch is in the normal position while the diesel generator continues to run. This is considered a desirable function to protect the generator under the following postulated circumstances: a fault on the 4160-V bus or a fault on a 4160-V feeder having a stuck breaker.

Tripping the generator breaker for the serious conditions shown above will limit damage to equipment, permitting prompt repair and return to service while the redundant diesel carries the essential loads. A study has shown that no step load of the loading sequence will cause the diesel breaker to trip. The heaviest load condition is at the start of the sequence of loads at time 12 s. (See tables 8.3-3, -4, and -5.) At this point, the generator might carry an inrush current of ~ 1600 A. From the relay curves, this current would close the relay in 4 to 5 s with zero-voltage restraint. With 78% voltage restraint, this current would close the relay in 17 to 18 s. With the diesel returning to 90% of rated voltage in 2.5 s, the 4160-V diesel breaker will not trip.

TABLE 8.3-11

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP A AVAILABLE, AND LOSS OF BUS 2E)

Pump Services	Bus 2F No.	Bus 2F hp[a] / kW[b]	Bus 2G No.	Bus 2G hp[a] / kW[b]
CS		-	2B	1000 / 798
RHR	2C	1080 / 862		-
RHRSW	2C	1225 / 977	2B or 2D	1225 / 977 or 1225 / 977
PSW	2D	600 / 487		-
600-V loads[c]		- / ≤ 218[d]		- / ≤ 813[d]
TOTAL kW		≤ 2544[d]		≤ 2588[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pump where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pump, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-12

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP A AVAILABLE, AND LOSS OF BUS 2F)

Pump Services	Bus 2E No.	Bus 2E hp[a] / kW[b]	Bus 2G No.	Bus 2G hp[a] / kW[b]
CS		-	2B	1000 / 798
RHR	2A	1080 / 862		-
RHRSW	2A	1225 / 977	2B	1225 / 977
				or
		-	2D	1225 / 977
PSW	2A	600 / 487	2B	600 / 487
600-V loads[c]		- / ≤ 838[d]		- / ≤ 813[d]
TOTAL kW		≤ 3164[d]		≤ 3075[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-13

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP A AVAILABLE, AND LOSS OF BUS 2G)

Pump Services	Bus 2E No.	Bus 2E hp[a] / kW[b]	Bus 2F No.	Bus 2F hp[a] / kW[b]
CS	2A	1000 / 798		-
RHR		-	2C	1080 / 862
RHRSW	2A	1225 / 977	2C	1225 / 977
PSW		-	2C	600 / 487
600-V loads[c]		- / ≤ 838[d]		- / ≤ 218[d]
TOTAL kW		≤ 2613[d]		≤ 2544[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pump where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pump, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-14

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP B AVAILABLE, AND LOSS OF BUS 2E)

	Bus 2F			Bus 2G		
Pump Services	No.	hp[a]	kW[b]	No.	hp[a]	kW[b]
CS		-		2B	1000	798
RHR	2D	1080	862		-	
RHRSW	2C	1225	977	2B	1225	977
					or	
				2D	1225	977
PSW	2D	600	487		-	
600-V loads[c]		-	≤ 218[d]		-	≤ 813[d]
TOTAL kW			≤ 2544[d]			≤ 2588[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pump where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pump, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-15

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP B AVAILABLE, AND LOSS OF BUS 2F)

Pump Services	Bus 2E No.	Bus 2E hp[a] / kW[b]	Bus 2G No.	Bus 2G hp[a] / kW[b]
CS	2A	1000 / 798		-
RHR		-	2B	1080 / 862
RHRSW	2A	1225 / 977	2B	1225 / 977
			or	
			2D	1225 / 977
PSW	2A	600 / 487	2B	600 / 487
600-V loads[c]		- / ≤ 838[d]		- / ≤ 813[d]
TOTAL kW		≤ 3100[d]		≤ 3139[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-16

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, RHR LOOP B AVAILABLE, AND LOSS OF BUS 2G)

	Bus 2E		Bus 2F	
Pump Services	No.	hp[a] / kW[b]	No.	hp[a] / kW[b]
CS	2A	1000 / 798		-
RHR		-	2D	1080 / 862
RHRSW	2A	1225 / 977	2C	1225 / 977
PSW		-	2C	600 / 487
600-V loads[c]		- / ≤ 838[d]		- / ≤ 218[d]
TOTAL kW		≤ 2613[d]		≤ 2544[d]

a. The horsepower considered is for the maximum load on the pumps, except for the PSW pump where load is considered with the turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pump, for which efficiency at 75% full load is considered.
c. See table 8.3-5.
d. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-17

CABLE AND RACEWAY COLOR CODES

System	Color Code for Cables	Color Code for Raceways
RPS and PCIS cables	Red tags at the terminal points	Red tape
ESS Divisional 1 cables	Yellow	Yellow
Associated cables in Division 1 raceways	Blue	Yellow
Diesel 2A cables	Yellow	Yellow
Diesel 1B cables	White	White
Nonclassified cables in diesel 1B raceways	Orange on White	White
ESS Divisional 2 cables	Green	Green
Associated cables in Division 2 raceways	Orange	Green
Diesel 2C cables	Green	Green

TABLE 8.3-18

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, AND LOSS OF DIESEL GENERATOR BATTERY 2A)[a]

	Bus 2F			Bus 2G		
Pump Services	No.	hp[b] /	kW[c]	No.	hp[b] /	kW[c]
RHR	2C	1080 /	862	2B	1080 /	862
RHRSW	2C	1225 /	977	2B	1225 /	977
					or	
				2D	1225 /	977
PSW	2C	600 /	487	2B	600 /	487
600-V loads[c]		- /	≤ 855[d]		- /	≤ 813[d]
TOTAL kW			≤ 3181[d]			≤ 3139[d]

a. The loading configuration corresponds to the loads required to cope with the worst-case break in the recirculation and CS loops.
b. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
c. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
d. See table 8.3-5.
e. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-19

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, AND LOSS OF DIESEL GENERATOR BATTERY 2C)[a]

	Bus 2E			Bus 2F		
Pump Services	No.	hp[b] /	kW[c]	No.	hp[b] /	kW[c]
RHR	2A	1080 /	862	2D	1080 /	862
RHRSW	2A	1225 /	977	2C	1225 /	977
PSW	2A	600 /	487	2D	600 /	487
600-V loads[c]		- /	≤ 838[d]		- /	≤ 189[d]
TOTAL kW			≤ 3164[d]			≤ 2515[d]

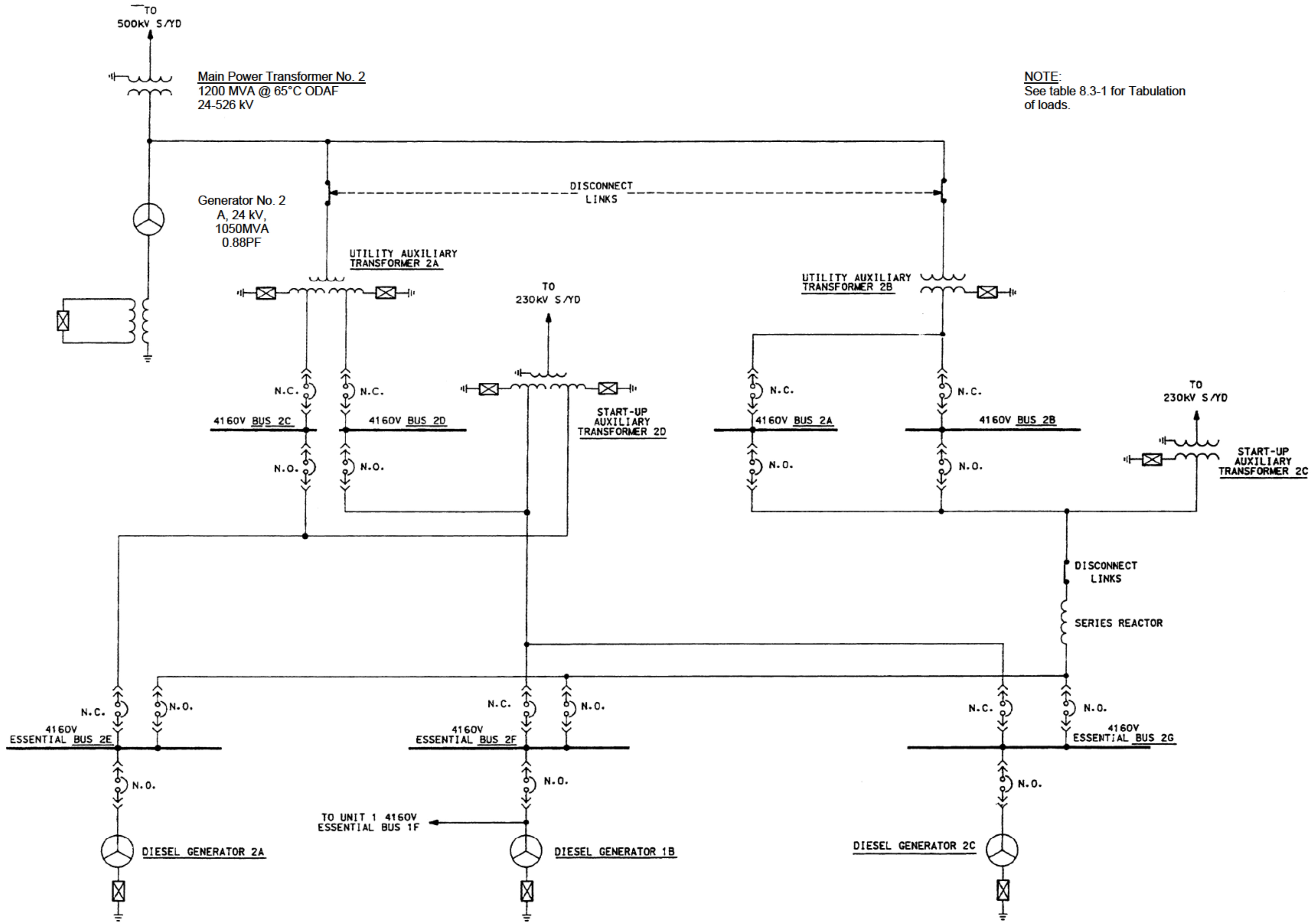
a. The loading configuration corresponds to the loads required to cope with the worst-case break in the recirculation and CS loops.
b. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
c. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
d. See table 8.3-5.
e. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.3-20

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES (LOSP, 10-60 min POST-LOCA, AND LOSS OF DIESEL GENERATOR BATTERY 1B)[a]

	Bus 2E			Bus 2G		
Pump Services	No.	hp[b] /	kW[c]	No.	hp[b] /	kW[c]
RHR	2A	1080 /	862	2B	1080 /	862
RHRSW	2A	1225 /	977	2B	1225 /	977
PSW	2A	600 /	487	2B	600 /	487
600-V loads[c]		- /	≤ 838[d]		- /	≤ 813[d]
TOTAL kW			≤ 3164[d]			≤ 3139[d]

a. The loading configuration corresponds to the loads required to cope with the worst-case break in the recirculation and CS loops.
b. The horsepower considered is for the maximum load on the pumps, except for the PSW pumps where load is considered with the turbine building isolated.
c. In converting hp to kW, motor full-load efficiency is considered, except for the PSW pumps, for which efficiency at 75% full load is considered.
d. See table 8.3-5.
e. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.



NOTE:
See table 8.3-1 for Tabulation of loads.

REF DWG H-23350 REV 6

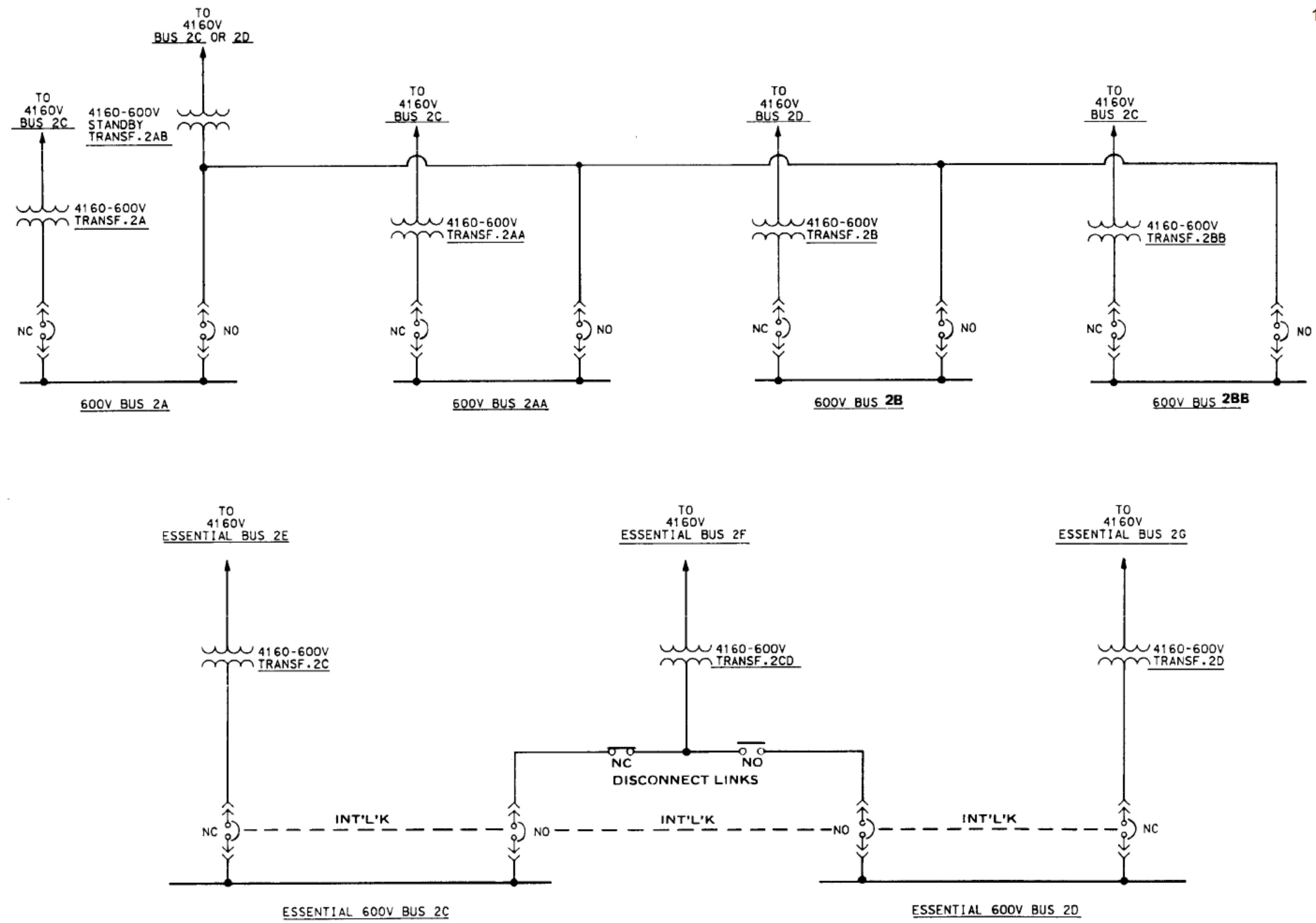
ACAD 2080301

REV 31 9/13

SOUTHERN COMPANY Energy to Serve Your World®	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	4160-V AUXILIARY ELECTRICAL POWER SYSTEM
		FIGURE 8.3-1

NOTE:

1. 600V COOLING TOWER BUSES 2E, 2F, 2G, 2H, 2J, & 2K NOT SHOWN.



REF DWG H-23350 REV 7

REV 19 7/01

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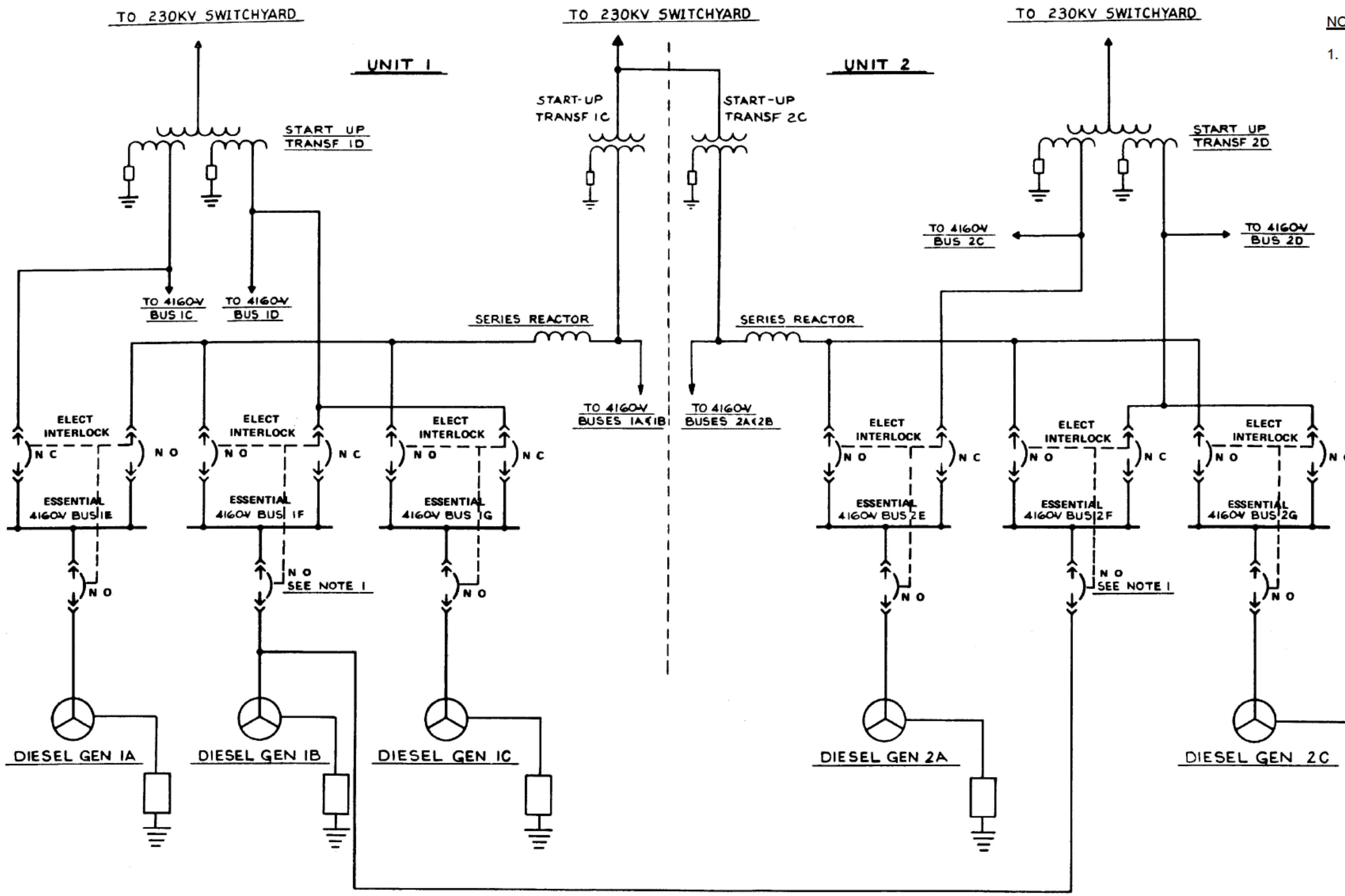
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

600-V AUXILIARY ELECTRICAL POWER SYSTEM

FIGURE 8.3-2



NOTES:

1. DIESEL GENERATOR 1B IS AUTOMATICALLY ALIGNED TO ACCIDENT UNIT.

REF DWG H-23350 REV 5
REF DWG H-13350 REV 5

REV 19 7/01

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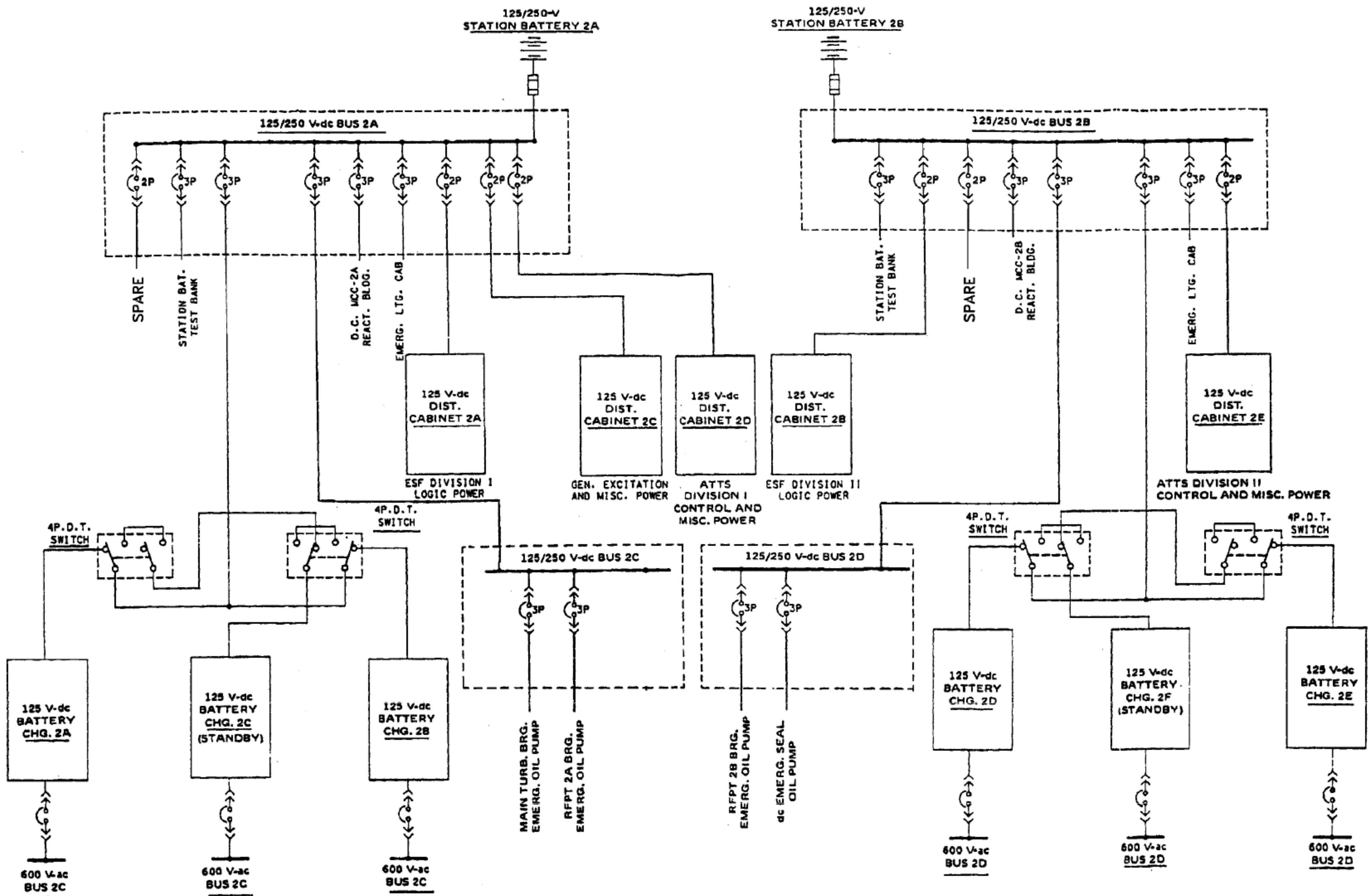
UNIT 2

4160-V ESSENTIAL POWER SYSTEM

FIGURE 8.3-3



REF DWG H-23390 SHEET 1 REV 45
REF DWG H-23390 SHEET 2 REV 13
REF DWG H-23399 REV 8
REF DWG H-27057 REV 10

ACAD 2080304

REV 19 7/01

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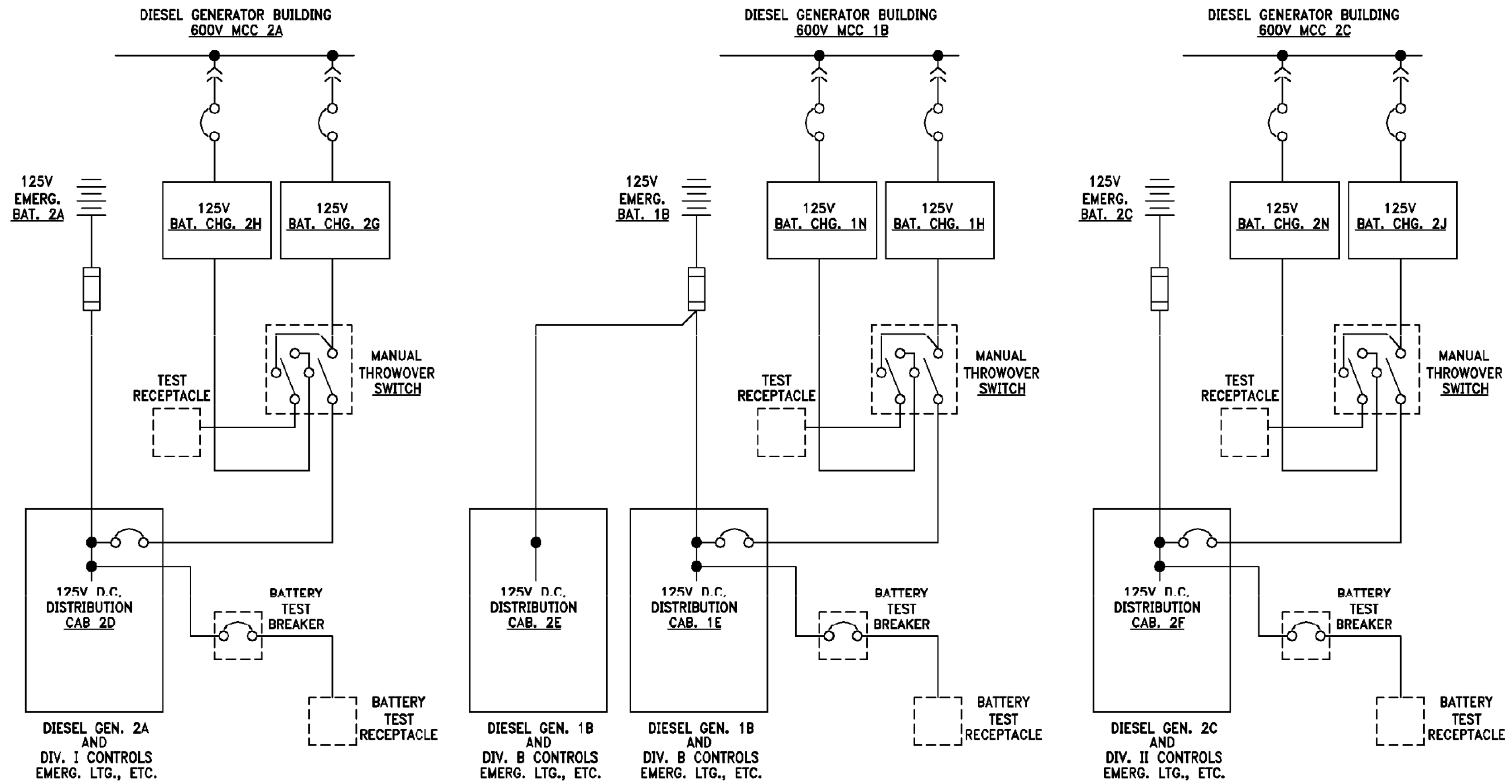
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

125-250-V-dc POWER SYSTEM

FIGURE 8.3-4



REF DWG H-23371 SHEET 1 REV 25
REF DWG H-23371 SHEET 2 REV 6
REF DWG H-13371 SHEET 1 REV 32

REV 28 9/10

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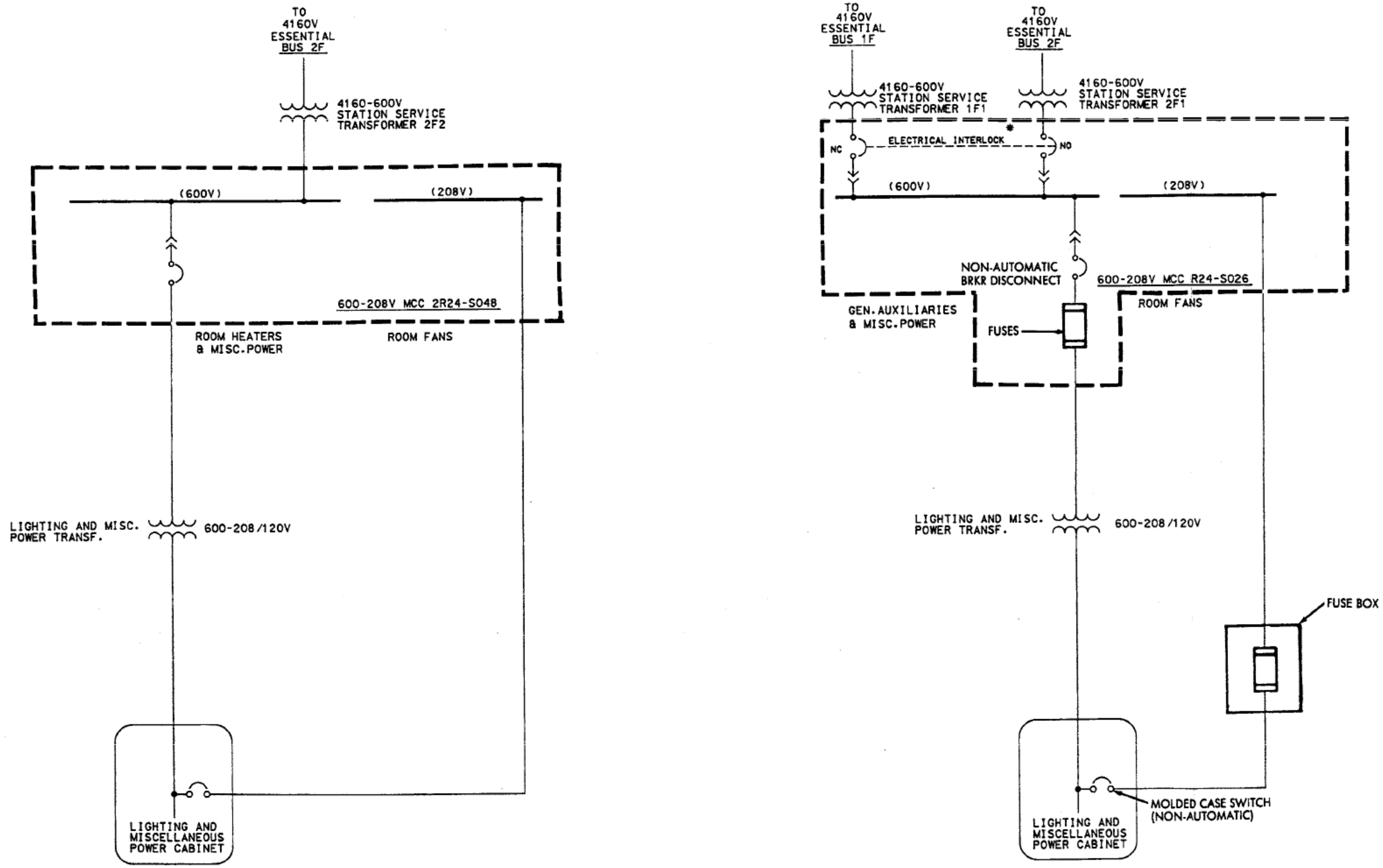
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

125-V-dc DIESEL AUXILIARY POWER SYSTEM

FIGURE 8.3-5



* INTERLOCK BETWEEN THESE CIRCUIT BREAKERS IS SUCH THAT POWER FEED TO MCC ALIGNS WITH THE ACCIDENT-UNIT.

REF DWG H-23316 REV 3
REF DWG H-13648 REV 19

REV 19 7/01

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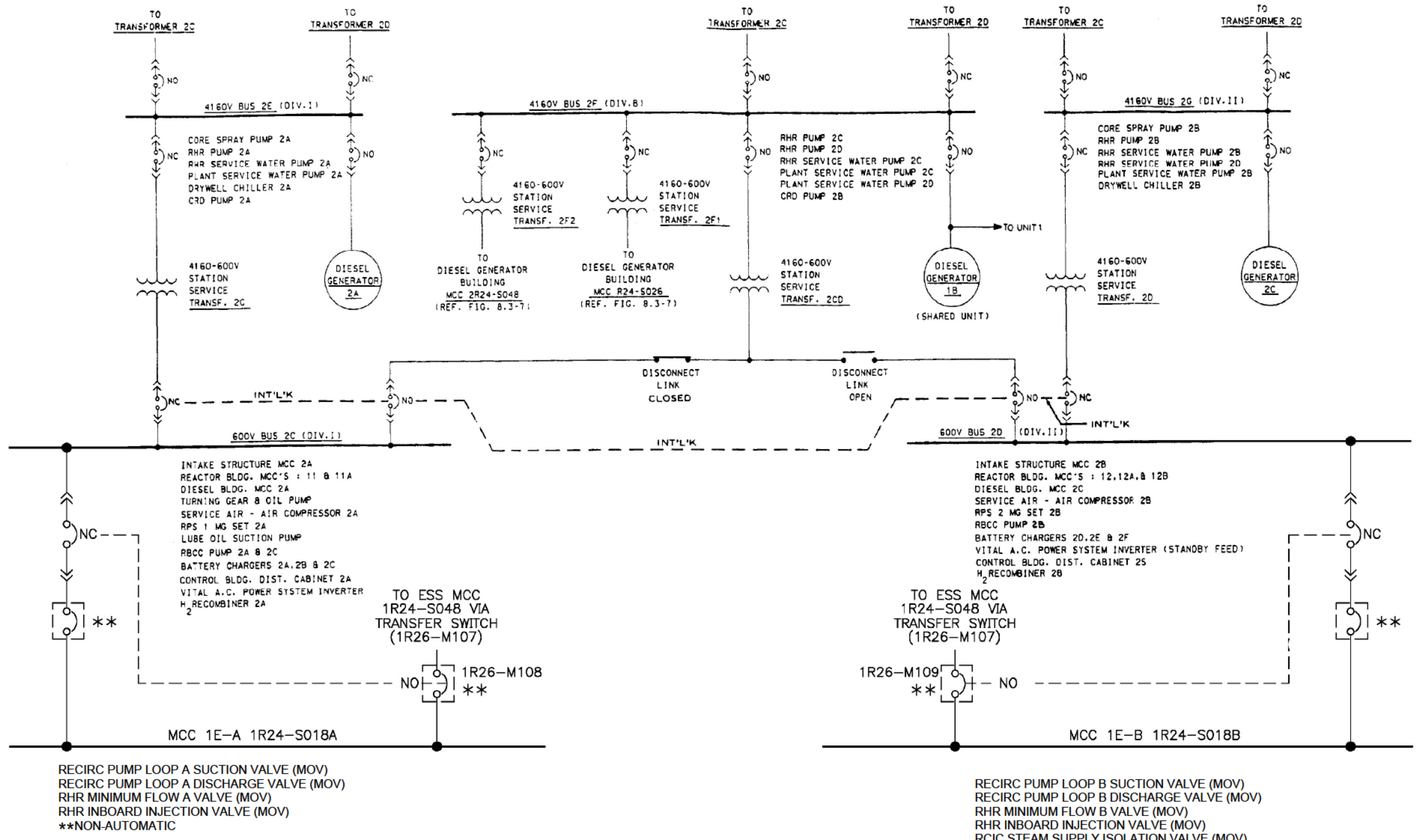
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

DIESEL GENERATOR 1B
600-208-V MCCs

FIGURE 8.3-7



REF DWG H-17012 REV 27
REF DWG H-23382 REV 33
REF DWG H-27021 REV 18
REF DWG H-23350 REV 8

ACAD 2080308

REV 19 7/01

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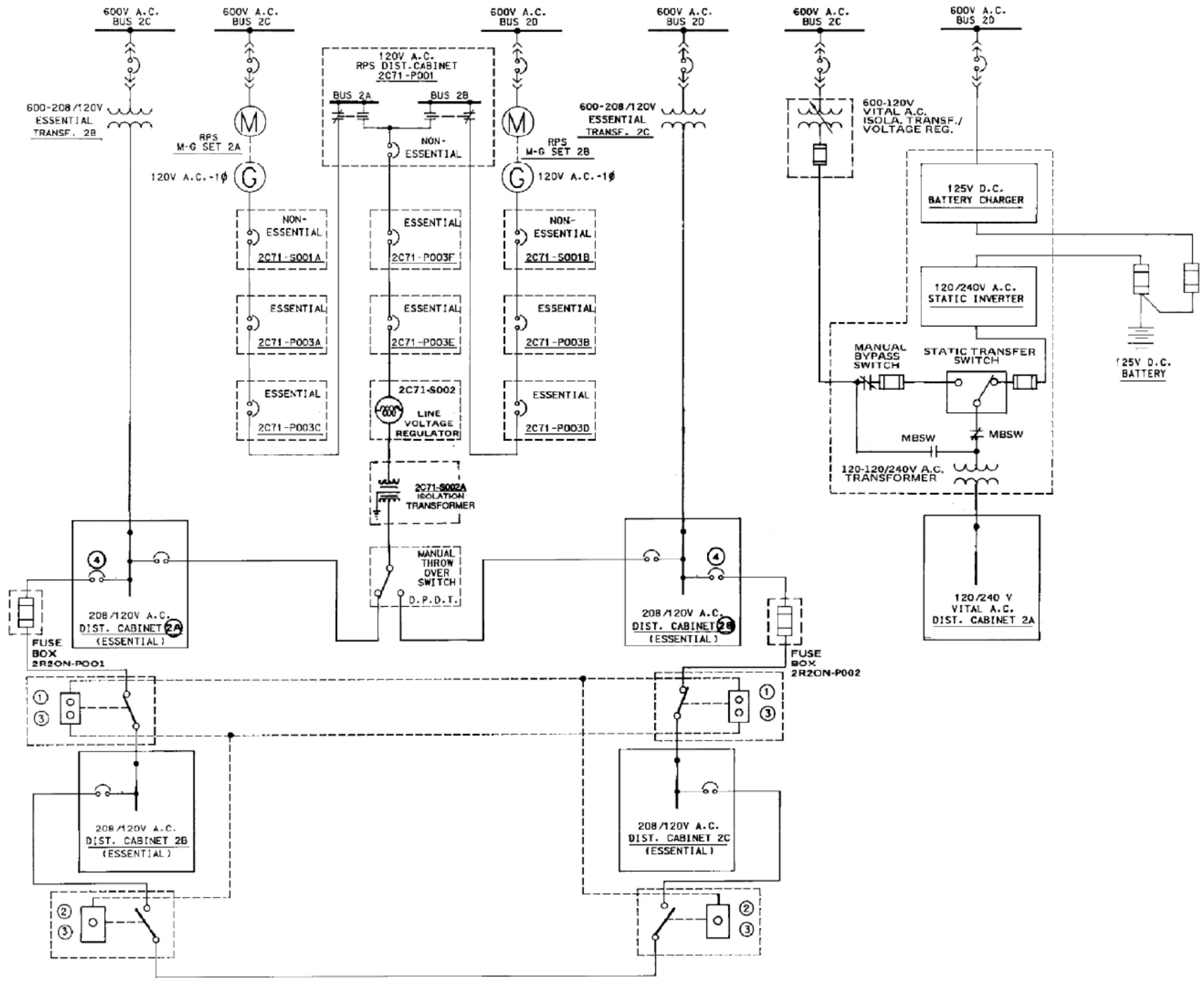
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

4160-V AND 600-V
ESSENTIAL BUSES AND LOADS

FIGURE 8.3-8



NOTES:

1. 4-POLE N.C. NON-FUS BLE DISCONNECT SWITCH WITH 2-KEY KIRK LOCK
2. 4-POLE N.O. NON-FUSIBLE DISCONNECT SWITCH WITH 1-KEY KIRK LOCK
3. ALL KEYS ARE REMOVABLE IN THE OPEN POSITION AND CAPTIVE IN THE CLOSED POSITION
4. 100A MOLDED CASE SWITCH (NON-AUTOMATIC BREAKER)

120/240-V VITAL ac DIST. CABINET 2A LOADS

FEEDWATER CONTROL SYSTEM
REACTOR MANUAL CONTROL SYSTEM
COMPUTER-NUCLEAR STEAM SUPPLY
STARTREC SYSTEM
ELECTRO HYDRAULIC CONTROL CABINET
PROCESS RADIATION MONITORING SYSTEM
TURNING GEAR SYSTEM
POST-ACCIDENT SAMPLING SYSTEM
TRAVERS NG INCORE PROBE CALIBRATION SYSTEM
REACTOR WATER CLEANUP SYSTEM
STARTUP RANGE NEUTRON MONITOR NG SYSTEM
NUCLEAR BOILER PROCESS INSTRUMENTATION SYSTEM
OFF-GAS SUPPORT SYSTEM
CRD HYDRAULIC CONTROL SYSTEM NSTRUMENTATION
RADWASTE MONITORING SYSTEM INSTRUMENTATION
TURB NE SUPERVISION INSTRUMENTATION SYSTEM
REACTOR RECIRC PUMP & MG SET CONTROLS
STACK INLET VALVE
GLAND SEAL BLOWER & VAC PUMP
SUBSTATION ANN
SAFETY PARAMETER DISPLAY SYSTEM

208/120-V-ac DIST. CABINET 2B ESSENTIAL LOADS

NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM
STEAM LEAK DETECTION SYSTEM
REACTOR RECIRC PUMP & M-G SET 'A'
REMOTE SHUTDOWN SYSTEM
PROCESS RADIATION MONITORING SYSTEM
RHR SYSTEM
CORE SPRAY SYSTEM
HPCI SYSTEM
H_2O_2 ANALYZER SYSTEM
REACT BLDG SERVICE WATER SYSTEM
DRYWELL PNEUMATIC SYSTEM
250-V-dc INVERTER SYSTEM
SAFEGUARD EQUIPMENT COOL NG SYSTEM
REACTOR BLDG VENTILATION SYSTEM
STANDBY GAS TREATMENT SYSTEM
DRYWELL COOLING SYSTEM
PR MARY CONTAINMENT PURGE & NERT NG SYSTEM
POST-ACCIDENT SAMPLING SYSTEM
DRYWELL-TO-TORUS D FF. PRESSURE SYSTEM
PLANT SERVICE WATER SYSTEM
NUCLEAR BOILER SYSTEM
D ESEL GENERATOR 2A
REACTOR & RADWASTE BLDG NSTRUMENT A R SYSTEM
120/208-V ESSENTIAL & EMERGENCY STATION SERVICE
CORE SPRAY JOCKEY PUMP SYSTEM

208/120-V-ac DIST. CABINET 2C ESSENTIAL LOADS

NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM
STEAM LEAK DETECTION SYSTEM
REACTOR RECIRC PUMP & SET 'B'
REMOTE SHUTDOWN SYSTEM
PROCESS RADIATION MONITORING SYSTEM
RHR SYSTEM
CORE SPRAY SYSTEM
HPCI SYSTEM
H_2O_2 ANALYZER SYSTEM
REACT BLDG SERVICE WATER SYSTEM
DRYWELL PNEUMATIC SYSTEM
250-V-ac INVERTER SYSTEM
SAFEGUARD EQUIPMENT COOL NG SYSTEM
REACTOR BLDG VENTILATION SYSTEM
STANDBY GAS TREATMENT SYSTEM
DRYWELL COOLING SYSTEM
CONTAINMENT ATMOSPHERE DILUTION SYSTEM
PR MARY CONTAINMENT PURGE & NERT NG SYSTEM
POST-ACCIDENT SAMPLING SYSTEM
DRYWELL-TO-TORUS D FF. PRESSURE SYSTEM
NUCLEAR BOILER PROCESS INSTRUMENTATION SYSTEM
AUTOMATIC DEPRESSURIZATION SYSTEM
PLANT HEATING SYSTEM
PR MARY CONTAINMENT ISOLATION SYSTEM
PLANT SERVICE WATER SYSTEM
CORE SPRAY JOCKEY PUMP SYSTEM
NUCLEAR BOILER SYSTEM

REF DWG H-23369 SHEET 1 REV 42
REF DWG H-23369 SHEET 2 REV 14
REF DWG H-23635 SHEET 2 REV 12
REF DWG H-23362 SHEET 1 REV 35

REV 20 7/02

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SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ac INSTRUMENT POWER SUPPLY SYSTEM

FIGURE 8.3-9

8.4 STATION BLACKOUT (SBO) (HNP-1 AND HNP-2)

The information provided in this section is applicable to HNP-1 and HNP-2 unless indicated otherwise.

8.4.1 INTRODUCTION

10 CFR 50, paragraph 50.63, Station Blackout Rule, requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specified duration. Licensees are expected to have the baseline assumptions, analyses, and related information used in their SBO evaluation documented and available for Nuclear Regulatory Commission (NRC) review. Section 50.63 also identifies the factors that must be considered in specifying the SBO duration and requires that, for the SBO duration, the plant be capable of maintaining core cooling and appropriate containment integrity.

The objective of the SBO rule is to reduce the risk of severe accidents resulting from SBO by maintaining highly reliable ac electric power systems and, as additional defense-in-depth, assure that nuclear plants can cope with an SBO for a specific period of time.

The governing criteria for SBO are contained in 10 CFR 50.63. The term "station blackout" is defined as the loss of offsite ac power to the essential and nonessential electrical buses concurrent with turbine trip and the unavailability of the redundant onsite emergency ac power systems. However, ac power to buses fed by station service batteries through inverters is considered available along with the dc power to buses fed by the batteries.

8.4.2 SBO COPING EVALUATION

Regulatory Guide (RG) 1.155, Station Blackout, describes a means acceptable to the NRC for meeting the requirements of 10 CFR 50.63. RG 1.155 states that the NRC has determined that the Nuclear Management and Resource Council (NUMARC) document NUMARC 87-00, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, also provides guidance that is in large part identical to the RG 1.155 guidance and is acceptable to the NRC for meeting these requirements. When reference to NUMARC 87-00 is made, it also includes reference to the supplemental NUMARC letter of January 4, 1990.[1,2] References 3, 4, and 5 summarize the SBO evaluation performed for an increase in the rated thermal power to 2804 MWt.

The reactor core and associated systems were reviewed to determine that there are sufficient capacity and capability to ensure that the core is cooled, the reactor coolant system is isolated, and appropriate containment integrity is maintained in the event of an SBO for the required duration.

Systems required for decay heat removal were reviewed to ensure that those portions of the systems which are required to cope with the consequences of an SBO are available. Effects of nonavailability of support systems, such as instrument air; heating, ventilation and

air-conditioning (HVAC); and ac power, are considered. Condensate storage tank (CST) and battery capabilities were reviewed for adequacy.

For the blacked-out unit, any one of the three emergency diesel generators may be used as an alternate ac (AAC) source for SBO coping. However, to represent the most limiting condition, emergency diesel generator 1B is designated as the AAC power source for either unit and can be aligned to Division 1 load centers and initiated within 1 h to the blacked-out unit when the diesel loading margins are met. Plant coping is controlled predominately by Class 1E dc power and steam driven sources until the AAC power is available for loading. A combination of battery power and emergency ac power from the AAC source is used to bring the blacked-out unit to and maintain a hot shutdown condition from full power. Tables 8.4-1 and 8.4-2 list the possible load distribution on emergency buses 1F and 2F, respectively, for an SBO event. Adequate cooling and equipment necessary to cope with an SBO will be available without interruption to both the blacked-out unit and the nonblacked-out unit.

8.4.2.1 <u>SBO Coping Duration</u>

RG 1.155 and NUMARC 87-00, Section 3, were used to determine an SBO coping duration of 4 h for HNP-1 and HNP-2. The specific SBO duration is based on the redundancy of the onsite emergency ac power sources, the reliability of the onsite emergency ac power sources, the expected frequency of loss of offsite power (LOSP), and the probable time needed to restore offsite power. The coping duration is based on the following design characteristics using NUMARC 87-00 methodology:

1. Offsite power design characteristic group is classified "P1."
2. Emergency power configuration group is classified "C."
3. Emergency diesel generator target reliability is 0.95.

8.4.2.2 <u>SBO Coping Analysis Assumptions</u>

The assumptions used in the coping analysis are as follows:

1. RG 1.155 and NUMARC 87-00 provide general guidance for the SBO coping analysis.
2. Both units are operating at 100% rated thermal power prior to the event initiation.
3. Initiating conditions are an LOSP to both units. SBO, however, is assumed only for one unit due to the independence of emergency ac sources. No design basis accidents, other events, or additional single failures other than the loss of one emergency diesel generator on the nonblacked-out unit are assumed to occur prior to or during the SBO event.
4. A reactor scram immediately follows an LOSP.

5. Reactor coolant system (RCS) inventory losses are limited to normal system leakage and recirculation pump seal leakages (18 gal/min per pump maximum).

6. Credit is taken for operator actions where appropriate.

7. Emergency diesel generator 1B can be loaded within 1 h of the SBO event if the diesel loading margins are met. However, AAC power from emergency diesel generator 1B is not required for suppression pool cooling during the 4-h coping period.

8. Equipment needed for the SBO coping duration is available at the site.

9. After the 4-h coping period, the station operators either restore offsite power or start the additional emergency diesel generator to bring the plant to a cold shutdown condition.

8.4.2.3 SBO Coping Capabilities

Applicable plant systems/functions, as identified in RG 1.155 and the NUMARC 87-00 guidelines, are available to successfully cope with the SBO event to the extent required by RG 1.155 for the required SBO duration.

The SBO coping evaluation concludes that the various systems and components required for reactor core cooling are available. The emergency diesel generator 1B in conjunction with the battery capacity were found to be adequate for the 4-h coping duration. The ability to maintain RCS inventory and containment integrity were evaluated and confirmed. The effects of the loss of ventilation on equipment needed for SBO were evaluated. The plant can successfully cope with the SBO event for the required 4-h duration with negligible impact on the equipment qualified life and with no impact on the operability of the equipment.

HNP has the capability to cope with an SBO for the coping duration of 4 h as discussed below:

1. Capability to provide core cooling is demonstrated by the following:

    a. RCS isolation

        RCS isolation is provided to prevent loss of inventory through normally open lines.

    b. Main steam system isolation

        Main steam isolation is achieved by automatic closure of the main steam isolation valves (MSIVs) upon loss of offsite power. Manual closure capability of the MSIVs is also available. Controlled steam release capability is available to remove decay heat via the safety relief valves (SRVs) to the suppression pool. The SRVs are self-actuating at the set relieving pressure, but may be operated manually at pressures below the valve setpoint.

c. High pressure coolant injection (HPCI) system availability

During SBO, the high injection volume of the HPCI system is not necessary, since loss of coolant accident conditions are not postulated.

d. Reactor core isolation cooling (RCIC) system availability

During SBO, a steam flowpath from the reactor vessel and a water flowpath from either the CST or the suppression pool are available to the turbine-driven RCIC pump.

The RCIC system starts and initially feeds to the reactor from the CST until either the CST reaches its low level setpoint or the suppression pool reaches its high level setpoint. Upon reaching either of these limits, the RCIC suction automatically shifts to the suppression pool. All necessary instrumentation and valves required to assure automatic transfer to the suppression pool are available during an SBO.

e. CST capacity is as follows:

Adequate condensate inventory is available for the required coping duration without additional water supply. The inventory of one CST is adequate for the required SBO coping duration of 4 h.

f. Battery and battery charger capacities are as follows:

To maintain the electrical and instrumentation components needed for core cooling and decay heat removal following SBO, Class 1E 125/250-V station service batteries are capable of powering the required loads for 2 h. The associated battery chargers for station service batteries 1A or 2A (essential division I) are energized after the emergency diesel generator 1B (AAC source) is connected within 1 h and power is available to the 600-V-ac load center buses to support the battery operation in excess of 2 h. The battery charger for diesel generator 1A or 2A is automatically energized within 1 h via the 600-V-ac load center buses. The capacity of emergency diesel generator batteries 1C and 2C is 4 h to support the required loads during SBO. The battery charger for emergency diesel generator battery 1B is automatically energized (within 1 h) to support the battery operation after emergency diesel generator 1B is on line. Therefore, the capacity of emergency diesel generator battery 1B is adequate to support the SBO loads. To support alternate diesel generator sources and bus alignment configurations, each of the emergency diesel generator batteries has a 4-h capacity for SBO loads.

g. Compressed-air system requirements are as follows:

All pneumatically operated valves required for SBO assume a fail-safe position upon loss of air pressure. The loss of the compressed air system

during SBO would have no impact on maintaining both decay heat removal capabilities and RCS inventory.

h. Instrumentation requirements

Adequate instrumentation is provided to assess the core reactivity, RCS inventory, core cooling capability, decay heat removal capability, and availability of Class 1E 125-V-dc and 120-V-ac systems.

i. Suppression pool cooling

The suppression pool is capable of accepting operation of the RCIC system and SRVs without any suppression pool cooling during the SBO coping duration. Although not required, suppression pool cooling capability can be initiated within 1 h when the AAC source becomes available by meeting the diesel loading margins.

2. Ability to maintain adequate RCS inventory is as follows:

As allowed by NUMARC 87-00 guidelines, recirculation pump seal leakage is assumed not to exceed 18 gal/min per pump. However, the RCIC system, even with flow reduced by 10% (40 gal/min) below its Technical Specifications minimum value of 400 gal/min, is capable of providing sufficient makeup inventory to the reactor pressure vessel to prevent the water level from dropping to Level 1.

3. Ability to maintain appropriate containment integrity is as follows:

Appropriate containment integrity is provided during the required duration of the SBO. Valve position indication and closure of certain containment isolation valves are provided independent of the preferred or Class 1E ac power supplies.

4. Effects of loss of ventilation are as follows:

Those areas of HNP which contain equipment required to operate during an SBO to achieve and maintain safe shutdown have been evaluated to determine their average ambient steady-state temperatures occurring during the SBO duration. This evaluation was performed in accordance with the guidelines established in NUMARC 87-00, Appendix F. This evaluation has established reasonable assurance of operability of equipment in these areas during an SBO event.

5. Equipment environmental evaluation is as follows:

Areas of the plant housing equipment/components required for SBO coping have environmental conditions which are either below the component environmental qualification design limit or are only slightly above the design limit and are well below the minimum generic limit established in NUMARC 87-00. To maintain a reasonable assurance for operation of the safety-related equipment, the door between the service building and the 130-ft elevation of the control building, and

the stairwell doors on the 130-ft elevation of the control building and on the roof of the main control room must be manually opened. This is to promote natural circulation into and out of the control building.

Weather hazards such as extreme temperatures, wind, and flooding will not impact components required for an SBO.

It has been demonstrated that there is reasonable assurance that the equipment will remain operable during and subsequent to an SBO event.

6. Identification of access to plant areas requirements is as follows:

   Area access, as well as the need to gain entry to other locked (secured) areas where remote equipment operation may be necessary, is not impacted by the effects of ac power loss, since a dedicated security diesel generator ensures the operability of the security system.

7. Emergency lighting requirements are as follows:

   Emergency lighting in the MCR is provided to enable station operators to perform the necessary manual actions to cope with the SBO. Adequate emergency lighting is available for those areas of the plant where operator actions and/or ingress or egress are required. Emergency lighting is provided via emergency lighting cabinets connected to the AAC source bus, the dc batteries, or the self-contained battery powered Appendix R lighting system.

8. Identification of required operator training and actions is as follows:

   Operator training and actions that are required, inside and outside the control room, to cope with the SBO event are identified in plant procedures.

9. Procedures interface considerations are as follows:

   RG 1.155 provides the guidance that procedures and training should include all operator actions necessary to cope with an SBO for at least the duration determined according to Regulatory Position 3.1 and to restore normal long-term cooling/decay heat removal once ac power is restored. Procedures have been integrated with plant-specific technical guidelines and the emergency operating procedure upgrade program established in response to Supplement 1 of NUREG-0737.

10. Diesel generator reliability program requirements are as follows:

    Elements of the emergency diesel generator program are contained in RG 1.155. These elements (or their equivalent) are addressed in the applicable plant procedures.

REFERENCES

1. "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC 87-00, Revision 1, August 1991.

2. NUMARC supplemental letter to the NUMARC Board of Directors, "Station Blackout (SBO) Implementation: Request for Supplemental SBO Submittal to NRC," January 4, 1990.

3. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 and 2," NEDC-32749P, General Electric Company, July 1997.

4. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2, Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

5. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Nuclear Plant Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 8.4-1

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUS 1F DURING SBO (HNP-1)

Engineered Safety Features	Maximum Load on Bus 1F hp[(a)] / kW[(b)]
RHR pump 1C 1E11-C002C	1125 / 902.41
RHRSW pump 1C 1E11-C001C	1200 / 957.43
PSW pump 1C 1P41-C001C	600 / 481.29
Emergency 600-V load center 1C 1R23-S003	- / 688.84
Diesel generator building MCC 1B 1R24-S026	- / 151.85
Diesel generator building MCC 1D 1R24-S048	- / 12.00
TOTAL kW	3193.82

a. The horsepower considered is for the maximum load on the pumps except for the PSW pump where load is considered with turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered.

TABLE 8.4-2

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUS 2F DURING SBO (HNP-2)

Engineered Safety Features	Maximum Load on Bus 2F hp[a] / kW[b]
RHR pump 2C 2E11-C002C	1080 / 861.69
RHRSW pump 2C 2E11-C001C	1225 / 977.38
PSW pump 2C 2P41-C001C	600 / 486.52
Emergency 600-V load center 2C 2R23-S003	- / 591.35
Diesel generator building MCC 1B 1R24-S026	- / 148.89
Diesel generator building MCC 2D 2R24-S048	- / 12.00
TOTAL kW	3077.83

a. The horsepower considered is for the maximum load on the pumps except for the PSW pump, where load is considered with turbine building isolated.
b. In converting hp to kW, motor full-load efficiency is considered.

9.0 AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

9.1.1 NEW-FUEL STORAGE (HNP-1 AND HNP-2)

The objective of the new-fuel storage arrangement is to provide specially designed dry, clean storage areas for the new-fuel assemblies.

9.1.1.1 Design Bases

9.1.1.1.1 Safety Design Bases

The new-fuel storage racks are designed to:

- Maintain sufficient spacing between the new-fuel assemblies to ensure that the array, when the racks are fully loaded, will have a $k_{eff} \leq 0.90$ for the dry condition and a $k_{eff} \leq 0.95$ in the event of complete flooding of the storage vault and the fuel racks being brought to their most reactive spacing.

- Withstand earthquake loadings to prevent damage to the structure of the racks and minimize distortion of the racks arrangement.

Area radiation monitors (ARMs) for criticality monitoring are not provided.

The Nuclear Regulatory Commission granted an exemption from 10 CFR 70.24 relative to the authorization to possess special nuclear material at Plant Hatch.(1) The exemption provides relief from the requirement to install criticality monitors that are not needed. Inadvertent or accidental criticality will be precluded through compliance with the following:

- Technical Specifications.

- Geometric spacing of fuel assemblies in the new fuel storage area and spent fuel storage pool.

- Administrative controls imposed on fuel handling procedures.

- Use of nuclear instrumentation that monitors behavior of nuclear fuel in the reactor vessel.

9.1.1.1.2 Power Generation Design Bases

New-fuel storage racks are designed and arranged so that the fuel assemblies can be handled efficiently.

9.1.1.2 Description

New-Fuel Storage Vault

After receipt, transfer to the operating floor, and uncrating, the new fuel is placed into dry storage in racks. These racks are contained in a Seismic Category I new-fuel storage vault. Removable grating, which will withstand a loading of 100 lb/ft^2, is provided over each new-fuel storage vault. The vaults are provided with drains to prevent water collection.

New-Fuel Storage Racks

The new-fuel storage racks provide a place for storing new fuel in the new-fuel storage vault (figure 9.1-1). Each new-fuel storage rack (figure 9.1-2) holds up to 10 new channeled or unchanneled fuel assemblies. The new-fuel storage racks are arranged in rows with a nominal 11.5-in. center-to-center distance between fuel assemblies placed in the storage racks. New-fuel storage racks are provided for at least 150% of the reactor core load. The fuel assemblies are loaded into the rack through a hole in the top of each rack. Each hole for a fuel assembly has adequate clearance for the insertion or withdrawal of the assembly while enclosed in a protective plastic wrapping. Guides are provided to guide the fuel element spacers the full length of their insertion into the rack so that damage to the fuel assemblies is precluded. The spacers and the upper tie plate of the fuel element rest against the rack to provide lateral support. The design of the racks prevents accidental insertion of the fuel assembly in a position not intended for the fuel. The weight of the fuel assembly is supported by the lower tie plate which is seated in a chamfered hole in the rack base.

Each new-fuel storage rack is designed as a Seismic Category I structure to resist sufficiently the response motion at the installed location within the supporting structure for the design basis earthquake.

9.1.1.3 Safety Evaluation

The calculations of k_{eff} are based upon the geometrical arrangements of the fuel array, and subcriticality does not depend upon the presence of neutron-absorbing materials. The arrangement of the fuel assemblies in the fuel storage racks results in $k_{eff} \leq 0.90$ in a dry condition, or in the absence of a moderator. In an abnormal condition when the fuel is flooded with water and the fuel elements are brought to their most reactive spacing, $k_{eff} \leq 0.95$.

To ensure that the design criteria stated above are met, the following conditions were analyzed:

- K_{eff} of the new-fuel storage array under normal conditions (dry), which resulted in a $k_{eff} < 0.5$.

- K_{eff} of the new-fuel storage array under abnormal conditions (flooded), which resulted in $k_{eff} < 0.867$.

The calculations for k_{eff} were performed using a 2-dimensional, 3-group diffusion theory code for a water temperature of 65°C. Room and fuel pool temperatures of 20°C and 65°C, respectively, were analyzed to ensure that 65°C was the more reactive temperature condition.

Stresses in a fully loaded rack do not exceed applicable specification requirements of the American Institute of Steel Construction (AISC) when subjected to a seismic loading of 0.72 g applied in any direction. A safety factor of 2, based upon the material yield strength or local critical buckling, is used where these specifications are not applicable.

The storage rack structure is designed to absorb an impact energy of at least 7000 ft-lb on an impact surface no larger than 3 in. in diameter. Under this impact force, those members which physically maintain the spacing to assure that $k_{eff} \leq 0.95$ with the vault flooded will remain intact.

The storage racks are designed to withstand a pullup force equal to the load rating of the overhead crane auxiliary hoist. This is necessary in the event that the fuel assembly or grappling device accidentally becomes fouled during removal. The stress in those members required to maintain the abnormal storage subcriticality conditions is ≤ 75% of the material yield strength or 75% of that stress at which local buckling occurs.

The new-fuel racks are designed to be restrained by holddown lugs to ensure that rack spacing does not vary under specified seismic loads. Holddown bolts restrain the rack both horizontally and vertically in case a stuck fuel assembly is inadvertently hoisted. All materials used in the construction of the new-fuel storage racks are specified in accordance with the applicable American Society for Testing and Material (ASTM) specifications, and all welds are in accordance with the American Welding Society (AWS) standards for materials used.

Materials selected are corrosion resistant or treated to provide the necessary corrosion resistance. The new-fuel storage racks are made from aluminum. The material choice is based on a consideration of the susceptibility of various metal combinations to an electrochemical reaction. When considering the susceptibility of metals to galvanic corrosion, aluminum and 300-series stainless steel are relatively close together insofar as their coupled potential is concerned.

The new-fuel storage racks are designed to meet Seismic Category I requirements as described in section 3.2.

9.1.1.4 Tests and Inspections

The new-fuel storage racks do not require any special periodic testing or inspection for nuclear safety purposes. Prior to receipt of new fuel, the rack arrangement in the new-fuel storage vault was dimensionally verified.

9.1.2 WET SPENT-FUEL STORAGE (HNP-1 AND HNP-2)

The objective of the wet spent-fuel storage arrangement is to provide specially designed underwater storage space for the spent-fuel assemblies which require shielding and cooling during storage and handling.

9.1.2.1 Design Bases

9.1.2.1.1 Safety Design Bases

The spent-fuel storage racks are designed to:

- Ensure that all arrangements of fuel in the spent-fuel storage racks are maintained in a subcritical configuration having a $k_{eff} < 0.95$.
- Withstand seismic loading to minimize distortion of the wet spent-fuel storage arrangement and to prevent the loss of fuel pool water.
- Be located within the plant secondary containment to prevent the release of significant amounts of radioactivity to the environs should the integrity of any fuel assembly be breached during or after the refueling process.

The fuel pool is designed so that no single failure of structures or equipment will cause inability to:

- Maintain irradiated fuel submerged in water.
- Reestablish normal fuel pool water level.
- Safely remove fuel from the plant.

A Seismic Category I backup system is provided to add water to the fuel pool if the normal makeup system is not available.

ARMs for criticality monitoring are not provided. (Reference paragraph 9.1.1.1 for discussion.)

9.1.2.1.2 Power Generation Design Bases

The fuel pool has a fuel storage capacity of more than five full-core loads of fuel assemblies.

The fuel storage racks are designed and arranged so that the fuel assemblies can be efficiently handled during refueling operations.

9.1.2.2 Description

The wet spent-fuel storage facility is located on the common refueling floor. Redundant radiation sensors are provided in the ventilation ducts servicing the refueling floor to detect any airborne radiation that might accidentally be released during the refueling process. These sensors activate the standby gas treatment system (SGTS) and isolate the refueling floor upon sensing high radiation. Additionally, the area radiation monitors on the refueling floor will alarm in the main control room (MCR) and locally if the refueling floor activity exceeds the normal background activity during refueling.

9.1.2.2.1 Fuel Storage Pool

The fuel storage pool is designed to Seismic Category I criteria. The fuel pool structure is designed for the following applied loads:

- Deadweight of the structural elements.
- Live loads acting on the structural elements.
- Hydrostatic load due to the water in the pool.
- Three-component operating basis earthquake (OBE) seismic load.
- Three-component safe shutdown earthquake (SSE) seismic load.
- Thermal loading based on normal operating conditions: pool water temperature of 150°F and ambient air temperature of 90°F.
- Thermal loading based on accident conditions: pool water temperature of 212°F and ambient air temperature of 90°F.
- Thermal loading based on normal operating conditions: pool water temperature of 150°F and ambient air temperature of 110°F.
- Thermal loading based on accident conditions: pool water temperature of 212°F and ambient air temperature of 110°F.

Loading combinations that produce the most severe loading to the structure were incorporated to verify that the structure would carry the mechanical and thermal loads for the design basis conditions. A postulated drop of a spent-fuel assembly from beneath the water's surface onto the spent-fuel pool stainless-steel liner plate and the storage racks was evaluated. It was determined a spent-fuel assembly dropped from a height of 17 ft above the liner plate (~ 2 ft above the spent-fuel storage racks) will not perforate the pool's liner plate.

In addition to analyzing load drops from beneath the spent-fuel pool water's surface, the effects of a drop of a new fuel assembly from ~ 2 ft above the water's surface was evaluated. It was determined the impact of the dropped fuel assembly could perforate the liner. However, the breaching of the liner plate will not result in uncovering the fuel in the storage racks. Other loads of smaller weights and diameters could perforate the liner plate as well. Regardless of the diameter of the perforation in the liner plate, the leak rate from the pool is controlled by the diameter of the drain line. Therefore, the effects of a drop of other items are bounded by the drop of the fuel assembly.

The maximum flowrate of fuel pool water through a breach in the liner plate is limited by the size of the liner drain system piping, which is 2 in. in diameter.

Interconnected drainage paths behind the liner plate are designed to:

- Prevent pressure buildup behind the plate.
- Prevent the uncontrolled loss of contaminated pool water to other relatively cleaner locations within the secondary containment.
- Provide expedient liner leak detection and measurement.

No outlets or drains are provided that might permit the pool to be drained below 10 ft above the top of the upper tie plates (barring, of course, a liner breach). This level provides a cover for the active fuel. The two inlet lines from the fuel pool cooling and cleanup system (FPCCS) penetrate the liner near the top of the pool and extend to near the bottom of the pool. Both of these lines are equipped with two check valves in series to prevent siphoning.

The maximum flowrate through the liner drain system piping was calculated to be 150 gal/min; therefore, the maximum flowrate out of the breach in the liner plate will be 150 gal/min regardless of the size of the breach since the flowrate of water from the breach is limited by the size of the drain system piping. Thus, loads dropped from higher distances above the surface of the water, while possibly causing larger breaches in the liner plate than the analyzed drop of a new fuel assembly, will not result in a greater leakage rate and, consequently, are bounded by this analysis.

The HNP-1 and HNP-2 normal fuel pool water makeup sources are capable of supplying water at 390 and 500 gal/min, respectively. This is over twice the maximum rate pool water can be drained through a breach in a liner plate. Consequently, the spent-fuel pools can recover and normal makeup water sources can maintain fuel pool water level in the event of any size breach of a pool liner. Additionally, makeup water can be provided to the fuel pool by the safety-related, Seismic Class 1 plant service water (PSW) system.

The upper portion of the HNP-1 and HNP-2 spent-fuel pools (i.e., that portion above the storage racks) contains ~ 800 and 700 gal of water per vertical inch, respectively. If the water is at its minimum Technical Specifications-required level of 21 ft over the top of irradiated fuel assemblies seated in the spent-fuel storage racks when the leak starts, it would take the HNP-1 spent-fuel pool ~ 22 h and the HNP-2 spent-fuel pool ~ 20 h to drain to the upper tie plates of the stored spent fuel at the maximum leakage rate of 150 gal/min. This is sufficient time to respond to low fuel pool water level alarms and begin makeup water flow from either the normal or backup makeup water system before the fuel in the storage racks is uncovered.

Low water level alarms are provided locally and in the MCR in the unlikely event of water loss. As a backup, flow alarms are provided in the drain lines of the reactor vessel-to-drywell seal, drywell-to-concrete seal, and the drain line of the fuel pool-to-reactor well gates to detect leakage.

Should the normal makeup water system be inoperable, the Seismic Category 1 PSW system will supply makeup water to the pool by opening three valves.

9.1.2.2.2 Spent-Fuel Storage Racks

The spent-fuel storage racks provide a storage place at the bottom of the fuel pool for the spent fuel received from the reactor vessel (figure 9.1-3, sheets 1 and 2). The majority of storage racks are high-density, poison-type racks, although racks for defective fuel are provided. The racks are full-length, top entry racks designed to maintain the spent fuel in a space geometry that precludes the possibility of criticality under normal and abnormal conditions. Normal conditions exist when the spent fuel is stored at the bottom of the fuel pool in the design storage position. Abnormal conditions may result from an earthquake, personnel errors, or equipment malfunctions.

The design of the high-density, spent-fuel storage racks was evaluated using the criteria provided in "OT Position for Review and Acceptance of Spent-Fuel Storage and Handling Applications" issued by the Nuclear Regulatory Commission on April 14, 1978, and later amended on January 18, 1979.

The high-density racks are modular and provide space for fuel assemblies with or without flow channels. Five basic configurations of modules provide maximum utilization of space in the pool (figure 9.1-3, sheets 1 and 2). The licensed spent-fuel pool storage capacity for fuel assemblies is 3349 (actual capacity 3181) for HNP-1 and 2933 for HNP-2. Spent fuel from HNP-2 can be stored in the HNP-1 pool, and vice versa.

The spent-fuel racks are designed to maintain subcriticality of the fuel, assuming the following applied loads:

- Dead loads (weight of rack and fuel assemblies) and hydrostatic loads.

- Live loads - the effect of lifting an empty rack during installation.

- Thermal loads - the uniform thermal expansion caused by pool temperature changes from the pool water and stored fuel.
- Seismic forces of OBE and SSE.
- Accidental drop of a fuel assembly from the maximum possible height.
- Postulated stuck fuel assembly causing an upward force.
- Tornado-generated missile.

The size of a load that may be carried over fuel assemblies in the spent-fuel racks and possibly dropped is limited to ≤ 1250 lb by the Technical Requirements Manual. Loads > 1250 lb may be carried over fuel assemblies in the spent-fuel racks provided that all the requirements of the Technical Requirements Manual are met, thereby precluding any load drop. This value represents the heavy load limit, defined in NUREG-0612, that represents the combined dry weight of a single spent-fuel assembly and its associated handling tool as assumed in the fuel-handling accident analysis. The weight of the handling tool includes the refueling mast and grapple head. The consequences of dropping any load ≤ 1250 lb are no more severe than those of a fuel-handling accident. The provisions employed to prevent movement of heavy objects over fuel assemblies in the spent-fuel racks are discussed in this section.

A. General Electric Spent-Fuel Racks

Each freestanding, high-density module, as shown on drawing no. S-40969, is fabricated from fuel storage tubes and made by forming an inner and outer tube of 304 stainless steel with an inner core of Boral poison. The completed storage tubes are fastened together by angles welded along the corners and attached to a baseplate to form storage modules. Each module is ~ 15 ft high. The high-density, spent-fuel racks are a base-supported module design (figure 9.1-4). The high-density module provides storage spaces for fuel assemblies on ~ 6.5-in., center-to-center spacing.

The module support system consists of a module baseplate, 4-ft pad assemblies, and 4 support pads (figure 9.1-4). The foot pads rest on the support pads to raise the module baseplate a minimum of 8 in. above the pool floor, allowing sufficient area to clear the swing bolts on the pool floor and to permit natural circulation of cooling water to the modules without taking credit for sources of forced cooling.

Most of the structural material used in fabrication of the high-density fuel storage modules is 304 stainless steel. The only structural material employed in the structure that is not 304 stainless steel is a special low-friction material used as a foot pad between the module and the support pad. Boral plates, used as a neutron absorber, are an integral nonstructural part of the basic fuel storage tube. These plates are sandwiched between the inner and outer wall of the storage tube and are not subjected to dislocation, deterioration, or removal. The inner and outer walls of the storage tube are welded together at each end for mechanical rigidity. Small openings are formed in the top and bottom of each tube assembly by leaving gaps in the weld to allow for the venting of the envelope between the inner and outer tube

walls. At normal pool water operating temperatures, there is no significant deterioration or corrosion of stainless steel or Boral.

One feature of the high-density racks is that they are not bolted to the fuel pool floor. Instead, the four corners of the module baseplate sit on special low-friction foot pads. This arrangement allows the module to slide, thus limiting the shear forces on the module during the seismic event. Selection of materials assures sliding will occur between the foot pad and support pad and not between the support pad and the pool floor inner plate. Sliding and overturning of the module were studied for SSE and OBE conditions. All of the modules were found to be stable under the worst postulated seismic loading conditions, and the minimum 2-in. clearance between modules precludes contact during a seismic event.

The high-density fuel storage modules were also evaluated to determine the effect of an impact load that is possible because of gaps between the fuel bundle and the module. The maximum internal forces developed in the module and the maximum sliding displacement of the module due to impact loads were determined to be acceptable.

The high-density fuel storage modules are arranged so that accidental insertion of an assembly between modules is impossible. Stress allowables for the high-density racks are based on American Society of Mechanical Engineers (ASME), Section III, Subsection NF. All materials used in the construction of these racks were specified in accordance with ASME specifications, and all welding was performed per ASME, Section IX.

B. Holtec Spent-Fuel Rack (HNP-2)

The Holtec freestanding, high-density rack module (figure 9.1-6, sheet 1), located in the contaminated equipment storage area (CESA) of the HNP-2 spent-fuel pool is constructed of SA240-Type 304 stainless-steel sheet and plate stock, and SA564-630 (precipitation hardened stainless steel) for the adjustable support spindles. The neutron absorber material, Boral, is the only nonstainless material utilized in the rack module. The rack module is ~ 15 ft high and has a center-to-center spacing of 6.25 in.

The rack module is designed in accordance with Section III, Division 1, Subsection NF of the ASME Boiler and Pressure Vessel Code, 1995. Allowable stresses for the high-density rack module are based on ASME Section III, Subsection NF. All materials used in the construction of the rack were specified in accordance with ASME specifications, and all welding was performed per ASME Section IX.

The rack's checkerboard array (figure 9.1-6, sheet 2) is formed from composite box assemblies. Each composite box is fabricated from two channels and seam welded. Sheathing is attached to each side of the box with Boral panels installed in the sheathing cavity.

The rack module is supported (figure 9.1-6, sheet 3) with remotely adjustable support pedestals. A bearing pad interposed between the rack pedestals and the pool liner diffuses the dead load of the loaded rack into the reinforced concrete structure. Sliding and overturning of the module were studied for design basis earthquake (DBE) and OBE conditions. The rack module was found to be stable under the worst postulated seismic conditions, and the rack-to-wall clearances preclude contact during a seismic event.

The rack module is non-flux-trap. Enrichment/burnup restrictions are imposed on all fuel stored in the rack.

Each spent-fuel storage rack and fixture loaded with fuel is designed to Seismic Category I criteria.

A separate pool is provided for the spent-fuel cask on the west side of the HNP-2 fuel pool as shown on drawing no. H-26103. The smaller pool is separated from the spent-fuel pool by walls extending above the normal water level and a pneumatically sealed gate which is closed during cask movement.

Protection against the cask drop is afforded by the HNP-1 single-failure-proof reactor building crane described in HNP-1 Final Safety Analysis Report (FSAR) section 10.20, the single-failure-proof spent-fuel cask lift yoke described in HNP-2-FSAR paragraph 9.1.5.2, and the interlocks and administrative controls described in the same section which limit the cask height over the refueling floor during cask-handling operations.

The HNP design also incorporates several levels of protection against the drop of other crane loads into the fuel pool and onto stored spent fuel. The HNP-1 reactor building crane is interlocked to prohibit operation over the fuel pool. These interlocks are independent of the load being handled by the crane, and can be overridden, but only under strict administrative controls.

The only postulated loads that require bypassing the interlocks which prohibit movement over the spent-fuel pool are the handling of the fuel pool plugs (10 tons) and gates, and the removal and installation of the old and new spent-fuel racks. The fuel pool gates and plugs are handled only under strictly controlled administrative procedures. The procedural controls ensure that loads > 1250 lb will not travel over fuel assemblies in the spent-fuel storage pool racks except under strict administrative controls as described in the Technical Requirements Manual.

The HNP-2 reactor building crane is not a single-failure proof crane but is used under strict administrative control over the refueling floor.

In addition, the reactor building crane's bridge and trolley tracks are provided with limit switches to prevent the trolley from entering the restricted fuel pool area of both units.

If unanticipated load handling should occur, the size of the load that can be handled over stored spent fuel, by any means, is limited to ≤ 1250 lb except under strict administrative controls as described in the Technical Requirements Manual.

9.1.2.3 Safety Evaluation

The design of the HNP-2 wet spent-fuel storage facility meets the requirements of Regulatory Guide 1.13 (March 1971).

9.1.2.3.1 Fuel Storage Pool

The fuel pool concrete structure, as well as each spent-fuel storage rack and fixture, are designed to Seismic Category I criteria.

Provisions are made for level detection to ensure the fuel in the fuel storage is covered with sufficient water for radiation shielding.

Leakage detection instrumentation is also provided to ensure an adequate fuel pool water level is maintained. The spent-fuel pool structure was designed to prevent inadvertent draining of the pool.

In the unlikely event the fuel pool water level dropped to the level of the fuel transfer canal, the fuel pool water level will be 14 ft 9 in., and the active section of the spent fuel stored in the pool will remain covered with water. Rapid boiling of the remaining water in the fuel pool will not occur. It would take 2.75 h for the pool water to reach boiling based on the following data:

Initial water temperature	150°F
Minimum water height	14 ft 9 in.
Fuel pool cross-section (plan)	40 ft x 33 ft
Heat load (normal condition)	11.60×10^6 Btu/h
Assumed rack capacity	3357

Normal design heat removal condition with a decay heat load of 11.60 MBtu/h represents the heat load in either HNP-1 or HNP-2 spent-fuel pool 30 days following the beginning of a refueling outage. The assumed fuel pool rack capacity of 3357 filled racks bounds the actual fuel pool rack capacity of 3181 for HNP-1 (licensed capacity of 3349) and 2933 for HNP-2. The time-to-boil period of 2.75 h is bounding for both HNP-1 and HNP-2.

During the 2.75 h, the following corrective actions can be taken to prevent boiling:

- Reposition gate over canal entrance.
- Locally open the condensate storage isolation valve and, from the MCR, start a transfer pump to initiate makeup from condensate storage (if available).
- Manually align the PSW system in the reactor building to provide pool makeup.

- Continue refilling pool to normal water level.

The sequence of performance for the above corrective actions would depend on the actual conditions detected during a water loss. For example, the recovery of sufficient water level above the irradiated fuel may be required prior to repositioning the gate, should initial radiation levels be too high for this manual action.

9.1.2.3.2 Spent-Fuel Storage Racks

The design of the spent-fuel storage racks provides for a subcritical multiplication factor (k_{eff}) for both normal and abnormal storage conditions. The design criterion for both normal and abnormal conditions is that k_{eff} is ≤ 0.95. Normal conditions exist when the fuel storage racks are located at the bottom of the pool covered at all times with a normal depth of water (a minimum of 21 ft over the top of irradiated fuel assemblies seated in the spent-fuel storage racks) for sufficient radiation shielding and with the maximum number of fuel assemblies in their design storage position.

A. General Electric Spent-Fuel Racks

A criticality analysis was performed for the high-density racks using a Monte Carlo program which solves the neutron transport equation as an eigenvalue or a fixed-source problem including the effects of neutron shielding. The storage space infinite multiplication factor (k_∞) was calculated for the high-density fuel storage system as defined by the assumptions and exact geometric specifications below:

- Standard boiling water reactor (BWR) fuel configurations.

- Maximum BWR fuel bundle multiplication factor (k_∞) of 1.33 in standard core geometry at 4°C to 100°C; the use of a maximum fuel k_∞ as a criticality base eliminates the need to analyze the multiplicity of U-235 enrichment and burnable poison combinations.

- Storage space pitch of 6.563 in.

- Minimum allowable boron (B-10) concentration equivalent to a homogeneous areal concentration of 0.013 g B^{10}/cm^2.

- Analysis conservatively performed using two-dimensional infinite lattice (X,Y) model (no credit taken for axial or radial neutron leakage).

- Credit taken for double-wall stainless steel tubes that separate fuel bundles.

This analysis (Reference 5) was performed specifically for GE14 and GNF2 fuel, but also addresses legacy spent fuel. The results of the calculations for several cases are listed in table 9.1-2. In no case under normal or abnormal conditions will k_∞ (and therefore, k_{eff}) be > 0.95.

The Westinghouse criticality analysis and documentation of methods for SVEA-96 Optima2 lead use assemblies when stored in the Hatch SFP racks are contained in reference 4.

B. Holtec Spent-Fuel Rack (HNP-2)

To ensure that the true reactivity will always be less than the calculated reactivity, the following conservative design criteria and assumptions were made:

- The moderator in the spent-fuel pool is unborated water at a temperature (4°C) that results in the highest reactivity.
- In all cases (except for the assessment of certain abnormal/accident conditions where neutron leakage is inherent), the infinite multiplication factor, k_∞, rather than the effective multiplication factor, k_{eff} (i.e., neutron loss from radial and axial leakage neglected), was used.
- Neutron absorption in minor structural members is neglected (i.e., spacer grids are analytically replaced by water).
- The racks are fully loaded, with the most reactive authorized fuel to be stored in the facility.
- Incore depletion calculations assume conservative operating conditions and an allowance for voids during incore BWR operations.
- Conservatively, uniform initial average enrichments, rather than distributed enrichments, were used for all fuel pins in a fuel assembly.

The two-dimensional CASMO-4 code was used as the principle method of analysis for the Holtec rack. CASMO-4 was used to perform depletion calculations on the fuel assembly, and using the restart option in CASMO-4, the fuel of a specified burnup was analytically transferred into the storage rack at a reference temperature of 4°C (39°F). The same fuel of a specified burnup was also analytically transferred into the standard cold-core geometry (SCCG) configuration, which is an infinite lattice with 6-in. spacing at a temperature of 20°C, with no control blades and no voids. All Xenon present during the depletion calculations was removed during the restarts in the rack and the SCCG. The reactivity effect of the natural uranium blankets normally located at the ends of the assemblies was conservatively neglected, since the infinite fuel length of the most reactive plane was assumed. Fuel assemblies GE3, GE4, GE5/GE6, GE7B/GE8B, GE9, ANF-92, GE11/GE13, and GE12/GE14 were analyzed at the maximum enrichment specified. The maximum k_∞ in the SCCG was specified as 1.33. Using the CASMO-4 results, the burnup corresponding to a k_∞ in the SCCG of 1.33 was determined, and the corresponding k_∞ in the rack was determined. The reactivity adjustments were added to the rack k_∞ to determine the maximum value, which was compared with the 0.95 k_{eff} limit.

The results of the calculations for several cases are shown in table 9.1-3. In no case under normal or abnormal conditions will k_∞, and therefore k_{eff}, be $>$ 0.95.

Accordingly, the criteria for spent fuel to be acceptable for storage in the Holtec spent-fuel rack are:

- Fuel assemblies with a planar SCCG k_∞ of ≤ 1.33, with a maximum planar average enrichment ≤ 4.8 wt % U-235.

  or

- Fuel assemblies having a maximum planar average enrichment of ≤ 3.3 wt % U-235, regardless of burnup, gadolinia, or the planar SCCG k_∞.

9.1.2.4 Tests and Inspections

Dimensional verification of the high-density storage modules was performed. Nondestructive examination of appropriate welds was performed per Section III of the ASME Code and the American Society for Nondestructive Testing. The concentration and distribution of the neutron-absorbing material (B_4C) was verified by the manufacturer using chemical analyses and/or neutron transmission tests. The dimensions of these Boral sheets were also checked prior to assembly of the storage modules. The presence of Boral in the fabricated fuel storage modules was verified at the site by scanning with a neutron source detector. The corrosion resistance of the Boral material is periodically assessed by examining Boral samples which are suspended in the fuel pool.

Prior to the insertion of spent fuel in the spent-fuel racks, the racks and rack arrangement in the fuel pool were dimensionally verified.

9.1.3 FUEL POOL COOLING AND CLEANUP SYSTEM (HNP-1 AND HNP-2)

The nonpoison fuel pool cooling and cleanup system (FPCCS) is designed to remove the decay heat generated by the spent-fuel assemblies stored in the fuel pool and maintain the pool water at a clarity and purity suitable for underwater operations and protection of personnel in the refueling area.

9.1.3.1 Design Bases

The FPCCS is designed to perform the following functions:

- Maintain the pool water temperature < 150°F under normal operating conditions, refueling conditions, and core offload conditions.

- Prevent overheating of the fuel assemblies by ensuring the fuel elements are completely submerged underwater.

- Maintain a minimum water level above the stored fuel assemblies to limit direct radiation as required by 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) for areas designated as unrestricted access.
- Minimize fission product concentration in the water through purification to permit unrestricted access for plant personnel to the wet spent-fuel storage area.
- Minimize corrosion product buildup to maintain the visual clarity needed for underwater handling of fuel assemblies.

9.1.3.2 System Description

9.1.3.2.1 General

The HNP-1 FPCCS includes two pumps, two heat exchangers, and two filter-demineralizer units (drawing nos. H-16002 and H-16003). The HNP-2 FPCCS includes one pump, one heat exchanger, and one filter-demineralizer unit (drawing nos. H-26039 and H-26040). Table 9.1-4 lists the design parameters of the major equipment in the HNP-1 and HNP-2 FPCCSs.

The two FPCCSs can be shared using an 8-in crosstie header from the HNP-1 to the HNP-2 FPCCS, thus, allowing one of the two HNP-1 trains to be shared with HNP-2 during refueling. Since both units are not refueled simultaneously, the sharing of the HNP-1 FPCCS with the HNP-2 FPCCS is practical. Interconnection of the residual heat removal (RHR) system to each unit's FPCCS is possible in the event unloading of an abnormal amount of irradiated fuel is required. The decay heat removal (DHR) system is also considered part of the FPCCSs.

All portions of the FPCCS between the RHR system cross connections up to and including the boundary isolation valves are Seismic Category I. The remainder of the system, including the heat exchanger, pump, and filter-demineralizer, is nonseismic.

During normal operation, the pump takes suction from the common outlet header of the spent-fuel skimmer/surge tanks and pumps the water through the heat exchanger and filter-demineralizer. From the filter-demineralizer, water is returned to the pool through two diffusers located at the bottom of the pool. The cool water traverses the spent-fuel assemblies, picking up heat and impurities before repeating the cycle by flowing over the adjustable weirs into the skimmer/surge tanks. The reactor building closed cooling water (RBCCW) system removes the heat from the fuel pool cooling heat exchanger.

In the event that an abnormally large amount of irradiated fuel is unloaded or the fuel cooling train experiences a failure during refueling operations, a cooling train of the RHR system consisting of an RHR pump and heat exchanger can be used for cooling the pool water. Also, the DHR system can be placed in service, as described below.

Additional cooling can be provided by the DHR system, which is primarily operated during refueling outages to provide decay heat removal from either the HNP-1 or the HNP-2 fuel pool. Use of the DHR system allows the RHR system and/or the FPCCS to be taken out of service for

inspections, repairs, and/or modifications during outages. The DHR system, which functions independently of the FPCCS, is divided into a primary and a secondary cooling loop. The primary cooling loop consists of stainless-steel piping which circulates water from the fuel pool through heat exchangers and back to the fuel pool. The suction and discharge piping to the fuel pool is designed with flanged connections just above el 228 ft where the piping penetrates the refueling floor. The piping is routed from the penetration to either the HNP-1 or the HNP-2 fuel pool as required. When not in use, the portion of the suction and discharge piping above el 228 ft may be removed and stored with blind flanges installed on the flanges at the refueling floor penetrations. For convenience, the portion of the piping over the fuel pools is designed and supported such that it may be removed or left installed even if the remainder of the piping above el 228 ft is removed. The primary cooling loop equipment consists of two 100% capacity pumps, two plate and frame heat exchangers, and one strainer, as well as the valves, controls, and process monitoring equipment necessary for proper system operation. All of this equipment is located on el 203 ft of the HNP-1 reactor building. Both suction and discharge pipes have anti-siphon holes located below the water surface but higher than minimum Technical Specifications levels to prevent inadvertent pool drawdown.

The DHR secondary cooling loop consists of stainless steel piping which circulates cooling water from the basin of the cooling towers through the heat exchangers and back to the hot water side of the cooling towers. Controls are provided to maintain the cooling water on the secondary cooling loop side at a higher pressure than the fuel pool water on the primary cooling loop side to ensure no leakage to the environment. The secondary cooling loop equipment consists of two 50% capacity pumps and two cooling towers, as well as valves, controls, and process monitoring equipment necessary for proper system operation. The secondary pumps and cooling towers are located outside on the roof of the railroad airlock at el 154 ft 4 in. The power supplies for both the primary cooling loop and the secondary cooling loop are from reliable power sources and may be backed up by a temporary diesel generator. The need for the diesel generator is dependent upon the decay heat load. The diesel generator is typically made available if the DHR system is to be used as the primary source of reactor core decay heat removal during the first 20 days of a refueling outage.

The DHR system is sized to handle a heat load of 40 MBtu/h. This is approximately equal to the heat load contributed to the fuel pool by a full-core offload 1 1/2 to 2 days after the reactor is shut down for refueling. Duplicates of major components (primary pump, heat exchanger, secondary pump, and cooling tower) are provided so that the loss of any single DHR system component does not mean total loss of system function. Analysis shows that the DHR system can maintain the fuel pool temperature ≤ 145°F even with the loss of any single DHR system component.

9.1.3.2.2 Heat Removal Capacity

For all three scenarios described below, heat loads were determined assuming the fuel pool to be filled to maximum capacity based on the pool initially empty and repopulated with fuel discharged from 24-month operating cycles at 2804 MWt. All of the discharged fuel batches were assumed to have operated in cycles which ran at 95% capacity factor. In all scenarios, the fuel pool was assumed to have 3357 rack locations. Assumed fuel rack capacity of 3357 filled racks bounds the actual fuel rack capacity of 3181 for HNP-1 (licensed capacity of 3349) and 2933 for HNP-2. Therefore, the heat load analysis for the discharge scenarios described

below represent a bounding analysis for HNP-1 and HNP-2. Maximum design cooling water temperatures of 105°F for RBCCW and 97°F for PSW were assumed for the evaluations.

A. Normal Condition

Normal condition defines the point at which one FPCCS train can maintain temperature < 150°F. The analysis was performed assuming the following discharge scenario:

1. Start with empty fuel pool.

2. Repopulate fuel pool from 2804-MWt 24-month operations proceedings as follows:

    - 237 bundles at 44 GWd/MT (first reload).

    - 240 bundles at 44 GWd/MT (13 subsequent reloads).

The analysis showed that the heat load is 8.54 x 10^6 Btu/h, after decaying for 87 days. Temperature is then maintained < 150°F with one train of the FPCCS in operation.

Realistically, it is desirable to maintain the fuel pool temperature ≤ 125°F. This will be achievable for normal operating conditions for the following reasons:

1. After a scheduled fall or spring refueling outage, RBCCW temperature should be < 90°F. This greatly increases the heat removal capacity of the FPCCS.

2. The DHR system (or a second train of the FPCCS) can be run until the freshly discharged fuel decays to a heat load where one train of the FPCCS will keep the pool temperature < 125°F.

B. Refueling Condition – Fuel Shuffle

A partial-core offload and fuel shuffle represent the same decay heat loads for spent-fuel pool cooling. A partial-core offload is the discharge fuel that is placed in the pool during a refueling outage, and a fuel shuffle is rearrangement of the fuel that is to remain in the core for the next operating cycle. During a fuel shuffle, fuel to be discharged (normally ~ 40% of the fuel bundles) is removed from the core to the pool, new fuel assemblies are loaded into the core, and the remaining fuel is shuffled to new core locations. All of the discharge fuel (partial-core offload) is not completely removed from the core until near the end of the fuel shuffle. It normally takes at least 12 days (288 hours) from the time the plant is shut down until the fuel shuffle is complete and all the discharge fuel is in the pool.

Assumptions for the refueling mode analysis are the same as those for the normal condition above, except the fuel pool heat load was calculated 150 h after offload of all discharge fuel and two FPCCS trains are in service. Analysis showed the

heat load is 17.78×10^6 Btu/h. Temperature is maintained < 150°F with two FPCCS trains in operation or with DHR system in operation until freshly discharged fuel decays to a heat load where one train of the FPCCS will keep the pool temperature < 150°F (normal condition).

C. Refueling Condition – Core Offload

A normal refueling results in either a partial-core offload into the spent-fuel pool or a discharge of the entire core into the pool. A full-core offload analysis was performed assuming the following discharge scenario:

1. Start with empty fuel pool.

2. Repopulate fuel pool from 2804 MWt 24-month operations proceedings as follows:

   - 205 bundles at 48 GWd/MT (first reload).

   - 216 bundles at 48 GWd/MT (12 subsequent reloads).

   - 560 bundles at 48 GWd/MT (final full-core discharge).

3. Calculate fuel pool heat load 150 h after shutdown.

   Analysis showed that the heat load was 34.88×10^6 Btu/h, which is the cumulative heat load in the pool after shutdown. With the DHR system in service, pool water temperature will be maintained < 150°F. Also, a single train of the RHR system aligned for fuel pool cooling duty, without the assistance of either the FPCCS or the DHR system, can maintain pool water temperature < 150°F.

   As an alternative to either placing the DHR system in service or aligning the RHR system to the fuel pool cooling mode for a full-core offload, the fuel may be allowed to decay in the reactor vessel until the heat load of the core has decreased to the point where two FPCCS trains can maintain the maximum operating temperature < 150°F.

Additionally, the DHR system may be used to remove the decay heat associated with a full-core offload. The largest heat load during a refueling outage typically occurs early in the outage, from approximately day 3 to day 9. Some time during this period, off loading of the core will usually begin. The decay heat load is shared between the RPV and the fuel pool. A representative value for the decay heat load during this period is ~ 35×10^6 Btu/h. The DHR system, with its decay heat load removal capacity of 40 MBtu/h, is fully capable of handling the load during this period.

As stated in paragraph 9.1.3.2.1, the DHR system is capable of handling the heat load to the spent fuel 1 1/2 to 2 days after the reactor is shut down for refueling. Therefore, the DHR

system is a viable method of decay heat removal for both the core and the spent-fuel pool, and may be used for several combinations; e.g., as a backup to shutdown cooling, fuel pool cooling, and fuel pool cooling assist; or as a primary method of decay heat removal.

For each design condition analyzed above, completely utilizing the fuel pool storage capacity, the present FPCCS, a single train of the RHR (for the full-core offload condition) or the DHR system is capable of maintaining pool water temperatures less than the maximum normal operating temperature of 150°F. Considering the conservative assumptions used in the calculations and past operating experience, the actual temperatures for each condition are expected to be lower than those calculated and described above.

Prior to each refueling outage, a realistic calculation of the fuel pool heat load is performed based on the actual number of assemblies in the fuel pool and the number of fuel assemblies being offloaded to the pool from the core. This calculation aids outage planners and operators in ensuring that sufficient decay heat removal is provided throughout different periods of the outage.

9.1.3.2.2.1 Local Fuel Bundle Thermal-Hydraulics

A. General Electric Spent-Fuel Racks

The bounding local thermal-hydraulic conditions for the fuel stored in the high-density storage modules were calculated. The calculation utilized limiting bundle power assumptions (e.g., enrichment and discharge exposure) and conservative decay heat parameters which are consistent with 24-month fuel cycles. Fuel bundle thermal hydraulic assumptions were representative of higher burnup 8x8 and 9x9 fuel designs. With the bulk water temperature of the fuel storage pool constant at 150°F, the calculated bundle exit temperature was < 170°F. These temperatures are low relative to structural integrity or corrosion limits for the structural components of the storage system and fuel.

Additionally, bounding local thermal-hydraulic conditions were calculated for fuel covered by a storage module identifier plate while stored in the high-density storage modules. The storage module identifier plate displays the storage module number and serves as an aid to personnel in locating fuel bundles stored in the spent fuel pool. The identifier plate is in the shape of a cuboid, one side of which is open and the opposite side of which has one 1-in. hole drilled in it per storage cell covered. The open side slides over the bail handles of fuel bundles stored in the storage module. In this manner, a method to identify the storage module number is provided while maintaining the ability to utilize all storage locations in the modules. Using the same limiting bundle power assumptions and conservative decay heat parameters discussed previously and assuming a bulk pool water temperature of 150°F, the calculated exit temperature for the bundle(s) covered by the identifier plate was < 210°F. This temperature also is low relative to structural integrity and corrosion limits for the structural components of the storage system and fuel.

B. Holtec Spent-Fuel Rack

The local thermal-hydraulic analysis performed for the CESA assumes the bulk pool temperature is at the design basis maximum 150°F temperature. The CESA does not have provisions for introducing forced cooling water into the space above the racks. Forced cooling is available from the spent-fuel pool area surrounding the CESA to maintain the bulk pool temperature < 150°F design limit. The decay heat transported from the CESA area fuel rack cells into this space is dissipated into the general spent-fuel pool area by a buoyancy-driven exchange of relatively cooler bulk pool water and CESA water. This water exchange exists above the 8-ft-high walls separating the CESA from the remainder of the spent-fuel pool. The water in the fuel rack will remain subcooled.

9.1.3.2.3 Makeup Water

The normal source of makeup water to the fuel pool is condensate water which is added directly to the pool from the condensate storage tank (CST). A separate condensate line connects to the reactor well for filling the reactor well and dryer-separator pool. Other sources of makeup are demineralized water hose stations located on the refueling floor area and PSW which serves as a Seismic Category I source.

Normal condensate makeup is set by direct visual observation of water level in the pool. To ensure that service water is not added inadvertently to the pool, two manual isolation valves are provided on the makeup line.

9.1.3.2.4 Cleanup Equipment

The filter-demineralizer system consists of a filter vessel, a resin trap, a holding pump, a precoat mixing tank, a precoat pump, valves, instrumentation, and controls necessary to achieve the automatic sequence of operation required for backwashing and application of precoat resin when the resins are exhausted. Normally, the entire fuel pool cooling water flow is processed through the filter-demineralizer by way of the filter vessel and the resin trap. The filter vessel contains stainless-steel cylindrical filter elements to which a layer of resin precoat is suspended by the action of the flowing process water. Downstream of the filter vessel is the resin trap which serves to capture the resins in the event of a gross breakthrough of the elements in the filter vessel. The holding pump is automatically activated whenever the flow of the process water is insufficient to hold the resins on the filter elements. The precoat resin is prepared in the precoat tank and is conveyed and applied to the filter elements by the precoat pump.

The filter vessel is enclosed in a shielded cell with components, such as valves and instrumentation, mounted outside the cell for accessibility.

The filter-demineralizer maintains total dissolved heavy element (Cu, Ni, Fe, Hg) content at ≤ 0.1 ppm with a pH range of 5.3 to 8.6 and a conductivity limit of ≤ 2.0 μS/cm. The normal flowrate produces approximately four complete water changes per day of the fuel pool. The

radioactive particulates removed from the pool are retained in the filter vessel which is enclosed in a shielded cell; thus, exposure of plant personnel to radiation is minimized.

9.1.3.2.5 Water Level

The normal water level in the pool is ~ 1 1/2 ft below the refueling floor, which is at el 228 ft. This level is maintained by regulating the addition of makeup and by adjusting the height of the weirs that overflow water from the pool to the skimmer/surge tanks. All penetrations of the fuel pool have been installed at such a height that their presence does not provide a possible drainage route that could lower the water level to < 10 ft above the top of the upper tie plates. A minimum of 10 ft of water above the top of the upper tie plates is maintained to limit direct radiation for normal plant operation on the refueling floor. Drainage penetrations are barred below the recommended safe water level for fuel assemblies. The fuel pool cooling water return lines are submerged at the bottom of the pool but have two check valves in series located near the normal water level to prevent siphoning of the pool water.

9.1.3.2.6 Materials

Carbon steel is used on piping, valves, and equipment upstream of the filter vessel. Downstream of the filter elements, stainless steel is used to minimize the addition of corrosion products to the pool.

9.1.3.3 Instrumentation Application

The operation of the fuel pool cooling pump is controlled from either the MCR or the local panel in the pump floor area. The local pump control is convenient for testing the pump. To prevent cavitation, a pressure switch automatically stops the pump at low-suction pressure. A pressure switch will initiate an alarm in the MCR caused by low pump discharge pressure. To prevent shutoff operation, a pressure switch sensing a high discharge pressure will automatically stop the pump and simultaneously initiate an alarm in the MCR.

Fuel pool level alarms are provided to ensure that the pool water level remains within the limits allowed for safe fuel handling. Abnormally high or low water levels in the pool will actuate an alarm in the MCR and pump floor area. A level switch on the skimmer surge tanks will initiate an alarm for a low surge tank level on the 203-ft elevation and in the MCR. A low water level alarm could be an indication of a leak in the system. The dryer-separator pool is provided with a high water level alarm. Level switches on leakoff lines will initiate an alarm in the MCR for leakages in the pool refueling gate, refueling bellows, and reactor well bellows. The alarms for the fuel pool and skimmer surge tank levels and the remote control station to actuate power-operated isolation valves for drains to the condenser hotwell, CST, and radwaste system are located on the pump floor area.

A high differential pressure and conductivity alarm on the filter vessel will indicate when precoat resin replacement is required. An alarm for high differential pressure across the resin trap

indicates a possible breakout of resins from the filter vessel. Alternately, the fuel pool cooling water conductivity can be monitored by use of laboratory samples.

9.1.3.4 Safety Evaluation

The FPCCS has no emergency functions during an accident.

In the event that a fuel pool cooling system is inoperable due to the loss of a pump or a heat exchanger, several options are available. The DHR system can be aligned to the fuel pool and used for the necessary decay heat removal. Also, the spare HNP-1 cooling train may be aligned to cool the fuel pool. If the DHR system and the spare HNP-1 cooling train are unavailable, cooling will be transferred to the RHR system, which has the capacity to handle the maximum postulated heat load in the pool and the reliability inherent to a safeguard system.

An analysis was performed to determine the plant conditions at which pool boiling might occur and the subsequent radiological impact.

A full-core offload creates the highest heat load in the fuel pool. However, with no fuel in the reactor pressure vessel (RPV), the RHR system is available for unrestricted fuel pool cooling. The redundant Seismic Category I design of the RHR system provides a high degree of assurance that it operates satisfactorily in the fuel pool cooling assist mode.

It was determined that the plant condition which would result in maximum pool boiling and radiological impact is the concurrent failure of both HNP-1 and HNP-2 FPCCSs and DHR system. Both fuel pools are loaded as delineated in paragraph 9.1.3.2.2.B. HNP-1 and HNP-2 are shut down for refueling 21 days apart, an assumed minimum time required to complete a refueling operation. Subsequently, each unit's FPCCS is lost 150 h after the second unit is shut down. Since decay heat loads for both units are conservatively assumed to be the same, either unit can be in the refueling condition first.

Calculations using pool volumes of 38,293 ft^3 indicate that the time to boil for HNP-1 and HNP-2 is 8.2 h. The makeup water requirement following boiling was calculated to be ~ 37 gal/min per unit. During transition to boiling, no credit is taken for evaporative heat losses. Water level is maintained by the Seismic Category I PSW system. Conservatisms are included in the analysis by assuming that all decay heat is rejected to the pool water and none is rejected to the structures. Also, the heat capacity of the makeup water is neglected.

After ~ 150 h following the second unit shutdown, the decay heat contributed by the balance of the core in the second unit RPV has decreased enough to allow aligning one train of RHR to provide fuel pool cooling and RPV cooling. With the RPV head and the fuel pool gates removed, the RHR system can be aligned for fuel pool and RPV cooling by installation of two spectacle flanges and operation of four isolation valves. The time required for realignment is 8 h.

A radiological analysis was performed to determine the thyroid dose at the site boundary/low population zone (LPZ), assuming that the HNP-1 and HNP-2 pools boil and that there has been an iodine spike in the pools. The assumptions used are as follows:

A. The time to reach boiling is 8.2 h for both units assuming an initial pool temperature of 150°F.

B. Boiling rate of the pool water is 18,300 lb/h for both units.

C. Volume of water in each pool is 38,293 ft^3.

D. All failed fuel rods of the full core (average 1% of the core) are present in the portion of the core discharged to the pool.

E. The normal I-131 release rate coefficient for leaking rods at 150 h for both pools is conservatively assumed as $4.6 \times 10^{-10}\ s^{-1}$. These release rates are assumed to be constant during the heatup and boiling periods.

F. The above release rate coefficient is spiked by a factor of 100 to simulate the heatup conservatively.

G. The decontamination factor for I-131 during boiling is conservatively assumed to be unity.

H. No credit is taken for iodine plate-out or filtration by the SGTS.

I. Conservative ground-level accident X/Q values are assumed for the dose calculation.

The results are summarized below:

- Site boundary/LPZ thyroid dose (0-2 h) 2.8 rem
- Site boundary/LPZ thyroid dose (0-4 days) 17.8 rem

To prevent uncovering the fuel elements (drainage penetrations are not allowed below the minimum required water cover for the fuel assemblies), return and makeup lines running to the bottom of the pool are provided with check valves to prevent siphoning of the pool water, and the spent-fuel cask storage is detached from the wet spent-fuel storage area.

The filter-demineralizer normally operates in conjunction with the cooling train, but in the event of its malfunctioning or if it is desired to enhance the cooling capacity of the system, the filter can be bypassed in favor of retaining only the cooling portion of the system.

Continuing efficiency of the heat exchange from the spent fuel to the pool water depends on the convectional waterflow through the storage tube and flow channel which, if present, encompasses a fuel bundle. The floc-like crud that adheres to the surfaces of the spent-fuel bundles was studied to determine whether it is a potential mechanism for blocking flow through the channel. The floc was found to be extremely fine; pieces that spalled off of the aggregate did not settle, but they flowed upward with the convectional current. Additionally, the floc was so fine that some of it passed through the conventional laboratory filter papers. Growth of floc-like crud in fuel storage conditions has not been observed in commercial facilities. The

potential for channel plugging by sedimentation or by blockage of flow passages is therefore negligible.

The HNP-2 FPCCS meets the requirements of Regulatory Guide 1.13 (March 1971), except that the primary water storage facility, the CST, is not Seismic Category I. The CST design is discussed in HNP-1-FSAR section 11.9 and HNP-2-FSAR subsection 9.2.6. The backup system for providing makeup water to the fuel pool is the Seismic Category I PSW system.

9.1.3.5 Tests and Inspections

Special tests are not required since, except during infrequent operations, the FPCCS is in continuous operation while spent fuel is stored in the pool. Routine visual inspection and checking of system components, instrumentation, and alarms are adequate to verify system operability.

During infrequent operations when an FPCCS is shut down or realigned such that it is not operating with a suction from its associated fuel pool and the spare HNP-1 fuel pool cooling subsystem is not aligned and operating, monitoring of pool temperature via the FPCCS pump suction temperature indicator is not available. In this situation, the DHR system may be placed in service and its temperature indications used to monitor fuel pool temperatures. The system is placed in service within 1 h following the loss of temperature indication. If the DHR system is not placed in service within the 1 h time frame, two calibrated temporary temperature monitoring instruments will be installed in the fuel pool. If the temperature reaches 120°F, either the DHR system will be placed in service, or the FPCCS will be returned to normal alignment and placed in service.

9.1.4 FUEL-HANDLING SYSTEM

The fuel-handling system provides a safe and effective means for transporting and handling fuel from the time it reaches the plant until the time it leaves the plant after post-irradiation cooling.

9.1.4.1 Reactor Building Crane

HNP-2 shares the reactor building crane provided for HNP-1 (HNP-1-FSAR section 10.20). A special provision for continuous rails between the HNP-1 and HNP-2 refueling floors is provided to bridge the 3-in. gap without structurally linking the buildings. The design utilizes a short wedge-shaped rail section held in place by clamps, which are designed to fail before excessive loads are transmitted from one building to the other. The wedge-shaped section is separated from the rails of the HNP-1 and HNP-2 buildings by ~ 1/4 in., thus allowing for the smooth movement of the crane over this section but maintaining the building separation for any minor building movements.

Use of the HNP-2 crane is administratively controlled (reference drawing H-10167). It is not single-failure proof and will not be used over any equipment required to reach and maintain cold shutdown. For conformance with industry initiative NEI 08-05, removal of the HNP-1 and HNP-

2 reactor vessel heads is restricted to use of the HNP-1 single-failure proof crane. Use of the HNP-1 and HNP-2 reactor building cranes complies with the refueling floor load paths shown on drawing H-10167, as appropriate.

9.1.4.2 Fuel-Servicing Equipment and Servicing Aids

A fuel preparation machine is used to strip the channel from spent-fuel assemblies and to install the used channels on new fuel bundles. This machine is designed to be removed from the pool for servicing. A channel-gauging fixture consisting of a "go, no-go" gauge is mounted near the fuel preparation machine.

A new fuel inspection stand is used to restrain the fuel bundle in a vertical position for inspection. The inspection stand can hold two bundles.

The general purpose grapple is a small, hand-actuated tool used generally with the fuel. The grapple can be attached to the reactor building auxiliary hoist, jib crane, and the auxiliary hoists on the refueling platforms. The general purpose grapple is used to remove new fuel from the vault, place it in the inspection stand, and transfer it to the fuel storage pool. It also can be used to shuffle fuel in the pool and to handle fuel during channeling.

A channel-handling boom with a spring loaded takeup reel is used to assist the operator in supporting a portion of the weight after the channel is removed from the fuel assembly. With the channel-handling tool attached to the reel, the channel may be conveniently moved between fuel preparation machines.

General area underwater lights are provided with a suitable reflector for downward illumination. Suitable light support brackets, independent of the platform, are furnished to support the lights in the reactor vessel to allow the light to be positioned over the area being serviced. Local area underwater lights are small diameter lights for additional downward illumination. Drop lights are quartz lamps with no reflector and are used for intense radial illumination where needed. These lights are small enough in diameter to fit into fuel channels or control blade guide tubes. A portable underwater television camera and monitor are part of the plant optical aids. This assists in the inspection of the vessel internals and general underwater surveillance in the reactor vessel and fuel storage pool. A general purpose clear plastic viewing aid that floats is used to break the water surface for better visibility.

A portable submersible-type underwater vacuum cleaner is provided to assist in removing crud and miscellaneous particulate matter from the pool floor or from the reactor vessel. The pump and the filter unit can be completely submerged for an extended period. Fuel pool tool accessories are also provided to meet servicing requirements.

9.1.4.2.1 RPV Servicing Equipment

RPV servicing equipment is supplied for safe handling of the RPV head and its component, including nuts, studs, bushings, and seals.

The head strongback or RPV head carousel / tensioner assembly is used for lifting the RPV head. The strongback is designed to keep the head level during lifting and transport. It is cruciform in shape with four equally spaced lifting points. The strongback is designed so that no single component failure can cause the load to drop or to swing uncontrollably.

The RPV head carousel / tensioner assembly is an integrated RPV head strongback and a stud tensioner carousel track, which is designed to carry the weight of the RPV head, stud tensioning system, and all head closure nuts and washers. The RPV head carousel / tensioner assembly strongback lifting function is identical to the head strongback.

A vessel nut-handling tool is provided. This tool handles one nut and features a spring device to lift the nut and clear the threads.

The head-holding pedestals are designed to properly support the vessel head and permit seal removal and replacement, seal surface cleaning, and inspection. The mating surface between RPV head and pedestal is selected to minimize the possibility of damaging the RPV head.

9.1.4.2.2 In-Vessel Servicing Equipment

The instrument strongback is attached to the reactor building crane auxiliary hoist and is used to lift replacement incore detectors from their shipping container. The instrument-handling tool is attached to the incore detector by the operators on the refueling platform. The strongback initially supports in the incore detector until the detector is lifted into the vessel. The incore detector is then decoupled from the strongback and is guided into place by a spring reel cable from below the reactor vessel. Final incore insertion is accomplished with the instrument-handling tool.

The instrument-handling tool is attached to the refueling platform auxiliary hoist and is used for removing and installing fixed incore detectors as well as handling neutron source holders and the source range monitor/intermediate range monitor dry tubes.

Each incore instrumentation guide tube is sealed by an O-ring on the flange. In the event that the seal needs replacing, an incore guide tube sealing tool is provided. The tool is inserted into an empty guide tube and sits on the beveled guide tube entry in the vessel. When the drain on the spring reel is opened, hydrostatic pressure seals the tool. The flange can then be removed for seal replacement.

The auxiliary hoist on the refueling platform is used with appropriate grapples to handle control rods, flux monitors, sources, and other internals of the reactor. Interlocks on both the grapple and auxiliary hoists are provided for safety purposes. The refueling interlocks are described and evaluated in subsection 7.6.1.

9.1.4.2.3 Refueling Equipment

The refueling platform is used as the principal means of transporting fuel assemblies back and forth between the reactor well and the fuel storage pool. The platform travels on tracks

extending along each side of the reactor well and the fuel storage pool. The platform supports the refueling grapple and auxiliary hoists. The grapple is suspended from a trolley system that can traverse the width of the platform. Platform operations are controlled from an operator station on the trolley. The platform contains a position indicating system that indicates the position of the fuel grapple over the core.
All equipment and structures into which fuel bundles are inserted are designed such that the possibility of jamming is remote. In addition, the refueling hoist is provided with a motor overload trip to prevent damage to the fuel bundle should it stick.

9.1.4.2.4 Storage Equipment

Specially designed fuel storage racks are provided. For a description of fuel storage racks and fuel arrangement, see subsections 9.1.1 and 9.1.2.

Defective fuel assemblies are placed in defective-fuel storage containers, which in turn are normally stored in the defective-fuel storage rack. These are used to isolate leakage of defective fuel while in the fuel storage pool and during shipping. A defective-fuel storage container containing a fuel bundle can be picked up and moved. It is also possible to remove a channel from a fuel bundle which is in a defective-fuel storage container.

Fuel container sipping heads, panels, and containers are separate pieces of equipment used for out-of-core wet sipping at any time. They are used to isolate a fuel bundle in a closed system. The containers cannot be used for transporting fuel bundles. The bail on the container head is designed so that it will not fit into any of the grapples.

9.1.4.2.5 Under RPV Servicing Equipment

The necessary equipment to remove several control rod drives (CRDs) during a refueling outage is provided. An equipment handling platform with a rectangular open center is provided. This platform can rotate to provide space under the vessel so that a CRD can be lowered and removed. A CRD facile which clamps onto the drive flange and directs water from the drive to a sump is used during drive removal. If a control rod guide tube must be removed, the thermal sleeve within the CRD housing must be rotated to disengage the guide tube. A thermal sleeve tool which permits installation or complete removal at the thermal sleeve is provided for this purpose. Special tools and instruments to service and test individual CRD hydraulic units are also provided.

Miscellaneous wrenches, a tapering tool, and a flaring tool are provided to install and remove the neutron detectors. The spring reel pulls the fixed incore detectors string into the incore guide tube and also seals the opening in the incore flange during incore servicing. A drain can be opened after incore insertion to drain any residual water. Correct seating of the incore string is indicated when drainage ceases.

9.1.4.3 <u>Fuel-Handling System</u>

The fuel-handling system provides a safe and effective means for transporting and handling fuel from the time it reaches the plant until it leaves the plant after post-irradiation cooling. The previous subsection has described the equipment and methods utilized in fuel handling. The following paragraphs describe the integrated fuel transfer system which ensures that the power generation design bases of the fuel-handling system and the requirements of Regulatory Guide 1.13 (March 1971) are satisfied.

9.1.4.3.1 Arrival of Fuel at the Plant Site

Fuel arrives at the plant site by truck. The fuel elements, enclosed in a plastic bag, are shipped in steel boxes which support the fuel element along its entire length. The steel box is contained in an overpack consisting of a wooden crate. Cushioning material positions the steel box in the wooden overpack. Each crate is designed to ensure subcritical geometry in handling. The fuel can be safely handled by operators wearing gloves and other protective clothing.

9.1.4.3.2 Departure of Fuel From the Plant Site

Fuel assemblies from the spent-fuel pool are conveyed by the fuel-handling bridge crane into the spent-fuel cask located in the HNP-2 cask pit. After insertion of the spent-fuel assemblies into the spent-fuel cask, the spent-fuel cask is transported to the reactor vessel head laydown area for closure and decontamination operations. Upon completion of the closure and decontamination operations, the cask is transported to the independent spent-fuel storage installation (ISFSI). The spent fuel will be stored at the ISFSI pending shipment to an NRC-approved repository or interim storage facility.

9.1.4.4 Refueling Procedure

Plant procedures describe the work efforts required during a refueling outage.

9.1.5 DRY SPENT-FUEL STORAGE (HNP-1 AND HNP-2)

In order to provide additional temporary spent-fuel storage capacity, Southern Nuclear Operating Company (SNC) elected to utilize the general license issued for storage of spent fuel in an ISFSI in accordance with 10 CFR 72, Subpart K. The general license is limited to storage of spent fuel which the general licensee is authorized to possess at the site under the specific license for the site and is restricted to use of spent-fuel casks that are approved by the NRC.

The ISFSI is located south of the protected area for the main plant, adjacent to the main rail line as shown on figure 1.2-1 and drawing no. E-10173. The ISFSI is located in a separate protected area and consists of four small pads, which are designed to accommodate 12 spent fuel casks each and support equipment and a large pad designed to accommodate 72 spent fuel casks and support equipment.

An evaluation of the cask designs and their acceptability for use at HNP is provided in the HNP ISFSI 10 CFR 72.212 report.

9.1.5.1 Spent-Fuel Cask

SNC selected the Holtec HI-STAR 100 and HI-STORM 100 cask systems for storage of spent fuel in the ISFSI. The NRC reviewed and approved the HI-STAR 100 design and issued Certificate of Compliance (CoC) 1008 to Holtec for the HI-STAR 100 cask in accordance with the requirements of 10 CFR 72. Similarly, the NRC reviewed and approved the HI-STORM 100 design and issued CoC 1014 for the HI-STORM 100 cask in accordance with the requirements of 10 CFR 72.

9.1.5.1.1 HI-STAR 100 Description

The HI-STAR 100 spent-fuel cask is composed of a multi-purpose canister (MPC) and overpack designed and certified for storage (10 CFR 72) and transportation (10 CFR 71) of spent nuclear fuel. The MPC is a stainless-steel container which contains a basket designed specifically for BWR fuel assemblies. The loaded MPC is placed inside the overpack which provides missile protection and shielding.

Each HI-STAR 100 spent-fuel cask is equipped with two, single-load path, lifting trunnions which are rated for a combined maximum load of 125 tons. The lifting trunnions for the HI-STAR 100 cask are designed in accordance with ANSI N14.6 and NUREG-0612 with a minimum safety factor of:

- Six times the weight of the cask to the yield strength of the materials of construction.

- Ten times the weight of the cask to the ultimate strength of the materials of construction.

A detailed description of the HI-STAR 100 cask is provided in Holtec Report HI-941184, "Topical Safety Analysis Report (TSAR) for the Holtec HI-STAR 100 Cask System."[(2)]

9.1.5.1.2 HI-STORM 100 Description

The HI-STORM 100 spent-fuel cask is part of the Holtec family of MPC-based spent fuel cask designs and utilizes the same MPC as the HI-STAR 100 cask system described above. As such, the MPC for the HI-STORM 100 cask system is certified for both storage and transportation of spent nuclear fuel in accordance with 10 CFR 72 and 10 CFR 71, respectively.

The HI-STORM 100 overpack is a steel and concrete cylindrical vessel that is certified for storage only in accordance with 10 CFR 72. The HI-STORM 100 overpack provides missile protection and shielding for the MPC during storage. All MPCs used in conjunction with the HI-STORM 100 cask system will be transferred to HI-STAR 100 overpacks prior to shipment.

Unlike the HI-STAR 100 overpack, the HI-STORM 100 overpack is not designed to be placed in the spent-fuel pool during MPC loading but, instead, utilizes a HI-TRAC 125 transfer cask for movement of the MPC to and from the spent-fuel pool. There are two configurations of the HI-TRAC 125 transfer cask approved for use at Hatch. In one configuration, the HI-TRAC 125 transfer cask is equipped with two interchangeable bottom lids, a pool lid and a transfer lid. The pool lid is used for all underwater activities associated with the HI-TRAC 125 transfer cask. The transfer lid is equipped with sliding doors to facilitate transfer of the MPC from the HI-TRAC 125 transfer cask to the HI-STORM 100 overpack for loading operations and vice-versa for unloading operations. The transfer lid is not placed in the spent-fuel pool during loading or unloading operations. A specially designed transfer slide is used to facilitate the HI-TRAC 125 transfer cask bottom lid change.

An optional configuration of the HI-TRAC 125 involves use of an adapter plate attached to the HI-TRAC 125 bottom flange to accommodate use of the pool lid and mating device originally designed for the HI-TRAC 125D. Use of the HI-TRAC 125 in this configuration will facilitate use of the supplemental cooling system (SCS), if required, and eliminates the need for bottom lid changeout prior to MPC transfer operations. This configuration may be used to load or unload any cask approved for use in the Hatch ISFSI but is required for those casks for which the SCS is required by Holtec Certification of Compliance (CoC) 1014.

The HI-TRAC 125 transfer cask is equipped with two, single-load path, lifting trunnions which are rated for a combined maximum load of 125 tons. The lifting trunnions for the HI-TRAC 125 transfer cask are designed in accordance with ANSI N14.6 and NUREG-0612 with a minimum safety factor of:

- Six times the weight of the cask to the yield strength of the materials of construction.

- Ten times the weight of the cask to the ultimate strength of the materials of construction.

A detailed description of the HI-STORM 100 system is provided in Holtec Report HI-2002444, "Final Safety Analysis Report (FSAR) for the Holtec HI-STORM 100 Cask System."(3)

9.1.5.2 Spent-Fuel Cask Lift Yoke

The HI-STAR 100 and HI-TRAC 125 casks are designed to use the same spent-fuel cask lift yoke to provide the interface between the HI-STAR 100 or HI-TRAC 125 casks and the HNP-1 reactor building crane. The spent-fuel cask lift yoke is a single-load-path special lift device designed in accordance with ANSI N14.6 and NUREG-0612, and is rated for a maximum load of 125 tons. The spent-fuel cask lift yoke is used for:

- Vertical lifting and handling of the HI-STAR 100 cask and HI-TRAC 125 transfer cask.

- Remote underwater installation of the MPC lid.
- MPC transfer between the HI-TRAC 125 transfer cask and the HI-STORM 100 overpack (not applicable to HI-STAR 100 casks).

The spent-fuel cask lift yoke (figure 9.1-5) consists of two parallel strongbacks that sandwich the crane hook and connect to the crane hook at the two main lift yoke pins which form the primary load path. The spent-fuel cask lift yoke has two closed-loop arms that fit over either the HI-STAR 100 or HI-TRAC 125 cask trunnions located near the top of each cask. Each lift yoke arm transmits the load to the strongbacks via a pair of actuation plates that allow the lift yoke arms to open and close. The actuation plates are attached to the strongbacks via solid steel pins. Each lift yoke arm attaches to the actuation plates via a slotted keyway. The spent-fuel cask lift yoke is designed such that it does not contain any load bearing welds. The weight of the cask is transferred from the trunnions to the main hook of the HNP-1 reactor building crane as follows:

- Lift yoke arms.
- Actuation plates.
- Actuation plate pins.
- Strongbacks.
- Main lift yoke pins.

In addition to use for movement of the HI-STAR 100 and HI-TRAC 125 casks, the spent-fuel cask lift yoke is equipped with slots and pins designed to support the weight of a loaded MPC during the HI-TRAC 125 transfer cask bottom lid change. Either the slots or the pins, in conjunction with slings meeting the guidance of NUREG-0612, may be used to support the weight of the MPC inside the HI-TRAC 125 transfer cask. The spent-fuel cask lift yoke arms remain attached to the HI-TRAC 125 transfer cask lifting trunnions during the bottom lid changeout operation.

The spent-fuel cask lift yoke slots and pins are also used during MPC transfer from the HI-TRAC 125 transfer cask to the HI-STORM 100 overpack. Either the slots or pins, in conjunction with slings that meet the guidance of NUREG-0612, may be used to slightly lift the MPC inside the HI-TRAC 125 transfer cask to remove the weight of the MPC from the pool lid or transfer lid, as applicable. The spent-fuel cask crane lift arms are not attached to the HI-TRAC 125 transfer cask trunnions during MPC transfer operations.

The weight of the cask is transferred from the MPC lift cleats to the main hook of the HNP-1 reactor building crane as follows:

- MPC slings.
- Strongback slots or MPC pins.

- Strongbacks.
- Main lift yoke pins.

Two spacers are used to position each pair of actuation plates. Four strongback spacers are provided to position the strongbacks.

The load bearing members of the spent-fuel cask lift yoke are designed to lift six times the maximum allowable weight of the loaded HI-STAR 100 or HI-TRAC 125 cask (i.e., 125 tons) without generating a shear stress or maximum tensile stress at any point in the device in excess of the corresponding minimum yield strength of their materials of construction. Additionally, the spent-fuel cask lift yoke load bearing members are designed to lift ten times the maximum allowable weight of the loaded HI-STAR 100 or HI-TRAC 125 cask without exceeding the ultimate strength of the materials of construction.

Structural fabrication of the spent-fuel cask lift yoke is performed to standards consistent with the service intended. All material is certified as to chemical and physical properties. In addition, all stressed members are inspected for internal defects.

Prior to first use, the spent-fuel cask lift yoke was subjected to a load test equal to 300% of the maximum load to which the device will be subjected. Following the load test, critical areas of the lift yoke were subjected to nondestructive testing in accordance with Section 5.5 of ANSI N14.6. For continued qualification of the spent-fuel cask lift yoke, the yoke is tested annually by one of the following methods:

A. After sustaining the test load (equal to 300% of the maximum load to which the device is subjected) for a period ≥ 10 min, critical areas are visually inspected for defects, and all components inspected for permanent deformation.

B. If surface cleanliness and conditions permit, dimensional testing, visual inspection, and nondestructive testing are performed in accordance with Section 5.5 of ANSI N14.6.

If the spent-fuel cask lift yoke has not been used for a period > 1 year, the above testing is not required. However, testing of the lift yoke as described above is required prior to subsequent use.

The HI-STAR 100 and HI-TRAC 125 cask lifting trunnions are designed to mate with the elliptical loops of the lift arms of the spent-fuel cask lift yoke. Design of the HI-STAR 100 and HI-TRAC 125 lifting trunnions, the spent-fuel cask lift yoke, and HNP-1 single-failure-proof reactor building crane, preclude the accidental drop of a spent-fuel cask.

9.1.5.3 <u>Spent-Fuel Cask Handling</u>

Due to differences in the design of the HI-STAR 100 and HI-STORM 100 systems, handling operations for each system are described separately below. During handling, administrative controls are used to prevent continued hoisting of the crane load block to the point of contact

with the upper head block of the crane (i.e., "two-block" condition) that could result in failure of the hoisting cables and uncontrolled lowering of the load. In addition, redundant limit switches are used to prevent the cask from being lifted to a height that would result in a "two-block" condition. The upper limit switch is set to stop the hoisting motion of the crane when 1 ft. 6 in. remain before reaching the "two-block" condition.

The essential elements for cask handling activities are normal care and rigging skills for handling heavy loads as described in NUREG-0612. The normal crane lift and travel controls are sufficient to perform the necessary handling activities associated with spent-fuel cask loading and unloading operations.

9.1.5.3.1 HI-STAR 100 Handling

The HI-STAR 100 cask is delivered to the area outside the HNP-1 railroad airlock using the cask transporter and is placed on the transfer cart. The transfer cart is designed to handle the HI-STAR 100 cask in a vertical orientation and to support the weight of a loaded MPC, HI-TRAC 125 transfer cask and HI-STORM 100 overpack during MPC transfer operations, which conservatively bounds the weight of the HI-STAR 100 system.

For MPCs not equipped with load attachment points meeting the guidance of NUREG-0612, the MPC must be placed inside the HI-STAR 100 overpack prior to movement into the reactor building and cannot be removed from the overpack while inside the reactor building. For MPCs equipped with load attachment points that meet the guidance of NUREG-0612, the empty MPC may be placed inside the HI-STAR 100 overpack prior to movement into the reactor building or placed on the transfer cart and moved into the HNP-1 reactor building equipment hatch. The transfer cart is precluded from significant movement and loss of its load during a design-basis seismic event by seismic restraints attached to the floor. MPCs with load attachment points meeting the guidance of NUREG-0612 may be moved as necessary within the reactor building in accordance with administrative controls to implement the applicable HNP commitments to NUREG-0612.

A small switchyard engine is used to move the transport cart into and out of the HNP-1 reactor building equipment hatch via the railroad airlock. When loaded with the HI-STAR 100 cask and/or a MPC and located in the HNP-1 equipment hatch, the transfer cart is precluded from significant movement and loss of its load during a design-basis seismic event by restraints installed in the floor.

The spent-fuel cask lift yoke is attached to the main hook of the HNP-1 single-failure-proof reactor building crane. The lift arms of the spent-fuel cask lift yoke are engaged with the cask by moving the lift arms to the down position with the elliptical loops of the lift arms over the cask trunnions. The spent-fuel cask is lifted to the refueling floor and placed in the HNP-1 or HNP-2 reactor vessel head laydown area or the HNP-1 dryer separator storage area for loading preparation operations. Upon completion of the preparation operations, the spent-fuel cask is moved to the HNP-2 spent-fuel cask pit, using the HNP-1 single-failure-proof reactor building crane. The spent-fuel cask pit gates are installed during movement of the spent-fuel cask to or from the HNP-2 spent-fuel cask pit.

The spent-fuel cask lift yoke is removed from the HI-STAR 100 spent-fuel cask to provide access to the MPC for loading of spent-fuel assemblies using the fuel-handling bridge. Upon completion of the spent-fuel loading operation, the MPC lid is placed on the MPC and the spent-fuel cask lift yoke reattached to the cask trunnions. Prior to movement of the flooded HI-STAR 100 spent-fuel cask from the spent-fuel cask pit, water is removed from the spent-fuel cask, as necessary, to assure that the weight of the flooded cask does not exceed the 125-ton rating of the HNP-1 reactor building crane, spent-fuel cask lift yoke, or HI-STAR 100 spent-fuel cask lifting trunnions. Following determination that the weight of the HI-STAR 100 cask does not exceed 125 tons, the spent-fuel cask is moved to the HNP-1 or HNP-2 reactor vessel head laydown area or the HNP-1 dryer separator storage area for decontamination and closure operations. Following decontamination and closure operations, the loaded spent-fuel cask is lowered from the refueling floor to the HNP-1 railcar airlock using the HNP-1 single-failure-proof reactor building crane and spent-fuel cask lift yoke onto the transfer cart in preparation for transport to the ISFSI. The HI-STAR 100 cask and transfer cart are moved from the reactor building to the turnaround pad where the HI-STAR 100 cask is removed from the transfer cart by the cask transporter. The cask transporter is used to move the HI-STAR cask to the ISFSI. Movement of the cask transporter is limited to the heavy load path shown on H-45458 to preclude damage to underground conveyances.

9.1.5.3.2 HI-STORM 100 Handling

HI-STORM 100 loading operations begin with movement of the HI-TRAC 125 transfer cask to the refueling floor. If stored outside the reactor building, the HI-TRAC 125 transfer cask is delivered to the area outside the railroad airlock using the cask transporter and placed on the transfer cart. The transfer cart is designed for movement of the HI-STORM 100 cask into and out of the reactor building with the cask in a vertical orientation.

For MPCs not equipped with load attachment points meeting the guidance of NUREG-0612, the MPC must be placed inside the HI-TRAC 125 transfer cask prior to movement into the reactor building. MPCs not equipped with load attachment points meeting the guidance of NUREG-0612 cannot be removed from the transfer cask while inside the reactor building except when lifted by the MPC lid lift cleats attached to the MPC lid. For MPCs equipped with load attachment points that meet the guidance of NUREG-0612, the empty MPC may be placed inside the HI-TRAC 125 overpack prior to movement into the reactor building or placed on the transfer cart and moved into the HNP-1 reactor building equipment hatch. MPCs with load attachment points meeting the guidance of NUREG-0612 may be moved as necessary within the reactor building using administrative controls to implement the applicable HNP commitments to NUREG-0612.

A small switchyard engine is used to move the transport cart into and out of the HNP-1 reactor building equipment hatch via the railroad airlock. When loaded with the HI-TRAC 125 transfer cask and/or a MPC and located in the HNP-1 equipment hatch, the transfer cart is precluded from significant movement and loss of its load during a design-basis seismic event by restraints attached to the floor.

The spent-fuel cask lift yoke is attached to the main hook of the HNP-1 single-failure proof reactor building crane. The lift arms of the spent-fuel cask lift yoke are engaged with the cask by

moving the lift arms to the down position with the elliptical loops of the lift arms over the cask trunnions. The HI-TRAC 125 transfer cask is moved to the refueling floor and placed in the HNP-1 or HNP-2 reactor head laydown area or the HNP-1 dryer separator storage area for loading preparations. Upon completion of loading preparations, the HI-TRAC 125 transfer cask is moved to the HNP-2 spent-fuel cask pit using the HNP-1 reactor building crane. The spent-fuel cask pit gates are installed during movement of the spent-fuel cask to or from the HNP-2 spent-fuel cask pit. The spent-fuel cask lift yoke is removed from the HI-TRAC 125 transfer cask to provide access to the MPC for loading of spent-fuel assemblies using the fuel-handling bridge. Upon completion of spent-fuel loading, the MPC lid is placed on the MPC and the spent-fuel cask lift yoke is reattached to the HI-TRAC 125 transfer cask trunnions.

The HI-TRAC 125 is moved to the HNP-1 or HNP-2 reactor vessel head laydown area or the HNP-1 dryer separator storage area for decontamination and closure operations. Following completion of the decontamination and MPC closure activities, the spent-fuel cask lift yoke arms are attached to the HI-TRAC 125 transfer cask and the loaded MPC is attached to the spent-fuel cask lift yoke strongback slots or the MPC pins. The transfer cask and loaded MPC are moved using the HNP-1 reactor building crane and positioned above the transfer slide using the HNP-1 reactor building crane. The transfer slide is used to facilitate changing the transfer cask bottom lid from the pool lid to the transfer lid. The transfer lid is designed to interface with the alignment plate installed on the HI-STORM 100 overpack to facilitate MPC transfer from the HI-TRAC 125 transfer cask to the HI-STORM 100 overpack. Use of the transfer slide and alignment plate is not required when the HI-TRAC 125 is configured for use with the pool lid and the mating device.

Prior to lowering the HI-TRAC 125 transfer cask from the refueling floor, the HI-STORM 100 overpack is loaded onto the transfer cart and moved into the HNP-1 equipment hatch, and the mating device or alignment device, as applicable, is lowered from the refueling floor and placed onto the HI-STORM using the HNP-1 reactor building crane.

Use of the HI-TRAC 125 configured for use with mating device requires the following:

- the transfer cart be equipped with a seismic isolation device (e.g., HERMIT);

- the seismic restraints be installed in the equipment hatch area at elevation 130’ to preclude movement of the cart perpendicular to the rails; and

- the mating device be bolted to both the HI-STORM 100 overpack and to the HI-TRAC 125.

If the HI-TRAC 125 is configured for use with the alignment device and the transfer lid, the seismic isolation device is not used between the HI-TRAC 125 and the transfer cart. Seismic restraints are installed to preclude movement of the transfer cart both parallel and perpendicular to the rails except during movement into or out of the equipment hatch area. In addition, the alignment plate used in conjunction with the transfer lid is not required to be bolted to the HI-STORM 100 overpack or the HI-TRAC 125 transfer cask.

The HNP-1 reactor building crane is used to lower the HI-TRAC 125 transfer cask from refueling floor onto the HI-STORM 100 overpack resting on the transfer cart. The HNP-1 reactor building

crane is disconnected from the HI-TRAC 125 transfer cask and reattached to the MPC lift cleats via slings through the opening in the transfer cask lid. The HNP-1 reactor building crane is used to lift the MPC slightly inside the transfer cask in order to remove the weight of the MPC from the pool lid or the transfer lid, as applicable, and allow the pool lid or transfer doors to be opened. A dedicated person is stationed at the HNP-1 reactor building crane switchgear to remove power from the crane in the unlikely event of uncontrolled lifting of the MPC from the HI-TRAC 125 transfer cask. Following removal of the pool lid using the mating device or opening of the doors on the transfer lid, as applicable, the MPC is lowered into the HI-STORM 100 overpack. The slings are removed from the MPC and the HNP-1 reactor building crane is reattached to the HI-TRAC 125 transfer cask. The HI-TRAC 125 transfer cask is removed from the HI-STORM 100 overpack following MPC transfer and moved to the HNP-1 dryer separator pit or the HNP-1 or HNP-2 spent-fuel storage cask area using the HNP-1 reactor building crane.

Following removal of the HI-TRAC from the HI-STORM 100 overpack, the HI-STORM 100 mating device, either with or without the pool lid or the alignment plate, as applicable, is transported to the refueling floor.

Upon completion of the MPC transfer, the seismic restraints are removed as necessary and the HI-STORM 100 overpack and loaded MPC are removed from the HNP-1 reactor building to the turnaround pad where the overpack lid is installed. Following installation of the overpack lid, the lift brackets are attached and the loaded HI-STORM 100 system is moved to the ISFSI using the cask transporter. Movement of the cask transporter is limited to the heavy-load path shown on H-45458 to preclude damage to underground conveyances.

REFERENCES

1. Letter from K. N. Jabbour (Nuclear Regulatory Commission) to J. T. Beckham, Jr. (Georgia Power Company), dated July 31, 1996, regarding exemption from the requirements of 10 CFR 70.24, “Criticality Accident Requirements.”

2. HI-941184, Holtec International Storage, Transport, and Repository Cask System (HI-STAR 100 Cask System), NRC Docket No. 72-1008, Revision 10, dated July 16, 1999.

3. HI-2002444, Final Safety Analysis Report (FSAR) for the Holtec International Storage and Transfer Operation Reinforced Module Cask System (HI-STORM 100 Cask System), NRC Docket 72-1014, Revision 0, dated July 19, 2000.

4. Westinghouse Report NF-BSN-10-10, “Supplemental Licensing Report, SVEA-96 Optima2 Lead Use Fuel Assemblies for Edwin I. Hatch Nuclear Plant, Unit 1,” Revision 0, February 2010.

5. Edwin I. Hatch Nuclear Plant Independent Spent Fuel Storage Installation, 10 CFR 72.212 Report, Docket Number 72-36.

6. GEH Report 0000-0141-6099-R1, “Generic Criticality Safety Analysis of GE High Density Fuel Storage Racks for GE14 and GNF2 Fuel,” Rev. 1, May 2012.

TABLE 9.1-2 (SHEET 1 OF 2)

GENERAL ELECTRIC SINGLE-CELL, HIGH-DENSITY FUEL STORAGE CRITICALITY RESULTS

Case	Description	K_∞	Error (1σ)	ΔK Uncertainty (2σ)[a]
1	Nominal rack dimensions[b] with flow channel at 20°C	0.90628	0.00028	-
2	Nominal rack dimensions without flow channel at 20°C	0.90334	0.00026	-
3	Same as case 1, except at 100°C	0.89995	0.00026	-
4	Same as case 1, except at 4°C	0.90703[c]	0.00028	0.00079
5	Eccentric Loading (4 Close fitting central bundles)[d]	0.90600	0.00026	-
6	Eccentric Loading (Close fitting 10x10 array)[d]	0.89677	0.00025	-
7	Eccentric Loading (Groups of 4)[d]	0.89338	0.00026	-
8	Every Other Bundle Rotated 90 degrees[d]	0.90648	0.00026	-
9	All Bundles Rotated 90 degrees[d]	0.90685[c]	0.00027	0.00078

a. Independent ΔK uncertainties combined using square root of the sum of the squares for applicable terms.
b. 6.563-in. pitch with nominal material thickness.
c. Largest positive reactivity increase from nominal case for each term is included in roll-up of ΔK_{BIAS}.
d. Analysis with channeled bundles.

TABLE 9.1-2 (SHEET 2 OF 2)

GENERAL ELECTRIC SINGLE-CELL, HIGH-DENSITY FUEL STORAGE CRITICALITY RESULTS

Spent Fuel Storage Rack Results Summary[a]

Term	Value
K_{Normal}	0.90628
ΔK_{Bias}	0.00682
$\Delta K_{Tolerances}$	0.00618
$\Delta K_{Uncertainty}$	0.00925
$K_{max(95/95)}$	0.92853

a. The maximum reactivity, considering all biases, tolerances, and uncertainties is calculated by the following: $K_{max(95/95)} = K_{Normal/Nominal} + \Delta K_{Bias} + \Delta K_{Tolerance} + \Delta K_{Uncertainty}$

TABLE 9.1-3

**HOLTEC SINGLE-CELL,
HIGH-DENSITY FUEL STORAGE CRITICALITY RESULTS**

Case	Description	K_∞ (+2σ)
1	Nominal rack dimensions with flow channel at 20°C	0.9113 ± 0.0021
2	Nominal rack dimensions without flow channel at 20°C	0.9097 ± 0.0022
3	Same as case 2, except at 65°C	0.9025 ± 0.0021
4[a]	Increased pitch without flow channel at 20°C	0.9070 ± 0.0022
5	Same as case 2 but with eccentric bundle position	0.8936 ± 0.0019
6[a]	Minimum pitch without flow channel at 20°C	0.9129 ± 0.0022

a. Criticality values for cases 4 and 6 were based upon deterministic CASMO calculations for which no uncertainty is available. Therefore, an uncertainty was assigned based upon similar MCNP studies, e.g., case 2 σ was assigned to cases 4 and 6.

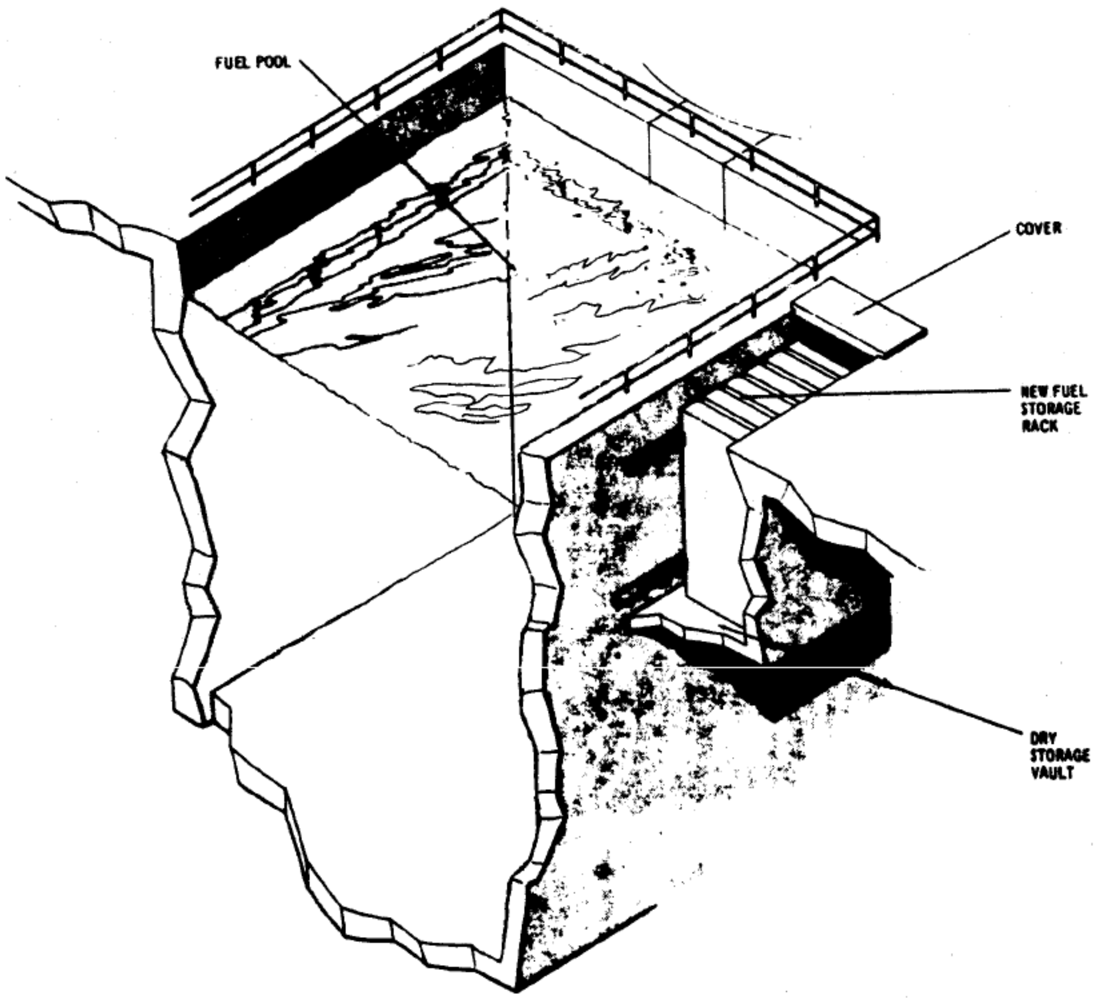
TABLE 9.1-4 (SHEET 1 OF 2)

FPCCS PARAMETERS AND EQUIPMENT LIST

	HNP-1		HNP-2	
Fuel Pool Cooling Pump				
Type of pump	Centrifugal (horizontal)		Centrifugal (horizontal)	
Number	2		1	
Service	Continuous		Continuous	
Design conditions				
Pressure (psig)	150		150	
Temperature (°F)	150		150	
Normal operating conditions				
Capacity (gal/min)	610		610	
Total developed head (ft)	260		190	
Suction pressure (maximum psig)	20		18	
Pumping temperature (°F)	125		125	
Type of drive	Electric motor		Electric motor	
Fuel Pool Heat Exchangers				
Type	Shell and tube (horizontal)		Shell and tube (horizontal)	
Number	2		1	
Duty (Btu/h)	8.48×10^6		4.24×10^6	
Design conditions	Tube Side	Shell Side	Tube Side	Shell Side
Fluid	Fuel pool cooling	RBCCW	Fuel pool cooling	RBCCW
Type of water	Demineralized H_2O	Inhibited demineralized H_2O	Demineralized H_2O	Inhibited demineralized H_2O
Flow (gal/min)	610	1200	610	1200
Design pressure (psig)	150	150	150	150
Design temperature (°F)	200	200	200	200
Normal pressure drop (psi)	7.182	12.686	7.182	12.686
Heat duty (Btu/h)	4.24×10^6	4.24×10^6	4.24×10^6	4.24×10^6
Inlet temperature (°F)	125	105	125	105
Outlet temperature (°F)	110.9	112.1	110.9	112.1

TABLE 9.1-4 (SHEET 2 OF 2)

	HNP-1	HNP-2
Fuel Pool Demineralizer Units		
Type of unit	Filter-demineralizer	Filter-demineralizer
Number supplied	2	1
Design conditions		
Flowrate	610	610
Design pressure (psig)	150	150
Temperature (°F)	125	150
Power sources		
Pumping	Normal auxiliaries	Normal auxiliaries
Control	Plant batteries	Plant batteries



Note:
1. Spent-fuel storage racks (Refer to figures 9.1-3 and 9.1-4 for detail arrangement).

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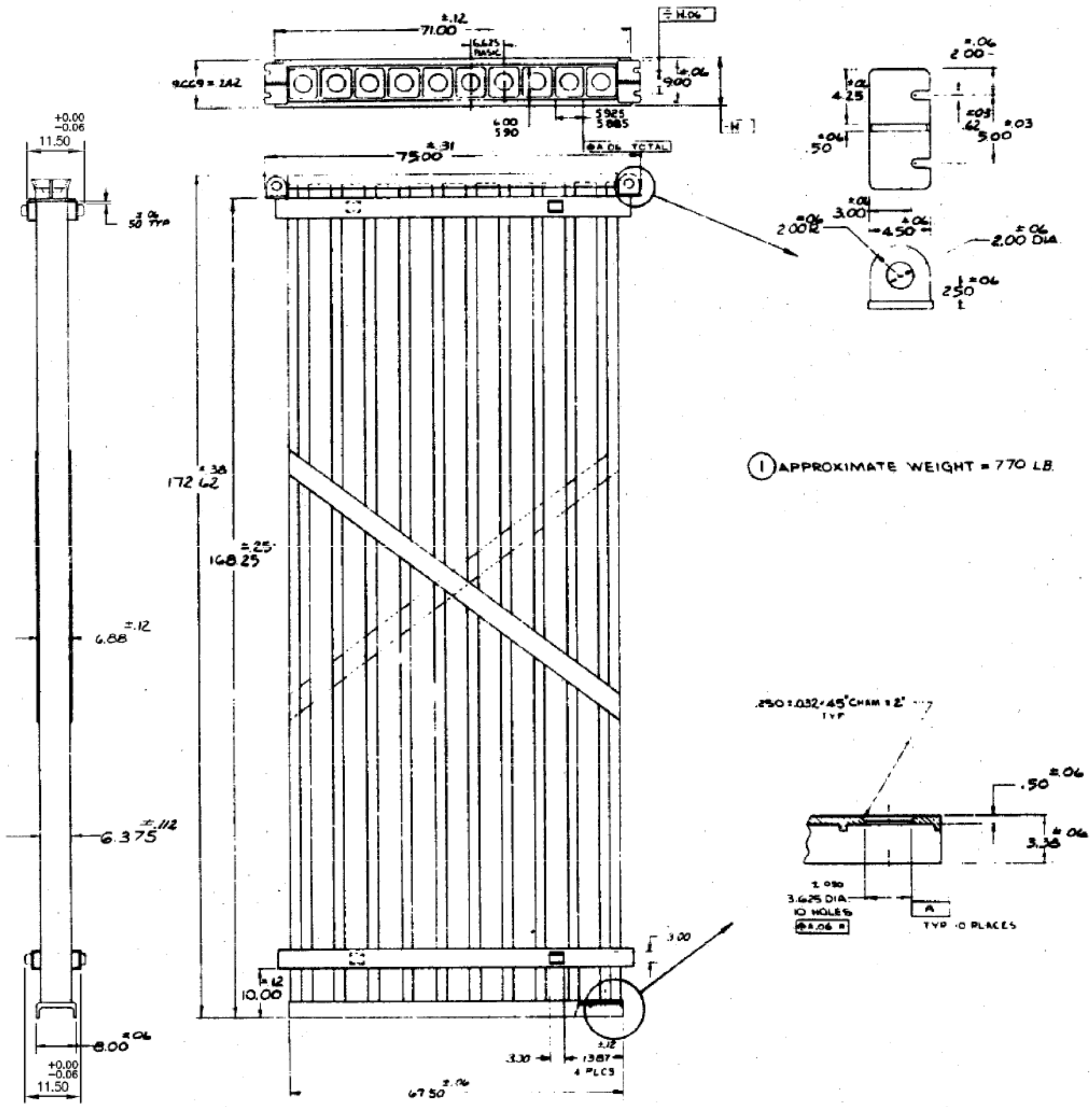
FUEL STORAGE ARRANGEMENT

FIGURE 9.1-1



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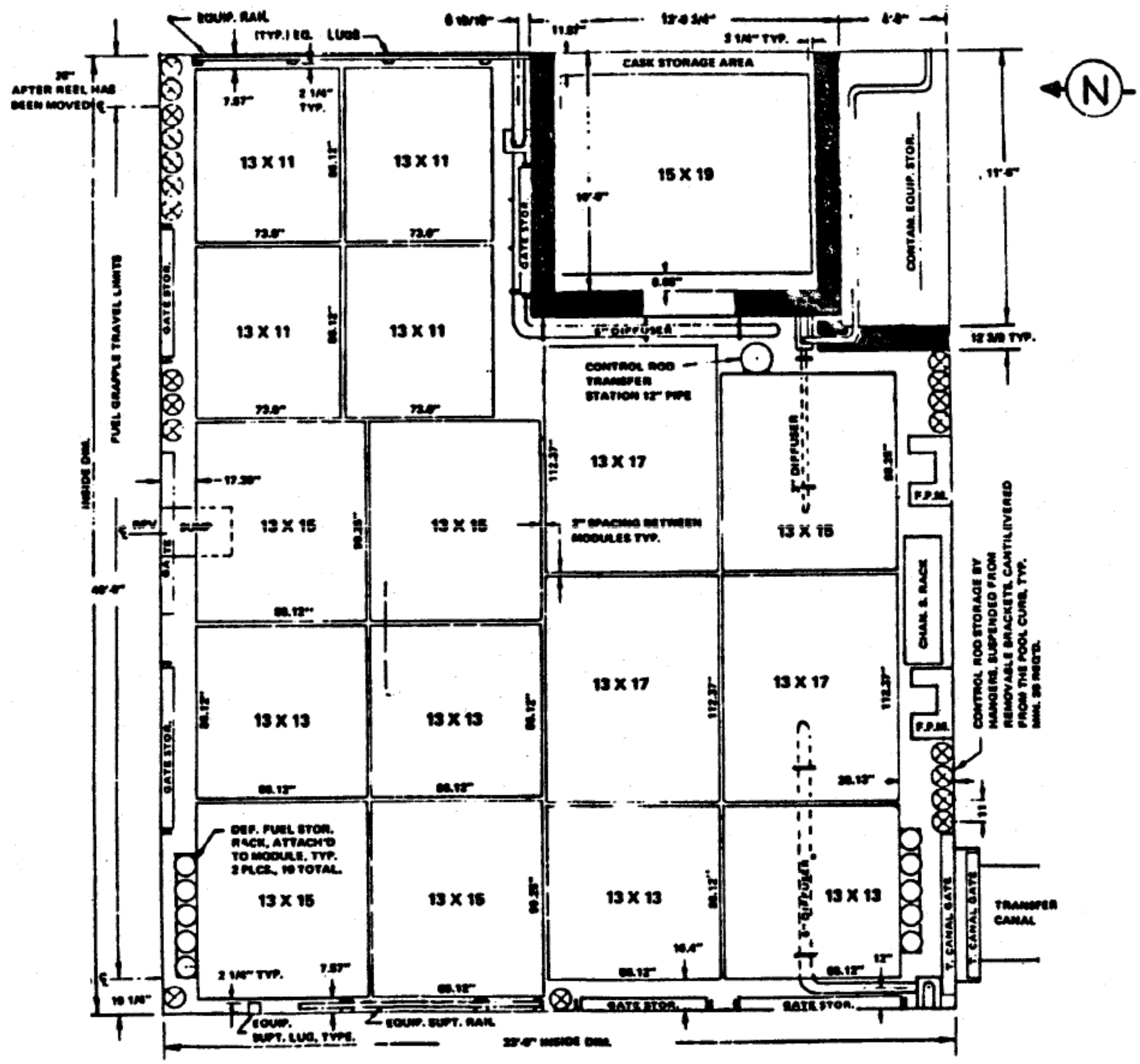
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

NEW FUEL STORAGE RACK OUTLINE

FIGURE 9.1-2



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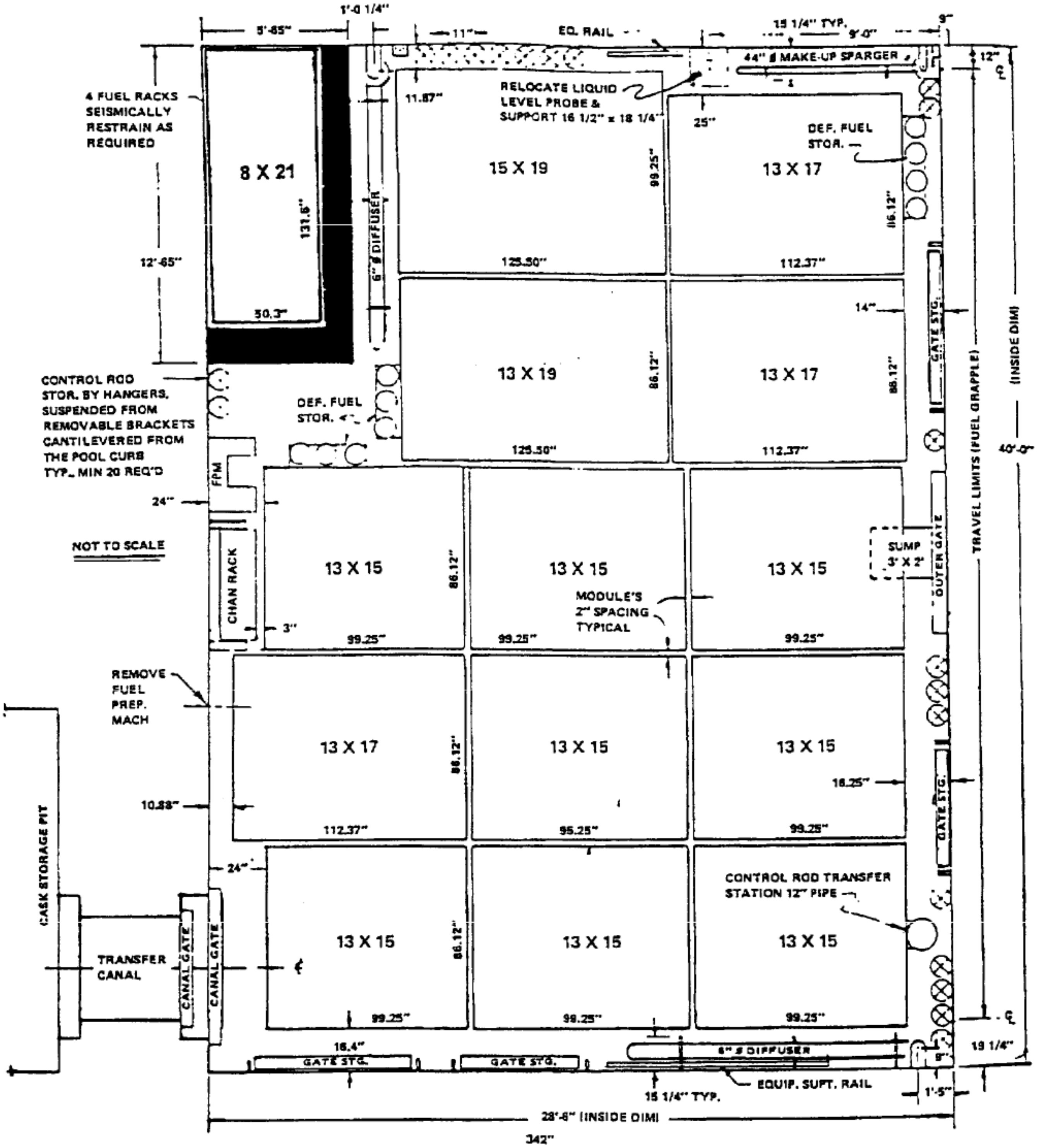
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

HIGH-DENSITY FUEL
STORAGE ARRANGEMENT

FIGURE 9.1-3 (SHEET 1 OF 2)



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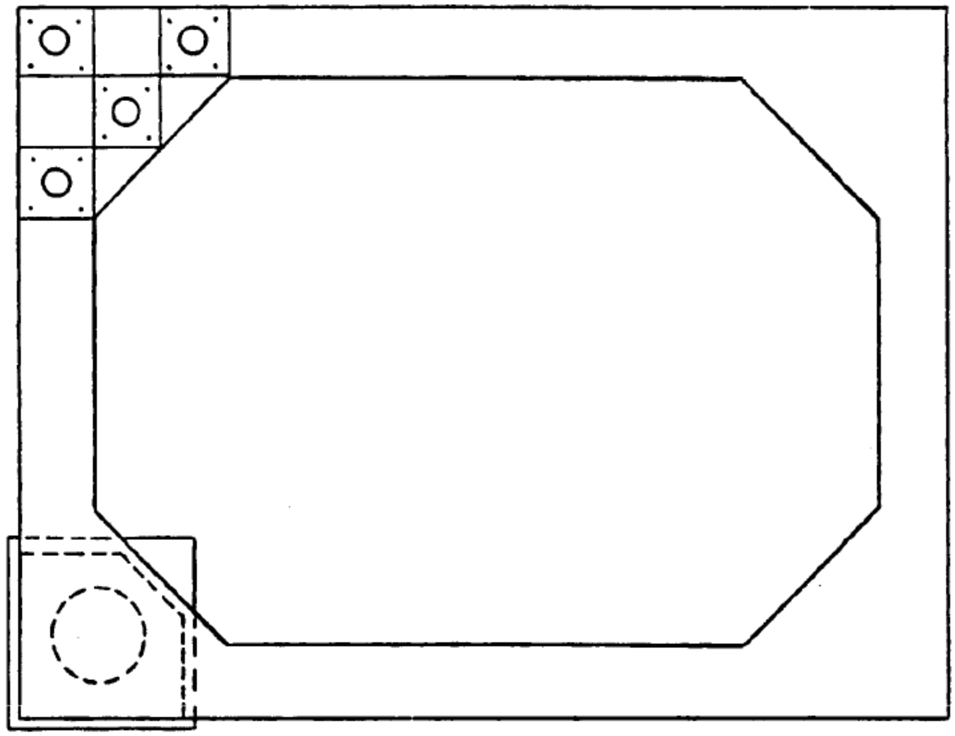
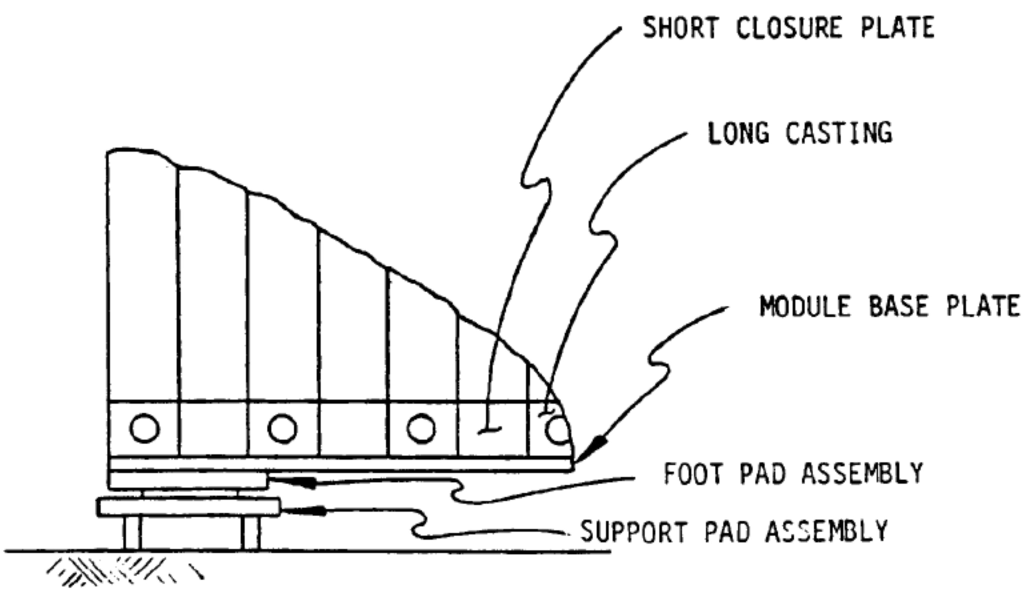
SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	HIGH-DENSITY FUEL STORAGE ARRANGEMENT
	FIGURE 9.1-3 (SHEET 2 OF 2)





ACAD 20901041

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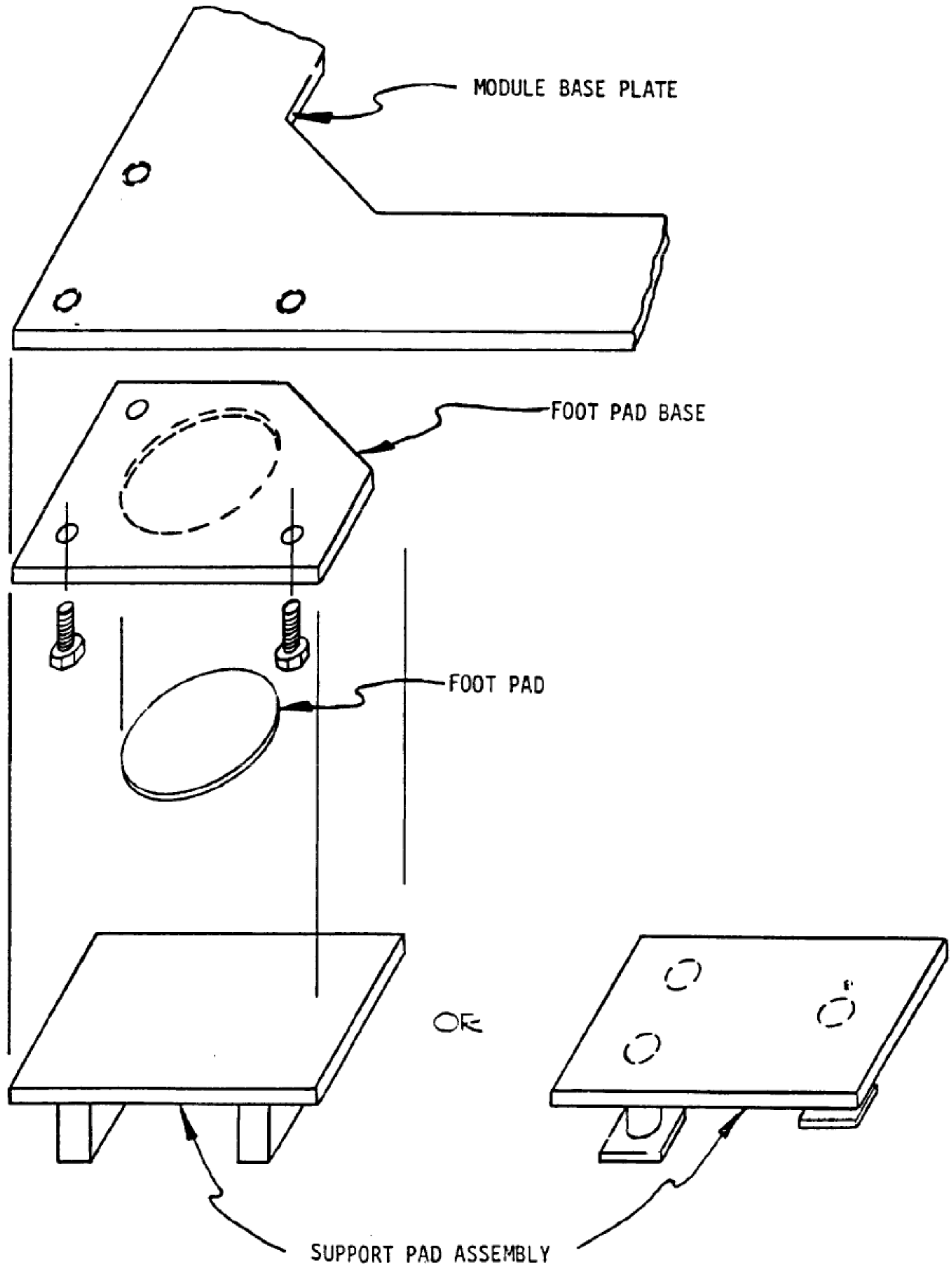
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

GENERAL ELECTRIC
MODULE SUPPORT SYSTEM

FIGURE 9.1-4 (SHEET 1 OF 2)



ACAD 20901042

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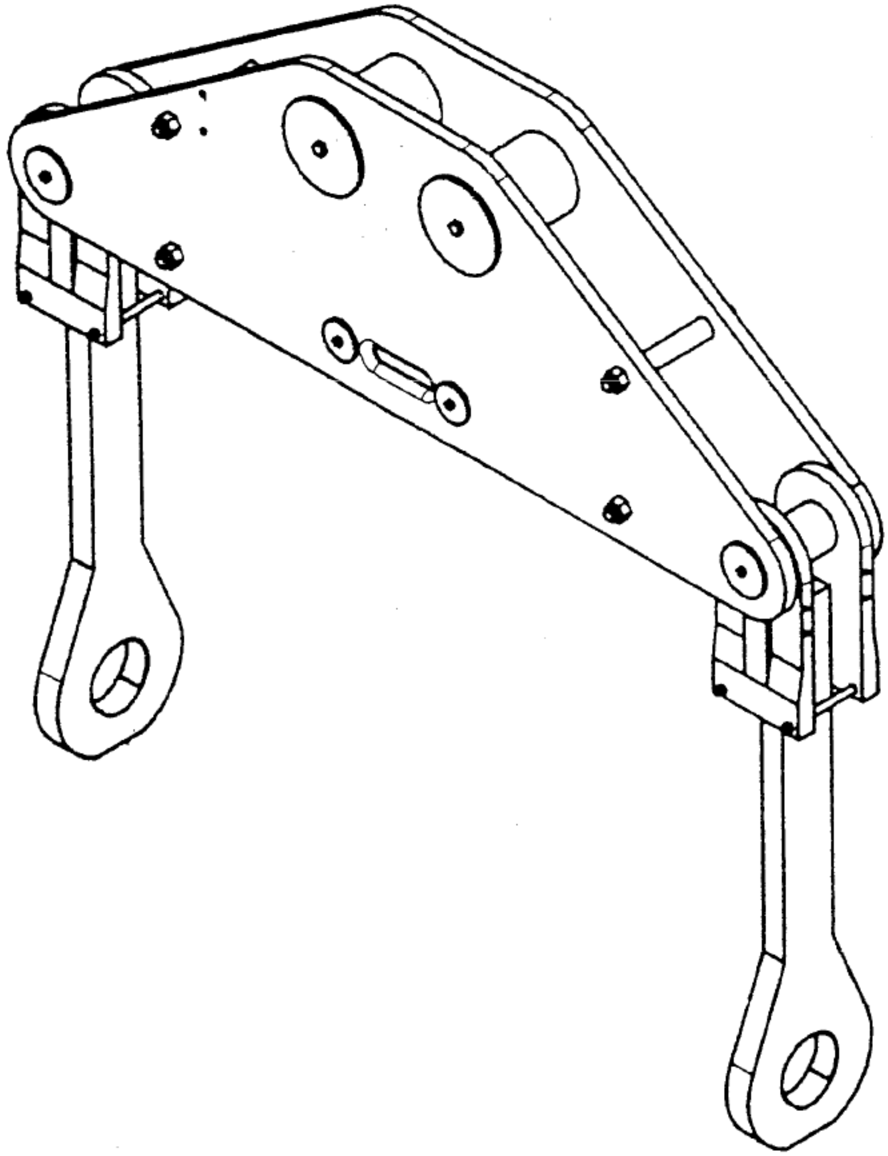
UNIT 1 AND UNIT 2

GENERAL ELECTRIC
MODULE SUPPORT SYSTEM DETAIL

FIGURE 9.1-4 (SHEET 2 OF 2)



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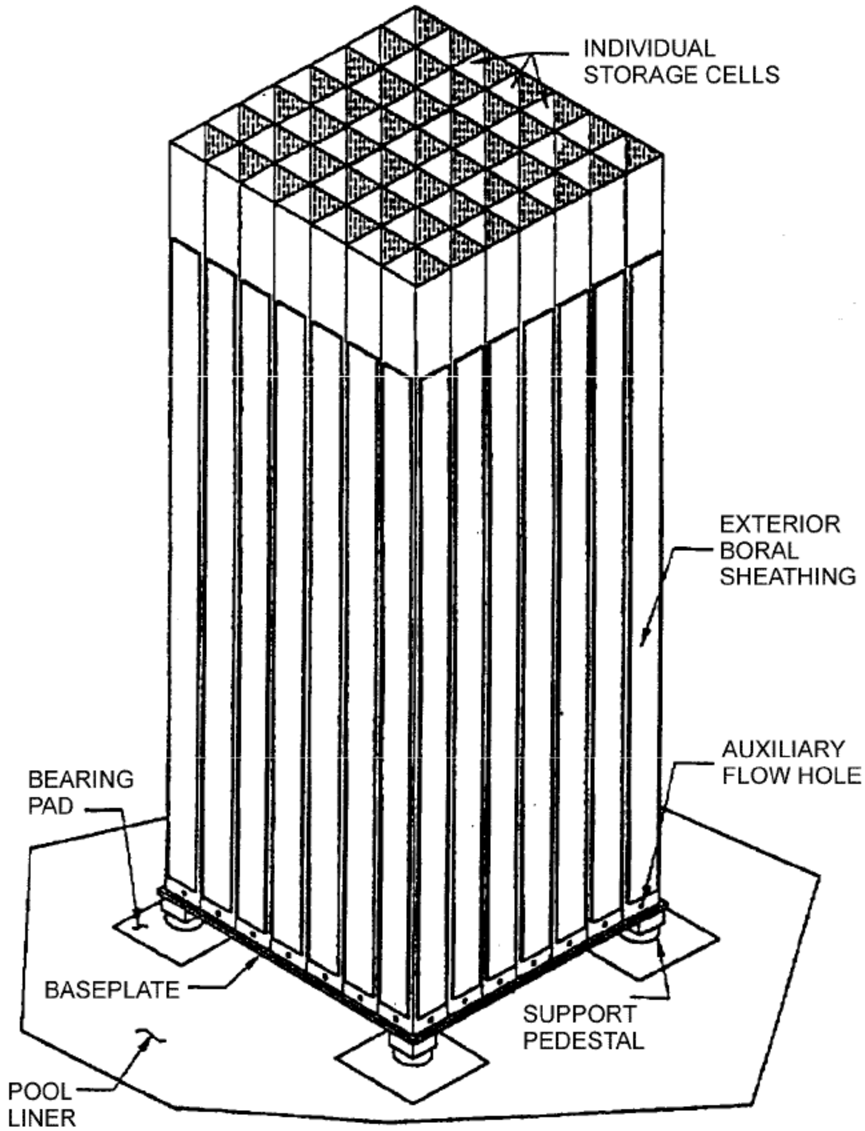
UNIT 1 AND UNIT 2

SPENT-FUEL CASK LIFT YOKE

FIGURE 9.1-5



Note: The number of cells shown is not intended to depict actual rack sizes.

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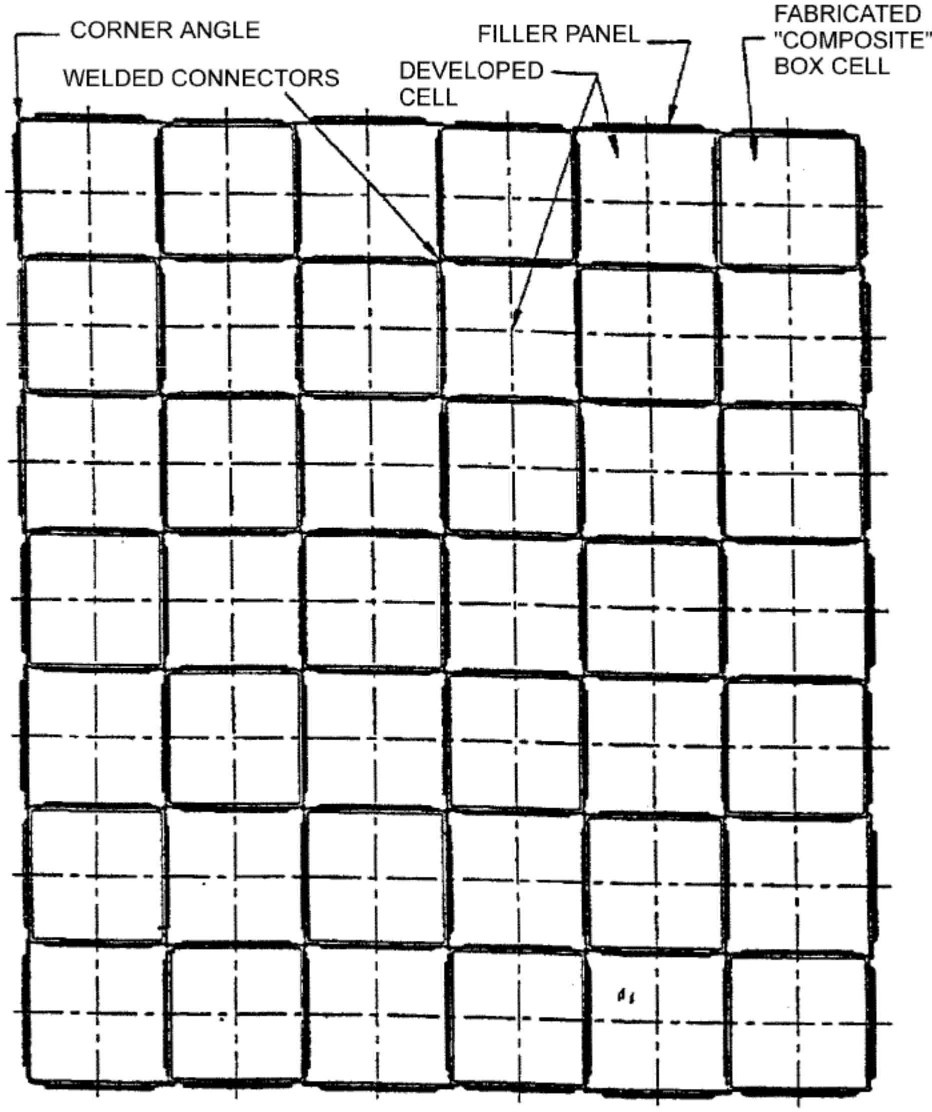
PICTORIAL VIEW OF A TYPICAL
HOLTEC RACK MODULE

FIGURE 9.1-6 (SHEET 1 OF 3)



Note: The number of cells shown is not intended to depict actual rack sizes.

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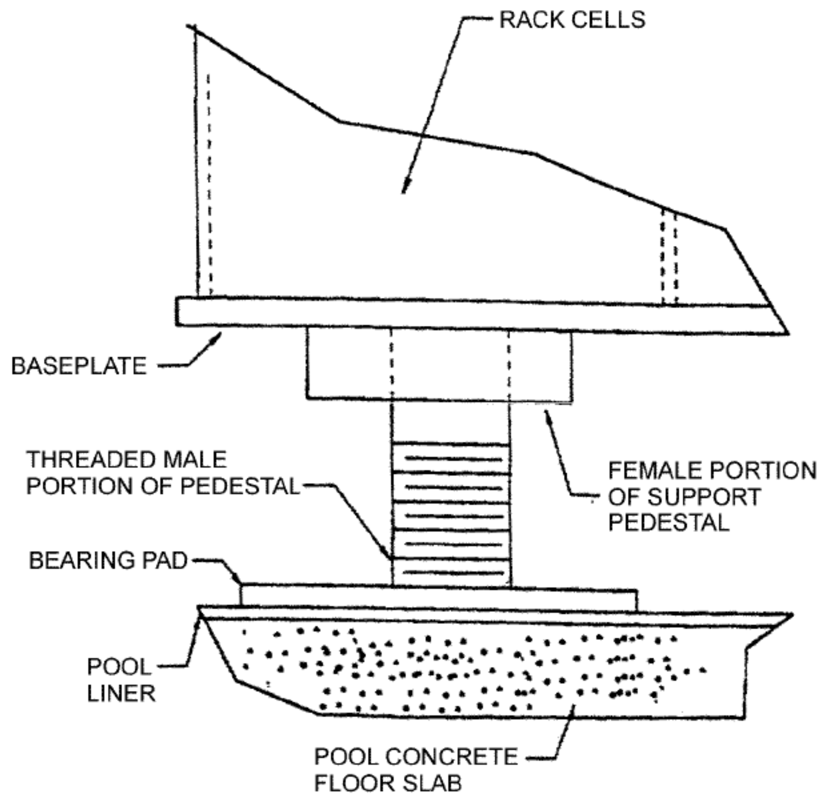
TYPICAL ARRAY OF
HOLTEC STORAGE CELLS

FIGURE 9.1-6 (SHEET 2 OF 3)



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ELEVATION VIEW OF A TYPICAL
HOLTEC RACK MODULE SUPPORT PEDESTAL

FIGURE 9.1-6 (SHEET 3 OF 3)

9.2 WATER SYSTEMS

9.2.1 PLANT SERVICE WATER (PSW) SYSTEM

9.2.1.1 Design Bases

9.2.1.1.1 Safety Design Bases

The PSW system is designed to supply a reliable source of cooling water to equipment required for accident conditions.

9.2.1.1.2 Power Generation Design Bases

The PSW system is designed to:

- Provide screened cooling water to the plant during normal operating and shutdown conditions.

- Provide makeup water to the circulating water system.

9.2.1.2 System Description

The PSW system is shown schematically in figure 9.2-1. Table 9.2-1 provides an additional description of the major components of the system. The physical arrangement of the PSW system components in the intake structure is shown on drawing no. H-21102.

The PSW system consists of four, one-third capacity vertical wetpit service water pumps (located in the river water intake structure), distribution piping, and controls.

Automatic, self-cleaning strainers are provided on the discharge side of the pumps to remove suspended matter from the pumped water.

The PSW system provides cooling water to:

- Turbine building heat exchangers associated with power conversion systems located in the turbine building.

- Reactor building closed cooling water (RBCCW) system heat exchangers.

- Radwaste building closed cooling water heat exchangers.

- Standby diesel generator heat exchangers.

- Primary containment (drywell) chiller condensers (subsection 9.4.6).
- Residual heat removal (RHR) pump coolers.
- Safeguard equipment heating, ventilation, and air-conditioning (HVAC) system (paragraph 9.4.2.2.3).
- Main control room environmental control (MCREC) system (subsection 9.4.1).

Three PSW pumps are required for normal operation; however, only one PSW pump from each division is required for plant startup, shutdown, and emergency shutdown. The fourth PSW pump is a standby pump available for use if one of the other three PSW pumps fails, if emergency conditions exist, or if plant conditions (such as increased heat load due to high ambient temperatures) warrant its use. The pumps are controlled so that if the operating pumps cannot maintain the required system pressure, the standby pump will start automatically. A separate standby diesel generator PSW pump is supplied to service standby diesel generator 1B.

The intake structure is supplied with traveling screens which prevent fouling of the pumps with small debris. Drawing nos. H-11142, H-21102, and S-55894 show the physical arrangement of the PSW system components inside the intake structure and the traveling water screens and screen wash equipment. The traveling water screens are designed to prevent small debris from entering the portion of the intake structure from which the pumps take suction. Larger debris are prevented from reaching the screens by the trash racks. The screen system is composed of two traveling screens, two motors, and two screen wash lines which operate in parallel to serve the common bay from which both the HNP-1 and HNP-2 pumps take suction. Post earthquake operation of the traveling water screens was not a design requirement; however, the specifications for both the trash rack and traveling water screens require that they maintain their structural integrity following a design basis earthquake (DBE). Therefore, the pumps would continue to be protected from river debris by both the trash racks and the traveling screens. In the unlikely event that the traveling water screens should begin to collect debris to the extent of impeding flow, redundant level switches located in the intake structure provide indication and annunciation in the main control room (MCR). Since any collection of debris on the traveling water screens would occur slowly, an ample amount of time would be available for plant operators to clear the screens.

The capability is provided to inject (as required) sodium hypochlorite, a corrosion inhibitor, and a silt dispersant into the systems to control organic biofouling, corrosion, and silt deposition in the pipe lines and heat exchangers. Drawing nos. H-11982 and H-43801 show the schematic arrangement of the water treatment system components/piping.

Water for equipment cooling is taken from the river via the intake structure by the PSW pumps and distributed by way of two header pipes to different areas of use. After passing through the components served by the PSW system, the water is discharged to the circulating water flume to make up for the drift and evaporation losses from the circulating water system. The PSW flow can exceed the makeup requirements of the circulating water system. A bypass is provided to allow discharge of the excess PSW directly to the river. Table 9.2-2 lists the components of the PSW system during normal and emergency conditions.

Figure 9.2-2 shows a typical PSW pump curve. When the PSW pumps are delivering their rated capacity of 8500 gal/min, 48 in. of submergence over the pump suction bell is required to provide adequate net positive suction head (NPSH) and preclude vortexing. The actual PSW pump suction elevation is at 57.2 ft mean sea level (msl); thus, the minimum water level in the pump well for maximum capacity PSW pump operation is 57.2 ft, plus the 4 ft of required submergence or 61.2 ft. This is equal to a river level at the intake structure of 61.3 ft msl with allowance for a 0.1-ft head loss through the trash racks and traveling screens. When the plant is operating at full power, only three of the four PSW pumps are required, each delivering ~ 7840 gal/min; thus, a water level of 61.2 ft in the pump well is more than adequate for full-power operation.

Shutdown cooling of the plant requires only one PSW pump, delivering 4428 gal/min. The Technical Specifications require plant shutdown if the water level, as measured in the pump well, decreases to < 60.5 ft msl. This is well above the minimum required to operate at the throttled level (7000 gal/min) and considerably more than required for single-pump operation for plant shutdown.

Both PSW divisions cross-connect to the corresponding RHRSW division. These cross-connections shall not be used during normal or design basis accident conditions at the plant. The cross-connections between PSW and RHRSW are provided with manual, double isolation valves which shall be maintained closed, except for periodic plant maintenance activities such as dead-leg flushing. The PSW-RHRSW cross-connections are only to be used in response to a beyond design basis external event (BDBEE).

9.2.1.3 Instrumentation Application

Pressure switches 2P41-N301A and B are used to start the standby pump or pumps on low system pressure. (See drawing no. H-21033.) Differential pressure switches are used to automatically backwash the PSW strainers. Differential pressure switches 2P41-N307A-D provide annunciation in the MCR on high flow into the turbine building supply header which is indicative of a rupture in the turbine building PSW piping. Pressure switches initiate an alarm in the MCR on low system pressure. Flow, pressure, and temperature test points and gauges are provided throughout the system.

A radiation monitor is provided in the PSW line returning to the flume and river. The monitor is equipped with a control room alarm and recorder. The monitor and alarm are for information only so that any radiation leak into the PSW system can be identified and isolated.

9.2.1.4 Safety Evaluation

The PSW pumps are located in the Seismic Category I intake structure. Also, the portions of the system, including the pumps, which are required for emergency cooling are designed as a Seismic Category I system and meet the single failure criteria.

The portion of the PSW system that supplies cooling water for equipment required for accident conditions is designed to:

- Withstand the DBE without impairing its function.
- Provide reliable cooling with sufficient capacity and redundancy.
- Operate during a loss-of-offsite power (LOSP).

The maximum theoretical flood level of the river is 105 ft msl, with a maximum wave crest height of 108.3 ft msl. The pump motors are all located at el 111 ft 0 in. msl in the intake structure so that they are able to operate during maximum flood conditions. The automatic backwash strainers are located below the flood level, but flooding only prevents backwashing operation and not the operation of the strainer. The strainer is designed so that, even without backwashing and assuming a 90% clogging of the strainers, the strainer differential pressure is no > 3 psid and the system flow is not retarded.

There are two pumps for each header. These headers distribute water to the diesel generator building, the reactor building, the control building, and the turbine building. There is no safety-related equipment requiring cooling water in the turbine building. During certain emergency conditions [LOSP and loss-of-coolant accident (LOCA)], the supply to this area is automatically isolated. All piping, except that in the turbine building and the discharge to the flume, is Seismic Category I.

The diesel generators, RHR pump seals, RHR pump room area coolers, high-pressure coolant injection (HPCI) pump room area coolers, and MCR air-conditioning units may require PSW during and following an LOSP, a LOCA, or a seismic event.

A PSW system single-failure analysis was performed in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment." The analysis evaluates individual single failures of all active components of the safety-related portion of the PSW system, assuming a LOCA, an LOSP, and a seismic event. The analysis demonstrates that the PSW system has adequate redundancy.

The failure of all surrounding nonseismic equipment or piping will not affect either of the two redundant PSW divisions and will not affect the operation of the system.

The potential for failures or malfunctions caused by freezing, icing, and other adverse environmental conditions is minimal based on historical weather data. As stated in section 2.4, the Altamaha River has never been known to freeze over; therefore, icing is not considered to be a problem. The winters in this part of Georgia, as reported in section 2.3, are mild. The average minimum temperature for the coldest month of the year is ~ 5°F above the freezing

point of water. Therefore, days during which temperatures drop below freezing for a short period of time would be infrequent; and prolonged periods (> 1 day) of below freezing temperatures are even less frequent. However, the possibility of below freezing weather was considered in the design of the water systems in the intake structure. It should be pointed out that the PSW pumps are required to be operating when the plant is operating and that the heat from these motors aids in maintaining the intake structure at a higher temperature than the surrounding air. Diverse environmental conditions are therefore not expected to cause failures or malfunctions in the components located in the intake structure.

Upon receipt of an LOSP or a LOCA signal, the system is automatically isolated from the turbine building; and essential portions are divided into two redundant systems, division I and II. Division I consists of pumps A and C, and division II consists of pumps B and D. Each division contains one header pipe. The turbine building is isolated at this time, and one pump in each division is automatically started. Each pump is connected to one of the essential buses; i.e., 2E, 2F, or 2G.

The PSW to the MCR HVAC is a backup source only, since these HVAC units are already supplied with cooling water from the HNP-1 PSW system. The two systems are capable of being isolated from each other.

While operating in the normal mode, supplying water to the turbine building, the headers for both divisions are interconnected by the turbine building supply header because three pumps are required for this operation. Valves 2P41-F316A, B, C, and D are provided to isolate the turbine building supply header. The following signals will cause these valves to close, isolating the turbine supply header:

- Manual close signal.
- Turbine building flooding.
- Loss-of-offsite power.
- Loss-of-coolant accident.

Once these valves are closed, there is no intertie between the two division headers, and divisions I and II are completely redundant to each other.

Flow from each division into the turbine building supply header is monitored by a system of orifices and differential pressure switches. High flow into the turbine building supply header (indicative of a possible pipe break) is alarmed in the MCR. Low pressure in either main header is alarmed in the MCR on separate annunciator windows.

In the normal operating mode, the pump controls are manual with the operator selecting which pumps are put into service. The operator positions the control switch of the remaining pump in the auto position; and, upon low pressure in the header, the standby pump is automatically started by pressure switch 2P41-N3O1A or B.

With the LOSP, all diesels are automatically started, connected to the respective 4160-V buses, and the load sequencers automatically start one pump in each division. When started from the standby condition and operated at full load, the diesel engines will operate for at least 3 min without a supply of plant service water to the heat exchangers.

While operating in the hot shutdown mode with an LOSP, diesels 2A and 2C ensure that both divisions of pumps, valves, controls, etc., have power. Either 600-V bus 2C (division I) or bus 2D (division II) may be supplied from diesel generator 1B via 4160-V bus 2F.

Diesel generator 1B is normally supplied with cooling water from standby diesel 1B PSW pump 2P4I-C002. This pump is completely independent of diesels 2A and 2C and is powered by diesel generator 1B. The capability exists to manually cross-connect the HNP-1 PSW system to supply cooling to diesel generator 1B during times when the standby PSW pump is inoperable.

The PSW pumps, strainers, piping, and valves in the intake structure, reactor building, and diesel generator building are all designed to American Society of Mechanical Engineers (ASME) Code, Section III, Class 3.

All underground piping was installed with HNP-1 and is designed to USAS B31.7, Class III.

The four PSW pumps are divided into two divisions of two pumps. Each division is isolated from the other by steel plates so that a line break in one division could not damage the other. The divisions are also isolated, by use of steel plates, from other equipment in the intake structure so that a break in any other system could not damage the PSW system.

Corrosion allowance was considered in the design of RCIC system components.

9.2.1.5 Tests and Inspections

Pumps, other components, and the system were inspected and tested after installation and prior to operation of the unit.

Additionally, the PSW system is proven operable by its use during normal plant operation.

9.2.2 REACTOR BUILDING CLOSED COOLING WATER (RBCCW) SYSTEM

9.2.2.1 Design Bases

The RBCCW system is designed to perform the following functions:

- Cool auxiliary plant equipment located in the reactor building.

- Serve as a closed-cycle barrier between potentially radioactive systems and the PSW system.

- Provide a cooling system utilizing clean inhibited water to substantially reduce the erosion and corrosion of the cooled components.

9.2.2.2 System Description

The RBCCW system is a closed-loop cooling system consisting of three 50% capacity pumps, 2 full-capacity heat exchangers, a surge tank, a chemical addition system, and a corrosion test loop with solids filter. The cooling water is conveyed by the pumps to the various system coolers and returned to the pumps by way of the RBCCW heat exchanger. Two of the RBCCW pumps are normally operating with the third pump on standby. The heat rejected by the RBCCW system to the heat exchanger is removed by the PSW system. A single RBCCW heat exchanger maintains the design RBCCW temperature ≤105°F, with a maximum PSW temperature of 95°F under all modes of operation.

During reactor blowdown to the condenser or radwaste system, two RBCCW pumps and one heat exchanger are used to remove heat, including the increased heat load from the reactor water cleanup (RWC) system nonregenerative heat exchanger. The use of both RBCCW heat exchangers is optional. Cooling water leaving the heat exchangers during the blowdown mode is 105°F maximum based on 95°F PSW.

The RBCCW system was reviewed for any impact associated with operation at 2804 MWt and an increase of the service water temperature to 97°F. The actual heat load cooled by the RBCCW heat exchanger was determined to be within the heat removal capability of the system with a service water temperature to 97°F and the design flow rate. Therefore, the heat exchanger has sufficient heat removal capability to maintain the RBCCW system supply temperature below the design limit of 105ºF.

An atmospheric surge tank, located at the highest point in the system, serves the following functions:

- Absorbs volumetric changes in system water inventory induced by temperature variations.

- Maintains a positive head in the system.

- Detects gross leakages in the system.

- Serves as a point for adding makeup water to the system.

The demineralized water transfer system supplies makeup water to the RBCCW system at the surge tank and to the chemical addition mixing tank. The overflow from the tanks is conveyed to the chemical waste neutralizer tank.

A corrosion inhibitor is added as necessary by the chemical addition system to minimize corrosion in the RBCCW system. The inhibitor is mixed in a chemical tank and then fed to the system by a metering type, positive displacement pump.

Corrosion is monitored by a corrosion test loop located near the RBCCW pumps. A small amount of flow from the pump discharge is routed through a coupon rack and returned to the pump suction piping. Sample coupons are examined periodically to verify the effectiveness of the corrosion inhibitor. A filter for removing solids from the system is also located in the test loop.

The following components are cooled by the RBCCW system:

- Two recirculation pump seal coolers, motor bearings, and air coolers.
- One drywell equipment drain sump cooler.
- One reactor building equipment drain sump cooler.
- Two control rod drive (CRD) pump coolers.
- Two reactor primary system sample coolers.
- Two reactor recirculation pump adjustable speed drive (ASD) heat exchangers.
- Two RWC system pump coolers.
- One RWC system nonregenerative heat exchanger.
- One fuel pool cooling heat exchanger.
- Two drywell pneumatic system coolers.

Each RBCCW pump has a connection for a permanent pressure gauge on the discharge side and for a temporary pressure gauge on the suction side for monitoring pump performance. Each pump has an associated pressure switch on the discharge header which starts the standby pump on sensing a decreasing pressure and actuates an alarm in the MCR. A flow element on the discharge header is used for evaluating the performance of the system.

The inlet and outlet connections of the RBCCW heat exchangers are provided with pressure gauges and temperature connections to monitor heat exchanger performance. A temperature element downstream of the heat exchanger records and indicates water temperature conditions, as well as provides high- and low-temperature alarms in the MCR.

Pressure gauges or connections for temporary pressure gauges are installed across each system cooler for flow balancing.

Makeup to the surge tank is regulated by an automatic level control. The high- and low-level alarm settings on the tank are located outside the extreme level variations induced by the

maximum and minimum predicated temperatures of the water to avoid spurious alarms. The extreme temperatures assumed for this purpose were 35°F and 105°F.

The RBCCW system is monitored continuously by the process radiation monitoring system and alarms for high radiation levels in the RBCCW are annunciated in the MCR.

The RBCCW system is designed to American National Standards Institute (ANSI) B31.1.0 and is qualified to Seismic Category I for piping inside the primary containment including the isolation valve outside the containment. The isolation valve and pipe outside containment up to the containment penetration are designed to ASME Code, Section III, Class 2.

A schematic diagram of the RBCCW system is shown on drawing nos. H-26054 and H-26055. Table 9.2-4 provides an additional description of the major components of the system.

9.2.2.3 Safety Evaluation

The RBCCW system is not required to be operable following a LOCA.

The reactor recirculation pump seals are still required for economic, not safety, reasons to be cooled following a shutdown of the pump caused by an LOSP. Cooling is maintained by running one RBCCW pump off the emergency diesels and resuming the flow of PSW to the RBCCW heat exchanger after plant safety shutdown conditions have been met. To ensure that adequate flow reaches the recirculation pump seal coolers, valve 2P42-F033 is closed to isolate nonessential equipment. The output of a single RBCCW pump far exceeds the cooling water requirements inside the containment; therefore, flow is restrained by also closing valve 2P42-F034 and diverting the water through restricting orifice 2P42-D001.

The incoming and outgoing RBCCW lines to the containment can be isolated by motor-operated valves (MOVs) remotely actuated from the MCR.

The loss of one of the two active RBCCW pumps causes the discharge pressure to drop and activate a pressure switch to start the standby pump and initiate an alarm in the MCR.

Service can be transferred to the second RBCCW heat exchanger should the active unit need to be taken off service.

Leakage from the RBCCW system is detected by monitoring abnormal sump flows and noting frequent replenishment of makeup to the surge tank. To prevent the release of chemically treated water to the environment, the PSW at the heat exchanger is maintained at a higher pressure than the RBCCW side. System drains are conveyed to the chemical radwaste system, except the heat exchangers and pumps which drain to the floor drain system.

The RBCCW heat exchangers, pumps, surge tank, chemical addition system, corrosion test loop, and critical valves requiring frequent operation are located in accessible areas. Piping is routed so as not to jeopardize safety-related equipment as a result of a pipe break since all piping outside the containment is not Seismic Category I.

In the unlikely event that the RBCCW system is unavailable, the plant would be brought to a safe shutdown condition.

9.2.2.4 Tests and Inspections

Pumps in the RBCCW system are proven operable by their use during normal plant operation. Rotating the operation of pumps and heat exchangers verified the availability of each unit. Motor-operated isolation valves are tested to ensure that they are capable of opening and closing by operating remote manual switches in the MCR and observing the position indicating lights. Routine visual inspection and testing of system components, instrumentation, and alarms is adequate to verify system operability.

9.2.3 MAKEUP DEMINERALIZED WATER SYSTEM (HNP-1 AND HNP-2)

9.2.3.1 Design Bases

The objective of the makeup water treatment demineralized water system is to provide a supply of treated water suitable as makeup for the plant and reactor coolant cycles and other demineralized water requirements.

The makeup water treatment system is designed to:

- Provide makeup water of reactor coolant quality.

- Provide an adequate supply of treated water for all plant operating requirements.

9.2.3.2 System Description

The makeup water system equipment is located in a building separated from the main power generation building ~ 300 ft to the north of HNP-1 and receives its supply water from two 750-gal/min capacity deep wells on the site. The system is shared with HNP-1 and consists of four filters arranged in parallel.

The demineralized water is stored in a 100,000-gal demineralized water storage tank from which it is pumped by two transfer pumps (one standby) to supply the plant requirements for demineralized water. The system is designed to produce 50 gal/min of demineralized water. The effluent is monitored. The piping and associated equipment are fabricated from corrosion-resistant materials which prevent contamination of the makeup water.

In addition to the demineralized water storage, a 500,000-gal condensate storage tank (CST) for each unit is provided to supply the necessary volume of high-purity water for initial testing and cleaning and to provide the required volume for refueling and emergency requirements (HPCI, reactor core isolation cooling (RCIC), condensate makeup, and reject).

The makeup demineralizer is started manually and shut down automatically by a high-level signal from the demineralized storage tank. It is automatically isolated from the demineralized water storage tank upon detection of high-effluent conductivity to prevent contamination of stored water.

The quality of water stored for makeup is maintained at the following purity level in accordance with BWRVIP-190, "BWR Water Chemistry Guidelines," or the latest approved industry guidance.

Conductivity	< 1.0 μmho/cm at 25°C
Chlorides (as Cl)	< 10 ppb
pH	Neutral (6.0 to 7.5 at 25°C)
Boron (as BO_3)	0.1 ppm

The four filters are each rated at 250 gal/min. The backwashing and rinsing of the filters is manually controlled.

The makeup water system wastes are routed to the neutralizing sump and recirculated to a waste collecting tank for pH neutralizing prior to being discharged to the river through the radwaste diffusion water discharge line.

The makeup water system supplies demineralized water to the following plant equipment and systems:

- Decontamination areas.
- Condensate storage and transfer system.
- RBCCW system.
- Standby liquid control system.
- Radioactive waste control system.
- Pressure suppression pool.
- Laboratories.
- Spent-fuel storage pool and fuel pool cooling and cleanup system.
- Vacuum pump.
- Stator winding cooling unit.
- Diesel generator expansion tanks.

- Plant heating system.
- HVAC chilled water systems.
- Off-gas system.
- Hot machine shop.

9.2.3.3 Instrumentation Application

The makeup water treatment system is furnished with a control panel located in the water treatment building which is designed for control of the system. Suitable alarms, pressure indicators, flow indicators, conductivity monitors, pH monitors, and silica analyzers are provided.

9.2.3.4 Safety Evaluation

The system does not provide any functions that are necessary to safely shut down the reactor, maintain the plant in a safe shutdown state, or mitigate the consequences of an accident. The system is designed so that malfunctions do not cause damage to safety-related equipment or systems.

9.2.3.5 Tests and Inspections

The makeup water treatment system is an operational system in daily use and does not require periodic testing to assure operability. The performance of the system is under surveillance at all times. High demineralizer effluent conductivity automatically isolates the system and initiates an alarm. Grab samples are periodically tested in the laboratory to verify demineralizer performance and to ascertain stored water quality.

9.2.4 POTABLE AND SANITARY WATER SYSTEM (HNP-1 AND HNP-2)

9.2.4.1 Design Basis

The potable and sanitary water system is designed to:

- Provide pressurized, filtered, chlorinated water for HNP-1 and HNP-2.
- Furnish water for drinking and sanitary purposes.
- Provide water which meets Georgia Department of Natural Resources, Environmental Protection Division, standards.

9.2.4.2 System Description

Water is supplied to the system from two deep wells located on the plant site. Each of the two well pumps is capable of providing 750 gal/min at 100 psig through antracite pressure filters in the makeup demineralizer to the 100,000-gal filtered water storage tank. The 20,000-gal sanitary water tank is filled from the filtered water storage tank by two 400 gal/min sanitary water booster pumps. Two 110-gal/min sanitary water pumps provide water from the sanitary water tank to designated locations in the plant through the distribution piping system. The sanitary water pumps maintain system pressure at 80 psig.

The sanitary water system is chlorinated by a hypochlorinator metering pump which draws sodium hypochlorite from storage bottles and injects it into the system. Hypochlorite solution is injected into the fill line running from the sanitary water booster pumps to the sanitary water tank. The system is chlorinated only when the sanitary water tank is being filled.

All nonradioactive sanitary waste water and sanitary waste water from hot toilets for both units is collected and then processed by the sewage treatment plant. All sanitary waste water from hot showers and hot lavatories is collected and then processed by the HNP-1 radwaste system.

9.2.4.3 Instrumentation Application

The instrumentation which monitors and controls the potable and sanitary water system includes a level controller to monitor and maintain the water level in the sanitary water tank. This controller automatically operates the sanitary water booster pumps and the hypochlorite metering pump to maintain an adequate supply of chlorinated water in the sanitary water tank. Two pressure switches on the discharge header from the sanitary water pumps automatically control the pumps to maintain system pressure. Sanitary water pump A maintains system pressure through continuous running; however, if system pressure drops to the setpoint of the first pressure switch, it will automatically start sanitary water pump B. When system pressure is restored, the second pressure switch automatically stops pump B.

9.2.4.4 Safety Evaluation

The system does not provide any functions that are necessary to safely shut down the reactor, maintain the plant in a safe shutdown state, or mitigate the consequences of an accident. The system is designed so that piping malfunctions do not cause damage or flooding of safety-related equipment or systems. The system design does not permit impurities to backflow into the piping system. The sanitary water system is not required for plant operation, and no potential for radioactive contamination exists since it is not connected to any radioactive systems. The system is provided with instrumentation that monitors and controls the potable and sanitary water processes to ensure system reliability over the full range of normal plant operation.

9.2.4.5 Tests and Inspections

The potable and sanitary water system has been preoperationally tested to demonstrate that the system will function in accordance with the design criteria set forth in the specifications and design drawings for this system. The design performance of the well water pumps, sanitary water pumps, and the sanitary water chlorination system was proven in a documented preoperational test.

Periodic water samples are taken to ensure that the system meets Georgia Department of Natural Resources, Environmental Protection Division, standards.

9.2.5 ULTIMATE HEAT SINK

9.2.5.1 Design Bases

9.2.5.1.1 Safety Design Bases

The ultimate heat sink is designed to provide adequate cooling to allow safe shutdown and cooldown of the plant following an accident in accordance with Regulatory Guide 1.27, "Ultimate Heat Sink," (March 1974).

9.2.5.1.2 Power Generation Design Bases

The ultimate heat sink is designed to provide adequate cooling water to dissipate waste heat from the plant during normal operation.

9.2.5.2 System Description

During normal operation, waste heat is removed from the plant by the circulating water system which dissipates the heat through the plant cooling towers. Makeup water is provided to the cooling towers from the PSW system. The normal service water requirements for HNP-1 and HNP-2 are ~ 47,127 gal/min.

During shutdown and accident conditions, waste heat is dissipated through the RHR heat exchangers to the residual heat removal service water (RHRSW), which is discharged to the cooling tower flume. During shutdown, this water may overflow the tower no. 2 basin into the overflow basin to the Altamaha River. Cooling water for the RHR heat exchangers is provided by four 50% capacity RHRSW pumps. Diesel and equipment cooling requirements during and following an accident are met by one of the four PSW pumps. Diesel generator 1B, which is shared with HNP-1, has a separate cooling water pump. This pump is referred to as the standby diesel generator service water pump and is considered part of the PSW system. All of these pumps are located in the river intake structure.

The Altamaha River is the sole source of water for the RHRSW, PSW pumps, and the diesel generator 1B cooling water pump. The average riverflow is 13,000 ft^3/s. The recorded minimum flow measured in 1925 at Charlotteville (~ 20 miles above the site) was 1200 ft^3/s. For a more detailed description of the RHRSW and PSW systems, see subsections 9.2.1 and 9.2.7.

9.2.5.3 Instrumentation Application

Instrumentation is provided to indicate whether the RHRSW or PSW systems are operating properly. In the event of an accident, automatic controls operate the PSW system as required for safety. In the event of a LOCA, automatic controls trip the RHRSW system as required.

9.2.5.4 Safety Evaluation

The RHRSW pumps are designed to operate at rated capacity when the river elevation is 59 ft, corresponding to a river discharge rate of 100 ft^3/s. The PSW pumps are designed to deliver a rated flow of 8500 gal/min when the river elevation is 61.7 ft, which corresponds to a river discharge rate of 800 ft^3/s. The requirement of the PSW pumps during shutdown or emergency operations is one pump operating at 4428 gal/min. By throttling the pump discharge to slightly over 8400 gal/min, the required river level is reduced to 61.2 ft, which corresponds to a river flowrate of 600 ft^3/s. The diesel generator 1B cooling water pump is designed to deliver a flow of 700 gal/min when the river elevation is 61.2 ft. Technical Specifications require plant shutdown if the river water level in the PSW pump well of the intake structure falls below 60.5 ft msl. These measures ensure that adequate cooling water is available even in the event of incredibly low flows. Also, close surveillance is given to maintaining the depth of the approach channel in the river during periods of low river flows to ensure that water is available to the pumps. In this respect, the area in front of the intake across the entire river is sounded each year in late spring or early summer. The rating curves, figures 2.4-8 and 2.4-34, will be verified at regular intervals at the permanent gauge station just downstream of the U.S. Highway No. 1 bridge by the United States Geologic Survey under an agreement with the Georgia Power Company. If any shift occurs in a manner which could adversely affect the water supply to the pumps, appropriate action will be taken to maintain the water supply capability under low-flow conditions. For more detailed discussion of the Altamaha River, see section 2.4.

The RHRSW and PSW systems are designed to Seismic Category I requirements and are designed such that no single failure in either system can prevent that system from performing its intended function.

The intake structure is designed to withstand severe natural phenomena such as the DBE, operating basis earthquake, tornado winds, and tornado-induced missiles.

Water enters the pump bay of the intake structure through two inlet bays each 9 ft 2 in. wide. (See drawing no. H-12192.) Each inlet bay is protected by a steel trash rack including a catenary trash rack and a traveling water screen. The trash rack section is separated from the traveling water screen section by a 2-ft 6-in.-thick reinforced concrete wall, and the traveling water screen section is separated from the pump bay by another 2-ft 6-in.-thick reinforced

concrete wall. Water passage through these walls is by an 11-ft-high opening from the structure base slab. At normal water level (71 ft 6 in.), these openings are ~ 4 ft below the water level. There is no commercial barge traffic on the river at present. However, the intake structure is protected by steel sheet pile cells from a direct hit by river traffic or debris flowing in the direction of the river channel. Traffic across the channel would of necessity be slow moving and would not damage the structure. The cells are further protected by wood fender piles to dissipate a part of the dynamic effect of a moving load. Periodic inspections and maintenance are conducted to ensure an open, well-defined channel to the intake structure. A 6-ft-long by 6-ft-high extension to the center wall between the inlet bays prevents blockage of both bays by the sinking of a boat or debris in front of the structure. Presently, there is no commercial river traffic passing the plant, and none is anticipated carrying cargoes of oil, toxic chemicals, explosives, or other potentially hazardous materials. River diversion has been considered and is discussed in section 2.4.

The inlet bays to the pump bay have been sized such that one bay can supply the water requirements for operating or for safe shutdown of both Units 1 and 2 at all river levels; thus, blockage of one bay, by any means, will not affect plant operation.

Results of analyses to determine the adequacy of the ultimate heat sink are:

A. The standard procedure used by General Electric in calculating total decay heat is to make the following conservative assumptions:

1. At the time the design basis accident (DBA) occurs, the reactor is at 105% of rated steam flow. This maximizes the decay heat generated.

2. The decay heat curve used is the ANS-S standard plus 20% for the first 1000 s and ANS-S standard plus 10% thereafter.

Table 9.2-7 shows the ANS-S normalized standard values as obtained from NEDO-10625. Table 9.2-8 shows the total integrated decay heat for HNP-2 obtained as per the assumptions above. Figure 9.2-3 displays the results given in table 9.2-8 in graphical form. Table 9.2-9 gives the decay heat injection rate, with figure 9.2-4 showing the results in graphical form.

B. The heat rejection rate and integrated heat rejected by the station auxiliary systems are based on the following equipment being in operation continuously for the 30-day period following the accident:

- Two core spray (CS) and RHR jockey pumps.
- Two RHR pumps.
- One HPCI pump room cooler.
- Two RHR and CS pump room coolers.
- Two diesel generators.

The auxiliary heat rejection rate and the integrated auxiliary heat rejected for the 30 days following an accident are shown in tables 9.2-10 and 9.2-11 and are also shown graphically in figures 9.2-5 and 9.2-6.

C. Tables 9.2-12 and 9.2-13 show the sensible heat rejection rate and integrated sensible heat rejected. The results are shown graphically in figures 9.2-7 and 9.2-8.

D. The total integrated heat rejected is the sum of the integrated decay heat, integrated auxiliary heat, and integrated sensible heat. The total integrated heat rejected is shown in table 9.2-14 and is shown graphically in figure 9.2-9. The total flow requirement for the heat exchangers is 24 ft^3/s. The lowest flow recorded in the river from 1931 - 1979 is 1430 ft^3/s, with the estimated minimum low flow being 1200 ft^3/s. (Reference subsection 2.4.11.)

E. The maximum allowable inlet water temperature is 97°F. This temperature is the design basis for the heat exchangers in the RHRSW and PSW systems, which are open systems discharging back to the Altamaha River downstream of the intake structure.

F. Figure 9.2-10 gives the curve for the PSW pump required NPSH, and also depicts the minimum NPSH available to the pump. The minimum NPSH is based on the river level at the theoretical minimum flow of 900 ft^3/s, which corresponds to a level of 62 ft, and a low barometric pressure of 29 in. of mercury.

The decay heat rejection rate and the integrated decay heat based on APCSB 9-2 are provided in tables 9.2-16 and 9.2-17. Figures 9.2-12 and 9.2-13 show graphically the rejection rate and integrated decay heat.

The decay heat release rate is based on data taken from figures 1, 2, and 3 of APCSB 9-2, as provided in table 9.2-15, and using the 105% rated steam flow power of 2.417 x 106 Btu/s.

The total integrated heat rejected is provided in table 9.2-18 and is shown graphically in figure 9.2-14.

The total integrated heat is the sum of the integrated decay heat values from table 9.2-17 and the integrated auxiliary heat values and sensible heat rejected values from tables 9.2-11 and 9.2-13.

More recent analyses were performed for a rated core thermal power of 2804 MWt. These analyses, which are documented in section 6.2, do not significantly affect the adequacy of the ultimate heat sink.

Table 3.2-1 and drawing nos. H-21033, H-21039, H-26050, and H-26051 delineate the Seismic Category I and quality group classification boundaries for the PSW system and the RHRSW system. Drawing nos. E-10173 and H-21102 show the layout arrangement for the intake structure and the location of the intake structure and discharge point in the plant layout.

9.2.5.5 Tests and Inspections

Tests and inspections for the RHRSW system and PSW system are included in subsections 9.2.1 and 9.2.7.

9.2.6 CONDENSATE STORAGE AND TRANSFER SYSTEM

9.2.6.1 Design Bases

The condensate storage and transfer system is designed to:

- Store condensate for the RCIC and HPCI systems.
- Maintain the level of condensate in the condenser hotwell.
- Provide condensate to other plant systems where required.

9.2.6.2 System Description

The condensate storage and transfer system schematic is shown on drawing no. H-26046. The condensate storage system consists of a 500,000-gal stainless-steel storage tank, two 500-gal/min condensate transfer pumps, and the necessary piping and instrumentation to convey and monitor the water to various systems. Additional equipment parameters are listed in table 9.2-5.

The CST is a covered atmospheric storage tank located outdoors and built to the requirements of ASME Section III, Class 3. The tank and transfer pumps are surrounded by a Seismic Category I and missile-proof retaining wall, integrally sized to hold the entire water inventory of the tank. With the exception of small instrument connections, a drain line, which is normally closed by a valve and a blind flange, and RCIC and HPCI suction connections to the tank, all other lines terminate inside the tank above the 100,000-gal level to ensure that RCIC and HPCI systems are not deprived of their minimum reserve storage requirements by other less essential systems. An overflow connection on the tank is piped to the radwaste system waste surge tank.

A single condensate transfer pump is required to furnish condensate water to various equipment in the reactor and radwaste building except for the RCIC, HPCI, CRD, CS, and condenser hotwell transfer lines which draw directly from the tank. The introduction of a low pump discharge pressure signal will automatically start the standby pump and simultaneously initiate an alarm in the MCR. To accelerate the filling of the reactor well and dryer separator pool during refueling, both transfer pumps are operated in parallel.

The CST is maintained with a water level > 15 ft above the tank bottom through the addition of demineralized water makeup. High tank level (43 ft above the tank bottom) will alarm in the MCR. Should the level in the tank fall below a preset level, a low-level signal automatically switches the HPCI and RCIC pump suctions to the suppression pool. Pressure gauges are

located at various points in the condensate transfer system for convenience in checking operating conditions.

A cross-connect line between HNP-1 and HNP-2 storage tanks provides the capability of transferring water between the two tanks, thereby increasing condensate storage capacity to either unit.

9.2.6.3 Safety Evaluation

The condensate transfer system is not a safety-related system.

The CST is the initial source of water for the RCIC and HPCI systems. By providing standpipes inside the tank for outlet lines designated for other systems, the RCIC and HPCI systems are assured of a 100,000-gal reserve. Should the water supply in the tank be depleted far below the minimum 100,000 gal, through operation of the HPCI and/or RCIC systems, or through leakage, a low-level signal automatically shifts the HPCI and RCIC pump suction paths to the suppression pool.

Plant administrative control limits the radioactivity level in the tank to 10^{-3} μCi/cc. With this level of activity, the dose at the site boundary to an individual due to direct radiation from the tank does not exceed the requirements of 10 CFR 20.1001 - 20.2401.

The reinforced concrete retaining wall surrounding the tank has the capacity to contain the contents of the storage tank to preclude spillage of condensate water to the environs in the event that the tank suffers a leak.

9.2.6.4 Tests and Inspections

The condensate transfer pumps are proven operable by virtue of being in service during normal plant operation and by periodically rotating the operation of the pumps. Routine visual inspection and checking of components, instrumentation, and alarms are adequate to verify system operability.

The CST vertical and horizontal joints between shell plates are full penetration welded with complete fusion as specified in ND-3844 of Section III of the ASME Boiler and Pressure Vessel Code, Winter 1971 Addenda. These joints have received a 100% radiographic examination exceeding the code requirements as specified above.

9.2.7 RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) SYSTEM

9.2.7.1 <u>Design Bases</u>

9.2.7.1.1 Safety Design Bases

The RHRSW system is designed to provide cooling water to the RHR system under post-accident conditions.

9.2.7.1.2 Power Generation Design Bases

The RHRSW is designed to:

- Preclude leakage of radioactive contamination to the RHRSW system from the RHR system.

- Provide cooling water to the RHR heat exchangers as required, during normal shutdown, and reactor isolation modes.

9.2.7.2 <u>System Description</u>

The RHRSW system is an open-loop system of piping, water pumps, valves, controls, and instrumentation as shown on drawing no. H-21039. Table 9.2-6 lists the design parameters of the major equipment in the system.

The RHRSW system has four pumps. The pumps are designed to develop sufficient head to ensure that the pressure on the cooling water side of the heat exchanger is always greater than the primary water side of the heat exchanger. The pumps provide at least 3500 gpm per pump at the minimum permissible river level of 60.5 ft MSL as required by the Technical Specifications for the Ultimate Heat Sink.

The cooling water is pumped from the Altamaha River to the RHR heat exchangers through the two main supply headers. After removing heat from the heat exchangers, the coolant is piped back through the 24-in. drain to the cooling tower flume.

The RHRSW system is designed for remote manual initiation. The power supply for the system is taken from an essential 4160-V-ac bus.

RHRSW is provided with two divisions to allow each system loop to operate independently. Two normally closed motor-operated crossover valves provide system flexibility so that any division I or division II operable pump may be lined up with any operable pump of the other division to supply the heat exchanger of the other division. Additionally, two manual isolation valves provide a second normally closed crossover between division I and division II.

The capability is provided to inject (as required) diluted solutions of sodium hypochlorite, sodium bromide, a corrosion inhibitor, and a silt dispersant into the RHRSW system to control organic biofouling, corrosion, and silt deposition in the pipe lines and heat exchangers.

Both RHRSW divisions cross-connect to the corresponding PSW division. These cross-connections shall not be used during normal or design basis accident conditions at the plant. The cross-connections between RHRSW and PSW are provided with manual, double isolation valves which shall be maintained closed, except for periodic plant maintenance activities such as dead-leg flushing. The RHRSW-PSW cross-connections are only to be used in response to a beyond design basis external event (BDBEE).

9.2.7.3 Instrumentation Application

The RHRSW system is designed for remote manual initiation and operates during testing, reactor shutdown, containment spray, and suppression pool cooling modes. The system is stopped automatically should low pressure coolant injection (LPCI) operation be required.

A flow control valve is provided on the RHR heat exchanger service water outlet. Its function is to maintain the pressure on the tube side above the pressure on the shell side inlet at all cooling water flowrates, thereby preventing reactor water leakage into the river water. Pressure switches on the service water inlet to the RHR heat exchanger provide a permissive for throttling of the flow control valve upon sensing sufficient pressure indicative of RHRSW pump availability to that RHR heat exchanger. This permissive can be overridden prior to pump start so that the RHRSW pump may be started with the flow control valve open to prevent subjecting the piping system to pump deadhead pressure. The operator restores the pressure interlock once the pump has started.

Pressure and flow indicators located in the MCR inform the operator of pump performance and/or line integrity.

Temperature elements located at the RHRSW discharge line from the RHR heat exchanger signal any abnormal temperature of RHRSW and sound an alarm in the MCR.

A 3- to 5-gal/min supply of sanitary water is provided for pump seal lubrication during pump starting. However, during emergency conditions, the RHRSW pumps may be started without this seal water, if necessary. A normally closed, solenoid-operated valve is provided for prelubrication of pump's rubber shaft bearings. Prior to pump starting, this valve is opened upon receiving a signal from a remote manual switch in the MCR, thereby providing water for prelubrication of pump's rubber shaft bearings.

The pump motors are cooled by water from the PSW system.

A low-flow bypass is provided from the pump discharge to the intake structure. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. A pressure control valve limits the bypass flow.

9.2.7.4 Safety Evaluation

The RHRSW system provides a reliable source of cooling water for the RHR heat exchangers, which are essential to a safe reactor shutdown following a design basis LOCA. Either of the two main supply headers provides adequate cooling water to meet safe shutdown requirements. The entire system is designed to withstand a DBE without impairing its function.

The RHRSW system is designed with sufficient redundancy so that no single active system component failure can prevent it from achieving its safety objective.

The intake structure, which houses the pumps, is designed to Seismic Category I requirements.

A cross-connect line is provided between the RHR system and RHRSW system so that service water may be pumped directly into the reactor vessel or into the containment via the spray headers.

The RHRSW system is designed to be operable during an LOSP.

The RHRSW pumps, strainers, piping, and valves in the intake structure and the reactor building are all designed to ASME Section III, Class 3, and Seismic Category I requirements. The potential for failures or malfunctions caused by freezing, icing, and other adverse environmental conditions was considered. The only components of the RHRSW system that are essential in attaining and maintaining a safe shutdown that are not housed within temperature controlled areas are those that are in the intake structure. The RHRSW pumps and associated piping are shown on drawing no. H-21102. As stated in section 2.4, the Altamaha River has never been known to freeze over; therefore, icing is not considered to be a problem. The winters in this part of Georgia, as reported section 2.3, are mild. The average minimum temperature for the coldest month of the year is ~ 5°F above the freezing point of water. Therefore, days during which temperatures drop below freezing for a short period of time are infrequent, and prolonged periods (> 1 day) of below freezing temperatures are even less frequent. However, the possibility of below freezing weather was considered in the design of the water systems in the intake structure. It should be pointed out the PSW pumps are required to be operating when the plant is operating, and the heat from these motors would aid in maintaining the intake structure at a higher temperature than the surrounding air. Diverse environmental conditions are therefore not expected to cause failures or malfunctions in the components located in the intake structure.

9.2.7.5 Tests and Inspections

The equipment and system were inspected and tested upon installation to ensure the integrity and capacity of the system. The tests and inspections included the following:

A. Pumps and Drive Motors

   Each pump is started and ran for sufficient time to ensure its proper operability. The operator records discharge pressures and abnormal vibration, and provides maintenance as needed.

B. Manual Valves

Each manual valve is operated through its complete range to ensure that it is in operating condition.

C. Check Valves

Check valves associated with equipment necessary for safe shutdown are tested periodically.

D. Control Valves

Each control valve is operated through its complete range of movement. Hand jacks are operated. Position lights on the panel are observed.

E. Power-Operated Isolation Valves

Power-operated isolation valves are tested to ensure that they are capable of opening and closing by operating manual switches in the MCR and observing the valve position lights.

In addition to the testing and inspection of individual system components, periodic functional testing is performed to ensure the operability of the system as a whole. The tests ensure, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCAs, including operation of applicable portions of the protection system and the transfer between normal and standby power sources.

TABLE 9.2-1

PSW SYSTEM EQUIPMENT DATA

PSW Pumps	
Quantity	Four 1/3 capacity
Type	Vertical turbine
Flow and head each	8500 gal/min at 275 ft[a]
Material	
Casing	Stainless steel
Impeller	Bronze
Shaft	Stainless steel
Motor	
Size	700 hp
Voltage/phase/cycle	4160/3/60
rpm	1180
Automatic Strainers	
Quantity	Two full capacity
Type	Automatic, self-cleaning
Capacity	25,500 gal/min
Pressure drop	2 psi
Standby Diesel Service Water Pump	
Quantity	One
Type	Vertical turbine
Flow and head	700 gal/min at 231.5 ft
Material	
Casing/impeller/shaft	Cast steel/bronze/stainless steel
Motor	
Size	60 hp
Voltage/phase/cycle	550/3/60
rpm	1780

a. This is a nominal reference value.

TABLE 9.2-2 (SHEET 1 OF 2)

PSW SYSTEM COMPONENT REQUIREMENTS

During normal operating conditions, water is supplied to the following:

Equipment	Flowrate[(a)] (gal/min) (each)
Drywell chiller condenser	900
RCIC pump room cooler	43
RHR pump seal cooler	20
RHR and CS pump room cooler	150
CRD pump room cooler	40
HPCI pump room cooler	40
Diesel generator cooler (during testing)	700
Waste gas refrigerator	25
Radwaste building closed cooling water heat exchanger	3000
Turbine building chiller condenser	1400
Vacuum pump heat exchanger	144
Condensate pump motor cooler	5
Condensate booster pump oil cooler	10
Main generator hydrogen cooler	625
Generator bus heat exchanger	80
Stator cooler	940
RBCCW heat exchanger	6193
Reactor feed pump turbine oil coolers	80
Main turbine oil coolers	2135
Electrohydraulic coolers	10
PSW pump motor cooler	2
RHRSW pump motor cooler	4
Hot machine shop air handling unit coil	38
Condenser unit sample room	5
Sampling system chiller assembly	34
Water analysis room air-conditioner	11
Main steam sample condenser	2

TABLE 9.2-2 (SHEET 2 OF 2)

Under emergency conditions, water is supplied to the following equipment to meet accident heat loads with a river water temperature of 97°F:

Equipment	Flowrate[(a)(b)] (gal/min) (each)
Diesel generator	725
Drywell chiller condenser	900
RCIC pump room cooler	43
RHR pump seal cooler	20
RHR and CS pump room cooler	150
CRD pump room cooler	40
HPCI pump room cooler	40
PSW pump motor cooler	2
RHRSW pump motor cooler	4

a. The actual flowrate varies depending on system alignment and demand.
b. Require minimum flowrate to meet accident heat load maybe less.

TABLE 9.2-4 (SHEET 1 OF 2)

RBCCW SYSTEM EQUIPMENT DATA

RBCCW Pumps

Quantity	Three 50% capacity each
Type	Horizontal, centrifugal
Flow and head	3000 gal/min at 160-ft TDH
Flow medium	Inhibited demineralized water
Material:	
Casing	Cast iron
Impeller	Cast iron
Shaft	Carbon steel with stainless-steel sleeve
Voltage/phase/cycle	550 V/3 phase/60 Hz
rpm	1750

RBCCW Heat Exchangers

Quantity	Two 100% capacity each
Type	Horizontal shell and tube
Capacity	35.0 x 10^6 Btu/h
Shell design	
Pressure/temperature	150 psig/200°F
Material	Carbon steel
Flow medium	Inhibited demineralized water, RBCCW
Tube design:	
Pressure/temperature	150 psig/200°F
Material	Admiralty
Flow medium	PSW

RBCCW Surge Tank

Quantity	One
Type	Vertical vented
Capacity, nominal	1000 gal
Design pressure	Atmospheric
Design temperature	150°F
Fluid	Inhibited demineralized water, RBCCW
Material	Coated carbon steel

RBCCW Chemical Addition System

Mixing tank	One 100 gal, vented, stainless steel
Feed pump	One metering type 170 gal/h, 100 psig maximum 1/2 hp, 208 V/3 phase/60 Hz
Agitator	One 1/3 hp, 208 V, 3 phase/60 Hz

TABLE 9.2-4 (SHEET 2 OF 2)

RBCCW Corrosion Test Loop

Coupon Rack	Four coupon holders with stainless-steel interconnecting piping and isolation valves, PVC mounting plate
Filter	6 5/8-in. diameter vertical tank with 1-in. inlet and outlet, 1/4-in. vent and drain connections, carbon steel; four-element stacks, each three elements high, design - 225 psig/300°F
Sample Sink	15 in. by 15 in. by 7 in. high, stainless steel

TABLE 9.2-5

CONDENSATE STORAGE AND TRANSFER SYSTEM
COMPONENT DESCRIPTION

<u>Condensate Transfer Pumps</u>

Quantity	Two
Type	Horizontal-centrifugal
Capacity	500 gal/min
Head	180-ft TDH
Flow medium	Condensate water
Material:	
Casing	Cast iron
Impeller	Bronze
Shaft	Carbon steel
Horsepower	40
Voltage/Phase/Cycle	550/3/60 Hz

<u>CST</u>

Quantity	One
Type	Cylindrical
Capacity	500,000 gal
Diameter/height	44 ft/44 ft
Design pressure	Atmosphere
Design temperature	20°F to 120°F
Material	Stainless steel

TABLE 9.2-6

RHRSW SYSTEM DESIGN PARAMETER

Pumps	
Quantity	Four (50% capacity)
Fluid	River water
Type	Vertical turbine
Nominal flow and head (each)	4000 gal/min at system pressure as specified by Design Calculation SMNH 04-008.
Material:	
Casing	Fabricated carbon steel A-53 or stainless steel
Shaft	416 stainless steel
Impellers	Bronze or Stainless Steel
Motors	
Size	1250 hp
Voltage/phase/cycle	4000/3/60
rpm	1780
Service factor	1.00

System Requirements

Service water pressure at RHR heat exchangers is at least 20 psi greater than reactor water pressure at the heat exchangers; thus, any leakage goes into the reactor water.

TABLE 9.2-7

NORMALIZED DECAY HEAT[a]

Time After Shutdown (s)	ANS (P/Po)	Time After Shutdown (s)	Experimental Mean (P/Po)	May-Witt (P/Po)	ANS (P/Po)
20.0	0.0582	3.0 E+06	1.79 E-03	1.90 E-03	1.90 E-03
30.0	0.0541	1.0 E+06	2.84 E-03	2.67 E-03	2.64 E-03
40.0	0.0512	9.0 E+05	2.98 E-03	2.78 E-03	2.74 E-03
50.0	0.0492	8.0 E+05	3.12 E-03	2.91 E-03	2.86 E-03
60.0	0.0477	7.0 E+05	3.30 E-03	3.08 E-03	3.00 E-03
70.0	0.0462	6.0 E+05	3.49 E-03	3.30 E-03	3.19 E-03
80.0	0.0451	5.0 E+05	3.77 E-03	3.58 E-03	3.42 E-03
90.0	0.0442	4.0 E+05	4.11 E-03	3.97 E-03	3.74 E-03
100.0	0.0434	3.0 E+05	4.57 E-03	4.50 E-03	4.18 E-03
150.0	0.0412	2.0 E+05	5.27 E-03	5.30 E-03	4.84 E-03
200.0	0.0382	1.0 E+05	6.50 E-03	6.68 E-03	6.03 E-03
250.0	0.0360	9.0 E+04	6.69 E-03	6.89 E-03	6.21 E-03
300.0	0.0345	8.0 E+04	6.90 E-03	7.13 E-03	6.43 E-03
350.0	0.0330	7.0 E+04	7.15 E-03	7.40 E-03	6.67 E-03
400.0	0.0318	6.0 E+04	7.43 E-03	7.71 E-03	6.95 E-03
450.0	0.0308	5.0 E+04	7.78 E-03	8.08 E-03	7.30 E-03
500.0	0.0300	4.0 E+04	8.21 E-03	8.55 E-03	7.74 E-03
600.0	0.0286	3.0 E+04	8.80 E-03	9.17 E-03	8.33 E-03
700.0	0.0275	2.0 E+04	9.68 E-03	1.01 E-02	9.23 E-03
800.0	0.0265	1.0 E+04	1.14 E-02	1.19 E-02	1.10 E-02
900.0	0.0257	9.0 E+03	1.17 E-02	1.22 E-02	1.13 E-02
		8.0 E+03	1.20 E-02	1.26 E-02	1.17 E-02
		7.0 E+03	1.24 E-02	1.30 E-02	1.21 E-02
		6.0 E+03	1.29 E-02	1.35 E-02	1.26 E-02
		5.0 E+03	1.36 E-02	1.42 E-02	1.32 E-02
		4.0 E+03	1.44 E-02	1.51 E-02	1.41 E-02
		3.0 E+03	1.55 E-02	1.64 E-02	1.53 E-02
		2.0 E+03	1.72 E-02	1.84 E-02	1.71 E-02
		1.0 E+03	2.04 E-02	2.23 E-02	2.08 E-02

a. Exposure (MWd/t) = ∞ ; irradiation time (s) = ∞.

TABLE 9.2-8

INTEGRATED DECAY HEAT[(a)] (HNP-2)

Time After Shutdown (s)	Integrated Decay Heat (10^6 Btu)	Time After Shutdown (s)	Integrated Decay Heat (10^6 Btu)	Time After Shutdown (s)	Integrated Decay Heat (10^6 Btu)
1.0×10^0		3.5×10^2	36.26	1.0×10^4	410.89
2.0		4.0	41.1	2.0	679.76
3.0		4.5	44.71	3.0	918.46
4.0		5.0	48.34	4.0	1135.99
5.0		5.5	51.97	5.0	1329.35
6.0		6.0	55.59	6.0	1546.88
7.0		6.5	58.0	7.0	1691.90
8.0		7.0	61.63	8.0	1885.26
9.0		7.5	65.26	9.0	2054.45
1.0×10^1	3.82	8.0	68.88	1.0×10^5	2223.64
1.0	5.27	8.5	72.51	2.0	3625.50
3.0	6.48	9.0	74.93	3.0	4834.00
4.0	7.61	9.5	77.34	4.0	6042.50
5.0	8.82	1.0×10^3	81.69	5.0	7009.30
6.0	9.91	2.0	132.94	6.0	8459.50
7.0	11.12	3.0	176.44	7.0	8822.10
8.0	12.08	4.0	217.53	8.0	9668.00
9.0	13.54	5.0	253.78	9.0	10393.10
1.0×10^2	14.50	6.0	290.04	1.0×10^6	11118.20
1.5	19.34	7.0	319.04	3.0×10^6	21269.60
2.0	24.17	8.0	350.47		
2.5	29.00	9.0	381.89		
3.0	33.35				

a. Assume P_o (at 105% rated steam flow) = 2.417×10^6 Btu/s; exposure = ∞; irradiation time = ∞.

TABLE 9.2-9

DECAY HEAT REJECTION RATE

Time After Shutdown (s)	Decay Rate (Btu/s x 10^4)	Time After Shutdown (s)	Decay Rate (Btu/s x 10^4)
2.0 x 10^1	16.80	1.0 x 10^4	2.92
3.0	15.70	2.0	2.45
4.0	14.80	3.0	2.21
5.0	14.30	4.0	2.06
6.0	13.80	5.0	1.94
7.0	13.40	6.0	1.85
8.0	13.10	7.0	1.77
9.0	12.80	8.0	1.71
1.0 x 10^2	12.60	9.0	1.65
1.5	11.90	1.0 x 10^5	1.60
2.0	11.10	2.0	1.29
2.5	10.40	3.0	1.11
3.0	10.00	4.0	0.99
3.5	9.60	5.0	0.91
4.0	9.20	6.0	0.85
4.5	8.90	7.0	0.80
5.0	8.70	8.0	0.76
6.0	8.30	9.0	0.73
7.0	7.90	1.0 x 10^6	0.70
8.0	7.70	3.0 x 10^6	0.51
9.0	7.50		
1.0 x 10^3	6.00		
2.0	4.52		
3.0	4.07		
4.0	3.75		
5.0	3.51		
6.0	3.35		
7.0	3.22		
8.0	3.11		
9.0	3.00		

TABLE 9.2-10

AUXILIARY HEAT REJECTION RATE
(Btu/s)

Equipment	Heat Rejected for Equipment
Two CS and RHR jockey pumps	30
Two RHR pumps	61
One HPCI pump room cooler	34
Two RHR and CS pump room coolers	550
Two diesel generators	5610
Total rejection rate for 30 days after LOCA	6285

TABLE 9.2-11

INTEGRATED AUXILIARY HEAT REJECTED

Time After Shutdown (s)	Integrated Auxiliary Heat (Btu)	Time After Shutdown (s)	Integrated Auxiliary Heat (Btu)
1.0×10^1	6.285×10^4	7.0×10^3	4.399×10^7
2.0	1.257×10^5	8.0	5.028×10^7
3.0	1.886×10^5	9.0	5.657×10^7
4.0	2.514×10^5	1.0×10^4	6.285×10^7
5.0	3.143×10^5	2.0	1.257×10^8
6.0	3.770×10^5	3.0	1.886×10^8
7.0	4.399×10^5	4.0	2.514×10^8
8.0	5.028×10^5	5.0	3.143×10^8
9.0	5.657×10^5	6.0	3.770×10^8
1.0×10^2	6.285×10^5	7.0	4.399×10^8
2.0	1.257×10^6	8.0	5.028×10^8
3.0	1.886×10^6	9.0	5.657×10^8
4.0	2.514×10^6	1.0×10^5	6.285×10^8
5.0	3.143×10^6	2.0	1.257×10^9
6.0	3.770×10^6	3.0	1.886×10^9
7.0	4.399×10^6	4.0	2.514×10^9
8.0	5.028×10^6	5.0	3.143×10^9
9.0	5.657×10^6	6.0	3.770×10^9
1.0×10^3	6.285×10^6	7.0	4.399×10^9
2.0	1.257×10^7	8.0	5.028×10^9
3.0	1.886×10^7	9.0	5.657×10^9
4.0	2.514×10^7	1.0×10^6	6.285×10^9
5.0	3.143×10^7	2.0	1.257×10^{10}
6.0	3.770×10^7	2.6	1.634×10^{10}

TABLE 9.2-12

SENSIBLE HEAT REJECTION RATE

Time After Shutdown (s)	Sensible Heat Rejection (Btu/s)	Time After Shutdown (s)	Sensible Heat Rejection (Btu/s)
1.0×10^1	0.0	7.0×10^3	0.1×10^4
2.0	0.0	8.0	0.0
3.0	0.0	9.0	0.0
4.0	0.0	1.0×10^4	0.0
5.0	0.0	2.0	0.0
6.0	0.0	3.0	0.0
7.0	0.0	4.0	0.5×10^2
8.0	0.0	5.0	0.0
9.0	0.0	6.0	0.2×10^3
1×10^2	1.0×10^4	7.0	0.2×10^3
2.0	1.0×10^4	8.0	0.1×10^3
3.0	1.0×10^4	9.0	0.5×10^2
4.0	1.0×10^4	1.0×10^5	0.5×10^2
5.0	1.0×10^4	2.0	0.5×10^2
6.0	1.0×10^4	3.0	0.3×10^2
7.0	8.0×10^4	4.0	0.3×10^2
8.0	13.0×10^4	5.0	0.1×10^2
9.0	9.0×10^4	6.0	0.0
1.0×10^3	6.5×10^4	7.0	0.0
2.0	2.0×10^4	8.0	0.0
3.0	0.8×10^4	9.0	0.0
4.0	0.7×10^4	1.0×10^6	0.0
5.0	0.3×10^4	2.0	0.0
6.0	0.2×10^4	2.6	0.0

TABLE 9.2-13

INTEGRATED SENSIBLE HEAT REJECTED

Time After Shutdown (s)	Integrated Sensible Heat (Btu)	Time After Shutdown (s)	Integrated Sensible Heat (Btu)
1.0×10^1	0.0	7.0×10^3	1.01×10^8
2.0	0.0	8.0	1.01×10^8
3.0	0.0	9.0	1.01×10^8
4.0	0.0	1.0×10^4	1.01×10^8
5.0	0.0	2.0	1.01×10^8
6.0	0.0	3.0	1.01×10^8
7.0	0.0	4.0	1.01×10^8
8.0	0.0	5.0	1.01×10^8
9.0	0.0	6.0	1.03×10^8
1.0×10^2	1.0×10^6	7.0	1.05×10^8
2.0	2.0×10^6	8.0	1.06×10^8
3.0	3.0×10^6	9.0	1.06×10^8
4.0	4.0×10^6	1.0×10^5	1.07×10^8
5.0	5.0×10^6	2.0	1.14×10^8
6.0	6.0×10^7	3.0	1.17×10^8
7.0	1.4×10^7	4.0	1.20×10^8
8.0	2.7×10^7	5.0	1.21×10^8
9.0	3.6×10^7	6.0	1.22×10^8
1.0×10^3	4.3×10^7	7.0	1.22×10^8
2.0	7.7×10^7	8.0	1.22×10^8
3.0	8.8×10^7	9.0	1.22×10^8
4.0	9.5×10^7	1.0×10^6	1.22×10^8
5.0	9.8×10^7	2.0	1.22×10^8
6.0	1.0×10^8	2.6	1.22×10^8

TABLE 9.2-14

TOTAL INTEGRATED HEAT REJECTED

Time After Shutdown (s)	Total Integrated Heat (Btu)	Time After Shutdown (s)	Total Integrated Heat (Btu)
1.0×10^1	3.88×10^6	7.0×10^3	4.65×10^8
2.0	5.39×10^6	8.0	5.01×10^8
3.0	6.67×10^6	9.0	5.38×10^8
4.0	7.86×10^6	1.0×10^4	5.74×10^8
5.0	9.13×10^6	2.0	9.07×10^8
6.0	1.03×10^7	3.0	1.21×10^9
7.0	1.15×10^7	4.0	1.45×10^9
8.0	1.26×10^7	5.0	1.71×10^9
9.0	1.41×10^7	6.0	2.03×10^9
1.0×10^2	1.61×10^7	7.0	2.24×10^9
2.0	2.75×10^7	8.0	2.49×10^9
3.0	3.83×10^7	9.0	2.72×10^9
4.0	4.76×10^7	1.0×10^5	2.96×10^9
5.0	5.61×10^7	2.0	5.00×10^9
6.0	6.54×10^7	3.0	6.84×10^9
7.0	8.04×10^7	4.0	8.66×10^9
8.0	1.01×10^8	5.0	1.03×10^{10}
9.0	1.17×10^8	6.0	1.24×10^{10}
1.0×10^3	1.31×10^8	7.0	1.33×10^{10}
2.0	2.20×10^8	8.0	1.48×10^{10}
3.0	2.87×10^8	9.0	1.62×10^{10}
4.0	3.40×10^8	1.0×10^6	1.75×10^{10}
5.0	3.79×10^8	2.0	3.01×10^{10}
6.0	4.28×10^8	2.6	3.61×10^{10}

TABLE 9.2-15

DECAY HEAT RELEASE RATE

Time After Shutdown (s)	Watts/Watt	Time After Shutdown (s)	Watts/Watt
1.0×10^{-1}	0.087	7.0	0.027
2.0	0.086	8.0	0.026
3.0	0.085	9.0	0.025
4.0	0.084	1.0×10^{3}	0.025
5.0	0.083	2.0	0.019
6.0	0.0825	3.0	0.016
7.0	0.082	4.0	0.015
8.0	0.081	5.0	0.014
9.0	0.080	6.0	0.0134
1.0×10^{0}	0.079	7.0	0.0127
2.0	0.075	8.0	0.0122
3.0	0.072	9.0	0.012
4.0	0.070	1.0×10^{4}	0.0115
5.0	0.068	2.0	0.0095
6.0	0.067	3.0	0.0084
7.0	0.066	4.0	0.0076
8.0	0.065	5.0	0.0070
9.0	0.064	6.0×10^{4}	0.0066
1.0×10^{1}	0.063	7.0	0.0062
2.0	0.060	8.0	0.006
3.0	0.060	9.0	0.0058
4.0	0.052	1.0×10^{5}	0.0057
5.0	0.050	2.0	0.0046
6.0	0.048	3.0	0.0040
7.0	0.046	4.0	0.0036
8.0×10^{1}	0.045	5.0	0.0033
9.0	0.044	6.0	0.003
1.0×10^{2}	0.042	7.0	0.0029
2.0	0.036	8.0	0.0027
3.0	0.033	9.0	0.0026
4.0	0.030	1.0×10^{6}	0.0025
5.0	0.029	2.0	0.0018
6.0	0.028	3.0	0.0005

TABLE 9.2-16

DECAY HEAT REJECTION RATE

Time After Shutdown (s)	Decay Rate (Btu/s x 10^4)	Time After Shutdown (s)	Decay Rate (Btu/s x 10^4)
1.0×10^{-1}	21.02	7.0	6.53
2.0	20.78	8.0	6.28
3.0	20.54	9.0	6.04
4.0	20.30	1.0×10^{3}	6.04
5.0	20.06	2.0	4.59
6.0	19.94	3.0	3.87
7.0	19.82	4.0	3.63
8.0	19.58	5.0	3.38
9.0	19.34	6.0	3.24
1.0×10^{0}	19.09	7.0	3.07
2.0	18.13	8.0	2.95
3.0	17.40	9.0	2.90
4.0	16.92	1.0×10^{4}	2.78
5.0	16.19	2.0	2.29
6.0	16.19	3.0	2.03
7.0	15.95	4.0×10^{4}	1.84
8.0	15.71	5.0	1.69
9.0	15.47	6.0	1.59
1.0×10^{1}	15.23	7.0	1.49
2.0	14.50	8.0	1.45
3.0	13.40	9.0	1.40
4.0	12.57	1.0×10^{5}	1.38
5.0	12.09	2.0	1.11
6.0	11.60	3.0	0.97
7.0×10^{1}	11.12	4.0	0.87
8.0	10.88	5.0	0.79
9.0	10.63	6.0	0.73
1.0×10^{2}	10.15	7.0	0.70
2.0	8.70	8.0	0.65
3.0	7.98	9.0	0.63
4.0	7.25	1.0×10^{6}	0.60
5.0	7.01	2.0×10^{6}	0.44
6.0	6.77	3.0×10^{6}	0.12

TABLE 9.2-17

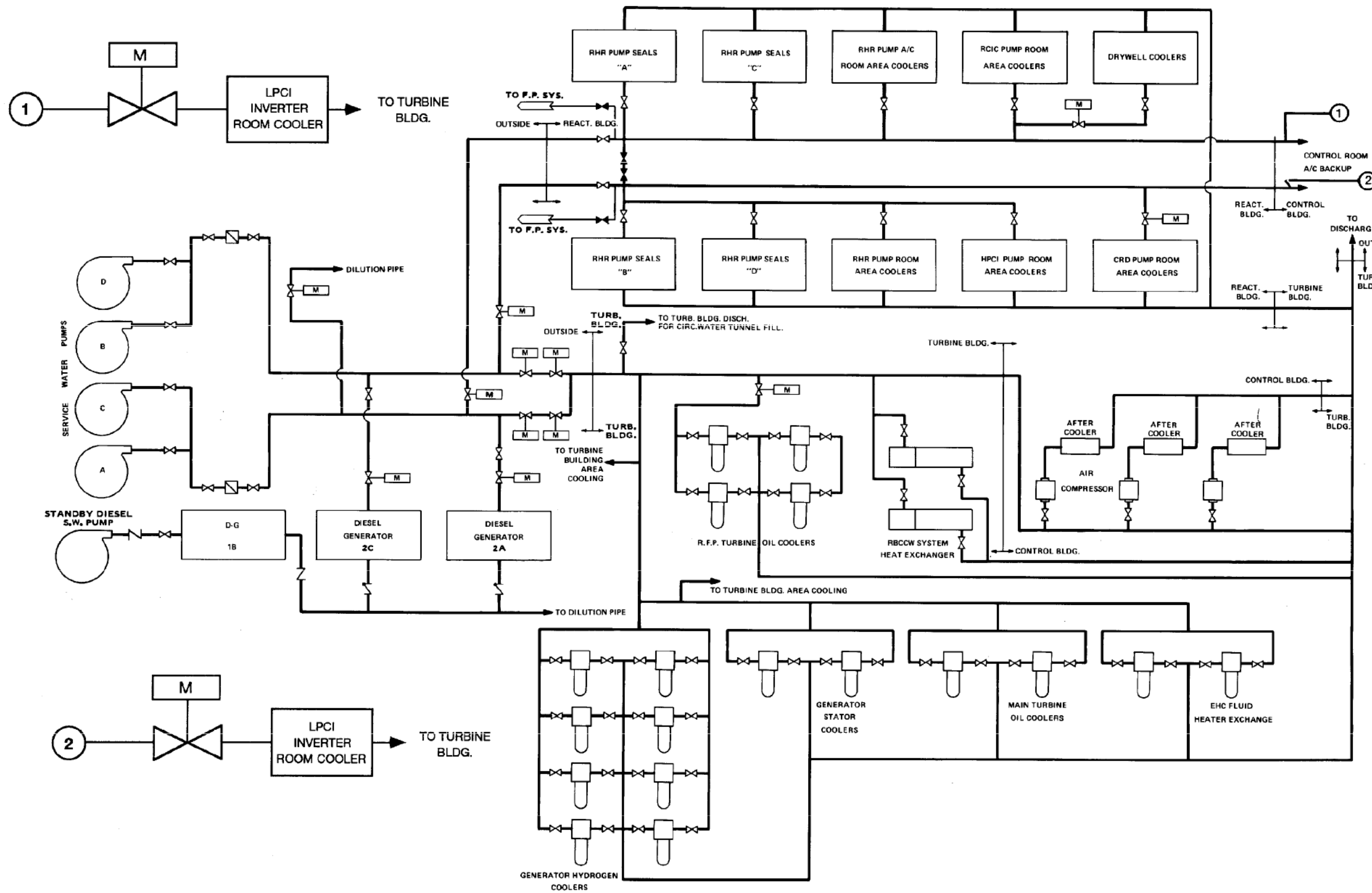
INTEGRATED DECAY HEAT

Time After Shutdown (s)	Integrated Decay Heat (Btu)	Time After Shutdown (s)	Integrated Decay Heat (Btu)
1.0×10^{-1}	2.102×10^{4}	7.0	5.88×10^{7}
2.0	4.19×10^{4}	8.0	6.52×10^{7}
3.0	6.26×10^{4}	9.0	7.14×10^{7}
4.0	8.30×10^{4}	1.0×10^{3}	7.74×10^{7}
5.0	1.03×10^{5}	2.0	1.31×10^{8}
6.0	1.23×10^{5}	3.0	1.73×10^{8}
7.0	1.43×10^{5}	4.0	2.10×10^{8}
8.0	1.62×10^{5}	5.0	2.46×10^{8}
9.0	1.82×10^{5}	6.0	2.79×10^{8}
1.0×10^{0}	2.01×10^{5}	7.0	3.10×10^{8}
2.0	3.87×10^{5}	8.0	3.40×10^{8}
3.0	5.65×10^{5}	9.0	3.69×10^{8}
4.0	7.37×10^{5}	1.0×10^{4}	3.98×10^{8}
5.0	9.02×10^{5}	2.0	6.52×10^{8}
6.0	1.06×10^{6}	3.0	8.68×10^{8}
7.0	1.23×10^{6}	4.0×10^{4}	1.06×10^{9}
8.0	1.38×10^{6}	5.0	1.24×10^{9}
9.0	1.54×10^{6}	6.0	1.40×10^{9}
1.0×10^{1}	1.69×10^{6}	7.0	1.55×10^{9}
2.0	3.18×10^{6}	8.0	1.70×10^{9}
3.0	4.57×10^{6}	9.0	1.85×10^{9}
4.0	5.87×10^{6}	1.0×10^{5}	1.98×10^{9}
5.0	7.11×10^{6}	2.0	3.23×10^{9}
6.0	8.29×10^{6}	3.0	4.27×10^{9}
7.0×10^{1}	9.43×10^{6}	4.0	5.19×10^{9}
8.0	1.05×10^{7}	5.0	6.03×10^{9}
9.0	1.16×10^{7}	6.0	6.79×10^{9}
1.0×10^{2}	1.26×10^{7}	7.0	7.50×10^{9}
2.0	2.21×10^{7}	8.0	8.18×10^{9}
3.0	3.05×10^{7}	9.0	8.82×10^{9}
4.0	3.81×10^{7}	1.0×10^{6}	9.43×10^{9}
5.0	4.53×10^{7}	2.0×10^{6}	1.46×10^{10}
6.0	5.21×10^{7}	3.0×10^{6}	1.74×10^{10}

TABLE 9.2-18

TOTAL INTEGRATED HEAT REJECTED

After Time Shutdown (s)	Total Heat Released (Btu)	Time After Shutdown (s)	Total Heat Released (Btu)
1.0×10^{1}	1.753×10^{6}	7.0	4.55×10^{8}
2.0	3.306×10^{6}	8.0×10^{3}	4.913×10^{8}
3.0	4.759×10^{6}	9.0	5.266×10^{8}
4.0	6.121×10^{6}	1.0×10^{4}	5.619×10^{8}
5.0	7.424×10^{6}	2.0	8.787×10^{8}
6.0	8.667×10^{6}	3.0	1.158×10^{9}
7.0	9.87×10^{6}	4.0	1.412×10^{9}
8.0	1.100×10^{7}	5.0	1.655×10^{9}
9.0	1.217×10^{7}	6.0	1.88×10^{9}
1.0×10^{2}	1.423×10^{7}	7.0	2.095×10^{9}
2.0	2.536×10^{7}	8.0	2.309×10^{9}
3.0	3.539×10^{7}	9.0	2.522×10^{9}
4.0	4.461×10^{7}	1.0×10^{5}	2.716×10^{9}
5.0	5.344×10^{7}	2.0	4.601×10^{9}
6.0	6.187×10^{7}	3.0	$6.273 z 10^{9}$
7.0	7.72×10^{7}	4.0	7.824×10^{9}
8.0	9.723×10^{7}	5.0	9.294×10^{9}
9.0	1.131×10^{8}	6.0	1.068×10^{10}
1.0×10^{3}	1.267×10^{8}	7.0	1.202×10^{10}
2.0	2.206×10^{8}	8.0	1.333×10^{10}
3.0	2.799×10^{8}	9.0	1.459×10^{10}
4.0	3.301×10^{8}	1.0×10^{6}	1.584×10^{10}
5.0	3.754×10^{8}	2.0	2.729×10^{10}
6.0	4.167×10^{8}	3.0	3.386×10^{10}



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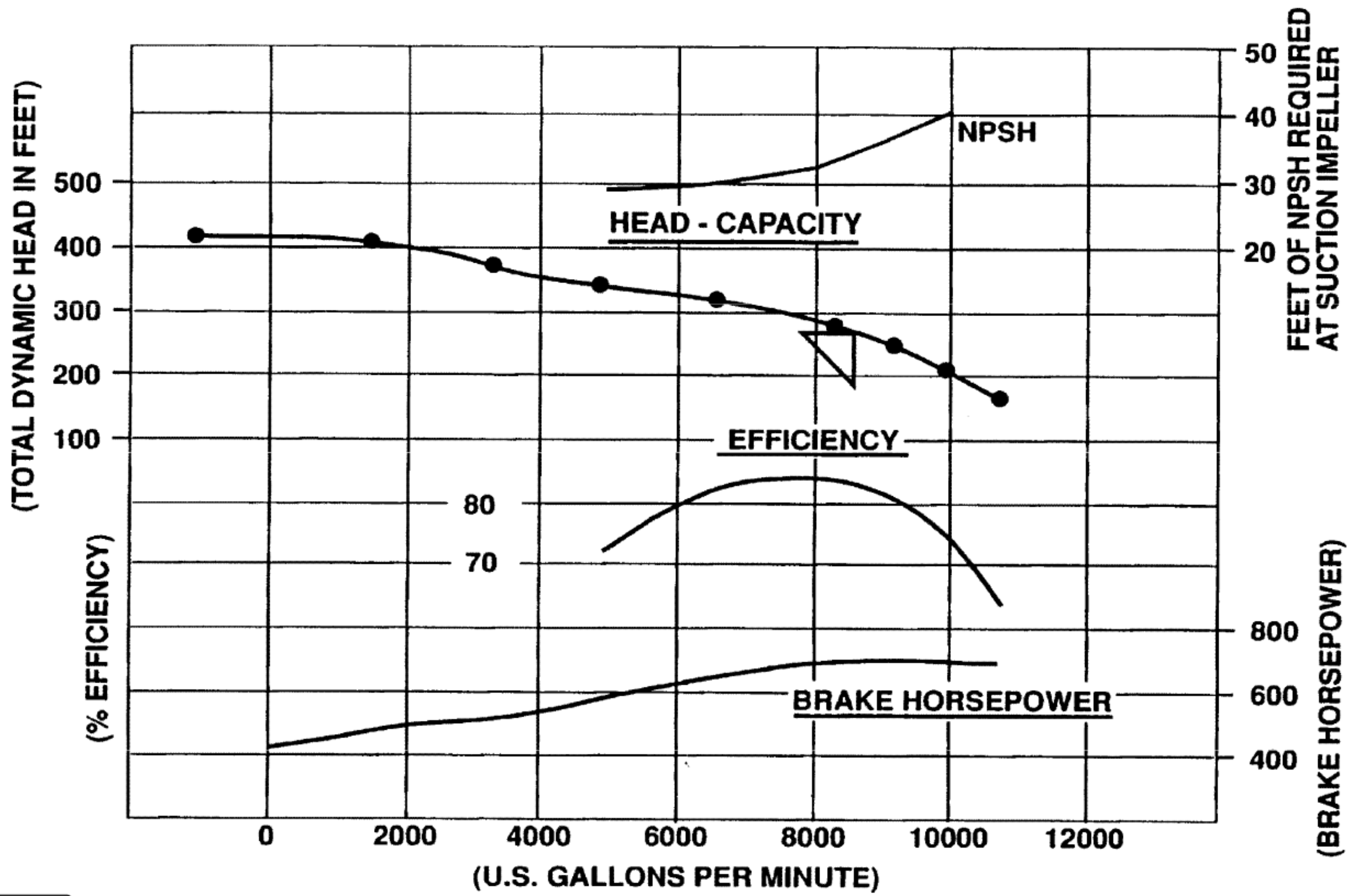
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

PSW FLOW DIAGRAM

FIGURE 9.2-1



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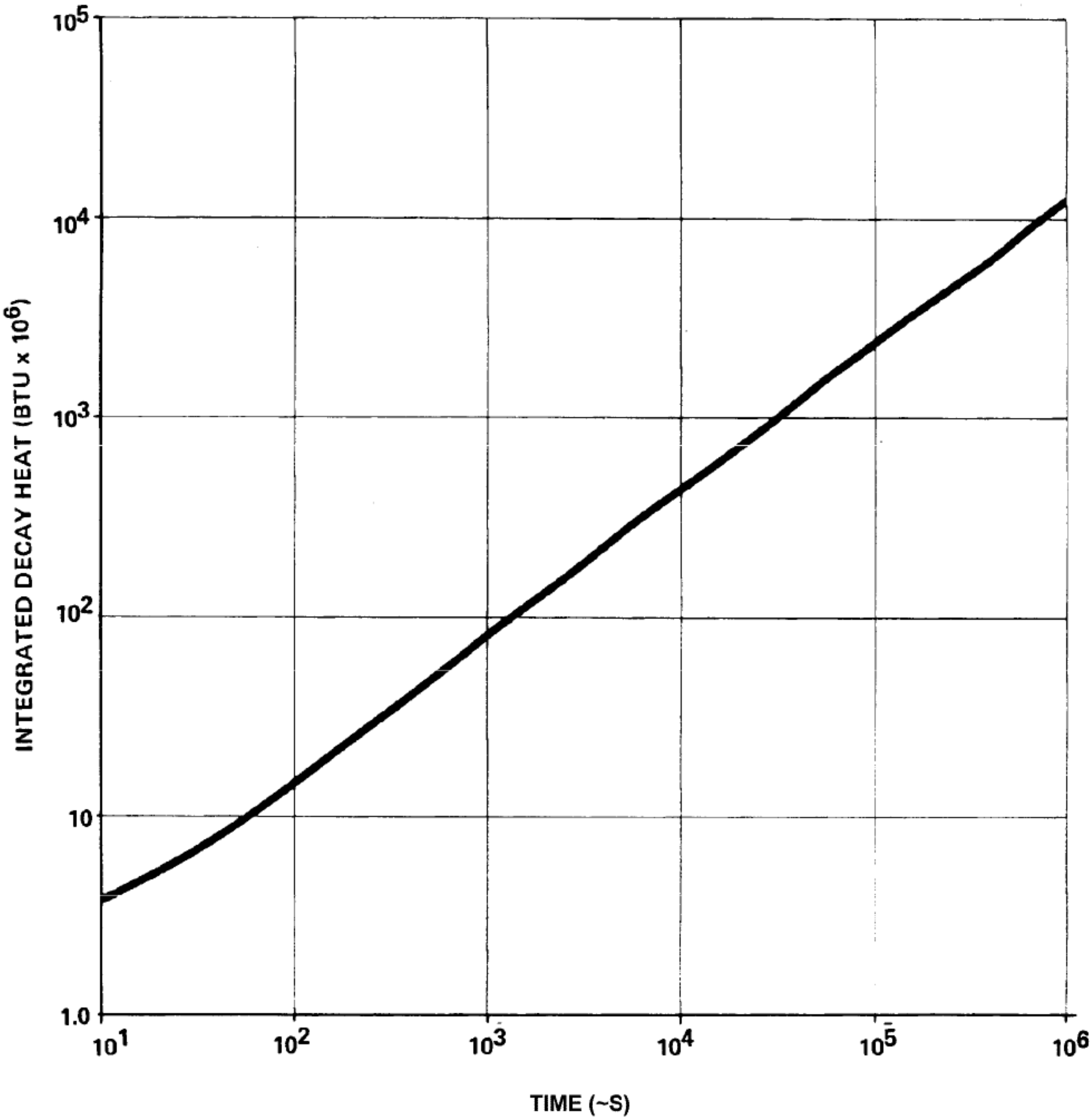
UNIT 1 AND UNIT 2

PSW PUMP CHARACTERISTICS
(TYPICAL)

FIGURE 9.2-2



$P_0 = 2.417 \times 10^6$ BTU/S

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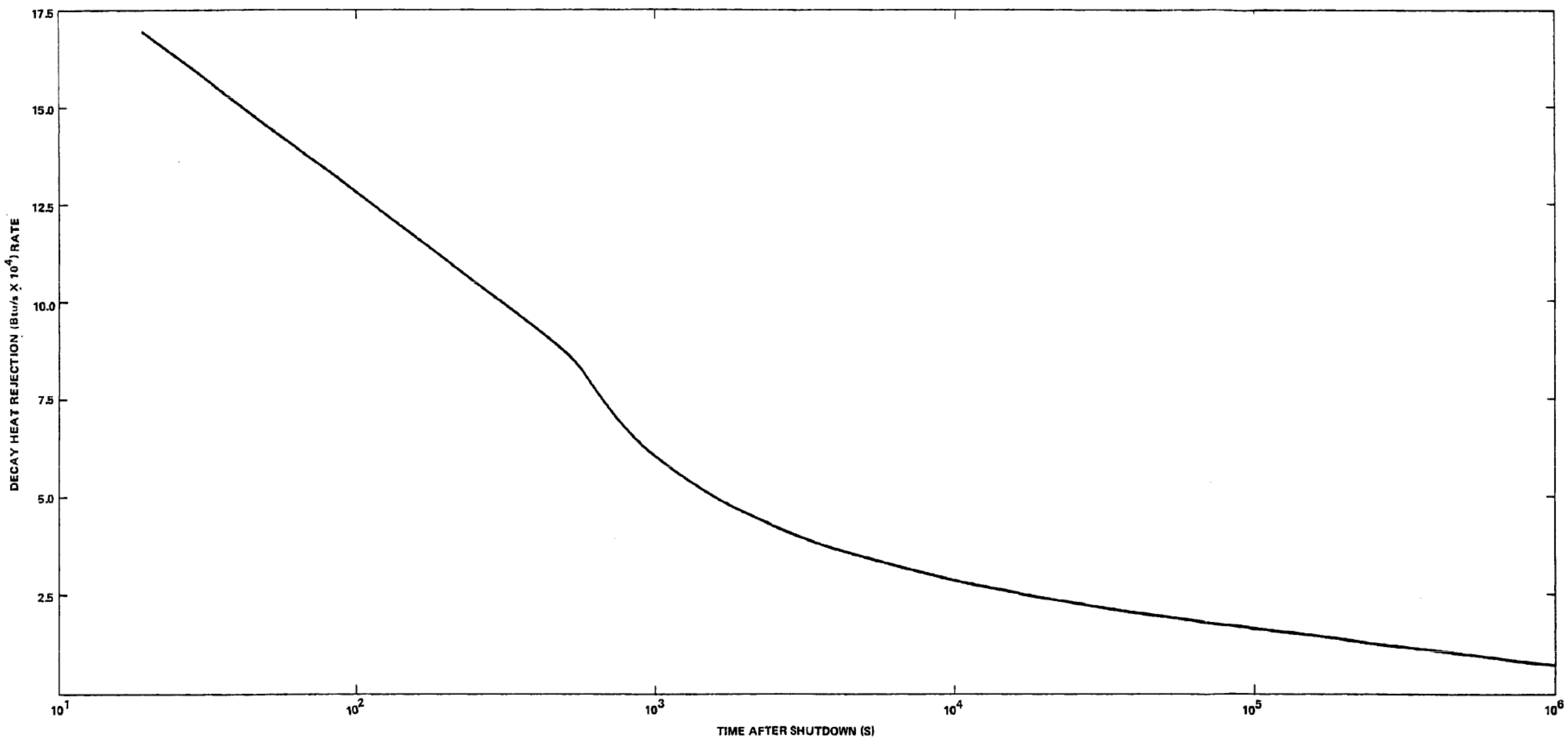
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

INTEGRATED DECAY HEAT INFINITE EXPOSURE AND IRRADIATION TIME

FIGURE 9.2-3



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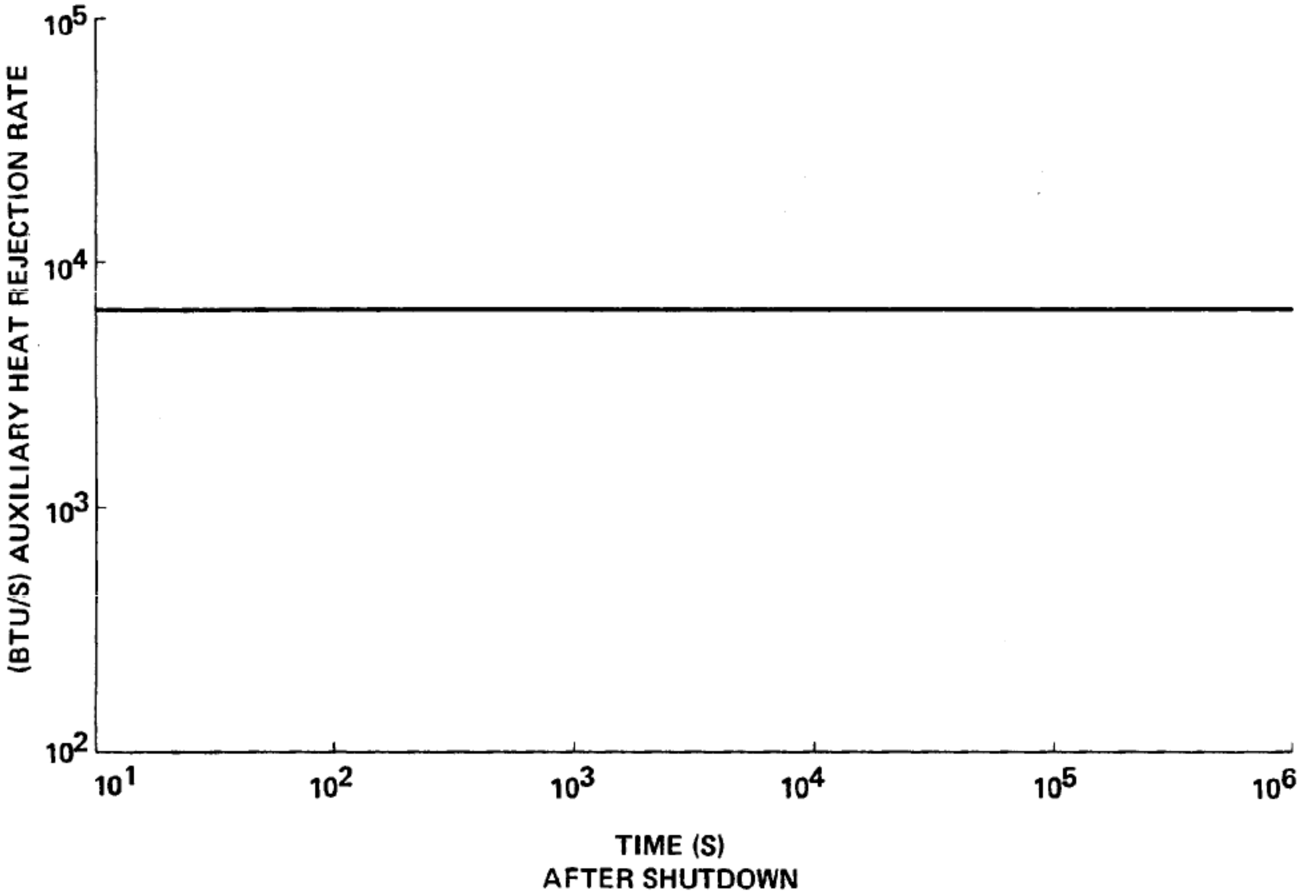
UNIT 2

DECAY HEAT REJECTION RATE

FIGURE 9.2-4



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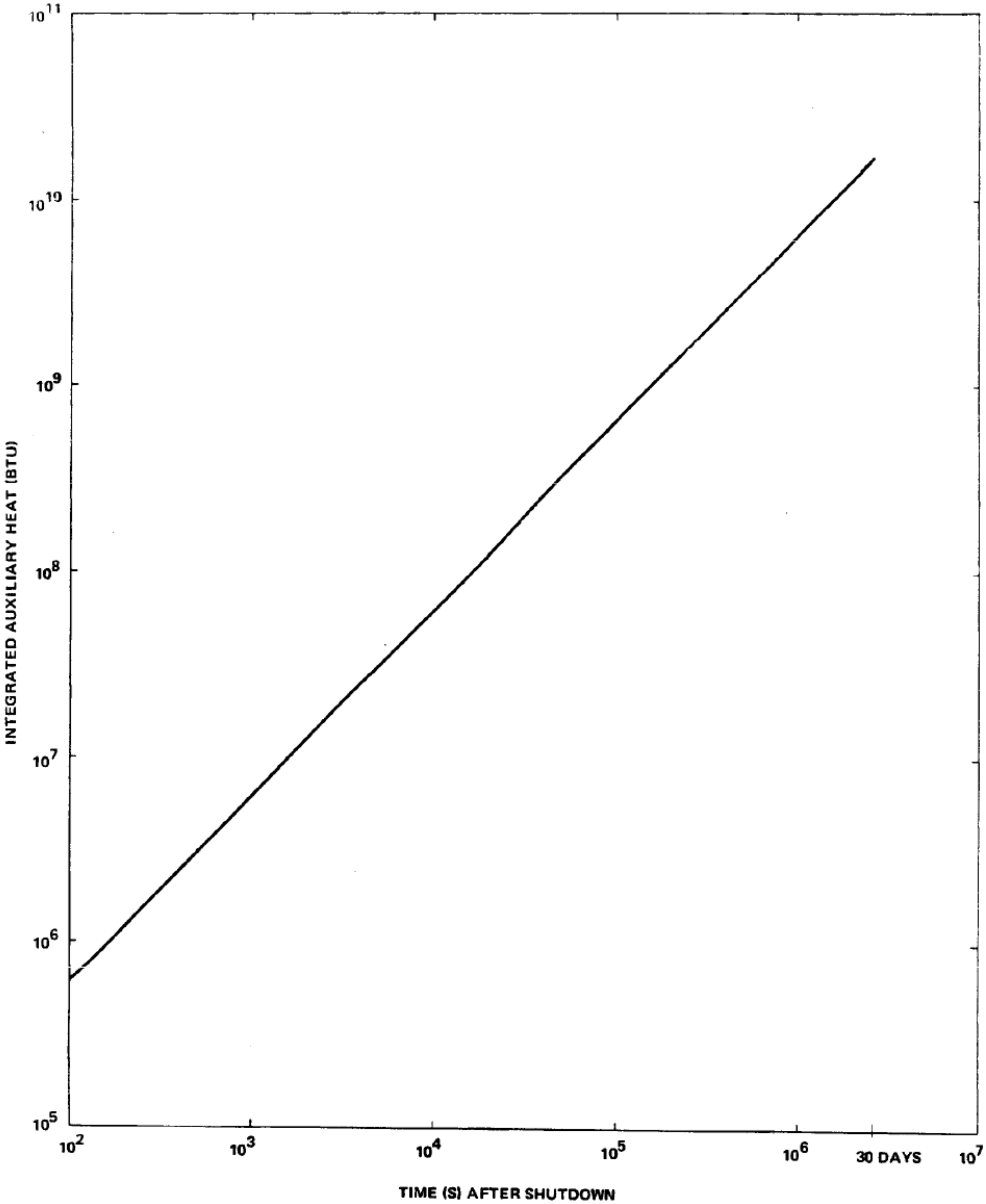
AUXILIARY SYSTEM HEAT REJECTION RATE

FIGURE 9.2-5



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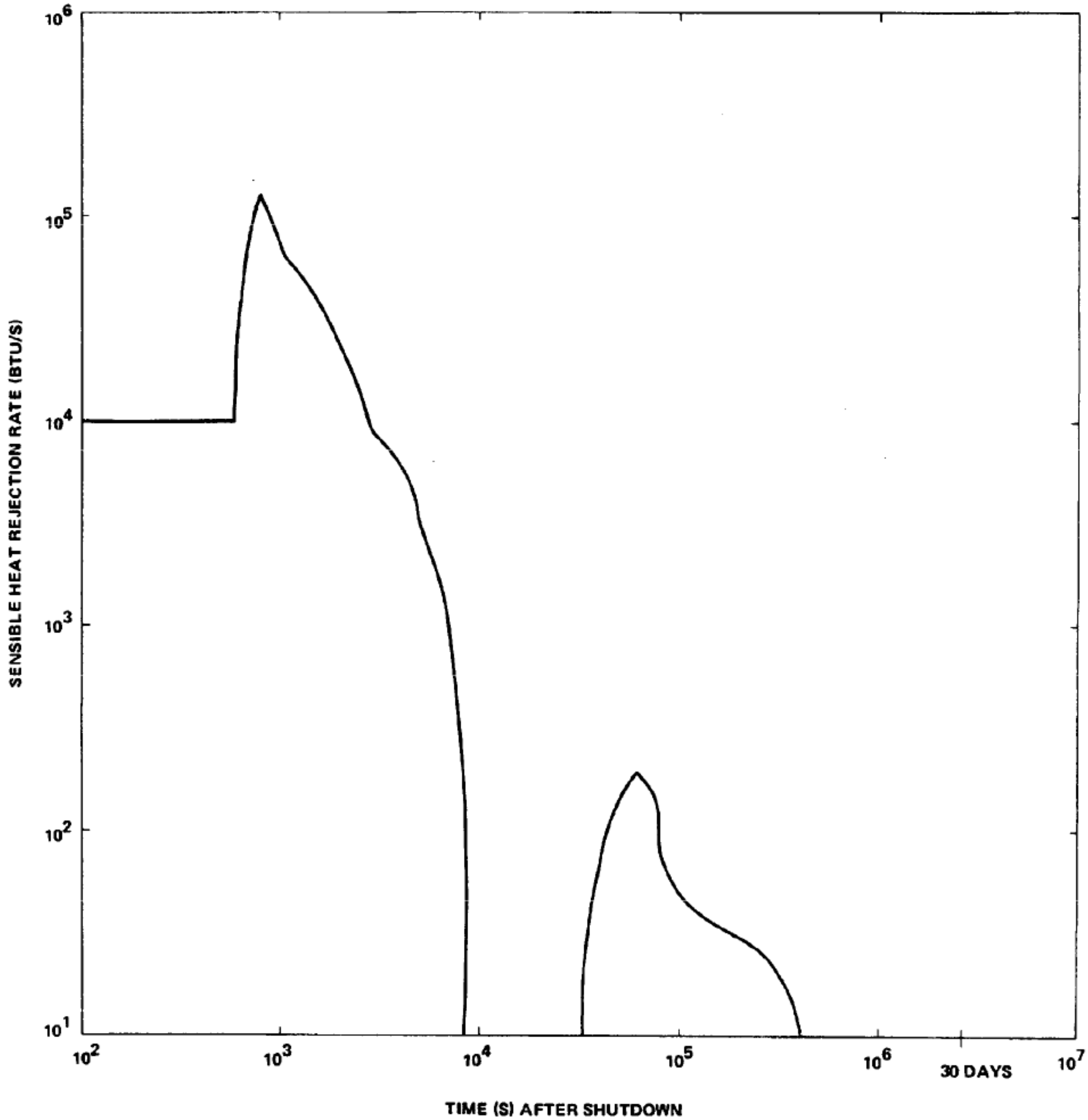
INTEGRATED AUXILIARY HEAT REJECTED

FIGURE 9.2-6



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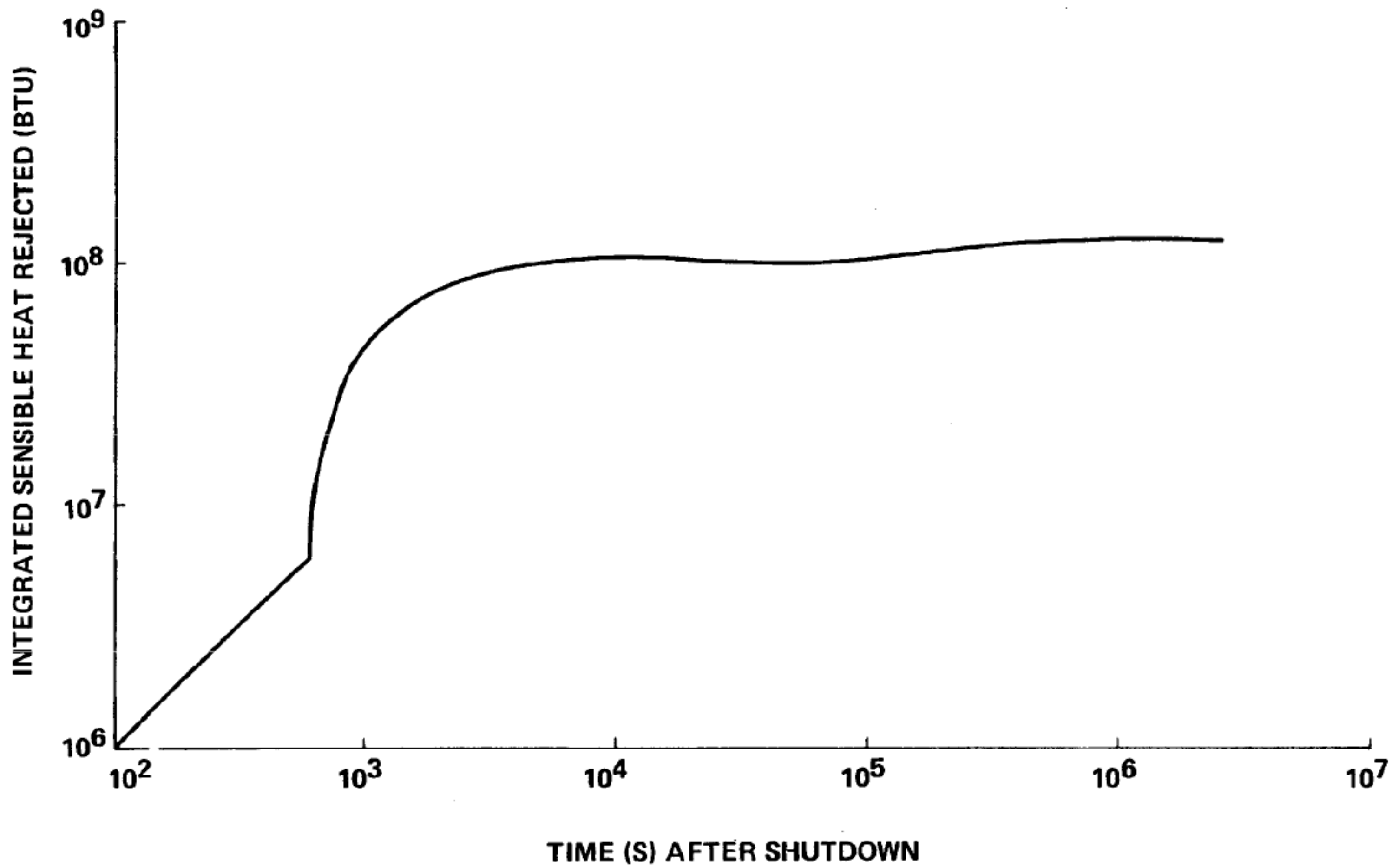
UNIT 2

SENSIBLE HEAT REJECTION RATE

FIGURE 9.2-7



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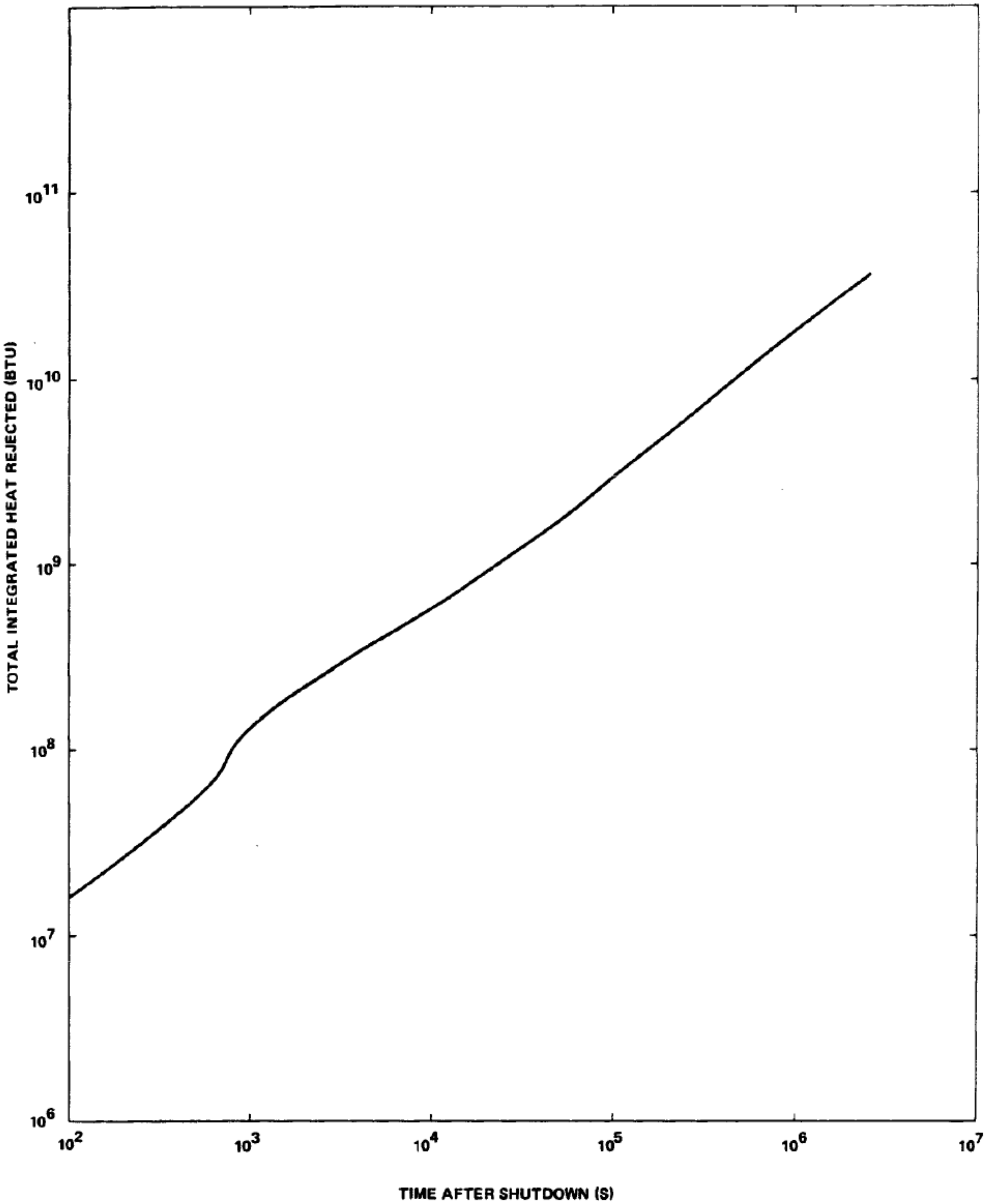
UNIT 2

INTEGRATED SENSIBLE HEAT REJECTED

FIGURE 9.2-8



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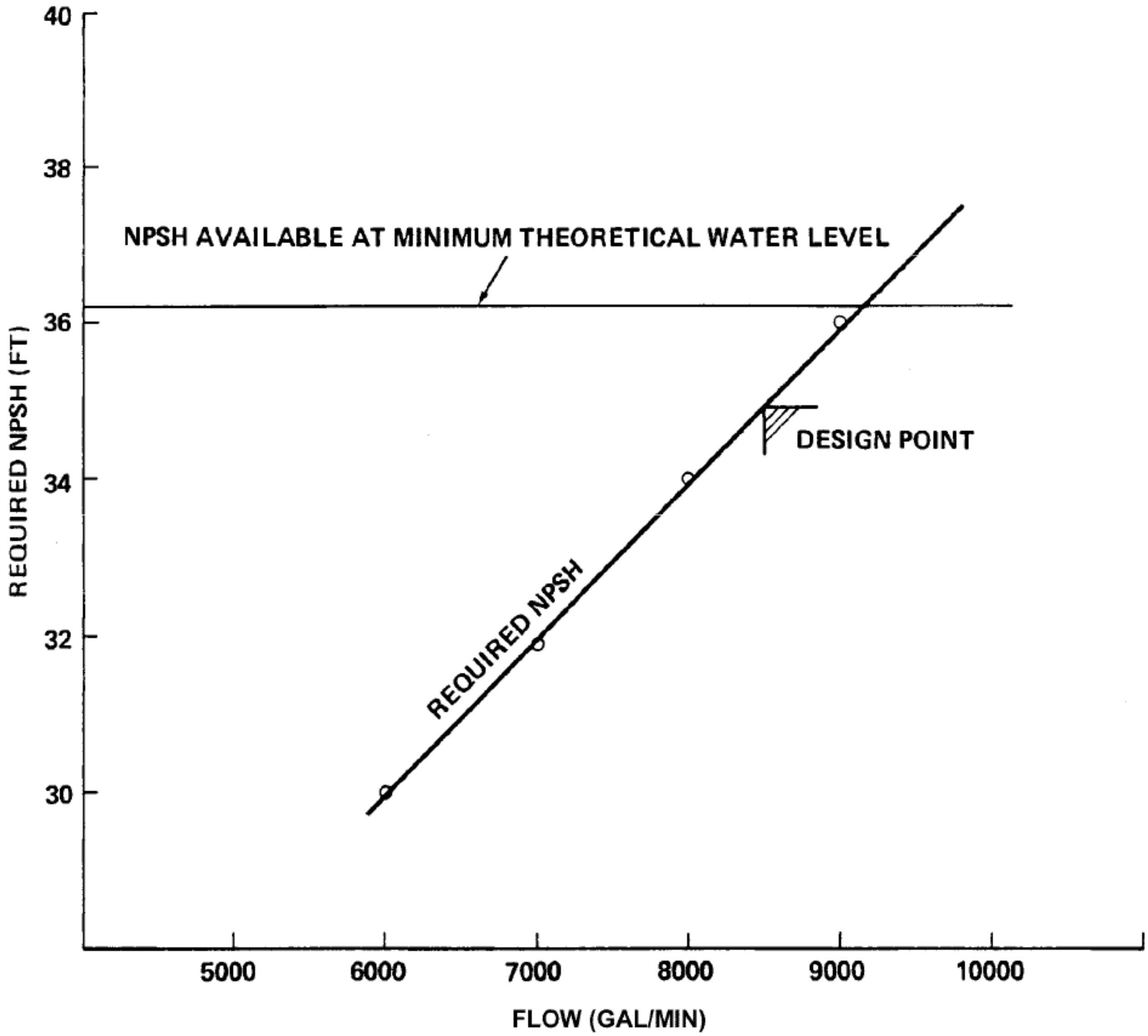
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TOTAL INTEGRATED HEAT REJECTED

FIGURE 9.2-9



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

PSW WATER PUMP REQUIRED
NPSH VERSUS FLOW

FIGURE 9.2-10

THIS FIGURE HAS BEEN DELETED.

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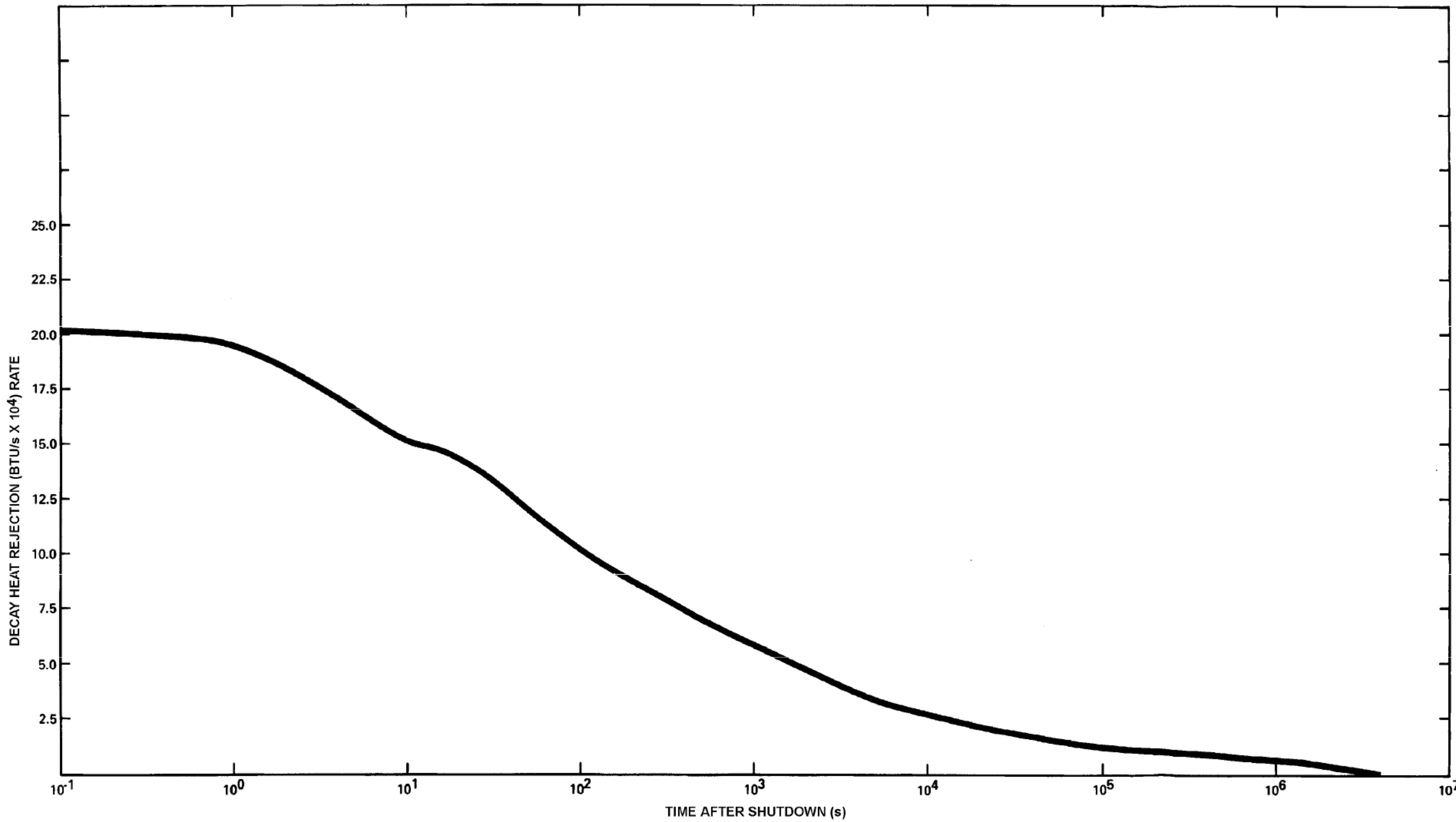
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RHRSW PUMP NPSH
REQUIRED VERSUS FLOW

FIGURE 9.2-11



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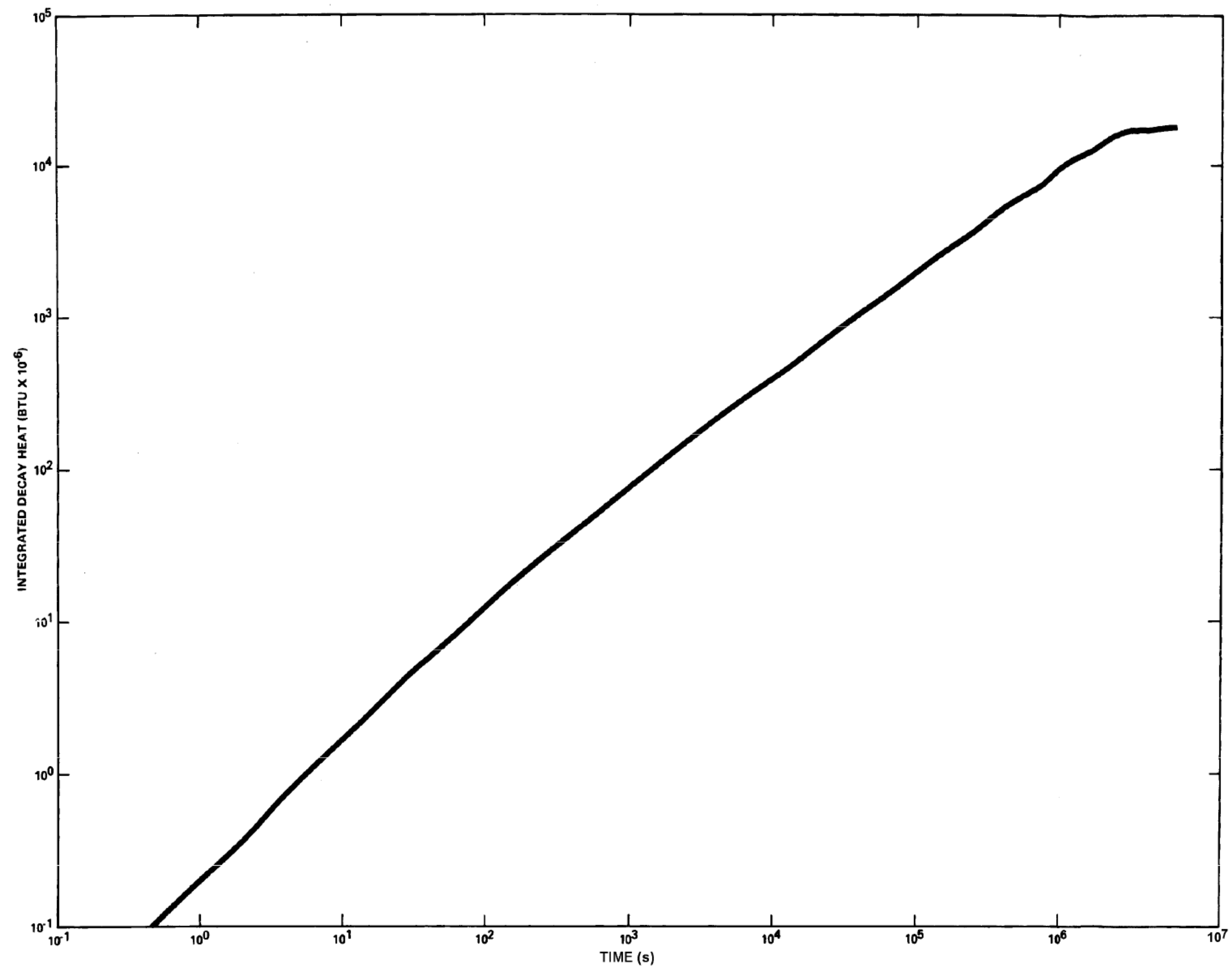
DECAY HEAT REJECTION RATE

FIGURE 9.2-12



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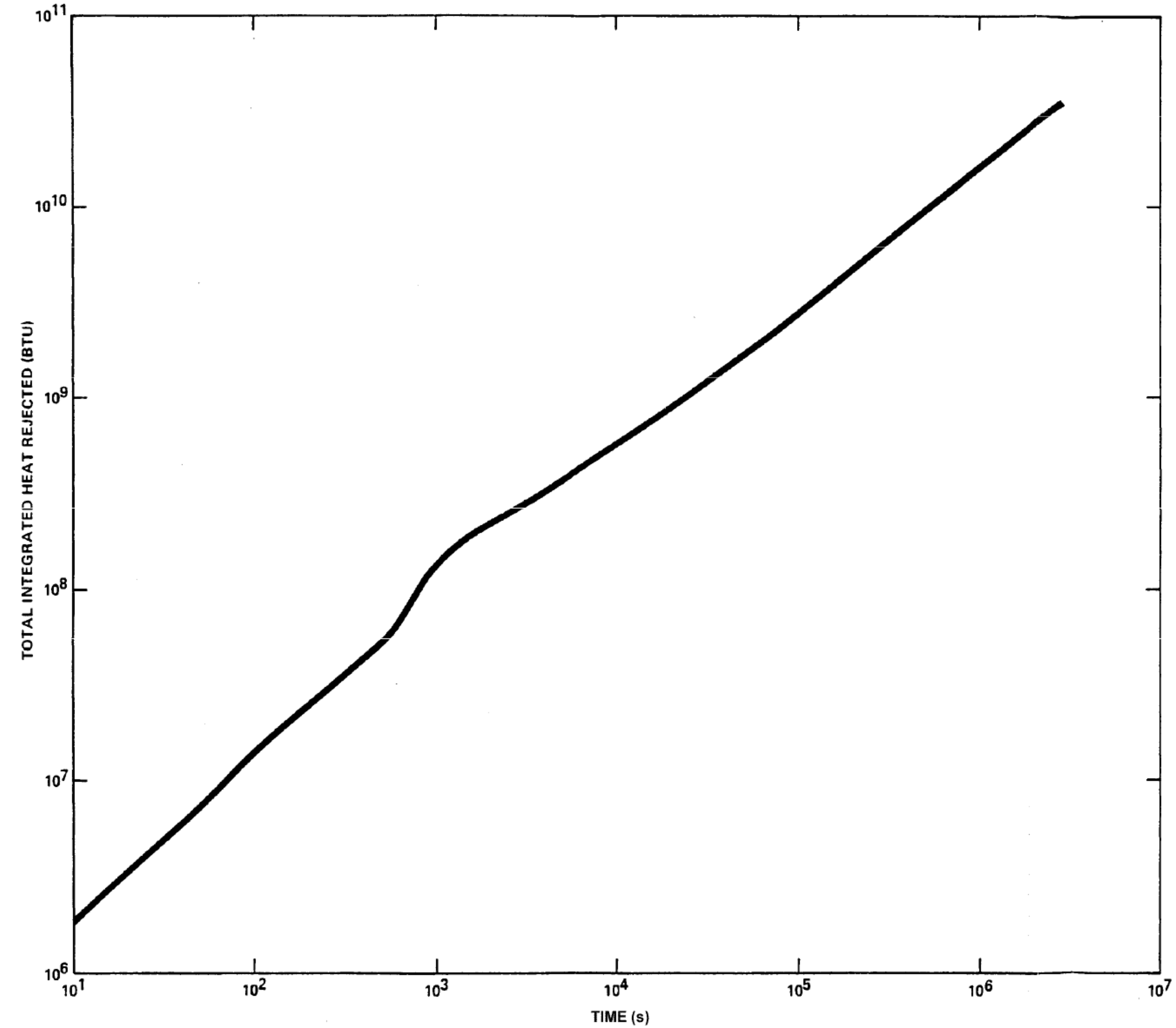
INTEGRATED DECAY HEAT

FIGURE 9.2-13



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UNIT 2

TOTAL INTEGRATED HEAT REJECTED

FIGURE 9.2-14

9.3 PROCESS AUXILIARIES

9.3.1 COMPRESSED AIR SYSTEMS

9.3.1.1 Design Bases

The compressed air systems are designed to provide the following:

- A continuous supply of dry, oil-free, filtered, compressed instrument air for use in the various plant instrumentation and other pneumatically powered equipment.

- A continuous supply of oil-free compressed service air to operate various types of plant servicing equipment and tools.

- A source of high-volume, low-pressure air for the fuel pool cooling and cleanup system (FPCCS) filter-demineralizers and reactor water cleanup (RWC) system filter-demineralizer backwashing operations.

- A source of high-volume, oil-free compressed service air to supply the air surge tank for the condensate polishing filter-demineralizer backwashing operations.

9.3.1.2 System Description

The compressed air systems, shown schematically on drawing nos. H-21028 and H-21077, consist of the service air and the instrument air systems. The instrument air system is divided into the following two subsystems:

- Noninterruptible: This system provides instrument air for the operation of certain emergency system components.

- Interruptible: This system provides instrument air to all other components not supplied by the noninterruptible system.

Motive gas for components within the drywell is supplied by the drywell pneumatic system and is discussed in subsection 9.3.6. The requirements for the remainder of the compressed air systems are supplied by 3 oil-free, screw-type air compressors (2 with a 500-sf^3/min capacity and 1 with a 700-sf^3/min capacity) connected in parallel and 2 low-pressure, high-volume air blowers.

The instrument air system includes an air dryer and two 100% capacity prefilters and afterfilters connected in parallel.

Internal to the air compressor, each screw-type (station service) air compressor has an intake filter, silencer, intercooler, aftercooler, moisture separator, blowoff cooler, oil cooler, oil reservoir

and automatic load controls. External to the air compressor, each has an aftercooler, moisture separator, dryer, receiver, valves, instrumentation, and associated piping. All compressor water jackets and coolers, as well as the external aftercoolers, are cooled by demineralized water in a closed loop which rejects its heat to a fan-cooled heat exchanger. Closed cooling water flow is maintained by two 100% capacity pumps. A portion of the cooling water return flow from the compressor cooling circuit is utilized as a heating source for the HVAC heating coil, which serves station battery rooms 2A and 2B. During normal operation, the one 700-sf^3/min compressor supplies all the compressed air requirements throughout the plant, exclusive of the drywell and the low-pressure requirements for demineralizers, with one of the two 500-sf^3/min compressors on automatic standby and the other in backup mode requiring operator action for energization.

The three station service air compressors discharge into a common manifold which feeds the instrument and service air systems. The instrument air passes through a prefilter, a heat reactivated desiccant dryer, and an afterfilter system that dries the air to a dew point of -40°F and removes up to 98% of particles 1.0 µm or larger before distribution throughout the plant. The service air is distributed throughout the plant for services not requiring filtered air. Automatic controls are provided to prevent the use of service air when the instrument air pressure decreases to 70 psig.

A low-pressure air blower supplies large volumes of low-pressure (18 psig) air to the FPCCS filter-demineralizers, and the RWC system filter-demineralizers for backwashing operations.

The condensate polishing system utilizes a large volume of service air to air surge backwash the demineralizer vessels. In this operation, an air surge tank stores service air for use during backwashing operations. The air surge backwash technique uses a short-duration, high-velocity burst of high-pressure service air that drives water to back wash the vessel elements.

9.3.1.3 Instrumentation Application

Instrumentation for the instrument and service air systems is primarily local and consists of pressure, differential pressure, and temperature indication and/or control. Pressure transmitters, pressure switches, indicating lights, and annunciation provide MCR indication of the system condition for both air systems. Both systems are intended to be maintained at constant pressure with local pressure reduction as required. Each station service air compressor may be started or stopped locally or from the MCR; local control is by a microprocessor-based system which provides indication, diagnostics, and equipment protection features.

9.3.1.4 Safety Evaluation

The compressed air systems are required for normal operation and startup of the plant. The air receiver capacity is adequate to supply instrument air to vital instrumentation for a period of not < 10 min in the event all air compressors fail. Because compressed air is not essential for safe shutdown of the plant, the compressed air systems do not switch automatically to operation from diesel generator power following a loss of normal power. However, either station service

compressor, 2A or 2B, has the capability of being operated from the standby diesel generation system.

Self-actuated valves are used to isolate nonessential portions of the instrument and service air systems on an abnormal pressure decay.

The noninterruptible portion of the instrument air system services certain valves in emergency systems for which operation is desirable, though not essential, following loss of pressure in the service air or interruptible portion of the instrument air system. The noninterruptible air system is Quality Group D with the exception of that portion serving the main steam isolation valves (MSIVs) which are Quality Group B and designed to be Seismic Category I. Check valves are provided to prevent the noninterruptible air header from depressurizing along with the rest of the air system in the short term. A nonredundant safety-grade nitrogen system automatically supplies the noninterruptible air system with long-term compressed gas based on low header pressure.

In addition, certain valves served by the noninterruptible air system, including MSIVs, are provided with Seismic Category I accumulators. These accumulators provide for reliable short-term operation of these valves if the nitrogen backup system is not available. Table 9.3-1 lists the valves provided with accumulators. Drawing nos. H-26260 and H-26261 show the arrangement of the accumulators.

The following vessels located onsite contain service and instrument air under pressure:

A. Service Air Receivers (2P51-A001 A, B, C)

The service air receivers (2P51-A001 A, B, C) are located inside the control building compressor room at el 112 ft 0 in. as shown on drawing no. H-12629. The design pressure and temperature for the receivers is 125 psig and 450°F, respectively. The normal operating pressure is 100 psig at a temperature of 100°F. The receivers are manufactured and tested in compliance with the American Society of Mechanical Engineers (ASME) Code, Section VIII, Unfired Pressure Vessels. The accumulators are equipped with safety relief valves which are set at 125 psig.

Since the service air receivers are located adjacent to the station battery room 2A, the possibility of failure has been evaluated. The normal operating temperature of 100°F is far above the nil ductility transition temperature (NDTT) for carbon steel. Thus, no mechanism for vessel rupture exists and only a line break is considered. At 125 psig and a maximum temperature of 125°F, the total internal energy that could be released is 5×10^6 ft-lb.

Postulating a complete break of the 8-in. line at the nozzle location 135 in. above the base flange, the maximum thrust at the nozzle is 11,400 lb at a pressure of 125 psig.

The critical section of the base, occurring through the center of the holes at 4.5 in. above the base flange, would be subjected to a moment of 1.49×10^6 in.-lb. The resulting bending stress would be 25,000 psi.

This does not exceed the ultimate material allowable stress of 70,000 psi. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile.

As shown above, there will be no possibility of loss of the batteries as a result of failure of these receivers.

The consequences of failure of the HVAC heating coil serving station battery rooms 2A and 2B were evaluated. Calculations determined that the weight of the volume of water from the closed cooling system in the HVAC supply duct in station battery rooms 2A and 2B would not result in the failure of the duct or its hangers, that spray from a coil failure would be contained in the duct and not spray onto the batteries, and that emptying the entire water volume of the cooling system into the station battery room with the resulting flood level would not damage or disable the station batteries.

B. Instrument Air Accumulators (2P52-A001 through -A016, 2P52-A018, and 2B21-A002 A, B, C, D)

There are 17 instrument air accumulators, 2P52-A001 through -A016 and 2P52-A018, located around the reactor building (drawing nos. H-26260 and H-26261). The design and normal operating pressures for the accumulators are 150 psig and 100 psig, respectively. The design and normal operating temperatures are 150°F and 100°F, respectively. The accumulators employ nitrogen as a backup source of motive gas. The liquid nitrogen system provides gaseous nitrogen at a maximum pressure of 140 psig.

The accumulators are constructed of SA-240, Type 304, stainless steel in compliance with the ASME Code, Section VIII, Division 1.

Since the accumulators are constructed of stainless steel, no possibility of brittle fracture is foreseen, nor is stress corrosion cracking considered a possibility because the accumulators are not subjected to a salt environment nor exposed to other fluids; therefore, no mechanism for vessel rupture exists.

The bursting pressure of the accumulators, based on minimum ultimate strength of the material is 1300 psig. The calculated burst pressure is 9.3 times the maximum operating pressure of 140 psig. At a maximum temperature of 125°F, the total internal energy that could be released would be 2.1×10^5 ft-lb.

Postulating a separation of the largest line entering the accumulators, which is 1 in., a thrust of 181 lb results, assuming a pressure of 140 psig.

This force is a much smaller load than the strength of the holddown bolts. The force needed to fail one bolt is 15,600 lb. Thus, the tank will not break loose as a

result of pipe failure and will not act as a missile. In addition, there are four instrument air accumulators (2B21-A002-A through D), as shown on drawing no. H-26070, in the instrument air system for the MSIVs. These accumulators have a design and operating pressure of 150 psig and 100 psig, respectively and are also designed for a 70-psig external pressure. These accumulators are backed up by the liquid nitrogen system which has a maximum operating pressure of 140 psig.

The accumulators are designed as Seismic Category vessels and in accordance with the ASME Code, Section III, Class 2. The design temperature is 150°F. The accumulators are constructed of SA-240, Type 304 stainless steel.

Since the accumulators are constructed of stainless steel, no possibility of brittle fracture is foreseen, nor is stress corrosion cracking considered a possibility because the accumulators are not subjected to a salt environment nor exposed to other corrosive fluids. Therefore, no mechanism for vessel rupture exists.

The bursting pressure of the accumulators, based on a minimum ultimate strength of the material, is 1460 psig. The calculated burst pressure of the accumulators is 10.4 times the maximum operating pressure which is assumed to be 140 psig. At a maximum temperature of 125°F, the total internal energy that could be released would be 2.1×10^5 ft-lb.

Postulating a separation of the largest line entering the accumulator which is 1 in., a thrust of 181 lb results assuming a pressure of 140 psig. The force is a much smaller load than the strength of the holddown bolts. The force needed to fail one bolt is 15,600 lb. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile.

C. Transfer Canal Transition Piece Seal Air Accumulator (2P51-A002)

The transfer canal accumulator is a 13-ft^3 tank (liquid volume) located on the refueling floor at el 228 ft 0-in. near the 3-in. gap between the HNP-1 and HNP-2 reactor buildings. This accumulator supplies air to the transfer canal transition piece horizontal seals. It has a design pressure of 200 psig and a normal operating pressure of 100 psig at 100°F with a safety relief valve set at 125 psig. The accumulator is manufactured and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Unfired Pressure Vessels.

The accumulator tank is mounted seismically to ensure that it cannot damage any safety systems in the area. Since it does not perform a safety function itself, it is not required to function after a seismic event; however, the supply piping to the tank and the discharge piping to the seals have been analyzed and installed to meet Seismic Category II/I criteria.

The normal operating temperature is far above the NDTT for carbon steel; thus, no mechanism for vessel rupture exists, and only a line break is considered. At

125 psig and a maximum temperature of 100°F, the total internal energy that could be released is 43,400 ft-lb.

Postulating a complete break of the 2-in. line at the nozzle connection, the maximum thrust is 500 lb at a pressure of 125 psig. This thrust generates a combined shear-tension load of < 5 of the anchor bolt allowables. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile. (See HNP-1-FSAR section 10.11.)

The entry of contaminants into the system has been minimized by employing oil-free, screw-type air compressors, moisture separators, air dryers, and particulate filters. The system is designed for 150 psig and 150°F. Compressor relief valves prevent system pressure from exceeding 125 psig.

The posterection cleaning consists of a series of blowdowns from the system normal pressure with the first blowdown point as near to each compressor as practical. The blowdown point progresses away from the compressors as determined by the absence of oil, moisture, and particles from the blowdown. The cleaning media is the oilfree air supplied by the compressor. Seismic Category I piping is used for noninterruptible services. All of the piping in the system is designed to the American National Standards Institute (ANSI) B31.1.0 Code with the following exceptions:

A. Service air entering the primary containment is ASME Code, Section III, Class 2, and Seismic Category I.

B. Nonsafety-related air accumulators and receivers are designed to ASME Code, Section VIII, Seismic Category I.

C. Safety-related air accumulators for the MSIVs are designed to ASME Code, Section III, Class 2, Seismic Category I.

9.3.1.5 Tests and Inspections

The instrument air and service air systems are pneumatically tested for leaks after posterection cleaning. Soap-bubble testing is used on joints and welds where feasible. Observable leaks are repaired by joint tightening or weld repair. Preoperational testing of the instrument air system meets the intent of Regulatory Guide 1.80 (June 1974).

The instrument and service air systems operate continuously and are observed and maintained during normal operation.

9.3.2 PROCESS SAMPLING SYSTEM

9.3.2.1 Design Bases

The process sampling system is designed to:

- Provide representative liquid and gas samples for laboratory or online analysis. These samples provide information required to monitor plant and equipment performance and changes to operating parameters.

- Minimize the contamination and radiation at the sample station.

9.3.2.2 System Description

Samples are taken from various streams and locations as indicated on table 9.3-2. Sample points are grouped as much as possible at normally accessible locations and drains are provided at these locations to limit the risk of contamination. Lines are sized to ensure purging and sufficient velocities to obtain representative samples. The system is supplied with local sampling valves at the sampling stations for drawing process fluid into a closed sample container. These grab samples are then taken to the laboratory for appropriate analysis. In addition, continuous automatic monitoring and alarm of undesirable conditions is provided using inline detectors where necessary.

High-temperature, high-pressure fluid samples first pass through sample coolers, are processed, and then are routed to the sample sink. All other liquid process samples are routed directly to the sample sink. The sample sink is furnished with an exhaust hood, a sink, a chiller, and a demineralized water supply. The sink drains discharge to either the clean radwaste, dirty radwaste, or chem radwaste drains, depending upon the nature of the sample.

9.3.2.3 Instrumentation Application

Local temperature indicators, after the high-temperature and high-pressure sample heat exchangers, indicate the sample temperature before a sample is drawn in a sample sink.

Local pressure indicators, after the high-temperature and high-pressure sample heat exchangers, guide the adjustment of throttling valves. Pressure reduction valves are provided to protect the equipment and operators.

Inline process monitors and analyzers send output signals to panel-mounted indicators and recorders at the sample stations, and to panel-mounted recorders and alarm consoles in the main control room (MCR).

9.3.2.4 Safety Evaluation

The process sampling system has no safety design basis. The system is not classified as Seismic Category I; however, the sample lines in the reactor building only are installed as Seismic Category I. Fume hoods with exhaust fans are provided at the sampling stations to minimize exposure of operators to contaminated air and vapor when grab samples are being taken.

9.3.2.5 Tests and Inspections

The process sampling system is proved operable by its use during normal plant operation. Grab samples are taken to verify the proper operation of the continuous samplers. Portions of the system normally closed to flow can be tested to ensure the operability and integrity to the system.

9.3.3 EQUIPMENT AND FLOOR DRAINAGE SYSTEM

9.3.3.1 Design Bases

The equipment and floor drainage system is designed to:

- Collect waste liquids from their points of origin and remove to a suitable disposal area.

- Ensure that the sump pumps discharge at a flowrate adequate for preventing sump overflow during normally anticipated drainage periods.

- Detect abnormal leak rates in the primary containment and in the reactor building through the use of sump pump run timers and instrumented drainage sumps.

9.3.3.2 System Description

9.3.3.2.1 General Description

The collection systems, drainage sources, and collection points from areas of potential radioactivity are shown on drawing nos. H-21061 through H-21063, H-26002, H-26075, H-26076, and H-26092. The equipment and floor drainage systems consist of collection piping, equipment drains, floor drains, vents, traps, cleanouts, and collection sumps.

9.3.3.2.2 Component Description

A. Collection Piping

In areas of potential radioactivity, the collection system piping for the liquid waste system is carbon steel. The collection system piping for potentially radioactive chemical waste is stainless steel. Where deemed necessary to vent radwaste drainage collection systems, connections are provided to the filtered ventilation system. Offsets in the piping are provided where necessary for radiation shielding. The fabrication of the piping provides for a uniform slope which induces waste to flow in the piping at a velocity of not < 2 ft/s.

All floor drains are installed with rims flush with the low point elevation of the finished floor. Floor drains in areas of potential radioactivity are welded directly to the collection piping and are provided with expandable T-handle plugs.

B. Reactor Building and Primary Containment Equipment Drains

Reactor containment equipment wastes are collected in two separate systems. The drywell equipment drains sump system collects all equipment drains located in the primary containment. The reactor building equipment drain sump system handles drainage from equipment drains located in the secondary containment. Equipment wastes are collected in closed piping and discharged to an equipment drain sump. Pumps are provided to transfer these wastes from the sumps to the radwaste system. Containment is provided in transferring waste from the sumps to the radwaste system by maintaining a minimum water level in the sump which seals the pump suction lines. The drywell equipment drain discharge line penetrating the primary containment has two isolation valves which close upon a high drywell pressure signal or low reactor water level (level 3) signal.

A leak detection feature is provided by monitoring the frequency and duration of pump runs. Presence of large leaks is further indicated by a temperature alarm in the MCR, sensed by a temperature element in the sump.

The discharge lines of the drywell floor drain and equipment drain sumps are provided with radiation monitors which shut off the sump pumps automatically on high radiation. This prevents pumping of high level contaminants to the radwaste building.

The reactor building diagonal rooms that house the emergency core cooling system (ECCS) equipment, the high-pressure coolant injection (HPCI) room, and the torus chamber room are each equipped with instrumented floor drain sumps. (See drawing no. H-26076.) No single failure of any instrumentation (including LS-N006) prevents any of the protective actions, i.e., sump isolation, from occurring. These sumps gravity drain to the reactor building floor drain sumps located in the southeast and southwest diagonal rooms.

The instrumented sumps are isolatable from each other by means of remotely-operated valves and are equipped with instrumentation capable of monitoring leakage rates and providing alarms in the MCR in the event of excessive leakage.

The reactor building floor drain sumps are each provided with two 50-gal/min sump pumps which are sized to remove the maximum amount of anticipated drainage during normal operation and maintenance periods. Control of these sumps is described in paragraph 9.3.3.3.

In the event of flooding from the torus, detectors in the torus chamber room sumps would detect and alarm the excessive leakage condition. Should the floor drain sump pumps be unable to discharge the excess drainage, the torus room sumps are automatically isolated to prevent flooding in the diagonal rooms. The diagonal rooms are separated from the torus chamber room by 2-ft-thick concrete walls that are designed to withstand the hydrostatic loads due to torus flooding. Piping penetrations into the diagonal rooms below the calculated maximum height of torus chamber flooding are sealed to prevent leakage. Entrance into the diagonal rooms is from above, thereby preventing potential leakage paths.

Flooding of a diagonal room or the HPCI room due to a line break in the room can be confined to that room alone by means of the remotely operated isolation valves in the drainage system. Redundancy of essential equipment and physical separation of the diagonal rooms, coupled with the remote isolation capability of the drainage system, ensures the protection of the ECCS against common flooding events.

Design provisions for protection against flooding due to natural phenomena are discussed in section 3.4.

C. Turbine Building Equipment Drains

The turbine building radioactive equipment drainage begins with drains at all items of equipment which require draining, collects in branch lines, empties into main waste lines, and discharges into the equipment drain sump located below the basement level. Sump pumps are provided to pump the discharge from the turbine building to the radwaste system.

D. Radwaste Building Equipment Drains

The radwaste building radioactive equipment drainage begins with drains at all items of equipment, collects in branch lines, and empties into main waste lines to a collecting sump. Sump pumps are provided to pump the discharge from the radwaste building sumps to the radwaste system.

E. Waste Gas Treatment Building Equipment Drains

The waste gas treatment building radioactive equipment drainage begins with drains at all items of equipment, collects in branch lines, and empties into main waste lines to a collecting sump. Sump pumps are provided to pump the waste from the waste gas treatment building sumps to the radwaste system.

F. Radioactive Floor Drainage System

Except for the floor drains in the condensate backwash receiving tank area, all floor drains for the reactor building, turbine building, waste gas treatment building, control building, and radwaste building are collected in branch lines, emptied into main waste lines, and discharged into floor drain sumps located in the basements or the lowest level of the buildings. Sump pumps transfer these wastes from the building sumps to the radwaste system.

The floor drain sump pumps in the reactor building and primary containment also incorporate the leak detection feature described above under reactor building and primary containment equipment drains; however, no temperature detection system is provided.

Floor drains in the condensate backwash receiving tank area are collected by a small sump and its sump pump discharges its collected drains to the turbine building floor drain sump.

G. Technical Support Center Carbon Filter Drains

The technical support center carbon filter drains empty into a collection sump located in the technical support center mechanical equipment room. No sump pumps are provided to discharge from this sump.

H. Nonradioactive Water Drainage System

Roof drains from the reactor building, radwaste building, turbine building, control building, and service building are collected and discharged to the storm drain system which discharges to the river.

Floor drains in the technical support center are also discharged to the storm drain system.

9.3.3.3 Instrumentation Application

Primary containment and reactor building sumps are provided with the following instruments and controls:

A. One of two sump pumps is started or stopped on rise or fall of the sump level as selected by the electrical alternator. If the level of water in the sump reaches an abnormally high level, both pumps are started automatically.

B. A leak detection feature is provided by monitoring the frequency and duration of pump runs. Presence of large leaks is further indicated by a temperature alarm in the MCR, sensed by a temperature element in the equipment sump.

C. A flow totalizer is provided in the discharge line of the drywell equipment and floor drain sumps to provide for periodic checks of identified and unidentified leakage rates.

D. High radiation levels sensed in the discharge lines of the primary containment sumps shut off the sump pumps automatically to prevent pumping of high-level contaminants to the radwaste building.

The other sumps, including other equipment drain sumps and turbine and radwaste building floor drain sumps, are provided with instrumentation similar to the above, except that they have no separate level switch for alarm, no temperature element or alarm, no leak detection system, and no high-radiation detection.

9.3.3.4 <u>System Evaluation</u>

To provide reliable operation of the plant equipment and floor drainage system, the sumps are provided with duplex sump pumps which were originally designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 3, with the exception of the condensate backwash receiving tank area sump pump. Replacement pumps may be procured and designed to the manufacturer's standard code.

Additionally, those sumps located within the reactor building and the primary containment are qualified to Seismic Category I requirements.

9.3.3.5 <u>Tests and Inspections</u>

Portions of the plant equipment and floor drainage systems were hydrostatically or air tested during erection to assure integrity of the system.

Other portions are proved operable by use during normal plant operation.

9.3.4 CHEMICAL, VOLUME CONTROL, AND LIQUID POISON SYSTEMS

This subsection is not applicable to a boiling water reactor (BWR). The standby liquid control system (SLCS) is discussed in section 4.2.

9.3.5 FAILED FUEL DETECTION SYSTEM

Although the BWR core is designed to operate for the full-fuel cycle with essentially no fuel rod failures, the process radiation monitoring system provides the capability to detect rod failures.

In the event of gross rod failure, the increased activity in the coolant will be transferred to the steam and detected by the main steam line radiation monitoring system. Downstream of the steam line monitors are the carbon bed vault monitoring subsystem, the air ejector off-gas RMS, and off-gas vent pipe radiation monitoring system. These subsystems are described in chapter 11.

9.3.6 DRYWELL PNEUMATIC SYSTEM

9.3.6.1 Power Generation Design Bases

A. The drywell pneumatic system supplies clean, dry, oilfree gas nominally at 90 psig to the equipment within the drywell requiring motive gas.

B. Gas receiver storage capacity is adequate to supply vital equipment with gas for a minimum period of 10 min.

9.3.6.2 Safety Design Bases

Provide pneumatic supply to safety relief valves (SRVs) to ensure short-term capability to actuate these valves when required.

A. Provide pneumatic supply to SRVs to ensure long-term capability to actuate these valves when required.

B. Protect against inadvertent actuation of SRVs and MSIVs due to excess pneumatic supply pressure.

C. Provide containment isolation capability.

D. Protect against depletion of the nitrogen supply and overpressurization of drywell due to rupture of the pneumatic header in drywell.

9.3.6.3 System Description

During normal operation, valves 2P70-F001A & B are opened, allowing the makeup nitrogen supply from the nitrogen inerting system (2T48) to satisfy motive gas requirements. The nitrogen is piped from the nitrogen supply through particulate filters and pressure regulators and ultimately distributed to the equipment in the drywell by two separate headers. (See drawing nos. H-26066 and H-28023.)

Supply header pressure regulators reduce the gas pressure to ~ 107 psig to maintain the pneumatic header pressure in the drywell above the minimum allowable 90 psig.

Vital components, such as MSIVs and main steam SRVs, have gas accumulators to ensure reliable operation in case of interruption of gas supply. In order to utilize receiver 2P70-A001 with the nitrogen supply, the internals of check valve 2P70-F016 must be removed and valve 2P70-F015 locked closed.

The original plant design utilized redundant compressors to take suction from the drywell atmosphere and return compressed gas to the drywell equipment. These compressors are now out of service. The compressors and the system malfunction alarm in the MCR are disconnected. The containment isolation valves on the compressor suction line remain operable and in place in a normally closed position.

A backup supply of nitrogen to the drywell is provided through three interchangeable nitrogen bottles and a manifold system at one of two emergency nitrogen hookup stations. This alternate mode of operation is described in paragraph 9.3.6.5.6.

9.3.6.4 Instrumentation Application

All control instrumentation for the drywell pneumatic system is located on the local panel except for the alarms which are located in the MCR. The remote manual switches for the makeup nitrogen supply valves and containment isolation valves are also located in the MCR.

Instrumentation consisting of pressure switches, level switches, pressure indicators, and differential pressure indicators is provided to ensure proper functioning of the system.

Pressure control valves are installed after the drywell pneumatic filters to reduce the supply gas pressure to meet the component requirement.

9.3.6.5 Safety Evaluation

Except for the main steam SRVs, pneumatic-operated devices in the drywell are designed for the fail-safe mode and do not require continuous gas supply under emergency or abnormal conditions.

9.3.6.5.1 Short-Term SRV Pneumatic Supply

Short-term SRV pneumatic supply requirements are satisfied by the individual accumulators provided for each ADS valve and installed for each non-ADS SRV. Each accumulator is sized to ensure two SRV actuations at 70% drywell design pressure (0.70 x 62 = 43.4 psig) within the first half hour. This elevated drywell pressure is the result of the largest primary system break for which the ADS is required. For smaller breaks in the drywell, or for breaks outside the drywell, the accumulator availability will be extended considerably. For events not involving breaks in the drywell, accumulator capacity is sufficient to ensure multiple SRV actuations for > 2 h.

The ADS is required for events where following an isolation, the reactor remains at high pressure, and the high-pressure makeup systems (e.g., HPCI) are not available to maintain vessel level. Specifically, for events resulting in reactor isolation or for small-break loss-of-coolant accidents (LOCAs) where break flow is insufficient to depressurize the reactor and HPCI is not available, the ADS valves must act to depressurize the vessel so that the low-pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system and the core spray (CS) system can be used to restore and maintain vessel level.

There are seven ADS valves, each provided with an accumulator. Analysis has shown that a maximum of one ADS valve could become pneumatically or electrically disabled due to a pipe break in the drywell. Therefore, a minimum of six ADS valves will be available during the first half-hour to depressurize the vessel if HPCI is not available. Per the Boiling Water Reactor Owners Group (BWROG) Emergency Procedure Guidelines (EPGs), the minimum number of SRVs required for rapid depressurization is three. In addition, for breaks less than three SRV port areas, at least three of the four non-ADS SRVs will be available. These valves can be manually actuated to help depressurize the vessel.

Soft-seated check valves were installed at the inlet to each ADS valve accumulator, as required by IE Bulletin 80-01, thus ensuring adequate leaktightness of the ADS valve accumulators in case their pneumatic supply is cut off. Pressure switches with alarms installed in the drywell pneumatic system supply headers will generate a low-pressure signal and alert the operator if the ADS accumulators are not being properly charged. A minimum accumulator pressure of 90 psig must be maintained during normal plant operation.

Other short-term pneumatic supply requirements for certain SRVs are stipulated by the low-low set (LLS) relief logic system.

9.3.6.5.2 Long-Term SRV Pneumatic Supply

Long-term SRV pneumatic supply requirements are satisfied by the modified drywell pneumatic system and the safety grade compressed nitrogen system. If the vessel has not been depressurized within the first half-hour after an isolation event (with or without a break in the drywell), at least three SRVs or an equivalent break size must be available to depressurize the vessel if required. Also, following certain events, a minimum of two SRVs may be required to provide an alternate shutdown cooling path for the vessel. (Reference BWROG EPG, Revision 18, August 27, 1981, written in response to NUREG-0737, Item I.C.1.) Specifically, this alternate shutdown cooling path is required when the RHR shutdown cooling path is not available.

9.3.6.5.3 Overpressure Protection Requirements

A pressure switch and alarm (2P70-PS-N017) installed in the common pneumatic supply header will alert the operator to excess pneumatic pressure which could cause inadvertent actuation of the SRVs or MSIVs. A relief valve (2P70-F100) provides positive overpressure protection. The high-pressure alarm and relief valve were added as required by IE Bulletin 80-25.

9.3.6.5.4 Containment Isolation Requirements

The design of the drywell pneumatic system satisfies the requirements of 10 CFR 50, Appendix A, General Design Criterion 56, concerning containment isolation. Two automatic isolation valves are provided for each header in the modified drywell pneumatic system.

Protection of the headers during a LOCA is provided by the flow instrumentation which will generate a high-flow signal and automatically close redundant isolation valves should an air header be ruptured inside the drywell. Provisions are included to allow containment leakage testing per 10 CFR 50, Appendix J.

9.3.6.5.5 Flow Instrumentation

Flow instrumentation is provided to sense a high flow or a rupture of either pneumatic header inside the drywell. The ruptured header will be automatically isolated, thus satisfying containment isolation requirements and ensuring that the liquid nitrogen tank (2T48-A001) will not be depleted and that the drywell will not be overpressurized due to uncontrolled nitrogen flow. A time delay is included in the high-flow isolation logic to ensure that isolation does not occur during normal actuation of air-operated valves in the drywell.

9.3.6.5.6 Protection Against Postulated Failures

The modified drywell pneumatic system uses two separate pneumatic headers inside the drywell, each supplying one-half of the SRVs (11 total) and other air-operated valves in the drywell. Four ADS valves and two non-ADS SRVs are on one header; the other three ADS valves and two non-ADS SRVs are on the second header. The two headers tie into a common header outside the drywell which is supplied by a safety grade, single-failure-proof compressed nitrogen system.

Separation is such that no pipe break in the drywell with a break area less than or equal to three SRV port areas can concurrently damage both pneumatic headers. This is significant because at least three SRVs, or an equivalent break size, are required to adequately depressurize the vessel. In addition, separation is such that no break described above can disable more than one ADS valve and one non-ADS SRV. Loss of one pneumatic header, one ADS valve, and one non-ADS SRV still leaves a minimum of three SRVs available for depressurization and alternate shutdown cooling. The ability of the SRVs to depressurize the reactor during design basis events is further protected by individual accumulators provided for each ADS valve. These accumulators are sized to ensure two SRV actuations at 70% drywell pressure. For smaller breaks, the accumulator availability will be extended considerably.

The drywell pneumatic system and the nitrogen system are not specifically protected from pipe break effects outside the drywell, except at the drywell penetrations. Credit is taken for local operator action to restore within 2 h the pneumatic supply, if damaged by a pipe break outside the drywell.

Three interchangeable nitrogen bottles and a manifold system are provided at the emergency nitrogen hookup station (2P70-F084) so the operator can restore pneumatic supply to the drywell in the event that the nitrogen supply from the purge and inerting system becomes unavailable as the result of a fire. The nitrogen bottles and manifold system are functionally not safety related. However, to protect the integrity of other safety-related systems in the area, the bottle rack is a Seismic Category I structure. A safety-related missile shield is installed above the bottle rack.

The drywell pneumatic system air receiver (2P70-A001) is located in the reactor building at el 158 ft as shown on drawing no. H-26066. The design pressure and temperature for the receiver are 150 psig and 200°F, respectively. The normal operating pressure is 125 psig at a temperature of ~ 100°F. The receiver is equipped with an SRV set at 145 psig and is manufactured and tested in compliance with ASME Code, Section III, Class 2.

The normal operating temperature of ~ 100°F is far above the NDTT of stainless steel. Thus, no mechanism for vessel rupture exists and only a line break is considered. At the design pressure and temperature, the total internal energy that could be released is 2.5×10^6 ft-lb.

The force needed to fail one bolt holding the manhole inspection cover is 75,750 lb. The force exerted on the cover at a pressure of 150 psig is 54,287 lb shared among 16 bolts. Postulating a separation of the largest line entering the receiver, which is a 2-in. line, a thrust of 797 lb results.

The critical section of the base would be subjected to a moment of 5.26×10^4 in.-lb. The force exerted would be shared by two of the four holddown bolts. However, assuming that only one bolt was subjected to the force exerted, the force would be 2664 lb. The force needed to fail one bolt is 57,750 lb. Thus, neither the tank nor any part of the tank will break loose or become a missile as a result of a pipe failure.

Each nozzle has been located such that it is not directed toward any essential or safety-related equipment. Therefore, jet loads resulting from the rupture of any piping connection would not impinge on any essential or safety-related equipment.

It is concluded that no protection beyond the existing fasteners and supports is required to protect against the aforementioned postulated failures.

The gas receiver and accumulators are designed, constructed, examined, tested, and stamped in full compliance with ASME Code, Section III, Class 2. All welded joints are 100% radiographed. A Seismic Category I design requirement is also specified.

9.3.6.6 Tests and Inspections

Preoperational inspection and testing were performed for each component during installation.

The drywell pneumatic system operates continuously when required and is monitored and maintained during normal plant operation.

SRV accumulator system leakage is checked during every refueling outage. Combined leakage from all points (i.e., check valve, solenoid valves, actuator, fittings, etc.) must be < 4.5 sf^3/h. Repairs needed to bring the leakage rate within the allowable value are made prior to plant startup.

9.3.7 TORUS DRAINAGE AND PURIFICATION SYSTEM

The torus drainage and purification system is typically not used either during plant shutdown or plant operation. A spool piece is removed and two manual isolation valves located adjacent to the torus are locked closed to ensure that torus water level cannot be inadvertently raised or lowered through system operation or leakage.

Alternate means are employed for torus cleaning during maintenance outages. Typically, a portable vacuum system with filters is used to periodically desludge the torus. The frequency of such torus cleaning is sufficient to ensure that the ECCS pump suction strainers can perform their function.

9.3.7.1 Design Bases

The torus drainage and purification system is designed to:

- Facilitate suppression pool drainage during plant outages requiring maintenance and inspection in the torus.
- Provide a means for cleanup of the suppression pool during drainage.
- Provide the capability for a low-flow cleanup of the suppression pool during normal plant operation.

9.3.7.2 System Description

The torus drainage and purification system is shown schematically on drawing no. H-26042. For ease of discussion, the torus drainage and purification system is subdivided as follows:

- Torus drainage and purification system (plant shutdown).
- Torus purification system (plant operating).

9.3.7.2.1 Torus Drainage and Purification System (Plant Shutdown)

The torus drainage and purification system for plant shutdown periods consists of the torus suction piping, a 1200-gal/min pump, and other piping and valves (drawing no. H-26042) as required to allow torus suppression pool waters to be transferred from the torus to either the

condensate storage tank (CST), the main condenser hotwell, or directly to the radwaste system storage tanks.

Discharge of the torus waters to the CST and the main condenser hotwell will be via the condensate polishing system (described in chapter 10) for removal of suspended and ionic impurities. Makeup to the suppression pool is provided by gravity drain from the CST.

Discharge of the torus waters to the radwaste system storage tanks is provided to facilitate the complete drainage of the suppression pool during shutdown should this ever be required. The system is fitted with a temperature switch on the discharge piping to terminate pump operation in the event pump discharge temperature exceeds 150°F in order to prevent rapid resin depletion due to elevated temperatures. Additionally, the pump is fitted with a low suction pressure trip to protect the pump during torus drainage.

9.3.7.2.2 Torus Purification System (Plant Operating)

In order to provide cleanup of the torus waters, a low-flow vacuum drag and gravity drain makeup system consisting of remotely actuated valves and drilled flow-control orifices allow the torus waters to be vacuum dragged from the torus to the main condensate pump common suction line. The condensate pump then directs the water to the reactor by way of the condensate polishing system. Replenishment of the torus water is by gravity drain from the CST once the remotely actuated makeup valves are manually operated from the MCR.

The vacuum drag and gravity drain systems are designed to operate simultaneously to maintain the torus water level within the design level control band. Deviation from normal water level due to differential flows in the drag and makeup systems automatically results in influent and effluent valve closure upon receipt of high and/or low torus water level (2 in. from reference), respectively. Once tripped, these valves remain in their closed positions until deliberate operator action is initiated to clear the trip condition and restore the system to operation.

Additionally, the valves are automatically tripped, terminating system operation and isolating the containment upon receipt of either a high drywell pressure signal or an MSIV closure.

The torus water effluent valves are also tripped closed on actuation of any turbine trip signal.

9.3.7.3 Instrumentation Application

9.3.7.3.1 Torus Drainage and Purification System (Plant Shutdown)

A pressure switch which senses pump suction pressure is provided to prevent pump damage during torus drainage due to inadequate suction pressure. This switch is set at 0.5 psig decreasing. A temperature switch is provided on the pump discharge piping to automatically initiate pump trip at 150°F increasing water temperature to prevent rapid depletion of filter demineralizer powdered ion-exchange resins. Pump discharge pressure may be determined by reading the local pressure indicator at the pump discharge piping.

9.3.7.3.2 Torus Purification (Plant Operating)

A differential pressure-indicating switch is provided across the flow-control orifice in the torus effluent line which actuates a lamp in the MCR to indicate that system flow has been initiated.

9.3.7.4 <u>Safety Evaluation</u>

The torus drainage and purification system is typically not used either during plant shutdown or plant operation. A spool piece is removed and two manual isolation valves located adjacent to the torus are locked closed to ensure containment integrity and to ensure that torus water level cannot be inadvertently raised or lowered through system operation or leakage.

9.3.7.4.1 Torus Drainage and Purification (Plant Shutdown)

The torus suction penetration and piping out to and including the first spectacle flange are designed in accordance with ASME Code, Section III, Class 2, piping requirements and to meet Seismic Category I requirements.

In order to prevent inadvertent pump operation, the local pump starting switch is provided with a key-lock feature which provides for close administrative control of the start-switch position. Remote switches in the main and radwaste control rooms are provided with only two selection positions: permissive (which allows the pump to be started locally, provided the key is available) and stop.

9.3.7.4.2 Torus Purification System (Plant Operating)

The torus water effluent piping out to the second isolation valve is designed in accordance with ASME Code, Section III, Class 2, piping requirements and to meet Seismic Category I requirements. Automatic trip features are provided to cause the isolation valves to close upon initiation of any trips, terminate system operation, and close isolation valves to maintain containment integrity and containment heat removal capability. The air-operated isolation valves are designed to fail closed on a loss of electrical power to the pilot solenoid valve, as well as on a loss of air supply.

With the exception of the containment isolation function, the torus drainage and purification system is not safety-related. Its performance is not required to mitigate the consequences of any design basis accident (DBA). The design, as indicated above, is such that no single failure causes reduction or degradation in the operation of any safety-related system.

9.3.7.5 <u>Tests and Inspections</u>

Prior to placing the systems in service, system and component operability was verified by manufacturer's performance testing where applicable and the system was preoperationally tested to determine that it performed its intended design functions.

System instrumentation was tested and calibrated initially during preoperational testing and subsequently in accordance with the quality assurance program described in section 17.2.

Remotely operated valves are periodically cycled to determine operability.

9.3.8 AUXILIARY STEAM (HNP-1 AND HNP-2)

9.3.8.1 Design Bases

The auxiliary steam system is designed to provide a source of low-pressure noncontaminated steam for various startup and plant service functions. These functions include:

- Supplying low-pressure steam to the reactor feed pump turbines during startup.
- Supplying low-pressure steam to the main steam moisture separator reheaters for blanketing. This function is currently not in use because blind flanges were installed to prevent leakage from the main steam system into the auxiliary steam system. These blind flanges are shown on FSAR drawings H-26063, H-11018, and H-11601.
- Supplying low-pressure heating steam to the refueling floor heating system heat exchangers.
- Supplying low-pressure heating steam to the condensate-polishing demineralizer precoat water heater.
- Supplying low-pressure steam to the HPCI and RCIC systems for overspeed testing.

9.3.8.2 System Description

The auxiliary steam system shown schematically on drawing no. H-26063 is supplied by a fossil-fired boiler that is common to both Hatch Nuclear Plant-Unit 1 (HNP-1) and Hatch Nuclear Plant-Unit 2 (HNP-2). Ten thousand pounds of steam per hour at ~ 200 psig are available for use for plant heating during cold weather and for the common steam vaporizer which converts liquid nitrogen into a gaseous state for inerting the HNP-1 and HNP-2 drywells.

The turbine building, reactor building, and radwaste building are served by a common header that enters the HNP-2 turbine building from the HNP-1 turbine building. A motor-operated isolation valve is provided in the header near the point at which it enters the HNP-2 turbine building. Branch lines to the various services are provided with either manual isolation valves or motor-operated isolation valves.

Condensate from the equipment served by the auxiliary steam system is collected in a common return header which joins the HNP-1 condensate collection header prior to returning to the circulating water flume.

The auxiliary boiler is a single-drum, fire-tube boiler designed to burn no. 2 fuel oil. Water is provided to the auxiliary boiler from the demineralized water system.

The plant heating system is comprised of two hot water heaters supplied by auxiliary steam centrifugal pumps for recirculating the hot water and various heating coils which are an integral part of the plant heating, ventilation, and air-conditioning (HVAC) systems which are further discussed in section 9.4. However, analysis indicates that the design temperatures of various buildings can be maintained with internal heat loads; therefore, use of the hot water heating coils/unit heaters is not necessary.

9.3.8.3 Instrumentation Application

The auxiliary steam system is provided with the following instrumentation:

A. Pressure indicators are installed in the main header and each branch line.

B. Temperature indicators are installed in the main header in the turbine building and radwaste building.

C. Flow elements are installed in the branch lines serving the HPCI turbine, the RCIC turbine, and the radwaste reboiler.

9.3.8.4 Safety Evaluation

The auxiliary steam system is not a safety-related system itself, but it has been analyzed with regard to effects of line breaks on safety-related equipment. Routing of the piping is such that there is no jet impingement on safety-related cables or other equipment from a critical-size crack in the line (paragraph 15A.5.6.2).

Auxiliary steam branch lines that serve as a backup to equipment normally supplied by reactor steam are provided with isolation valves plus a check valve to ensure there is no backflow of reactor steam into the auxiliary steam system.

9.3.8.5 Tests and Inspections

The auxiliary steam system was hydrostatically tested following erection to ensure the integrity of the system.

System instrumentation is periodically calibrated to ensure its accuracy.

TABLE 9.3-1

PNEUMATICALLY OPERATED VALVES PROVIDED WITH ACCUMULATORS

Fail/Position[a]	Valve No.	Service
Open	2E51-F003	RCIC torus suction
Open	2E41-F051	HPCI torus suction
Open	2T48-F310, F311	Reactor building to torus vacuum breaker
Open	2E21-F019A, B	Core spray system torus suction
Open	2P41-F066, F067	Service water to reactor building
Open	2E11-F065A, B, C, D	RHR system torus suction
Open	2P33-F004, F003, F012, F011	H_2/O_2 analysis A system - drywell
Open	2P33-F007, F015	H_2/O_2 analysis A system - torus
Closed[b]	2B21-F028A, B, C, D	Main steam line isolation
Open	2P33-F002, F05, F010, F013	H_2/O_2 analysis B system - drywell
Open	2P33-F006, F014	H_2/O_2 analysis B system - torus

a. Fail position is defined as that position assumed by the valve upon loss of either pneumatic or electrical power.
b. All main steam line isolation valves will fail closed on loss of electrical power; however, these valves are fitted with air accumulators and redundant electrical power supplies.

TABLE 9.3-2 (SHEET 1 OF 2)

PROCESS SAMPLING SYSTEMS

Description	Location	Purpose
Nuclear Steam Supply System		
Main steam	Main steam line	Carryover quality
Suppression pool	Suppression pool	Monitor corrosion and activity
SLCS	SLCS tanks	Sodium pentaborate concentration
Reactor water	Recirculation system	Monitor reactor water when cleanup is isolated
Reactor water	Recirculation system	Zinc concentration
Main Condenser Circulating Water System		
Circulating water	Pump discharge	Determine chlorine concentration
Spent-Fuel Pool Cooling and Demineralizer System		
Fuel pool filter-demineralizer	Inlet	Fuel pool quality
Fuel pool filter-demineralizer	Outlet	Filter efficiency
Condensate System		
Condensate	Condensate pump discharge	Condensate quality and tube leaks
Condensate demineralizer	Outlet	Condensate quality
Condensate	Condensate booster pump discharge	Condensate quality

TABLE 9.3-2 (SHEET 2 OF 2)

Description	Location	Purpose
Reactor Feedwater System		
Feedwater	Six places in heater train feed piping	Water quality
Feedwater	After last heater	Water quality
Feedwater	GEZIP skid	Zinc concentration
RWC Demineralizer System		
Filter-demineralizer	Inlet	Reactor water quality
Filter-demineralizer	Outlet	Filter efficiency
Makeup		
CST	Pump discharge	Water quality
Reactor Building Closed Cooling Water System		
Cooling water	Pump discharge	Water quality
Radwaste System - Liquid		
Waste surge tank	Pump discharge	Process data
Waste collector tank	Pump discharge	Process data
Floor drain collector tank	Pump discharge	Process data
Waste sample tank	Pump discharge	Discharge suitability
Floor drain sample tank	Pump discharge	Discharge suitability
Radwaste filter-demineralizer	Outlet	Filter efficiency
Chemical sample tank	Pump discharge	Discharge suitability
Chemical waste tank	Pump discharge	Process data
Chemical waste/floor drain neutralizer tank	Pump discharge	Process data

9.4 AIR-CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

9.4.1 MAIN CONTROL ROOM (HNP-1 AND HNP-2)

9.4.1.1 Design Bases

9.4.1.1.1 Safety Design Bases

The main control room environmental control system (MCRECS) is designed:

- With sufficient redundancy and separation of active components to provide reliable operation under normal conditions and ensure operation under emergency conditions.
- To provide purging capability for removing radioactive and foreign material from the main control room (MCR) environment.
- To detect and limit the introduction of radioactive material into the MCR.

9.4.1.1.2 Power Generation Design Bases

The MCR air-conditioning and filtration system is designed to:

- Provide an environment with controlled temperature to ensure both the comfort and safety of the operators and the integrity of the MCR components.
- Minimize the possibility of exhaust air recirculation into the air intake.

9.4.1.2 System Description

The MCRECS is shown on drawing nos. H-16042 and H-26094. Major system components and significant parameters associated with each component are listed in table 9.4-1. Flowrates for the various modes of operation are shown on drawing no. H-26094.

The MCR is a shared facility divided into two adjacent open areas; one area serves HNP-1, and the other area serves HNP-2.

The MCR is fully air-conditioned and maintained at ~ 72 to 79°F dry bulb throughout the year. The air-conditioning system consists of three condensing units (chillers) and three corresponding air-handing units (AHUs). Each AHU has two stages of cooling. The first stage of cooling is activated when the associated AHU is placed into service. A duct-mounted thermostat operates the second stage of cooling when additional cooling is required. Two of the three AHUs have operable electric heaters in the associated room air supply duct.

Wall-mounted thermostats in the MCR control operation of the heaters for winter heating.

The air-conditioning system is operated with one or two AHUs in service such that upon failure of a normally operating AHU, at least one AHU will remain in operation, or the designated standby AHU will autostart to assist the MCRECS pressurization mode in maintaining ≥ 0.1-in. water gauge (WG) positive pressure relative to the turbine building. Upon failure of an operating AHU and low-flow subsequent autostart of the designated standby unit, the associated dampers will reposition, and an alarm will annunciate in the MCR. (A discussion of the pressurization mode is provided in paragraph 6.4.1.2.2.1.)

The two MCR exhaust fans are normally not operated and are normally isolated from the outside air via normally closed isolation dampers. The fans are operated only for purging smoke from the MCR in the event of a fire. When operating, the fans exhaust to the reactor building vent plenum. The exhaust air flowrate is controlled by two-position volume dampers in the exhaust fan inlet.

Two filter trains (described in detail in section 6.4) with two booster fans remove any airborne radioactivity from the MCR environment. Each filter assembly is designed to serve both areas. Both filter assemblies are normally placed in the automatic mode. When required for MCR pressurization, both booster fans automatically initiate. Upon verification of proper operation of the fans and exhaust dampers, one fan may be shut off and placed in the standby position. If the fan motor in the operating assembly fails, the standby assembly comes on automatically, and an alarm is annunciated in the MCR. Except for testing during normal operation, the filter assemblies are not in use.

The MCR is protected from high radiation due to airborne radioactivity by pressurization (section 6.4).

When operated, as above, the MCRECS maintains MCR temperature between 72 and 79°F dry bulb with outside air temperature variations from 20 to 95°F dry bulb. MCR relative humidity is not directly controlled but will not exceed 75%.

For purging, the air-conditioning systems have the capability of meeting 50% supply and 100% exhaust air requirements of the MCR. The exhaust fan discharge is directed to the reactor building exhaust plenum. The flowrate is ~ 14,000 ft^3/min for supply and 11,500 ft^3/min for exhaust during purging.

9.4.1.2.1 Other Modes

Though not normally used, two other modes of the MCRECS exist, the isolation and purge modes. These modes are manually controlled by the plant operator.

In the isolation mode, the inlet outside air dampers 1Z41-F015 and 1Z41-F016 are manually closed with the control switches. This mode is used to eliminate outside air makeup in the event of a toxic environment outside of the MCR.
In the purge mode, both of the above-mentioned dampers are manually opened. One of the two 100% capacity exhaust fans, 1Z41-C011A or B, is manually started. Following the manual start

of the fan, the associated exhaust damper, 1Z41-F018A or B, automatically opens, and the associated volume control damper, 1Z41-F017A or B, is opened with its control switch. The purge mode is used, if necessary, to purge the smoke from the MCR, for example, in the event of a fire.

Both the isolation and purge modes are overridden by a pressurization signal.

9.4.1.3 Safety Evaluation

A safety evaluation for the MCRECS filters is presented in paragraph 6.4.1.4.

A discussion of MCR habitability during a design basis accident (DBA) is presented in section 15.3.

A failure analysis of major system components is presented in table 9.4-2. A failure analysis for the MCR filtration filters and fans is presented in table 6.4-2. No single active or passive electrical failure will cause the loss of supply or exhaust air for the MCR. The single-failure criterion is met, since all active components are located in the redundant portions of the system. Where redundancy does not exist (e.g., restroom exhaust dampers and exhaust fan isolation dampers), the system is normally operated such that at least one isolation barrier is normally closed. In the case of the restrooms, the doors provide that barrier. Upon verification that the exhaust dampers have closed for the pressurization mode, access to the restrooms is provided via these doors. In the case of the exhaust fan isolation dampers, the fans are normally not operated, and the dampers are normally closed.

If the outside air supply is shut off and the MCR is placed into the isolation mode, the MCR will remain habitable in the isolation mode for ~ 14 people for at least 50 h.

Evacuation instructions are prescribed in the Emergency Implementing Procedures (EIPs).

9.4.1.4 Tests and Inspections

Preoperational and startup testing were performed on this system during the preoperational and startup testing of HNP-1 in 1974. Normal operational surveillance is in accordance with the HNP-1 and HNP-2 Technical Specifications.

9.4.2 REACTOR BUILDING

9.4.2.1 Design Bases

9.4.2.1.1 Safety Design Bases

The reactor building emergency core cooling system (ECCS) room coolers are designed:

- With sufficient redundancy and separation of components to provide reliable operation under normal conditions and to ensure operation under emergency conditions.

- To provide a source of cooling to support the operation of the ECCS.

9.4.2.1.2 Power Generation Design Bases

The remainder of the reactor building heating, ventilation, and air-conditioning (HVAC) system is designed to:

- Provide an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by the removal of the heat dissipated from the plant equipment.

- Promote air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust.

- Minimize the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates and/or radioiodine contamination exists.

9.4.2.2 System Description

The reactor building HVAC system is shown schematically on drawing nos. H-26008, H-26025, H-26067, H-26071, H-26072, and H-50563. Major system components and the significant parameters associated with each component are listed in table 9.4-3.

For ease of system description, the reactor building HVAC system is divided into the following subsystems:

- Refueling zone HVAC system.
- ECCS room coolers.
- Reactor building and radwaste building chilled water system.
- Steam chase cooling.

9.4.2.2.1 Reactor Zone HVAC System

The reactor zone HVAC system, shown schematically on drawing no. H-26067, is not a safety-related system. During normal plant operation, the system maintains the normally accessible areas of the reactor building between 65°F and 90°F with outside temperature variations between 20°F and 95°F dry bulb.

Fresh supply air is filtered and tempered through a bank of prefilters and a hot water heating coil and distributed by two supply fans via ducting to the accessible areas of the reactor building. However, analysis indicates that the design temperature of the reactor building can be maintained with internal heat loads; therefore, use of the hot water heating coil is not necessary. Normally, one supply fan is in operation while the other is in standby condition. If the operating fan motor fails, the standby fan starts automatically and an alarm indicating fan failure is annunciated in the MCR.

Heat acquired by the ventilation air in the accessible areas is removed by local recirculating fan coil cooling units. Where required, chilled water cooled fan coil cooling units are provided to supplement the forced-air ventilation system in heat removal, thereby minimizing the quantity of outside air that must be circulated through the reactor building.

The ventilation air follows a flowpath starting with the supply air in the accessible areas and finally exhausting via the inaccessible areas. By virtue of exhaust air system register locations, and since the exhaust air system is designed to maintain the reactor building at a slightly negative pressure with respect to atmosphere, cooled air from accessible areas is caused to flow to inaccessible areas of the reactor building.

Exhaust air is collected via ducting in the inaccessible areas and routed to the exhaust system filter train. This exhaust system filter train consists of a prefilter, carbon adsorber and a high-efficiency particulate air (HEPA) filter. The exhaust system is provided with one filter train and two exhaust fans.

Normally, one fan is in operation while the other is maintained on standby. In the event of operating fan motor failure, the standby fan is started automatically and an alarm is annunciated in the MCR. Normally, exhaust air is discharged to the environment via the reactor building exhaust plenum.

The reactor zone exhaust ventilation system is fitted with duct-mounted radiation monitors. In the event of high radiation in the airstream, the monitors will cause shutdown of the normal supply and exhaust systems and initiate standby gas treatment system (SGTS) operation. A

description of the SGTS is provided in subsection 6.2.4. Detailed information concerning the process radiation monitoring system is provided in subsection 11.4.1.

9.4.2.2.2 Refueling Zone HVAC System

The refueling zone HVAC system, shown schematically on drawing no. H-26072, is not a safety-related system. During normal plant operation, the system maintains the refueling floor area between 65°F and 104°F dry bulb with outside temperature variation between 20°F and 95°F dry bulb.

Fresh supply air is filtered and tempered through a prefilter and a hot water heating coil and distributed by two supply fans via ducting to selected areas of the refueling floor. However, analysis indicates that the design temperature of the refueling floor can be maintained with internal heat loads; therefore, use of the hot water heating coil is not necessary. Normally, one fan is in operation while the other is maintained on standby. If the running fan motor fails, the standby fan is started automatically and an alarm indicating fan failure is annunciated in the MCR.

Exhaust air may be drawn either from the floor area or, to reduce the potential for airborne radioactivity during work in the fuel pool, by a sweep action from the fuel pool surface via ducting.

All exhaust air collected is then discharged via two 50% filter trains by one of two 100% exhaust fans. Operation of the exhaust fans is identical to that described for the supply air fans. Supply and exhaust fan blades may be adjusted manually to allow for 50% capacity operation during filter train maintenance. The filter trains are similar to those described in paragraph 9.4.2.2.1.

The refueling zone exhaust system is fitted with duct-mounted radiation monitors for monitoring the exhaust air stream. If the radiation monitors detect a high-radiation level, the supply and exhaust fans in the refueling zone HVAC system will be automatically stopped, the isolation dampers will be closed, and an alarm will be annunciated in the MCR.

A high-radiation condition in the HNP-2 refueling zone initiates simultaneously the stopping of HNP-1 refueling and reactor zone HVAC systems, since the HNP-2 refueling zone communicates with the HNP-1 refueling zone and the latter with the HNP-1 reactor zone. At the same time, alarms in the HNP-1 portion of the MCR are initiated and the SGTSs of HNP-1 and HNP-2 are started automatically.

The HNP-2 loss-of-coolant accident (LOCA) signals (drywell high pressure or reactor pressure vessel (RPV) low water level 2) will also shut down the HNP-2 refueling floor HVAC system and initiate the HNP-2 SGTS.

During normal conditions, exhaust air is discharged to the environment via the reactor building exhaust plenum.

9.4.2.2.3 ECCS Room Coolers

Safety-related plant service water (PSW) cooled cooling units, shown schematically on drawing no. H-26071, are provided to remove the heat buildup due to emergency core and shutdown cooling, suppression pool cooling, and suppression pool spray (residual heat removal (RHR) and core spray (CS) pumproom coolers only) operation in the following locations:

- High-pressure coolant injection (HPCI) pumprooms.
- RHR and CS pumprooms.

Cooling units of the same quality are also provided in the reactor core isolation cooling (RCIC) pumproom and the control rod drive hydraulic system (CRDHS) pumproom.

Each room is provided with two 100% capacity fan coil units.

During normal plant operation for the control rod drive (CRD), RCIC, and HPCI pumproom coolers, both coolers are maintained in AUTO. Separate temperature sensing elements are provided for each unit. The CRD pumproom coolers start automatically when the respective room temperature exceeds a preset value. The HPCI and RCIC pumproom coolers start automatically when the respective turbine steam supply valve opens (system startup) or if the respective room temperature exceeds a preset value. The auto start logic for high temperature and system startup is sealed in upon initiation. The fans must be manually shut down and the auto start logic manually reset. Additionally, any one cooler can be operated as needed by placing the control switch in the RUN position. The cooler in AUTO will start automatically if the operating cooler fails or if the respective room temperature exceeds a preset value. If the failed unit restarts, the AUTO unit automatically stops and returns to the auto start condition. Upon startup of a cooler, the associated PSW control valve opens, initiating cooling water flow through the unit cooling coils.

During normal plant operation, all four of the RHR/CS pumproom coolers are in AUTO. Separate temperature sensing elements are provided for each unit. A cooling unit in AUTO will start automatically if the respective room temperature exceeds a preset value, on respective pump startup, or if the running unit fails. If any of these conditions clears, the unit automatically stops and returns to the auto start condition. Upon startup of a cooler, the associated PSW control valve opens, initiating cooling water flow through the unit cooling coils.

The ECCS room coolers described above are designed to assure operability during and subsequent to the design basis earthquake (DBE) to support the operation of those systems required to mitigate the consequences of the DBA.

All components, including fans, supports, instrumentation, ductwork, and connecting piping and valves, have been designed to Seismic Category I requirements. Quality group classifications of these components are discussed in subsection 3.2.2.

The cooling units maintain the temperature in these rooms, as described in paragraph 9.4.2.2.1, during normal plant operation, RHR shutdown cooling, suppression pool cooling, and suppression pool spray operation.

Under conditions requiring ECCS initiation and operation, the cooling units maintain the temperature below a maximum of 148°F dry bulb in the HPCI and RCIC pumprooms, below a maximum of 110°F dry bulb in the CRDHS pumprooms, and less than a maximum of 145°F dry bulb in the RHR and core spray pumprooms commensurate with an outside temperature of 95°F dry bulb.

9.4.2.2.4 Reactor Building and Radwaste Building Chilled Water System

The reactor building and the radwaste building chilled water system (drawing nos. H-26008, H-26025, and H-50563) consists of two chilled water pumps, two centrifugal chillers, two condenser circulation water pumps, two cooling towers, and several fan coil units. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water pump circulates chilled water through the respective chiller and fan coil units. Condenser water from the cooling towers is circulated through the chiller condensers for cooling by the condenser circulation water pumps.

Normally, one chiller, one condenser circulation water pump, and one chilled water pump operate while the others are on standby. If the operating chiller fails, the MCR is alarmed and the standby chiller is started manually. Necessary controls and instrumentation have been provided to protect the chiller components against abnormal pressure or temperature within the system.

The chilled water is supplied to the fan coil units. The fan coil units transfer heat from the areas in which they are located to the recirculated chilled water system. For areas with variable cooling loads, the fan coil units have automatic three-way mixing valves to modulate the waterflow according to cooling requirements. For other areas with constant cooling load, manual valves will suffice to maintain a uniform flow of chilled water through the fan coil units.

Corrosion and water volume control for the chilled water side of the system are provided by the chemical feed pump, the chemical addition tank, and the expansion tank of the primary containment chilled water system which is discussed in subsection 9.4.6. Treatment of the condenser water side of the system is provided by a packaged, automatic chemical treatment system located in the chiller equipment building. This system is automatic and controls pH and conductivity.

The mechanical forced-draft cooling towers are designed to furnish water at 85°F to the condensers with return water at 95°F. Chiller condenser return flow to the cooling towers will be automatically bypassed as necessary to maintain minimum chiller condenser cooling water temperature for winter operation. The tower basin water level is automatically controlled. Makeup water for towers 2P65-B004A,B is provided by the potable water system. The outdoor piping is heat traced for winter operation. The equipment for the chilled water system is located on the roof of the HPCI room at el 132 ft. This system supplies the fan coil units in the reactor building and the radwaste building. The reactor building fan coil units are described in paragraph 9.4.2.2.1; the radwaste building fan coil units are described in paragraph 9.4.3.2.

9.4.2.2.5 Steam Chase Cooling

The steam chase area is served by two cooling units: a primary unit and a secondary unit. Each cooling unit consists of a unit housing containing a chilled water cooling coil and a supply fan. Both units have ducted supply air; however, only the primary unit has ducted return air. It is for this reason that the secondary unit is not considered as 100% backup, even though the rated cooling capacity of both units is the same. The cooling coils of the two units are piped in series and are served by the reactor building and radwaste building chilled water system (2P65).

During normal plant operation, only the primary unit is in operation. High temperature in the steam chase area, which would indicate primary unit failure, automatically starts the secondary unit. When the secondary unit is in operation, annunciation in the MCR alerts the operator that the secondary unit in the steam chase has been activated.

Both cooling units in the steam chase area are considered nonsafety related.

9.4.2.3 Safety Evaluation

9.4.2.3.1 Reactor Zone HVAC System

The reactor zone HVAC system, described in paragraph 9.4.2.2.1, is not a safety-related system.

However, the HVAC system incorporates some features designed to assure reliable operation for the normal operating plant conditions. Such features include:

- A 100% standby supply air fan.
- A 100% standby exhaust air fan.
- A 100% capacity normally operating exhaust filter train.
- A 100% standby fan on one of the fan coil cooling units.

At the secondary containment boundary, the supply and exhaust ducts penetrating the walls, as well as the double isolation dampers on either side of the walls, are designed to Seismic Category I requirements. The dampers automatically close to isolate the secondary containment on a LOCA and high-radiation signal and fail closed. The isolation of the reactor building HVAC system simultaneously activates the SGTS.

Radiological consequences are discussed in chapter 12. A failure analysis for major system components is presented in table 9.4-4.

9.4.2.3.2 Refueling Zone HVAC System

The refueling zone HVAC system, described in paragraph 9.4.2.2.2, is not a safety-related system. However, the HVAC system incorporates some features designed to assure reliable operation for normal operating plant conditions. Such features include:

- A 100% standby supply air fan.
- A 100% standby exhaust air fan.
- Two 50% capacity normally operating exhaust filter trains.
- Provision to adjust manually the supply and exhaust fan flowrates so that one filter (50% normal airflow) can be used during filter maintenance periods.

The integrity of the HNP-2 refueling zone HVAC system is assured by Seismic Category I. Dampers on both sides of the supply and exhaust ducts penetrating the refueling area walls automatically close on initiation of high radiation in the refueling area or a LOCA condition. The dampers fail closed and are designed to Seismic Category I requirements. Isolation of the fuel-handling area from the reactor building and the outside atmosphere simultaneously activates the SGTS. Both of these postulated accidents are detected by redundant instrumentation and annunciated in the MCR. (See chapter 7 for a description of instrumentation for engineered safety features and subsection 6.2.4 for a description of the SGTS.)

Radiation detectors are located in the exhaust ducts close to the storage pools so that radiation can be detected promptly and the refueling area isolated before any appreciable amount of radioactivity leaves the area. The small amount of contaminated air that does leave the area will be processed through the exhaust filter train.

The HNP-1 fuel-handling area and reactor building, as well as the HNP-2 fuel-handling area, communicate; thus, a high-radiation condition in any of these areas will automatically isolate the HVAC systems for all three areas.

Radiological consequences are discussed in chapter 12. A failure analysis is presented in table 9.4-4.

9.4.2.3.3 ECCS Room Coolers

Operation of the ECCS room coolers, as described in paragraph 9.4.2.2.3, is required to support ECCS component operation and, in the case of the RHR and CS pumproom coolers, the shutdown cooling, suppression pool cooling, and suppression pool spray functions of the RHR system. Consequently, these units must remain functional during and after the DBE and are, therefore, designed in accordance with Seismic Category I requirements.

Because these units are located in the rooms occupied by major ECCS components, the cooling units are afforded the same degree of protection from missiles, fire, and other hazards that the ECCS components themselves are afforded.

A safety evaluation of the ECCS subsystems is presented in section 6.3. A failure analysis for the major system components is presented in table 9.4-4.

9.4.2.3.4 Reactor Building and Radwaste Building Chilled Water System

The reactor building and the radwaste building chilled water system, as described in paragraph 9.4.2.2.4, is not a safety-related system.

However, the reactor building and the radwaste building chilled water system incorporates some features designed to assure reliable operation for the normal operating plant conditions. The chillers are composed of two 100% redundant units with their associated recirculation pumps. On loss of the active unit, an alarm would be annunciated in the MCR and the standby chiller would be started manually.

A failure analysis for major system components is presented in table 9.4-4.

9.4.2.4 Tests and Inspections

The reactor building HVAC system, which encompasses those subsystems described in subsection 9.4.2, was inspected, component by component, prior to installation and is available for periodic inspection during plant operation. Instruments and controls were tested for actuation at the proper setpoints, and alarm functions were checked for operability and limits during preoperational testing.

The filtration and air-conditioning equipment, including refrigerant piping and distribution ductwork, was tested for leaks and balanced after installation in accordance with the Sheet Metal and Air Conditioning Contractors National Association Low Velocity Duct Construction and the Associated Air Balance Council Standards for Field Measurement and Instrument, Form 81266, Volume I, 1970.

Because the system is in use during normal plant operation, the availability of active components is evident to the plant operators. The ECCS room coolers were tested during testing of the ECCS pumps.

The HEPA filters were tested before installation. Each filter was dioctyl phthalate (DOP) smoke tested containing 0.3-μm particle size to determine the efficiency of the HEPA filter media and the leaktightness of the filter frame and gasket. Particle penetration did not exceed 0.03% for 0.3-μm-diameter homogeneous particles of DOP.
In-place filter testing was initially performed prior to placing the system into service. Since the HEPA filters are credited in the offsite dose analysis for compliance with 10 CFR 50 Appendix I, they are in-place tested periodically in accordance with ASME N510-1989. The charcoal is replaced as needed.

The HEPA filters are procured with a particulate removal efficiency of 99.97% and the carbon filter with a methyl iodide removal efficiency of 97.0% when tested at 30ºC and 95% relative humidity per ASTM D3803-1989.

9.4.3 RADWASTE BUILDING

9.4.3.1 Design Bases

The radwaste area HVAC system is designed to:

- Provide temperature control and air movement control for personnel comfort.
- Optimize equipment performance by removal of heat dissipated from plant equipment.
- Provide a sufficient quantity of filtered fresh air for personnel.
- Provide for air movement from areas of lesser potential airborne radioactivity to areas of greater potential airborne radioactivity prior to final exhaust.
- Minimize the possibility of exhaust air recirculation into the air intake.
- Minimize the escape of potential airborne radioactivity to the outside atmosphere during normal operation by exhausting air, through a suitable filtration system, from the areas in which a significant potential for radioactive particulates and radioactive iodine contamination exists.

9.4.3.2 System Description

The radwaste area HVAC system is shown schematically on drawing no. H-26090.

The major system components and the significant parameters associated with each component are listed in table 9.4-5.

During normal system operation, outside air is ducted to the radwaste building by two supply fans. Normally, one supply fan operates while the other is on standby. If the operating fan motor fails, the standby fan starts automatically and an alarm is annunciated in the radwaste control room.

Outside air is filtered and tempered by filter trains and a hot water heating coil. However, analysis indicates that the design temperature of the radwaste building can be maintained with internal heat loads; therefore, use of the hot water heating coil is not necessary. The filtered and tempered air is then discharged into the building corridor and working floor areas for distribution to equipment cells or areas of higher potential airborne radioactivity; from there, it is eventually removed by the exhaust system.

Exhaust air is ducted from the radwaste building into the reactor building vent plenum. The exhaust system consists of two 50% capacity filter trains and two 100% capacity exhaust fans. One exhaust fan normally operates while the other is on standby. If the operating exhaust fan fails, the standby fan starts automatically and an alarm is annunciated in the radwaste control room.

System operation as described above maintains temperatures between 65°F and 110°F in occupied areas other than the radwaste control room, consistent with outside temperature variations of between 20°F and 95°F anticipated throughout the year. In areas other than those designed for frequent personnel occupancy, such as storage-tank rooms, pumprooms, and other equipment cells, temperatures are allowed to approach 120°F.

Three local chilled water fan coils are provided in particular areas of the radwaste building to reduce the ventilation air temperature and remove the heat dissipated from the equipment.

The local chilled water fan coils are supplied cooling water from the reactor building and the radwaste building chilled water system, described in paragraph 9.4.2.2.4.

The radwaste control room HVAC system consists of a primary system and a secondary system. The primary system consists of an air-handling unit with a direct expansion coil and a roof-mounted condensing unit. The secondary system consists of a fan coil unit mounted inside the radwaste control room. The primary HVAC system for the radwaste control room normally operates to provide temperature control for the control room, and the secondary system is only used as a backup to the primary system.

Each exhaust filter train consists of the following components:

- Prefilter.
- Charcoal adsorber.
- HEPA filter.

Radiation monitors are provided in the exhaust duct of the radwaste building to detect high radiation. If these monitors detect a high-radiation level or the monitor fails, an alarm will be annunciated on the radiation monitoring panel in the MCR.

Instruments are provided to monitor pressure drop across the filter train and its components.

A temperature sensor provided in each charcoal bed stops the operating fan on detection of increasing temperature, and an alarm is annunciated in the radwaste control room. A water deluge system is manually activated.

9.4.3.3 Safety Evaluation

The radwaste area HVAC system is not a safety-related system. However, the HVAC system incorporates some features that are designed to assure radwaste system operation for normal operating plant conditions. Such features include:

- A 100% standby supply air fan.
- A 100% standby exhaust air fan.
- Two 50% capacity normally operating charcoal filter trains.
- Provision to adjust supply and exhaust fan flowrates manually so that one filter (50% of normal airflow) can be used during filter maintenance periods.
- A 100% standby reactor/radwaste building water chiller and recirculating water pump.

Radiological consequences are discussed in chapter 12. A failure analysis for major system components is presented in table 9.4-6.

9.4.3.4 Tests and Inspections

System equipment, piping, and distribution ductwork were tested and balanced after installation in accordance with the Sheet Metal and Air Conditioning Contractors National Association Standard for High Velocity Duct Construction and the Associated Air Balance Council Standards for Field Measurement.

The HEPA filters were tested before installation. Each filter was dioctyl phthalate (DOP) smoke tested containing 0.3-μm particle size to determine the efficiency of the HEPA filter media and the leaktightness of the filter frame and gasket. Particle penetration did not exceed 0.03% for 0.3-μm-diameter homogeneous particles of DOP.

In-place filter testing was initially performed prior to placing the system into service. Since the HEPA filters are credited in the offsite dose analysis for compliance with 10 CFR 50 Appendix I, they are in-place tested periodically in accordance with ASME N510-1989. The charcoal is replaced as needed.

The HEPA filters are procured with a particulate removal efficiency of 99.97% and the carbon filter with a methyl iodide removal efficiency of 99.0% when tested at 30ºC and 95% relative humidity per ASTM D3803-1989.

9.4.4 TURBINE BUILDING

9.4.4.1 Design Bases

The turbine building HVAC system is designed to:

- Provide temperature control and air movement control for personnel comfort.
- Optimize equipment performance by the removal of heat dissipated from plant equipment.
- Provide a sufficient quantity of filtered fresh air for personnel.
- Provide for air movement from areas of lesser potential airborne radioactivity to areas of greater potential airborne radioactivity prior to final exhaust.
- Minimize the possibility of exhaust air recirculation into the air intake.
- Minimize the escape of potential airborne radioactivity to the outside atmosphere during normal operation by exhausting air, through a suitable filtration system, from the areas in which a significant potential for radioactive particulates and radioactive iodine contamination exist.

9.4.4.1.1 Alternative Source Term (AST) Design Function

As part of the implementation of an AST (reference subsection 15.1.11), the exhaust only portion of the turbine building HVAC is credited with purging the area around the main control room following a LOCA, MSLBA, and control rod drop accident (CRDA). The credited exhaust rate is 15,000 ft^3/min.:

- With sufficient redundancy to ensure reliable operation within 9 h of a LOCA, main steam line break (MSLB), or CRDA.
- To purge the area around the MCR to reduce the activity available for leakage into the MCR following a LOCA, MSLB, or CRDA.
- To operate without being dependent upon the availability of offsite power supplies.
- With sufficient redundancy so that no single active system component failure can prevent the system from fulfilling its safety function.

9.4.4.2 System Description

The turbine building HVAC system is shown schematically on drawing no. H-26086.

The major system components and the significant parameters associated with each component are listed in table 9.4-7.

Fresh air from outside is supplied to the turbine building by a duct system with two supply fans. Normally, one fan operates while the other is on standby. The supply air may be augmented by opening the turbine building railroad door. If an operating supply fan fails, the standby fan starts automatically, and an alarm is annunciated in the MCR. The normal outside supply air is filtered through filter trains and tempered through a hot water heating coil.

Air is exhausted from the turbine building by a duct system to the outside environment via the reactor building vent plenum by two exhaust fans. The exhaust from the turbine building is filtered by two 50% capacity filter trains. Each filter train consists of a bank of prefilters, carbon adsorbers, and HEPA filters. The carbon adsorber bank is provided with a water deluge system. Only one of the two 100% capacity exhaust fans is normally operating. If the operating exhaust fan fails, the standby exhaust fan starts automatically and an alarm is annunciated in the MCR.

The following describes the changes implemented to turbine building ventilation exhaust system to support the AST credited function of purging the area around the main control room following a LOCA, MSLBA, and CRDA. The credited exhaust rate is 15,000 ft^3/min. The turbine building ventilation exhaust system consists of four exhaust fans, two per unit, and associated exhaust ductwork. The exhaust fans are normally supplied by nondiesel-backed power; however, after the referenced DBAs with loss of offsite power (LOSP), each fan is capable of being supplied with diesel-backed power by manually transferring power via a manual transfer switch positioned to the diesel-backed power source. Also, the associated solenoid valves are powered with diesel-backed power that controls operation of the fan inlet dampers required for exhaust fan operation. The operator manually aligns each associated fan manual transfer switch to the alternate diesel-backed power supply position. Operator manual action is administratively controlled after the initial 10 min post DBA. Finally, noninterruptible instrument air with backup nitrogen is provided to the turbine building ventilation exhaust system control panel, damper air actuators which control the variable pitch of the exhaust fans, and the damper air actuators that control the inlet damper to the exhaust filtration units.

Inlet vane control is provided for each supply and exhaust fan to maintain a constant fan capacity. Adequate instrumentation is provided to monitor the performance of the system. Fan coil cooling units are provided to remove heat dissipated from the equipment and piping. These cooling units are located in areas of maximum heat dissipation to provide local cooling of the affected areas and to minimize the amount of ductwork. Each cooling unit consists of a chilled water cooling coil, the plenum, and an adjustable pitch vaneaxial fan. The chilled water is circulated through the cooling coils.

Hot water unit heaters are provided along the exposed walls of the turbine building above el 164 ft 0 in. The hot water is supplied from a closed pump loop called the plant heating system. However, analysis indicates that the design temperature of the turbine building can be maintained with internal heat loads; therefore, use of the hot water heating coil/unit heaters is not necessary.

The turbine building exhaust fans and filter trains are located at el 203 ft 0 in. of the reactor building. The turbine building supply fans are located in the radwaste building at elevation 178 ft 0 in. The fan coil cooling units and hot water unit heaters are located at various elevations of the turbine building.

The turbine building chilled water system (drawing nos. H-26088 and H-26089) consists of two chilled water pumps, two centrifugal chillers, and several fan coil units. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water pump circulates chilled water through the respective chiller and fan coil units. The cooling of the chiller condensers is provided by the plant service water system.

Normally, one chiller and one chilled water pump operate while the others are on standby. If the operating chiller fails, the MCR is alarmed and the standby chiller is automatically started. Necessary controls and instrumentation have been provided to protect the chiller components against abnormal refrigerant pressure or temperature within the system.

During peak summer months both chillers, along with their respective chilled water pumps, may be operated in parallel to compensate for high temperature in the turbine building.

9.4.4.3 Safety Evaluation

The turbine building HVAC system is not a safety-related system. However, the HVAC system incorporates some features designed to assure turbine building operation for normal operation plant conditions. Such features include:

- A 100% standby supply air fan.
- A 100% standby exhaust air fan.
- Two 50% capacity normally operating charcoal filter trains.
- Provision to adjust supply and exhaust fan flowrates manually so that one filter (50% of normal airflow) can be used during filter maintenance periods.

Radiological consequences are discussed in chapter 12. A failure analysis for major system components is presented in table 9.4-8.

As part of the implementation of an AST (reference subsection 15.1.11), the turbine building ventilation exhaust system is credited with purging the area around the main control room following a LOCA, MSLBA, and CRDA. The credited exhaust rate is 15,000 ft^3/min. The exhaust fans are normally supplied by nondiesel-backed power; however, after the referenced DBAs with LOSP, each fan is capable of being supplied with diesel-backed power by manually transferring power via a manual transfer switch positioned to the diesel-backed power source. Operator manual action is administratively controlled after the first 10 min. Also, noninterruptible instrument air is provided to increase system reliability. Finally, applying the precedent established by NRC approval of the nonsafety-related main steam isolation valve alternate leakage treatment path, seismic verifications were developed and are maintained to

demonstrate that the HNP-1 and HNP-2 turbine building exhaust ductwork will remain in place and maintain exhaust flow in the event of a design basis earthquake. These verifications are based on earthquake experience data and use the methodology documented in Electric Power Research Institute (EPRI) Technical Report 1007896," Seismic Evaluation Guidelines for HVAC Duct and Damper Systems," dated April 2003.

9.4.4.4 Tests and Inspections

System equipment, piping, and distribution ductwork were tested and balanced after installation in accordance with the Sheet Metal and Air Conditioning Contractors National Association Standard for High Velocity Duct Construction and the Associated Air Balance Council Standards for Field Measurement.

The HEPA filters were tested before installation. Each filter was dioctyl phthalate (DOP) smoke tested containing 0.3-μm particle size to determine the efficiency of the HEPA filter media and the leaktightness of the filter frame and gasket. Particle penetration did not exceed 0.03% for 0.3-μm-diameter homogeneous particles of DOP.

In-place filter testing was initially performed prior to placing the system into service. Since the HEPA filters are credited in the offsite dose analysis for compliance with 10 CFR 50 Appendix I, they are in-place tested periodically in accordance with ASME N510-1989. The charcoal is replaced as needed.

The HEPA filters are procured with a particulate removal efficiency of 99.97% and the carbon filter with a methyl iodide removal efficiency of 97.0% when tested at 30ºC and 95% relative humidity per ASTM D3803-1989.

9.4.5 DIESEL GENERATOR BUILDING

9.4.5.1 Design Bases

9.4.5.1.1 Safety Design Bases

The diesel generator building heating and ventilation system is designed to:

- Be operable from either normal or emergency power supply systems.
- Perform the intended functions before, during, and after a DBE.
- Provide temperature and air movement control to prevent the ambient temperatures in the diesel generator room from exceeding the maximum allowable temperature of 122°F when the diesel generator is running.

9.4.5.1.2 Power Generation Design Bases

The diesel generator building heating and ventilation system is additionally designed to:

- Automatically isolate the diesel generator bays and/or fuel oil day tank rooms if the carbon dioxide flooding systems are activated.

- Exhaust heat and fumes from the switchgear rooms and/or the diesel generator building battery rooms in the event of a fire.

- Prevent hydrogen gas generated in the diesel generator building battery rooms from concentrating in an explosive mixture.

9.4.5.2 System Description

The diesel generator building ventilation system is shown on drawing no. H-12619. The major system components and the significant parameters associated with each component are listed in table 9.4-9.

To simplify description, the system is discussed in the context of the following subsystems:

- Diesel generator rooms heating and ventilating systems.

- Battery rooms ventilation systems.

- Switchgear rooms heating and ventilation systems.

- Oil storage rooms ventilation systems.

9.4.5.2.1 Diesel Generator Rooms Heating and Ventilation Systems

The diesel generator rooms heating and ventilating systems consist of one power roof (normal) exhaust ventilator in each room for exhausting heat from the rooms when the generator is shut down and two 100% capacity power roof exhaust ventilators in each room for exhausting heat from the rooms during generator actuation. Two motor-operated wall air intake louvers, with fire dampers in each room, replenish the air removed by the exhaust ventilation. One louver serves as the air intake to the generator area; the other serves as the air intake to the battery rooms through the generator area.

The systems consist of controls that automatically activate and deactivate the exhaust ventilators and open and close the wall louvers. Three 50% capacity electric resistance unit heaters maintain a minimum temperature within the rooms.

On a rise in temperature in each room, a room thermostat fully opens the main wall louver in its respective room on reaching its setpoint. On a continued rise in temperature in the respective

room, the ventilating thermostat for the normal exhaust ventilator activates this ventilator and sends a redundant open signal to the main wall louver when its setpoint is reached. The failure of the main louver (LV-6) to open > 50% of the louver area, or the failure of more than two of the four louver sections to open may result in room temperature exceeding the maximum allowable ambient operating temperature of 122°F. The ramification of this failure has been evaluated in table 9.4-10 and is shown to be acceptable. On even further rise in temperature in each room, the ventilating thermostats for the two 100% capacity exhaust ventilators activate the primary 100% capacity exhaust ventilator in its respective room on reaching its setpoint. On a drop in temperature in each room, the ventilating thermostat for the primary exhaust ventilator and the thermostat for the normal exhaust ventilator deactivates these ventilators. The room thermostat closes the main wall louver in its respective room on reaching its setpoint. On an additional temperature drop in each room, each heating thermostat activates its respective electric heater on reaching its setpoint.

Each heating thermostat will deactivate its respective electric heater when the room temperature rises above its setpoint. On failure of the primary roof exhaust ventilator, its airflow switch activates its matching standby 100% capacity exhaust ventilator fan. Upon reaching its setpoint, a firestat and/or CO_2 triggering device in each generator room deactivates all exhaust ventilators (generator room, oil storage room, and battery room), closes the wall louvers, and closes the fire dampers in its respective room.

9.4.5.2.2 Battery Rooms Ventilation Systems

The battery rooms ventilation systems consist of two 100% capacity exhaust ventilators in each room for exhausting hydrogen from the rooms, a motor-operated wall air intake louver in each generator room for supplying air to the battery rooms through the generator rooms, and a battery room air intake fire damper.

The ventilation systems are provided electrical power by the associated diesel generator in the event of a loss of offsite power (LOSP).

The battery rooms exhaust ventilators were designed for automatic cyclic operation by use of a timer to reduce hydrogen concentration in the battery rooms. The timer activates one selected exhaust ventilator in each battery room and fully opens the wall louver in its respective generator room. Following each cycle run, the timer deactivates the selected exhaust ventilator and closes the wall louver in its respective generator room. Upon reaching its setpoint, the firestat in each battery room activates the selected battery room exhaust ventilator fan motor and opens the wall louver in its respective generator room. The battery room air intake fire damper closes on direct exposure to fire passing through the opening or on a signal from any generator room/oil storage room firestat and/or CO_2 triggering device. The signal from the generator room/oil storage room firestat and/or CO_2 triggering device also deactivates the battery room exhaust ventilator.

The battery rooms exhaust ventilators can also be operated manually, and administratively controlled by a plant procedure. In manual mode, one exhaust ventilator in each battery room is operated. If the operating exhaust ventilator should fail, the redundant exhaust ventilator in the affected battery room is manually activated.

9.4.5.2.3 Switchgear Rooms Heating and Ventilation Systems

The switchgear rooms heating and ventilation systems consist of two 100% capacity power roof exhaust ventilators in each room for exhausting heat from the rooms, a motor-operated wall air intake louver in each room to replenish the air removed by the exhaust ventilators, and three 50% capacity electric resistance unit heaters in each room for maintaining a minimum temperature within the rooms.

The ventilation system consists of controls for automatically activating and deactivating the exhaust ventilators and unit heaters, for automatically switching to standby equipment in the event of failure of primary equipment, for opening and closing the wall louvers, and for activating the ventilation systems in the event of a fire within the rooms.

On a rise in temperature in each room, the ventilating thermostat activates the primary roof exhaust ventilator and fully opens the wall louver in its respective room on reaching its setpoint.

On a drop in temperature in each room, the ventilating thermostat deactivates the primary exhaust ventilator and closes the wall louver in its respective room on reaching its setpoint. On a continued drop in temperature in each room, each heating thermostat activates its respective electric heater on reaching its setpoint. Each heating thermostat deactivates its respective electric heater when the room temperature rises above its setpoint.

On failure of the primary roof exhaust ventilator, its airflow switch activates its matching standby exhaust ventilator fan. Upon reaching its setpoint, the firestat in the switchgear room activates both exhaust ventilators in the room and opens the wall louver in its respective room.

9.4.5.2.4 Oil Storage Rooms Ventilation Systems

The oil storage rooms ventilation systems consist of two 100% capacity power roof exhaust ventilators in each room for exhausting fumes from the rooms, a motor-operated wall air intake louver in each room to replenish the air removed by the exhaust ventilators, and a fire damper in each room for sealing the louver opening in the event of a fire within the room.

The primary exhaust ventilator in each oil storage room operates continuously under normal operating conditions. Upon failure of the primary exhaust ventilator, the standby exhaust ventilator autostarts. The oil storage rooms ventilators can also be operated manually and administratively controlled by a plant procedure. In the manual mode, one exhaust ventilator in each oil storage room is operated continuously. If the operating exhaust ventilator should fail, the redundant exhaust ventilator in the affected oil storage room is manually activated. The wall louver in each room is fully open under normal operating conditions.

Upon reaching its setpoint, a firestat and/or CO_2 triggering device in the generator room/oil storage room deactivates all exhaust ventilator fan motors and closes the wall louvers in their respective rooms.

9.4.5.3 Safety Evaluation

A failure analysis of the diesel generator building heating and ventilation system is presented in table 9.4-10.

Analyses have been performed to investigate the operational effect on the function of the diesel engine combustion air intake system under any meteorological and accident condition due to:

- Recirculation of the diesel generator exhaust.
- A fire inside the diesel generator building.
- A nitrogen storage tank rupture.

Table 9.4-11 provides the results of these analyses.

The ventilation system components are designed to Seismic Category I requirements.

Drawing no. H-12619 shows the arrangement of the diesel generator rooms, complete with the air intake louvers, and figure 9.4-1 shows the location of the diesel engine exhaust chambers.

Paragraph 8.3.1.1.3 describes the seismic qualification of the diesel engine generator units, including component parts and associated systems.

Tornado missile protection afforded the diesel generator combustion air intakes and exhaust is shown on drawing no. H-12619, which shows the arrangement for a typical diesel generator room, battery room, switchgear room, and oil storage room. Combustion air for diesel operator generation is supplied through the corridor and then through the individual diesel generator room combustion air intakes. Tornado missile protection is provided by the corridor exterior wall immediately opposite the ventilation air louvers. Cooling air to prevent the ambient room temperature from exceeding the maximum allowable ambient operating temperature of 122°F is supplied to each diesel generator room through its main louver, LV-6. Drawing no. H-12320 further illustrates the general arrangement of the diesel generator building, which shows that the corridor itself is protected from tornado missiles by the labyrinth at each end of the diesel generator building. Each generator diesel drive exhausts through a Seismic Category I muffler located on the roof of the diesel generator building. The mufflers present a relatively low profile target and are protected from missiles by the building roof parapet. In addition, the engine exhaust mufflers are separated from each adjacent muffler by ~ 30 ft.

In the event of an LOSP, all system equipment will automatically receive electrical power from the diesel generator associated with its respective room. Therefore, in an LOSP, the loss of an active diesel generator will only affect its own ventilation system and not the ventilation and operation of the other diesel generators.

Normal override is provided to activate or deactivate each exhaust-ventilation fan motor and louver motor as required.

Each wall air intake louver is equipped with a mechanical spring that automatically closes the louver upon loss of power to the drive mechanism.

9.4.5.4 Tests and Inspections

All components of the diesel generator building heating and ventilation system were preoperationally tested before placing the system in service and have been periodically tested thereafter.

9.4.6 PRIMARY CONTAINMENT (DRYWELL) COOLING

9.4.6.1 Design Bases

The primary containment (drywell) cooling system is designed:

- With sufficient redundancy and separation of components to provide reliable operation under normal conditions and to ensure operation of the fans under emergency conditions.

- To control temperature and prevent thermal stratification in the drywell area.

- To optimize equipment performance by removal of heat dissipated from the plant equipment .

9.4.6.2 System Description

9.4.6.2.1 Drywell Cooling (Air Side) System

The drywell cooling system is shown schematically on drawing nos. H-26074, H-26080, and H-26081. The significant parameters associated with the major components of the HVAC system and its chilled water system are listed in table 9.4-12.

The drywell cooling system maintains a maximum temperature of 135°F dry bulb in the drywell area during normal operation and a maximum temperature of 165°F dry bulb in the event of a loss-of-offsite power. (The drywell average air temperature limit for normal operation is ≤ 150°F.) During periods of extended maintenance or extended shutdown, the temperature of the drywell space is maintained by circulation from areas around the vessel and from the reactor building which is maintained at a minimum of 65°F.

The drywell cooling system consists of eight fan coil units and recirculating fans which are not required to operate following a LOCA. The fan coil units and recirculating fans are automatically disengaged during a LOCA but may be restored to service manually by the operator.

The function of the fan coil units is to remove the heat in the drywell by drawing the hot air in the space through cooling coils. In turn, the cooling coils are cooled by the primary containment (drywell) chilled water system. The two recirculating fans at el 196 ft 0 in. are tied to the operation of the two fan coil units at el 183 ft 6 in. A typical fan coil unit consists of a housing enclosing one full-capacity fan and two 50% capacity cooling coils. 2T47-B010A,B consist of a housing enclosing one full-capacity fan and three 33 1/3% capacity cooling coils. Ductwork, dampers, and controls are added to the discharge side of the fan coil units for proper distribution of cooling air.

The function of the recirculating fans is to assist the fan coil units in mixing the drywell air, thus maintaining a uniformly even temperature throughout the drywell space. There are four recirculating fans, each provided with its own ductwork. The two recirculating fans at el 183 ft 6 in. are tied to the operation of the two fan coil units at el 196 ft 0 in. and are redundant to each other. The two recirculating fans at el 117 ft 0 in. are both normally in operation and independent of the fan coil units. A single recirculating fan at el 117 ft 0 in. in operation will be sufficient.

In the event of an LOSP, all fan coil units (except 2T47-B010A,B), recirculating fans, and primary containment water chillers are transferred to the emergency diesels. The fan coil units and recirculating fans are started automatically from diesel power on an LOSP. However, the drywell fan coil units perform no active safety-related function. The primary containment chilled water system provides cooling to the units. The chilled water system forms a closed loop inside the containment with primary containment isolation valves on the outboard side of both the supply and return headers. Therefore, the cooling coils within the fan coil units form a portion of the closed-loop pressure boundary. The fan coil units are classified as safety related to support the containment boundary safety-related function.

Temperature elements on fan coil discharge ducts convey temperature indications as well as actuating alarms for high air temperature in the MCR. The loss of chilled water in an operating fan coil unit raises the air temperature and causes the actuation of an alarm in the MCR.

Space temperature sensors at critical areas of the drywell detect hot spots. An alarm is initiated in the MCR upon activation of the standby recirculating fan and associated fan coil units.

Loss of airflow on all fan coil discharge ducts (except 2T47-B010A,B) is detected by flow switches and is alarmed in the MCR.

9.4.6.2.2 Primary Containment (Drywell) Chilled Water System

The primary containment (drywell) chilled water system (drawing nos. H-26080 and H-26081) consists of two chilled water recirculation pumps, two centrifugal chillers, a chemical addition tank, a chemical feed pump, an expansion tank, and several fan coil units. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water recirculation pump circulates chilled water through the respective chiller and fan coil units. The cooling of the chiller condensers is provided by the PSW system.

Normally, one chiller and one chilled water recirculation pump operate while the others are on standby. If the operating chiller fails/trips, the MCR is alarmed and the standby chiller is started automatically. Necessary controls and instrumentation have been provided to protect the chiller components against abnormal pressure or temperature within the system. A microprocessor based local control panel includes the following information:

- Compressor motor thrust bearing temperature.
- Refrigerant temperature.
- Condenser evaporator refrigerant temperature.
- Compressor discharge temperature.
- Chilled water leaving/supply water temperature.
- Chilled water return water temperature.

In addition, the local panel provides the following chiller trip information:

- Low oil pressure.
- High condenser pressure.
- High motor journal bearing temperature.

The recirculated chilled water is supplied to the fan coil units. The fan coil units transfer heat from the areas in which they are located to the recirculated chilled water system. For areas with constant cooling load, manual valves will maintain a uniform flow of chilled water through the fan coil units.

A chemical feed pump and a chemical feed tank are provided to treat the chilled water chemically to prevent corrosion. An expansion tank is provided to compensate for fluctuations in water volume as the water temperature varies. In addition, the tank serves as a medium for making up water lost due to minor leaks in the system, as well as a means of detecting gross leakages.

This makeup water is supplied from the demineralized water system. (Reference subsection 9.2.3.) The chemical addition tank, the feed pump, and the expansion tank are shared with the reactor building and the radwaste building chilled water system.

The equipment for the chilled water system is located at el 164 ft 0 in. of the reactor building. The system supplies the drywell coolers.

9.4.6.3 Safety Evaluation

9.4.6.3.1 Primary Containment (Drywell) Cooling (Air-Side System)

The drywell cooling system is not a safety design system. However, the drywell cooling system incorporates certain features, described below, that are designed to assure availability of the system not only for normal operating plant conditions but also for the fan portion following a postulated LOCA:

- A standby recirculating fan in lieu of one of the three normally operating recirculating fans.
- Three standby fan coil units in lieu of the five normally operating fan coil units.
- A 100% standby chilled water pump and chiller for the chilled water serving the cooling coils.
- Provision to connect the fans of all fan coil units (except 2T47-B010A,B) and the recirculating fans to the emergency diesels in the event of an LOSP.
- The fans and electric motor drivers for the fan coil units and the recirculating fans are designed and documented to withstand LOCA conditions. However, they are not required to meet 10 CFR 50.49 regulations.
- Provision to restore fans to service manually following automatic LOCA trip.

Radiological consequences are discussed in chapter 12.

A failure analysis for major components of this system and its chilled water system is presented in table 9.4-13.

9.4.6.3.2 Primary Containment (Drywell) Chilled Water System

The primary containment (drywell) chilled water system, described in paragraph 9.4.6.2.2, is not a safety-related system.

However, the primary containment (drywell) chilled water system incorporates some features designed to assure reliable operation for the normal operating plant conditions. The chillers are composed of two 100% redundant units with their associated recirculating pumps. On loss of the active unit, an alarm would be annunciated in the MCR and the standby chiller would be started automatically. The chillers can be operated from the emergency diesels in the event of an LOSP.

The chillers are not required to operate following a LOCA. The chillers are automatically tripped during a LOCA, but may be restored to service manually by the operator.
A failure analysis for major system components is presented in table 9.4-13.

9.4.6.4 Tests and Inspections

The drywell cooling system, which consists of fans, cooling coils, ductwork, instruments, and controls, is tested before installation as follows:

Major System Components	Standard
Fans	Air Moving and Conditioning Association (AMCA) 210-67
Cooling coils	American Refrigeration Institute Standard 410-64

The distribution ductwork is tested for leaks and balanced after installation in accordance with the Sheet Metal and Air Conditioning Contractors National Association Low Velocity Duct Construction and the Associated Air Balance Council Standards for Field Measurement and Instrumentation, Form 81266, Volume 1, 1970.

Each component was inspected prior to installation and is available for periodic inspection. Instruments and controls are tested for actuation at the proper setpoints, and alarm functions are checked for operability and limits during preoperational testing.

Because the drywell cooling system is in use during normal plant operation, the availability of active components is evident to the plant operators, and there is no need for further online testing. Portions of the system normally closed to flow are periodically tested to ensure operability and integrity of the system. Standby fan coil units and recirculating fans are tested periodically to ensure the reliability of all system components.

9.4.7 CONTROL BUILDING

The MCR HVAC system is discussed separately in subsection 9.4.1 and section 6.4. The HVAC systems for the remaining portions of the control building are covered in this section.

9.4.7.1 Design Bases

9.4.7.1.1 Safety Design Bases

The control building HVAC systems are designed with sufficient redundancy and separation of components to provide reliable operation under normal conditions and to ensure operation under emergency conditions of ventilation for the battery rooms and cooling for the low pressure coolant injection (LPCI) inverter room.

9.4.7.1.2 Power Generation Design Bases

The control building HVAC systems are additionally designed to:

- Provide temperature and air movement control for personnel comfort and equipment operation.

- Optimize equipment performance by the removal of heat dissipated from plant equipment.

- Provide an adequate supply of filtered fresh air for personnel.

- Minimize the possibility of exhaust air recirculation into the air intake.

9.4.7.2 System Description

The control building HVAC systems are shown schematically in drawing nos. H-16034, H-16035, H-16040 through H-16042, H-26093, H-26094, H-26116, H-40056, H-51178, and H-51179. The significant parameters associated with the major components of the systems are listed in table 9.4-14. A single-failure analysis for major system components is presented in table 9.4-15. The control building HVAC systems are described in the paragraphs below.

9.4.7.2.1 Computer Room (HNP-1 and HNP-2)

Computer room facilities are used jointly by HNP-1 and HNP-2. The computer room (drawing no. H-16035) is air conditioned by three packaged-type air conditioners. Normally, two air conditioners operate while the third is on standby and operated as needed during peak summer months. When energized, each unit operates independently of the other and is controlled by a separate thermostat. Each unit is started manually.

Makeup and exhaust air to the computer room is provided by the control building ventilation system. Inside the computer room, conditioned air is recirculated by the air-conditioning units. The air discharged from the three air conditioners is combined into two supply ducts leading to the computer room.

A temperature switch at the cooling coils regulates the temperature of the conditioned air. A flow switch at each fan initiates an alarm in the MCR on a loss of flow.

The computer room HVAC is designed to maintain the computer room temperature at a maximum of 76°F dry bulb and 50% RH when the outside temperature is between 20 to 95°F dry bulb.

The package-type air conditioners are located at el 147 ft 0 in.

9.4.7.2.2 Water-Sampling Room

The water sampling room (drawing no. H-16035) is air conditioned by two 100% packaged-type air conditioners. Normally, one air-conditioning unit operates while the other is on standby.

When energized, each unit operates independently of the other and is controlled by a separate thermostat. Each unit is started manually.

Makeup air to the water sampling room is provided by the control building ventilation system. Fume hoods are provided on sample sinks to prevent the spread of potential airborne contaminants. Both fume hoods and room space exhaust to the control building exhaust system. This exhaust is then released to the outside environment via the reactor building vent plenum.

An electric reheat coil is provided on the fan discharge duct of each of the two air-conditioning units. The electric reheat coils are controlled by room thermostats.

A temperature switch at the cooling coils regulates the temperature of the conditioned air. A temperature switch at the electric reheat coils regulates air temperature. When the airflow drops to a predetermined level, a flow switch cuts off power to the reheat coils to prevent burning out the heating elements.

The water-sampling room HVAC is designed to maintain the water-sampling room temperature at a maximum of 76°F dry bulb and 50% relative humidity when the outside temperature is between 20 to 95°F dry bulb.

The package-type air conditioners are located at el 112 ft 0 in.

9.4.7.2.3 Radio Chemistry Laboratory and Health Physics Area (HNP-1 and HNP-2)

The radio chemistry laboratory and health physics area are shared jointly by HNP-1 and HNP-2. The radio chemistry laboratory and health physics area (drawing no. H-16034) are air conditioned by two air-conditioning systems, which are the normally operating air-conditioning system (NOACS) and the emergency operating air-conditioning system (EOACS). The NOACS consists of two air-handling units (Z41-B005A and B), two condensing units (Z41-B009A and B), and associated supply and return ducts. Normally, both NOACS trains operate. When in operation, each train operates independently of the other and is controlled by a separate thermostat, (Z41-TIS-N300A and Z41-TIS-N300B), respectively.

The air discharged from the air conditioners is distributed through branch ducts. An electric heating coil is located in each of the branch ducts. Except for the annunciator room, each electric heating coil provides zone temperature control in the area it serves by reheating the air.

Makeup air is provided from the adjoining ventilated area of the control building. Exhaust air from the laboratory and hoods is ducted to the turbine building exhaust system. This exhaust is filtered and then released to the outside environment via the reactor building vent plenum. Exhaust from the noncontaminated areas (toilets and showers) is ducted to the control building exhaust system.

Recirculated air from the conditioned spaces is ducted back to the air-conditioning units.

A temperature switch at the cooling coils regulates the temperature of the conditioned air. A temperature switch for the electric reheat coils regulates the air temperature. When airflow drops to a predetermined level, a flow switch cuts off power to the reheat coils to prevent burning out the heating elements.

The radio chemistry and health physics area HVAC is designed to maintain the radio chemistry and health physics area temperature at a maximum of 76°F dry bulb and 50% relative humidity when the outside temperature is between 20 and 95°F dry bulb.

For the NOACS, the condensing units and air-handling units are located in the control building at el 130 ft 0 in.

The EOACS consists of one air-handling unit (Z41-B100), one chilled water unit (Z41-B101), one charcoal filter train (Z41-D013), one electric heating coil (Z41-B102), and associated supply and return duct.

Occasionally, the EOACS may be used during maintenance of the NOACS and basically is used during emergency operations. The EOACS is designed to maintain a slightly positive pressure in the health physics area and the radio chemistry laboratory. The EOACS is controlled by a separate thermostat (Z41-TS-N034). The supply and return air from this system is integrated to the duct system of the NOACS.

The return air and outside makeup air is mixed, heated as required, conditioned, and filtered by the charcoal filter train. The filter train has instrumentation and controls to maintain desired temperature and relative humidity. The filter train has a manually activated deluge water system for fire protection.

The chilled water unit has its own control to control the leaving chilled water temperature.

The chilled water unit, air-handling unit, electric heating coil, and charcoal filter train are located outside near the control building outside air intake.

9.4.7.2.4 Cold Lab (HNP-1 and HNP-2)

The cold lab facilities are shared jointly by HNP-1 and HNP-2. The cold lab (drawing no. H-40056) is air conditioned by two packaged-type air conditioners. Normally, both air conditioners operate when energized; each unit operates independently of the other and is controlled by a separate thermostat.

Both air conditioners discharge air into a common supply duct. An electric reheat coil is located in the supply duct to maintain the indoor design temperature. The room thermostat controls the reheat coil.

Makeup air for the conditioned space is provided from the adjoining control building ventilated area. Room air is recirculated through the air-conditioning units. Exhaust from the conditioned space is ducted to the turbine building exhaust system. This exhaust is filtered and then released to the outside environment via the reactor building vent plenum.

A temperature switch at the cooling coils regulates the temperature of the conditioned air. A temperature switch for the electric reheat coils regulates air temperature. When the airflow drops to a predetermined level, a flow switch cuts off power to the reheat coils to prevent burning out the heating elements.

The cold lab HVAC is designed to maintain the cold lab temperature at a maximum of 76°F dry bulb and 50% relative humidity when the outside temperature is between 20 to 95°F dry bulb.

The package-type air conditioners are located in the cold lab conditioned space at el 112 ft 0 in.

9.4.7.2.5 Cable Spreading Area (HNP-1 and HNP-2)

The cable spreading area facilities are shared jointly by HNP-1 and HNP-2. The cable spreading area (drawing nos. H-16042 and H-26094) is ventilated by a supply and exhaust fan.

Outside air is ducted to the cable spreading room at el 147 ft 0 in. by one supply fan. The outside air supply is filtered through a roll filter.

Exhaust air from the cable spreading room is ducted to an exhaust fan. The exhaust fan discharges the air to the outside environment via the reactor building vent plenum.

When the outside air falls below 57°F, a portion of the exhaust air is diverted from the exhaust fan discharge and mixed with the incoming outside air to keep the room above 57°F. A damper on the exhaust fan discharge automatically maintains the room temperature by regulating the quantity of exhaust air diverted for mixing.

Outside air supply at a maximum temperature of 95°F adequately holds the cables below 135°F, which is well below the actual rating of 90°C (194°F) for all safety-related cables.

The supply and exhaust fans are located in the control building at el 180 ft 0 in.

The cable spreading room supply fan and exhaust fan are automatically tripped upon the automatic initiation of the pressurization mode of the MCREC system. The cable spreading room supply and exhaust fans are secured to preclude a potential malfunction of those fans which could potentially impact the capability to maintain the MCR at a positive pressure relative to the surrounding turbine building. Refer to HNP-2-FSAR paragraph 6.4.1.2.2.1 for a discussion of the pressurization mode of the MCREC system.

9.4.7.2.6 Battery Rooms

The battery room (drawing nos. H-16041 and H-26093) exhaust fans are designed to operate automatically in the event of an LOSP when normal ventilation is not available and to perform the following functions:

- Provide ventilation at the rate of 12 air changes per hour.
- Prevent the hydrogen generated in the room from concentrating in excess of 4% by volume.

Two emergency exhaust fans are provided for the battery rooms (which include the station batteries) in the control building. The two exhaust fans are independent of each other. Under normal conditions, the control building ventilation is adequate for removing any hydrogen concentration. These fans may be manually operated when the normal ventilation system is not operating or as required by operations personnel. To ensure operation during an LOSP, the fans are automatically aligned and started from the emergency diesels. Operation from the diesels is maintained until normal power is restored.

The air exhausted from the battery rooms is replaced by air drawn from the control building normal supply ventilation system ductwork. Replacement air is supplied at the rate of 12 air changes per hour.

Station service battery rooms 2A and 2B are provided with a common hot-water heating coil to temper the outside air during the winter months to ensure the design capacity of the batteries can be discharged upon demand.

The fans, instruments, and supply and exhaust ductworks are designed to meet Seismic Category I requirements.

9.4.7.2.7 Shift Supervisor's Area

The shift supervisor's area consists of an office, kitchen, and storage room. The area is maintained at 76°F dry bulb ± 2°F and 50% relative humidity (max) year round by an independent HVAC system. The major system components are an air-handling unit, water cooled condenser, electric duct heater, and small exhaust fan. All components are sized for 100% capacity.

The air-handling unit consists of a fan section, direct expansion cooling coil, and filter section. The water cooled condensing unit has a refrigerant cooled compressor, anti-short cycle circuit, and cylinder unloading controls. The heater is an electric-duct insert-type, and the exhaust fan is a low-capacity roof ventilator-type.

The air-handling unit is located in the ceiling space of the storage room, and the condenser is located on the roof of the building. Air is supplied to each room (storage, office, and kitchen) and is returned to the air-handling unit from the ceiling space. Registers are located in each room to allow return air to flow into the ceiling space. A fan exhausts kitchen air to the turbine building atmosphere. Makeup air is provided to the system from the cable spreading room supply air header.

Once the system is manually energized, a thermostat takes over and dictates operation of the air-handling unit and condenser. If the condition dictates, the thermostat will be manually switched to the heating mode, and the duct heater will operate as necessary. The kitchen

exhaust fan is manually energized from a local switch in the kitchen area and is operated as necessary.

9.4.7.2.8 Other Control Building Ventilation Areas

Ventilation for various other control building ventilation areas (drawing no. H-16034) is provided by supply and exhaust fans of the control building ventilation.

Supply air from the outside is delivered to these control building areas by a duct system with three supply fans common for both HNP-1 and HNP-2. Normally, two supply fans are operating while the third is on standby. The outside supply air is filtered through a roll filter.

The HNP-2 control building is provided with its own exhaust fans. Exhaust from the control building area for HNP-2 is ducted to the outside environment through the reactor building vent plenum by two exhaust fans. Normally, one exhaust fan is operating while the second fan is on standby. The failure of the operating exhaust fan motor automatically activates the standby exhaust fan. In case both exhaust fans fail upon loss of power supply, a natural convection flowpath may be established by opening access doors in the ductwork upstream of the exhaust fans.

When the outside air falls below 40°F, the supply air is tempered by the hot water heating coils (plant heating system) to maintain a comfortable working temperature of at least 65°F inside the building. However, analysis indicates that the design temperature of the control building can be maintained with internal heat loads; therefore, use of the hot water heating coils is not necessary. A maximum temperature of 110°F is maintained when the outside air is 95°F.

The control building supply fans are located at el 130 ft 0 in. and the exhaust fans at el 228 ft 0 in.

9.4.7.2.9 LPCI Inverter Room[a]

The LPCI inverter room, which is used jointly by HNP-1 and HNP-2, is served by a normal air-handling unit.

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a. HNP-1 and HNP-2 LPCI inverters were replaced with Class 1E power supplies backed by dedicated diesel generators (HNP-1-FSAR figure 8.5-1, HNP-2-FSAR figure 8.3-8). The PSW supply for the two essential LPCI inverter room coolers has been retired in place.

9.4.7.2.9.1 Normal LPCI Inverter Room Cooling. The LPCI inverter room is maintained at ~ 76°F dry bulb by the normal air-handling unit located within the room (drawing no. H-51179). The normal air-handling unit is sized for 100% capacity and is nonsafety related.

The normal air-handling unit is a vertical, floor-mounted unit that consists of a fan section, a chilled water cooling coil section, a filter section, and a discharge plenum. Control building chilled water flows through the cooling coil to remove the room heat load (drawing no. H-51178). The air-handling unit recirculates the air within the room.

The normal air-handling unit is controlled from a switch on the locally mounted combination starter. Once energized, the fan of the air-handling unit operates continuously to circulate the air within the LPCI inverter room. If power is lost and then restored, the unit will automatically restart. As the room temperature fluctuates, a temperature controller throttles the three-way control valve to vary the chilled water flow through the cooling coil and thus controls the room temperature.

9.4.7.2.10 Vital ac Room (HNP-2)

The HNP-2 vital ac room is maintained at ~ 76°F dry bulb by a dedicated air-handling unit located within the room (drawing no. H-51179). The air-handling unit is sized for 100% capacity and is nonsafety related. The air-handling unit is a vertical, floor-mounted unit that consists of a fan section, a chilled water cooling coil section, a filter section, and a discharge plenum. Control building chilled water flows through the cooling coil to remove the room heat load (drawing no. H-51178). The air-handling unit recirculates the air within the room. During normal operations, the ventilation fan exhausts air from the room, with makeup ventilation being induced through the wall transfer grille (drawing no. H-16041). The air change rate satisfies the hydrogen removal requirements.

Under accident conditions, air from the working floor area is induced through the wall transfer grille by the control building emergency exhaust fans, discussed in paragraph 10.9.3.6.7 of the Unit 1 FSAR, to limit hydrogen concentrations in the room (drawing no. H-16041).

The air-handling unit is controlled from a switch on the locally mounted combination starter. Once energized, the fan of the air-handling unit operates continuously to circulate the air within the vital ac room. If power is lost and then restored, the unit will automatically restart. As the room temperature fluctuates, a temperature controller throttles the three-way control valve to vary the chilled water flow through the cooling coil and thus controls the room temperature.

9.4.7.2.11 Reactor Protection System (RPS) Motor-Generator (MG) Set Rooms

A chilled water cooling coil module is mounted in the outside air supply air duct to provide cooling during summer months to the HNP-1 and HNP-2 RPS M-G set rooms. The cooling coil module consists of an inlet (shutoff) damper, two 1-in. 30% efficiency filters, moisture eliminator and an outlet (balancing) damper. The cooling coil is served by the control building chilled water system (2P67). The cooling coil is drained during the winter months to prevent the coil from freezing.

The cooling coil module is nonsafety related.

9.4.7.2.12 Control Building Chilled Water System

The LPCI inverter room, the HNP-1 and HNP-2 vital ac rooms, and the HNP-1 and HNP-2 RPS M-G set rooms are normally cooled by a nonessential control building chilled water system.

The control building chilled water system (drawing no. H-51178) consists of an air-cooled, skid-mounted chiller unit, two full-capacity chilled water circulating pumps, an expansion tank, an air separator, a chemical addition tank, and related piping, valves, and instrumentation. The chiller unit and circulating pumps are located in the yard due west of the control building and due south of the service building passageway to the power block. A chilled water pump is run continuously to guard against freezing during winter operation. The other pump is secured, isolated, and drained during winter operation. The air separator, chemical addition tank (both located in the HNP-2 control building, el 130 ft 0 in.) and expansion tank (located in the HNP-2 turbine building, el 164 ft 0 in.) are installed on the pump suction header.

The chiller and chilled water pump utilize 480-V/3 phase/60 Hz power coming from HNP-2 turbine building 600-V MCC 2R24-S040 through a 575-480 V transformer, 2R11-S102. Nameplate voltage of the chiller and pumps is 460 V.

The supply and return piping headers are routed from the yard through the control building to supply chilled water to air-handling unit 2Z41-B100 located in the LPCI inverter room, to cooling coil 2Z41-B023 mounted in the branch air duct supplying HNP-1 and HNP-2 RPS MG set rooms, and to air-handling units Z41-B040 and 2Z41-B040 located in the HNP-1 and HNP-2 vital AC rooms, respectively.

The chilled water supply uses a three-way control valve around each AHU to allow for cooling load fluctuations. These three-way control valves are controlled by temperature sensors and temperature controllers. These control circuits are pneumatic with the air supply coming from the HNP-2 instrument air system (2P52).

The chilled water pumps are controlled from switches on locally mounted combination starters. The chiller is controlled by a local switch, by an interlock between the pumps and the chiller, and by the chiller's internal interlocks. Once energized, the control building chilled water system (chiller and one pump) is in continuous service during all periods of normal plant operation. If power is lost and then restored, the equipment will automatically restart after a time delay. This time delay is internal to the chiller logic and is required to prevent unit damage. The system functions with one of two chilled water circulating pumps in operation. The other pump serves as a manual backup.

The chiller unit (2P67-B001) operates as demand dictates to maintain a constant supply water temperature. If demand is low, the chiller reduces capacity by one of the following methods: fan cycling, cylinder unloading, or unit shutdown. Permissive controls between the chiller and the pumps are provided. If the operating chilled water pump or the chiller trips, a trouble alarm is initiated in the MCR.

Makeup water to the expansion tank/system is manual via piping connected to the HNP-1 demineralized water system (P21). The expansion tank is fitted with a level gauge and a level switch which alarms in the MCR on low level.

All three alarm conditions (chiller compressor and pump trips and low water level in the expansion tank) are annunciated through one common trouble alarm on MCR panels H11-P657 and 2H11-P657.

9.4.7.3 Safety Evaluation

9.4.7.3.1 Personnel Rooms

The systems listed below provide adequate capacity to ensure that proper temperatures are maintained in the various portions of the control building under operating and shutdown conditions in all types of weather. The systems are located within the control building and arranged for ease of access, control, and monitoring. These HVAC systems are not engineered safeguard systems, and no credit is taken for their operation in analyzing the consequences of any accident:

- Computer room.
- Water sampling room.
- Radiochemistry laboratory and health physics area.
- Cold lab.
- Cable spreading area.
- Shift supervisor's area.
- HNP-2 vital AC room.
- Other control building areas.

Areas in the control building subject to oil fires are enclosed inside firewalls and protected by automatic fixed-spray systems that annunciate in the MCR.

9.4.7.3.2 Battery Rooms

The exhaust fans provided for the battery rooms (which include both the HNP-1 and HNP-2 vital ac rooms) prevent the buildup of hydrogen concentration in the rooms by exhausting the air continually during the periods when the control building ventilation is not operating. The LOSP automatically energizes the exhaust fans. Under normal conditions, the control building

ventilation fans are adequate for removing any hydrogen concentration; however, the emergency exhaust fans may be manually operated as required.

Airflow switches in each exhaust fan duct actuate an alarm in the MCR when any of the battery room exhaust fans are not operating.

To ensure the operability of the battery room exhaust system, the exhaust fans, ductwork, instrumentation, and controls are designed to meet Seismic Category I requirements.

9.4.7.4 <u>Tests and Inspections</u>

The control building ventilation systems, which consists of fans, heating coils, refrigeration units, ductworks, instruments, and controls, were tested before installation as follows:

Major System Components	Standard
Battery room exhaust fans	AMCA 211 and 300-67
Other fans	AMCA 210-67 and 74

The distribution ductwork was tested for leaks and balanced after installation. For original plant construction, testing was performed in accordance with the Sheet Metal and Air Conditioning Contractors National Association Low Velocity Duct Construction Standard and the Associated Air Balance Council Standards for Field Measurement and Instrumentation, Form 81266, Volume 1, 1970.

Each component was inspected prior to installation. Components of each system are accessible for periodic inspection during plant operation.

Instruments were calibrated during testing. Automatic controls were tested for actuation at the proper setpoints. Alarm functions were checked for operability and limits during preoperational testing.

The systems were operated and tested initially with regard to flow paths, flow capacity, and mechanical operability.

9.4.8 WASTE GAS TREATMENT BUILDING

9.4.8.1 <u>Design Bases</u>

The waste gas treatment building HVAC system is designed:

- With sufficient redundancy and separation of components to provide reliable operation under normal conditions.

- To provide temperature control, humidity control, and air movement control for personnel comfort.
- To optimize equipment performance by the removal of heat dissipated from plant equipment.
- To provide an adequate supply of filtered fresh air for personnel.
- To minimize the possibility of exhaust air recirculation into the air intake.

9.4.8.2 System Description

The waste gas treatment building HVAC system is shown schematically in drawing no. H-16549. The significant parameters associated with the major components of the system are listed in table 9.4-16.

The waste gas treatment building HVAC is designed to maintain the building temperature, excluding the carbon adsorber vaults, within 70 to 90°F dry bulb when the outside temperature is between 20 to 95°F dry bulb. The operating temperature inside the carbon adsorber vaults can be selected and maintained within a range of 60 to 80°F dry bulb when the outside temperature is between 20 to 95°F dry bulb.

The waste gas treatment building HVAC system consists of two redundant chillers and two recirculating pumps that supply chilled water to the waste gas treatment air-handling units of HNP-1 and HNP-2. HNP-2 consists of two air-handling units inside the carbon adsorber vaults and one air-handling unit in the waste gas treatment building space. An air-handling unit consists of rows of cooling and heating coils and a vaneaxial fan to circulate air through the coils and rooms. Chilled water is supplied to the cooling coils; the heating coils are electrically powered.

Normally, a chiller and an associated recirculating pump are operating while the other chiller and recirculating pump are on standby. The chillers and associated recirculating pumps are manually started.

The two air-handling units inside the carbon adsorber vaults are redundant units; one is normally in operation while the other is on standby. Failure of the active unit causes a flow switch to be actuated, energizing the standby unit and initiating an alarm in the MCR. The vaneaxial fans in the carbon adsorber vault and waste gas treatment building units recirculate the conditioned air as well as the makeup air added to the rooms.

The outside air made up to the vault and building space is passed through roll filters before entering the air-handling units. Air from the vault and building space is expelled to the main stack by two 100% capacity exhaust fans serving both waste gas treatment areas of HNP-1 and HNP-2. One exhaust fan is normally operating while the second is on standby. Failure of the operating fan causes the standby fan to start automatically and initiates an alarm in the MCR.

A differential pressure switch installed across the inlet and outlet chilled water lines to the chiller indicates loss of flow, thus alerting the operator to start the standby recirculating pump or chiller. A three-way flow regulator on the chilled water line to each air-handling unit controls the cooling temperature in the associated air-handling unit.

A flow switch on the exhaust fan and one on the operating air-handling unit automatically start the standby fan and air-handling unit upon loss of airflow. An alarm is sounded in the MCR upon loss of flow to the operating vault air-handling unit, building air-handling unit, and the operating exhaust fan.

9.4.8.3 Safety Evaluation

The waste gas treatment building HVAC system is not a safety-related system. However, the system incorporates certain features designed to assure availability of the system for normal operating plant conditions.

Radiological consequences are discussed in chapter 12. A single-failure analysis for major system components is presented in table 9.4-17.

9.4.8.4 Tests and Inspections

The distribution ductwork is tested for leaks and balanced after installation in accordance with the Sheet Metal and Air Conditioning Contractors National Association Low Velocity Duct Construction and the Associated Air Balance Council Standards for Field Measurement and Instrumentation, Form 81266, Volume 1, 1970.

The air-handling units were tested and inspected prior to installation and are available for periodic inspection during plant operation. Instruments and controls were tested for actuation at the proper setpoints, and alarm functions were checked for operability and limits during preoperational testing.

Because the air-handling units are in use during normal plant operation, the availability of active components is evident to the plant operators, and there is no need for frequent online testing. Portions of the system normally closed to flow are periodically tested to ensure operability and integrity of the system. Standby air-handling units are periodically tested to ensure the reliability of all system components.

9.4.9 TECHNICAL SUPPORT CENTER

9.4.9.1 Design Basis

The Technical Support Center (TSC) HVAC system is nonsafety related and is designed to:

- Maintain a suitable environment for personnel occupancy and equipment operation during radiological events.

- Provide an adequate supply of filtered fresh air during normal operation and accident conditions.

- Minimize airborne radioactivity in the TSC during and after an accident.

9.4.9.2 System Description

The TSC is shown schematically on drawing no. H-26002. The significant parameters associated with the major components of the system are listed in table 9.4-18.

During the normal mode of operation, the TSC HVAC system central air-handling unit (X75-B001) draws outside air through a louver located on the east side of the mechanical equipment room at a rate of 5500 ft^3/min and provides environmentally controlled air throughout the TSC via a ductwork system. The air-handling unit consists of a roll filter and a direct expansion (DX) cooling coil supplied by a condensing unit (X75-B002). The air-handling unit is located in the mechanical equipment room, and the condensing unit is located outside at the south end of the building. A separate duct-mounted electric heater (X75-B004) maintains the TSC space temperature when dehumidification is provided and supplies heat during winter months. Cutout switches are provided for the electric heater for low airflow or high temperature. The roll filter is equipped with a high differential pressure alarm.

Additional system components include a duct silencer (X75-D006) downstream of the air-handling unit, an electric duct heater (X75-B003) in the conference room, a flow-indicating switch (X75-R006), and a restroom exhaust fan (X75-C002). The flow switch alarms on low airflow. The duct heater has cutout switches for both low airflow and high temperature. All components are sized for 100% capacity.

If emergency conditions exist, filter train fan unit X75-C001 will be activated causing automatic damper alignment to direct the outside air and some recirculation air to the filter train (X75-D001) first before entering the central air-handling unit. This activation will be automatic on a high-radiation signal at the TSC air intake louver. The filter train fan may also be manually activated from the TSC.

Once in the accident mode, air is circulated throughout the TSC with an outside air makeup rate of 500 ft^3/min as before. In the accident mode of operation, the TSC can maintain a slight positive pressure with respect to the ambient surroundings. The restroom exhaust fan will be manually isolated in the accident mode which will automatically close the exhaust damper. A differential pressure-indicating switch will alarm on low positive pressure and a radiation-indicating switch will alarm on high radiation in the discharge ductwork.

The filter train consists of a prefilter, electric heater, high-efficiency particulate air (HEPA) filter, two carbon adsorber banks, another HEPA filter, and the separate centrifugal fan (X75-C001) as mentioned before. Differential pressure indicators are provided for each filter train section. A pressure switch will alarm upon a high overall pressure drop through the filter assembly.

Temperature elements located inside the filter train will annunciate an alarm upon carbon bank high temperature, trip filter train fan X75-C001, and automatically realign the dampers to divert the outside air directly to the central air-handling unit similar to normal mode operation. Upon fire detection in the filter train assembly, a deluge sprinkler system can be manually actuated. A timer is provided to monitor filter train usage.

9.4.9.3 Safety Evaluation

The TSC HVAC system is not a safety-related system. However, the system includes a nonredundant, nonsafety-related filter train that will reduce the occupants' radiation exposure in the event of an accident.

Radiological consequences are discussed in chapter 12. A failure analysis for major system components is presented in table 9.4-19.

9.4.9.4 Tests and Inspections

The distribution ductwork was tested for leaks and balanced after installation in accordance with applicable low-velocity duct construction codes.

The air-handling units were tested and inspected prior to installation and are available for periodic inspection.

The filter train system was tested in accordance with AMCA 210-74, AMCA 500-75, and ANSI N510-75.

Other safety codes for fire protection, electrical wiring, and refrigeration systems are also applicable.

9.4.10 RIVER INTAKE STRUCTURE (HNP-1 AND HNP-2)

9.4.10.1 Design Bases

9.4.10.1.1 Safety Design Bases

The river intake structure ventilation system is designed to:

A. Operate from normal and emergency power supply systems.

B. Limit the average ambient temperature in the area to 122°F.

C. Perform before, during, and after a DBA.

9.4.10.1.2 Power Generation Basis

The river intake structure HVAC is additionally designed to limit the minimum temperature in the area to 40°F with the outside air temperature at 10°F.

9.4.10.2 System Description

The river intake structure HVAC system consists of three 50% capacity roof-mounted exhaust ventilators, four wall-mounted gravity-operated air intake louvers, and six wall-mounted unit heaters (drawing no. H-44073). The ventilators are powered from separate power sources (one each from HNP-1, division I; HNP-1, division II; and HNP-2, division I). Each ventilator has a separate control station and is operated by an individual thermostat. The independent controls are powered from the MCC control transformer for the associated fan. Since plant service water pumps operate during normal and accident conditions in the plant, the three thermostats and the individual fan control stations are located in the HNP-1 and HNP-2 plant service water pump bay area. The locations of the thermostats ensure the ventilation system is always activated when operation of the plant service water pumps causes a heat buildup in the area. The six unit heaters and their associated thermostats are strategically located at different areas of the building to provide adequate area coverage for maintaining the building above freezing temperatures.

9.4.10.3 Safety Evaluation

A failure analysis of the river intake structure ventilation system is presented in table 9.4-20. The ventilation system components are designed to Seismic Category I requirements. In the event of loss of offsite power, the ventilation system is powered from diesel generators.

TABLE 9.4-1

**MCR AIR-CONDITIONING AND FILTRATION SYSTEM
COMPONENT DESCRIPTION**

Air-handling units	
No.	3
Size (each) (% capacity)	50
Type	Horizontal draw-through
Capacity (each) (sf^3/min)	14,000 (15,500 for B003C only)
Heat removal capacity (each) (Btu/h)	483,000
Motor	15 hp, 550 V/60 Hz/3 phase
Condensing units	
No.	3
Size (each) (% capacity)	50
Compressor type	Open, reciprocating
Compressor capacity (ton)	40.2
Motor	50 hp, 550 V/60 Hz/3 phase
Condenser cooling water flow (each) (gal/min)	120
Cooling water source	PSW
Electric heating coils	
No.	3 (2 active, 1 disconnected)
Size (each) (% capacity)	50
Rating (each) (kW)	60
Exhaust fans	
No.	2
Type	Axial with variable inlet vane control
Capacity (each) (ft^3/min)	11,500
Motor	7 1/2 hp, 550 V/60 Hz/ 3 phase
Booster fans	
No.	2
Type	Centrifugal
Capacity (each) (sf^3/min)	2500
Motor	5 hp, 550 V/60 Hz/3 phase

<u>NOTE</u>:
Filter trains are discussed in section 6.4.

TABLE 9.4-2 (SHEET 1 OF 2)

MCR HVAC SYSTEMS FAILURE ANALYSIS

Component	Malfunction	Comments
Air handling unit	Failure of fan motor	Overload protection device trips motor, annunciates in the MCR, and starts standby AHU. Low-flow switch on fan discharge also alarms in the MCR.
	Reduced flow	Low-flow switch on fan discharge alarms in the MCR and automatically starts the standby AHU.
	Loss of refrigerating unit	Operators in MCR detect rise in room temperature and start the standby AHU.
	Loss of heating coils	Operators in MCR notice drop in room temperature and start the standby AHU
	Loss of airflow through heating coils	Low-flow switch automatically shuts off power to the coils to prevent burnout.
Booster fan	Motor overload	Overload protection device trips motor. Low-flow switch on fan discharge alarms in the MCR and automatically starts the standby booster fan.
	Reduced flow	Low-flow switch on fan discharge alarms in the MCR and automatically starts the standby booster fan.
Condensing unit	Loss of PSW divisional cooling water supply	Trip of the operating unit. The standby unit will be manually aligned to the available PSW division, and will be started.

TABLE 9.4-2 (SHEET 2 OF 2)

Component	Malfunction	Comments
Exhaust fan	Motor overload	Overload protection device trips motor. Discharge and inlet dampers close to isolate MCR. Operator starts standby exhaust fan.
	Reduced flow	Operators in the MCR sense the reduced flow and manually start the standby exhaust fan.
Dampers	Failure of dampers	Dampers connecting the charcoal filters to the outside fail open on loss of electrical power or operating air. This is the desired position for MCR pressurization. The dampers are provided with Seismic Category I air accumulators and receive power from the emergency diesels to ensure they can be closed if isolation is required. Double damper isolation is provided with all other isolation dampers failing closed. Dampers in the AHUs fail open, thus ensuring operation of the AHUs is not restricted.
Power source	LOSP	The HVAC equipment in the MCR is shifted to emergency diesel power.
Filter trains	All postulated failures	See table 6.4-2.

TABLE 9.4-3 (SHEET 1 OF 4)

DESCRIPTION OF REACTOR BUILDING HVAC SYSTEM, AND REACTOR BUILDING AND RADWASTE BUILDING CHILLED WATER SYSTEM MAJOR COMPONENTS

Safety-Related Components[(a)]

Reactor bldg HVAC System (2T41)

ECCS fan coil units (RHR pumprooms)	
Equipment MPL nos.	2T41-B002A&B; B003A&B
Coils/unit	1
Air flowrate (each) (sf^3/min)	25,600
Cooling capacity (each) (Btu/h)	975,000 (B002A&B) 900,000 (B003A&B)
Cooling media	PSW
Design inlet water temperature (°F)	95
Cooling media flowrate (gal/min)	150
Fans/unit	1
Capacity (each) (sf^3/min)	25,600
Motor	25 hp, 550 V/60 Hz/ 3 phase
ECCS fan coil units (HPCI pumproom)	
Equipment MPL nos.	2T41-B005A&B
Coils/unit	1
Air flowrate (each) (sf^3/min)	12,000
Cooling capacity (each) (Btu/h)	110,000
Cooling media	PSW
Design inlet water temperature (°F)	95
Cooling media flowrate (gal/min)	40
Fans/unit	1
Capacity (each) (sf^3/min)	12,000
Motor	7.5 hp, 550 V/60 Hz/3 phase
RCIC pump room coolers	
Equipment MPL nos.	2T41-B004A&B
Coils/unit	1
Air flowrate (each) (sf^3/min)	7000
Cooling capacity (each) (Btu/h)	75,000
Cooling media	PSW
Design inlet water temperature (°F)	95
Cooling media flowrate (gal/min)	43
Fan/unit	1
Motor	5 hp, 550 V/60 Hz/3 phase

a. Evaluation of the safety-related components has demonstrated that the components are capable of providing adequate heat removal to meet accident requirements with cooling water temperature of 97ºF.

TABLE 9.4-3 (SHEET 2 OF 4)

Nonsafety-Related Components

Reactor bldg HVAC system (2T41)

Reactor zone supply air filter	
Equipment MPL no.	2T41-D001
Type	Horizontal, draw-through, floor-mounted
Reactor zone supply fans	
Equipment MPL nos.	2T41-C001A&B
Type	Vaneaxial
Capacity (each) (sf^3/min)	6500
Motor	15 hp, 550 V/60 Hz/3 phase
Reactor zone exhaust filter trains	
Equipment MPL no.	2T41-D005
Type	Draw-through, floor-mounted
Media	TEDA-impregnated
Capacity	6500
HEPA efficiency (%)	99.97 (for 0.3 µm)
Charcoal efficiency	
Methyl iodine at 30°C and 95% RH[a]	97 (New Carbon)
Charcoal depth (in. minimum)	8
Reactor zone exhaust fans	
Equipment MPL nos.	2T41-C007A&B
Type	Vaneaxial
Capacity (each) (sf^3/min)	6500
Motor	25 hp, 550 V/60 Hz/3 phase
Refueling zone supply filter train	
Equipment MPL no.	2T41-D002
Type	Horizontal, draw-through, floor-mounted
Refueling zone supply fans	
Equipment MPL nos.	2T41-C002A&B
Type	Vaneaxial
Capacity (each) (sf^3/min)	30,000
Motor	50 hp, 550 V/60 Hz/3 phase

TABLE 9.4-3 (SHEET 3 OF 4)

Refueling zone exhaust filter trains	
Equipment MPL nos.	2T41-D007 & -D008
Type	Draw-through, floor-mounted
Media	TEDA-impregnated
Capacity (each) (sf^3/min)	15,000
HEPA efficiency (%)	99.97 (for 0.3 µm)
Charcoal efficiency (%)	
Methyl iodine at 30ºC and 95% RH	99 (New Carbon)
Charcoal depth (in. minimum)	4
Refueling zone supply fans	
Equipment MPL nos.	2T41-C005A&B
Type	Vaneaxial
Capacity (each) (sf^3/min)	30,000
Motor	100 hp, 500 V/60 Hz/3 phase
Reactor bldg and radwaste bldg chilled water system (2P65)	
Chillers	
MPL nos.	2P65-B001A&B
Type	Centrifugal compression
Capacity (each) (tons)	175
Motor	238 hp, 575 V/60 Hz/3 phase
Cooling water flow (gal/min)	875
Chilled water flow (gal/min)	250
Chilled water pump	
Equipment MPL nos.	2P65-C001A&B
Type	Centrifugal
Capacity (each) (gal/min)	250
Head (ft)	156
Motor	20 hp, 575 V/60 Hz/3 phase
Condenser circulation water pump	
Equipment MPL nos.	2P65-C002A&B
Type	Centrifugal
Capacity (each) (gal/min)	700
Head (ft)	83
Motor	20 hp, 575 V/60 Hz/3 phase

TABLE 9.4-3 (SHEET 4 OF 4)

Cooling towers	
Equipment MPL no.	2P65-B002
Type	Counterflow, forced-draft
Fan	1
Motor	40 hp, 575 V/60 Hz/3 phase
Equipment MPL no.	2P65-B004A&B
Type	Crossflow, induced-draft
Fans	2
Motor	20 hp, 575 V/60 Hz/3 phase

a. RH = relative humidity.

TABLE 9.4-4 (SHEET 1 OF 5)

REACTOR BUILDING HVAC SYSTEM, AND REACTOR BUILDING AND RADWASTE BUILDING CHILLED WATER SYSTEM FAILURE ANALYSES

Component	Malfunction	Comments
		Reactor Zone HVAC System
Supply fan	Failure of fan motor	Overload protection device trips motor, actuates alarm at the MCR, and automatically starts the standby supply fan. Low-flow switch on fan discharge also alarms in the MCR.
	Reduced flow	Low-flow switch on fan discharge alarms in the MCR. The operator starts the standby supply fan.
Heating coils	Loss of hot water heating coils	The design temperature of the reactor bldg can be maintained with internal heat loads; therefore, use of the hot water heating coils is not necessary. Loss of the hot water heating coils will not affect equipment/plant operation.
Inlet guide vanes on fans	Closure of guide vanes	Guide vanes revert to a minimum opening, which stops the active fan and initiates an alarm in the MCR. The operator starts the standby fan.
Fan coil units	Failure of fan motor	Overload protection device trips motor. Fan coil unit B017 supplies air to most of the building areas. A standby fan starts upon loss of the active fan. A low-flow switch alarm alerts the operator start the standby fan. Other fan coil units with single fans are located in areas where loss of cooling will not be detrimental to plant operation.
	Reduced flow	See discussion above on failure of fan motor.
	Loss of cooling coils	The areas served by the chilled water units can withstand the loss of the fan coil units. Only ECCS areas are provided with PSW cooled cooling units.

TABLE 9.4-4 (SHEET 2 OF 5)

Component	Malfunction	Comments
	Reactor Zone HVAC System (continued)	
Exhaust fan	Failure of fan motor	Overload protection device trips motor, actuates alarm in the MCR, and automatically starts the standby exhaust fan. Low-flow switch on fan discharge also alarms in the MCR. Supply fan stops if both exhaust fans fail.
	Reduced flow	Low-flow switch on fan discharge alarms in the MCR. Operator starts standby exhaust fan. Supply fan stops if both exhaust fans stop.
Dampers	Failure of dampers	Dampers on the supply and exhaust fans fail close, thus preventing accidental release of room atmosphere outside the building. Low-flow switches alarm in the MCR.
Power source	Loss-of-offsite power	Temporary loss of ventilation will not harm equipment or affect plant operation. Supply and exhaust dampers fail closed to isolate the building. Ventilation may be shifted to SGTS.
Exhaust filter train	Obstruction of filter elements	High differential pressure across specific filter elements alarms in the MCR. The exhaust and supply fans are stopped by the operator, and intake and outlet isolation dampers are closed. The SGTS may be activated while the defective filter is replaced or, if no radiation is evident, the supply and exhaust fans may be operated with the guide vane adjusted to 50% capacity. The fan coil cooling units will continue to operate.
	High temperature in charcoal bed coal bed	A temperature sensor in the charcoal bed senses high temperature and stops the active exhaust fan and corresponding supply fan, and an alarm is annunciated in the MCR. The deluge system is manually activated as needed.

TABLE 9.4-4 (SHEET 3 OF 5)

Component	Malfunction	Comments
	Refueling Zone HVAC System	
Supply fan	Failure of fan motor	Overload protection device trips motor, actuates an alarm in the MCR, and automatically starts the standby supply fan.
	Reduced flow	Low flow condition on the fan discharge is alarmed in the MCR. The operator starts the standby supply fan.
Heating coils at supply filter	Loss of hot water heating coils	The design temperature of the refueling floor can be maintained with internal heat loads; therefore, use of the hot water heating coils is not necessary. Loss of the hot water heating coils will not affect equipment/ plant operation.
Hot water heaters	Loss of hot water heating coils	The design temperature of the refueling floor can be maintained with internal heat loads; therefore, use of the hot water heaters is not necessary. Loss of the hot water heaters will not affect equipment/plant operation.
	Failure of fans	See discussion on loss of heating coils.
Exhaust fan	Failure of fan motor	An overload protection device trips the motor, actuates an alarm in the MCR, and automatically starts the standby exhaust fan. A low-flow switch on the fan discharge also initiates an alarm in the MCR. The supply fan automatically stops if both exhaust fans stop.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby exhaust fan. The supply fan automatically stops if both exhaust fans stop.
Inlet guide vanes on fans	Closure of guide vanes	Guide vanes revert to a minimum opening, which stops the active fan The operator starts the standby fan.
Dampers	Failure of dampers	Dampers on the supply and exhaust fans fail closed, thus preventing release of room atmosphere outside the building. A low-flow switch initiates an alarm in the MCR.

TABLE 9.4-4 (SHEET 4 OF 5)

Component	Malfunction	Comments
	Refueling Zone HVAC System (continued)	
Power source	LOSP	Loss of ventilation will not harm equipment or affect plant operation. Supply and exhaust dampers fail closed to isolate the area. Ventilation may be shifted to the SGTS.
Supply and exhaust filter train	Obstruction of filter elements	High differential pressure across specific filter elements alarms in the MCR. The exhaust and supply fans are stopped by the operator, and the intake and outlet isolation dampers are closed. The SGTS may be activated while the defective filter is replaced or, if no radiation is evident, the supply and exhaust fans may be operated with the fan blades adjusted to 50% capacity. The fan coil cooling units will continue to operate.
	High temperature in charcoal bed	A temperature sensor in the charcoal bed senses high temperature and stops the active exhaust fan and corresponding supply fan; an alarm is annunciated in the MCR. The deluge system is manually activated as needed.
	ECCS Room Coolers	
Fan (all)	Failure of fan motor	The standby fan unit will automatically start if the primary fan unit fails with a MCC breaker trip, or if room temperature exceeds the preset value. A low-flow switch on the fan discharge initiates an alarm in the MCR.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby fan coil unit.
Isolation valves (PSW)	Failure of power	Isolation valves for service water to fan coil units fail open, thus ensuring that waterflow to to units is not interrupted.
Power source	LOSP	Fan coil units are transferred to emergency diesels.

TABLE 9.4-4 (SHEET 5 OF 5)

Component	Malfunction	Comments
		Reactor Bldg and Radwaste Bldg Chilled Water System
Water chiller	Loss of operating chiller	An alarm is annunciated in the MCR, and the standby chiller can be started locally.
	Failure of isolation valve on chilled water lines to fan coil units	The valve fails open; thus, chilled waterflow to the fan coil units is not interrupted.
Power source	LOSP	Loss of chilled water will not harm equipment or affect plant operation.
Chilled water recirculation pump	Loss of operating pump	The low-flow alarm is annunciated on the local panel, and the standby pump can be started locally.
Condenser circulation water pumps	Loss of operating pump	The low-flow alarm is annunciated on the local panel, and the standby pump can be started locally.
Cooling tower	Loss of cooling tower	A loss of chilled water from the reactor bldg and radwaste bldg chilled water system chillers occurs, but chilled water can be provided from the primary containment (drywell) chilled water system. The loss of water will not harm equipment or affect plant operation.

TABLE 9.4-5

RADWASTE AREA HVAC SYSTEM MAJOR COMPONENTS

Supply filter train	
No.	2
Type	Prefilter with heating coil
Supply fan	
No.	2
Type	Vane
Capacity (sf^3/min)	24,000
Motor	20 hp, 550 V/60 Hz/3 phase
Exhaust filter train	
No.	2
Type	Charcoal adsorber
Capacity (each) (sf^3/min)	13,000
Media	TEDA-impregnated
HEPA efficiency (%)	99.97
Charcoal efficiency (%)	
Methyl iodine at 30ºC and 95% RH	99 (New Carbon)
Charcoal depth (in. minimum)	4
Exhaust fans	
No.	2
Type	Vaneaxial
Capacity (each) (sf^3/min)	24,000
Motor	60 hp, 550 V/60 Hz/3 phase

TABLE 9.4-6 (SHEET 1 OF 2)

RADWASTE AREA HVAC SYSTEM FAILURE ANALYSES

Component	Malfunction	Comments
Supply fan	Failure of fan motor	Overload protection device trips motor, actuates an alarm in the local control room, and automatically starts standby supply fan. Low-flow switch on fan discharge alarms in the local control room.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the local control room. The operator starts the standby supply fan.
Supply heating coils	Loss of hot water heating coils	The design temperature of the radwaste building can be maintained with internal heat loads; therefore, use of the hot water heating coils is not necessary. Loss of the hot water heating coils will not affect equipment/plant operation.
Chilled water	Failure of fan motor or blade	Rising temperature in the room will not harm equipment or affect plant operation. Supply and exhaust fans hold down the room temperature.
	Loss of chilled water	See preceding discussion of failure of fan motor or blade.
Exhaust fan	Failure of fan motor	Overload protection device trips motor, actuates alarm at local control room, and automatically starts standby exhaust fan. A low-flow switch on fan discharge initiates an alarm in the local control room.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the local control room. The operator starts the standby exhaust fan.
Variable pitch blades on fan	Failure of variable pitch blades	Blades revert to a minimum pitch, which initiates a low-flow alarm in the local control room. The operator starts the standby fan.

TABLE 9.4-6 (SHEET 2 OF 2)

Component	Malfunction	Comments
Supply and exhaust filter train	Obstruction of filter elements	High differential pressure across a specific filter element alarms in the local control room. The exhaust and supply fans are stopped by the operator and reenergized with fan blades adjusted to 50% capacity. The chilled water cooling system continues to operate while the defective filter is replaced.
	High temperature in charcoal bed	A temperature sensor in the charcoal bed senses high temperature and stops the active exhaust fan; an alarm is annunciated in the main and local control rooms. The operator manually stops the supply fan. The deluge system is manually activated as needed.
Power source	LOSP	Loss of the HVAC system will not harm equipment or affect plant operation.

TABLE 9.4-7 (SHEET 1 OF 2)

DESCRIPTION OF TURBINE BUILDING HVAC SYSTEM MAJOR COMPONENTS

Supply air filters	
No.	1
Type	Horizontal draw-through, floor-mounted
Supply fans	
No.	2
Type	Vaneaxial
Capacity (sf^3/min)	20,000
Motor	20 hp, 550 V/60 Hz/3 phase
Exhaust filter trains	
No.	2
Type	Draw-through, floor-mounted
Capacity (sf^3/min.)	15,000
Media	TEDA-impregnated
HEPA efficiency (%)	99.97 (for 0.3 µm)
Charcoal efficiency	
Methyl iodine at 30°C and 95% RH	97 (New Carbon)
Charcoal depth (in. minimum)	8
Exhaust fans	
No.	2
Type	Vaneaxial
Capacity (sf^3/min)	25,000
Motor	75 hp, 550 V/60 Hz/3 phase
Hot water unit heaters	
Quantity	4
Fan type	Vaneaxial
Heating duty (Btu/h)	350,000
Capacity (sf^3/min)	8200
Motor	5 hp, 208 V/60 Hz/3 phase
<u>Chilled water system</u>	
Chillers	
No.	2
Type	Centrifugal
Cooling capacity (tons)	700
Compressor 2A	
Type of compressor	Centrifugal
No. of stages	2
Type of refrigerant	R134a
Motor	1000 hp, 4000 V/60 Hz/3 phase

TABLE 9.4-7 (SHEET 2 OF 2)

Compressor 2B	
Type of compressor	Centrifugal
No. of stages	2
Type of refrigerant	R134a
Motor	900 hp, 4000 V/60 Hz/3 phase
Refrigerant condenser	
Flowrate (gal/min)	1600
Pressure drop (ft WG)	13.0
Entering water temperature (°F)	90.0
Leaving water temperature (°F)	103.3
Heat rejection (thousand Btu/h)	10,528
Evaporator	
Flowrate (gal/min)	1000
Pressure drop at rated flow (ft WG)	10.6
Entering water temperature (°F)	66.8
Leaving water temperature (°F)	50.0
Recirculating pump (chilled water)	
Quantity	2
Type	Centrifugal
Capacity (gal/min)	1040
Head (ft)	107
Motor	75 hp, 550 V/60 Hz/3 phase
Chemical feed pump and tank pump	
Quantity	1
Maximum pump capacity (gal/min)	18.0
TENV motor (hp)	1/3
rpm	1700
Chemical addition tank	
Material	Stainless-steel 304
Capacity (gal)	50
Wall thickness (gage)	15
Expansion tank	
Quantity	1
Capacity (gal)	90
Design pressure (psig)	75
Design temperature (°F)	200
Size	24-in. x 4-ft straight length
Material	Carbon steel

TABLE 9.4-8 (SHEET 1 OF 2)

TURBINE BUILDING HVAC SYSTEM FAILURE ANALYSES

Components	Malfunction	Comments
Supply fan	Failure of fan motor	An overload protection device trips the motor, actuates an alarm in the MCR, and automatically starts the standby supply fan. A low-flow switch on the fan discharge also initiates an alarm in the MCR.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby supply fan.
Supply heating coils	Loss of hot water heating coils	The design temperature of the turbine building can be maintained with internal heat loads; therefore, use of the hot water heating coils is not necessary. Loss of the hot water heating coils will not affect equipment/plant operation.
Chilled water cooling units	Failure of fan motor	Rising temperature in the room will not harm equipment or affect plant operation. Supply and exhaust fans hold down the room temperature.
Water chillers and recirculating pumps	Loss of chilled water	In the event of loss of an active unit, the operator starts the standby unit.
Hot water unit heaters	Failure of fan motor	The design temperature of the turbine building can be maintained with internal heat loads; therefore, use of the hot water heaters is not necessary. Loss of the hot water heaters will not affect equipment/plant operation. Supply and exhaust fans hold down the room temperature.
	Loss of hot water heating coils	See preceding discussion on failure of fan motor.

TABLE 9.4-8 (SHEET 2 OF 2)

Components	Malfunction	Comments
Exhaust fan	Failure of fan motor	An overload protection device trips the motor, activates an alarm in the MCR, and automatically starts the standby exhaust fan. A flow switch on the fan discharge initiates an alarm in the MCR.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby exhaust fan.
Inlet guide vanes on fans	Closure of guide vanes	Guide vanes revert to a minimum opening, which stops the active fan. The operator starts the standby fan.
Supply and exhaust filter train	Obstruction of filter elements	High differential pressure across specific filter elements alarms in the MCR. The supply and exhaust fans are stopped by the operator and reenergized with fan blades adjusted to 50% capacity.
	High temperature in charcoal bed	A temperature sensor in the charcoal bed senses high temperature and stops the active exhaust fan; an alarm is annunciated in the MCR. The operator manually stops the supply fan. The deluge system is manually activated as needed.
Power source	LOSP	Loss of the HVAC system will not harm equipment.

TABLE 9.4-9

DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM COMPONENTS

Equipment	Capacity	Remarks
Roof ventilator, V-1 motor	30,000 ft^3/min, 5 hp, 550 V/ 60 Hz/3 phase	Ventilators redundant, two 100% units each generator room
Roof ventilator, V-2 motor	5300 ft^3/min, 3/4 hp, 208 V/ 60 Hz/3 phase	No redundancy
Roof ventilator, V-3 motor	4000 ft^3/min, 3/4 hp, 208 V/ 60 Hz/3 phase	Ventilators redundant two 100% units each switchgear room
Roof ventilator, V-4 motor	720 ft^3/min, 3/4 hp, 208V/ 60 Hz/3 phase	Ventilators redundant, two 100% units each battery room
Roof ventilator, V-5 motor	350 ft^3/min, 1/2 hp, 208 V/ 60 Hz/3 phase	Ventilators redundant, two 100% units each oil storeroom
Heater, H-1	12.5 kW, 550 V/ 60 Hz/3 phase	Heaters redundant, three 50% units each generator room
Heater, H-2	7.5 kW, 550 V/ 60 Hz/3 phase	Heaters redundant, three 50% units each switchgear room

TABLE 9.4-10 (SHEET 1 OF 3)

DIESEL GENERATOR BUILDING HEATING AND VENTILATION SYSTEM FAILURE ANALYSES

Component	Malfunction	Comments
	Generator Room	
Roof vent, V-2	Failure of normal roof exhaust ventilator or control, resulting in high generator room temperature	If operating ventilator fails, fan thermostats sense a continued rise in temperature and activate primary roof exhaust ventilator V-1.
Roof vent, V-1	Failure of primary roof exhaust ventilator or control, resulting in no airflow	If operating ventilator fails, its airflow switch activates its matching standby exhaust ventilator fan motor.
Louvers, LV-6	Failure of louver operator	The louvers are divided into four sections with individual power operators. The louvers fail closed, but the closing of one section would still leave sufficient opening in the remaining sections to keep the diesels supplied with air. The operator can override the louver limit switch to start the roof vent fans.
	Fire damper MK FD-3 closed or louver LV-6 closed (more than two out of four louver sections)	Cooling airflow through the louver is reduced or shutoff such that ambient temperatures in the affected diesel generator room may exceed the maximum allowable ambient operating temperature of 122°F. Operator surveillance of the diesel generator rooms will determine the high temperature in the room. This will initiate corrective action to solve the high temperature problem or to declare the affected diesel generator inoperable. The alternate diesel generator train is available.
Heater, H-1	Failure of heater control, resulting in no output or low output	If one heater fails, the remaining two heaters have capacity to adequately heat generator room automatically.

TABLE 9.4-10 (SHEET 2 OF 3)

Component	Malfunction	Comments
	Battery Room	
Roof vent, V-4	Failure of primary roof exhaust ventilator or control, resulting in no airflow	If operating ventilator fails, its airflow switch activates its matching standby exhaust ventilator fan motor, thus preventing high hydrogen concentration. Manual activation of the standby exhaust ventilator can also be administratively controlled by plant procedures.
Louvers, LV-8 in generator room	Failure of louver operator	The louvers fail close. Louvers LV-6 located beside louvers LV-8 can continue to supply air to the battery room provided they are opened manually, or automatically on high room temperature. An operator must override louver LV-8 limit switch to start roof vent fan.
	Switchgear Room	
Roof vent, V-3	Failure of primary roof exhaust ventilator or control, resulting in no airflow	If operating ventilator fails, its airflow switch activates its matching standby exhaust ventilator fan motor.
Louvers, LV-5	Failure of louver operator	The louvers are divided into two sections with individual power operators. The louvers fail close, but the closing of one section still leaves sufficient opening in the remaining section to keep the room supplied with air. The operator can override the louver limit switch to start the roof vent fan.
Heater, H-2	Failure of heater or control, resulting in no output or low output	If one heater fails, the remaining two heaters have capacity to adequately heat switchgear room automatically.

TABLE 9.4-10 (SHEET 3 OF 3)

Component	Malfunction	Comments
	Oil Storage Room	
Roof vent, V-5	Failure of primary roof exhaust ventilator or control, resulting in no airflow	If operating ventilator fails, its airflow switch activates its matching standby exhaust ventilator fan motor, thus preventing high fume concentration. Manual activation of the standby exhaust ventilator can also be administratively controlled by plant procedures.

TABLE 9.4-11

RESULTS OF ANALYSES ON DIESEL ENGINE COMBUSTION AIR INTAKE SYSTEM

Condition	Concentration at Diesel Generator Intake (%)	Limiting Concentration for 100% Efficiency (%)
Recirculation of exhaust	CO_2 - 0.1 N_2 - 0.5	15
Fire in room (CO_2)[a]		
Normal operation	10.5	15
Fire door failure	10.4	
Louvers failure	< 10	
Vent motor failure	< 5	
Fire in oil storage room	< 5	
Nitrogen storage tank rupture	~ 5	15

a. The diesel engine in the room where the fire occurs will be shut down with high CO_2 concentration in the combustion air intake. The concentrations at the intake given are for the diesel generator adjacent to the one in which the fire occurs.

TABLE 9.4-12 (SHEET 1 OF 3)

PRIMARY CONTAINMENT (DRYWELL) COOLING SYSTEM EQUIPMENT LIST

Nonsafety-Related Equipment

Primary containment (drywell) chilled water system (2P64)

Chillers	
Equipment MPL nos.	2P64-B006A&B (one standby)
Type	Centrifugal compression
Capacity (each) (tons)	450
Motor	600 hp, 4000 V/60 Hz/3 phase
Cooling water media	PSW
Cooling media water flow (gal/min)	900
Chilled water flow (gal/min)	675
Refrigerant	R134a
Recirculation pump	
Equipment MPL nos.	2P64-C008A&B
Type	Centrifugal
Capacity (each) (gal/min)	675
Head (ft)	160
Motor	50 hp, 550 V/60 Hz/3 phase
Chemical addition tank	
Equipment MPL no.	2P64-A002
Type	Vertical, with agitator
Capacity (gal)	52
Chemical feed pump	
Equipment MPL no.	2P64-C009
Type	Diaphragm
Capacity (gal/min)	7 (maximum)
Motor	1/3 hp, 115 V/60 Hz/1 phase
Expansion tank	
Equipment MPL no.	2P64-A001
Capacity (gal)	100

TABLE 9.4-12 (SHEET 2 OF 3)

Primary containment (drywell) cooling (air-side) system (2T47)

Fan coil units (el 114 ft 6 in.)	
Equipment MPL nos.	2T47-B010A&B
Design temperature (°F)	135 normal
Coils per unit	
Capacity of three-coil unit (Btu/h)	1,100,000
No. of coils per unit	3
Design pressure (psig)	150
Pressure drop (ft of water)	12.2
Type of water	Primary containment (drywell) chilled water system
Fans per unit	
Capacity (sf^3/min)	14,000
No.	1
Type	Vaneaxial, adjustable pitch
Motor	Direct-drive, 25 hp, 550 V/60 Hz/3 phase
Fan coil units (el 127 ft 9 in.)	
Equipment MPL nos.	2T47-B008A&B; 2T47-B009A&B
Design temperature (°F)	135 normal
Coils per unit	
Capacity of two-coil unit (Btu/h)	2,442,300
No. of coils per unit	2
Design pressure (psig)	150
Pressure drop (ft of water)	16.8
Type of water	Primary containment (drywell) chilled water system
Fans per unit	
Capacity (sf^3/min)	25,000
No.	1
Type	Vaneaxial, adjustable pitch
Motor	Direct-drive, 75 hp, 550 V/60 Hz/3 phase
Fan coil units (el 183 ft 6 in.)	
Equipment MPL nos.	2T47-B007A&B
Design temperature (°F)	135 normal
Coils per unit	
Capacity of two-coil unit (Btu/h)	586,160
No. of coils per unit	2
Design pressure (psig)	150
Water pressure drop (ft)	4.3
Type of water	Primary containment (drywell) chilled water system

TABLE 9.4-12 (SHEET 3 OF 3)

Primary containment (drywell) cooling (air-side) system (2T47) (continued)

Fans per unit	
Capacity (sf^3/min)	8,000
No.	1
Type	Vaneaxial, adjustable pitch
Motor	Direct-drive, 30 hp, 550 V/60 Hz/3 phase
Recirculating fan (el 196 ft 0 in.)	
Equipment MPL nos.	2T47-C001A&B
Capacity per fan (sf^3/min)	12,000
Type	Vaneaxial, adjustable pitch
Motor	Direct-drive, 30 hp, 500 V/60 Hz/3 phase
Recirculating fan (el 117 ft 0 in.)	
Equipment MPL nos.	2T47-C002A&B
Capacity per fan (sf^3/min)	3000
Type	Vaneaxial, adjustable pitch
Motor	Direct-drive, 2 hp, 208 V/60 Hz/3 phase

TABLE 9.4-13 (SHEET 1 OF 2)

PRIMARY CONTAINMENT (DRYWELL) COOLING SYSTEM FAILURE ANALYSES

Component	Malfunction	Comments
		Air Side of System (except 2T47-B010A&B)
Fan coil unit	Failure of fan motor	An overload protection device trips the motor, actuates an alarm in the MCR, and automatically starts the standby fan coil unit. A low-flow switch on the fan discharge also initiates an alarm in the MCR.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby fan coil units.
	LOSP	Fan coil units, recirculating fans, and chillers are transferred to the emergency diesels. All fan coil units and recirculating fans automatically start upon an LOSP.
	Loss of chilled water	Cooling coils are not required during and after a DBE or LOCA. For normal operation, loss of the operating chiller actuates an alarm in the MCR and starts the standby chiller. The chiller can be supplied by the emergency diesels during and after an LOSP. High air duct temperature also alarms in the MCR.
Recirculating fan	Failure of fan motor	An overload protection device trips the motor, actuates an alarm in the MCR, and, for recirculation fans at el 196 ft 0 in. only, the standby fan coil unit and associated recirculation fan automatically start. Tripping the recirculating fan motor at el 117 ft 0 in. alarms only in the MCR, since the remaining recirculating fan is adequate.

TABLE 9.4-13 (SHEET 2 OF 2)

Component	Malfunction	Comments
Recirculating fan (cont)	Reduced flow	The fan motor overheats from lack of airflow and tripout. An alarm is annunciated in the MCR, and for the recirculating fan at el 196 ft 0 in., the standby fan coil unit and associated recirculating fan automatically start.
		Hot spots in certain areas of the drywell are detected by space temperature sensors, and an alarm is annunciated in the MCR. The operator starts the standby fan coil unit and associated recirculating fan at el 196 ft 0 in.
	LOSP	All recirculating fans and associated fan coil units are automatically transferred to diesel power.
Ventilation supply ducts	Failure or gross leakage of ducts on fan coil units	Decrease or loss of air flow actuates a flow switch and initiates an alarm in the MCR. The operator starts the standby unit.
	Failure or gross leakage of ducts on recirculating fans	An overheated fan motor or hot spots in the drywell alarm in the MCR. The operator starts the standby unit.
	Water Side of System	
Primary containment water chillers	Loss of operating chillers	An alarm is annunciated in the MCR, and the operator starts the standby chiller.
	LOSP	Chillers will be transferred to the emergency diesels.
	Failure of isolation valve on chilled water line	The valve will fail open; thus, waterflow to the fan coil units is not interrupted.
Recirculation pump	Loss of operating pump	The low-flow alarm is annunciated in the MCR, and the standby pump can be started locally.

TABLE 9.4-14 (SHEET 1 OF 6)

CONTROL BUILDING HVAC SYSTEMS EQUIPMENT LIST

Computer room air-conditioning units

No.	3
Type	Package refrigeration
Capacity (tons)	5
Compressor motor	1.5 hp, 208 V/60 Hz/3 phase
Fan capacity (ft^3/min)	2000
Fan motor	1.5 hp, 208 V/60 Hz/3 phase
No. of electric coils	2
Capacity per coil (kW)	10

Water sampling room air-conditioning units

No.	2
Size (% capacity)	100
Type	Package refrigeration
Capacity (tons)	5
Compressor motor	1.5 hp, 208 V/60 Hz/3 phase
Fan capacity (ft^3/min)	2000
Fan motor	1.5 hp, 208 V/60 Hz/3 phase
No. of electric coils	2
Capacity per coil (kW)	17.6

Radiochemistry laboratory and health physics area units

No.	2
Size (% capacity)	100
Type	Package refrigeration
Capacity (tons)	20
Compressor motor	25 hp, 208 V/60 Hz/3 phase
Fan capacity (ft^3/min)	4100
Fan motor	3 hp, 208 V/60 Hz/3 phase
No. of electric coils	3
Capacity per coil (kW)	20

TABLE 9.4-14 (SHEET 2 OF 6)

<u>Cold lab air-conditioning units</u>	
No.	2
Size (% capacity)	100
Type	Package refrigeration
Capacity (tons)	3
Compressor motor	1 hp, 208 V/60 Hz/3 phase
Fan capacity (sf^3/min)	1000
Fan motor	1 hp, 208 V/60 Hz/3 phase
No. of electric coils	1
Capacity per coil (kW)	20
<u>Cable spreading room units</u>	
Supply fan	
No.	1
Type of fan	Centrifugal, backward-inclined
Capacity (ft^3/min)	15,700
Motor	7.5 hp, 550 V/60 Hz/3 phase
Drive	V-belt
Exhaust fan	
No.	1
Type of fan	Centrifugal, backward-inclined
Capacity (ft^3/min)	14,800
Motor	5 hp, 550 V/60 Hz/3 phase
Drive	V-belt
<u>Battery room exhaust fan units</u>	
No.	2
Type of fan	Vaneaxial
Capacity (ft^3/min)	1800
Motor	1.5 hp, 208 V/60 Hz/3 phase
Drive	Direct
<u>Shift supervisor's area</u>	
Air-handling unit	
No.	1
Size (% capacity)	100
Type	Horizontal, draw-through
Capacity (tons)	8.7
Fan capacity (ft^3/min)	3000
Fan motor	1 hp, 200 V/60 Hz/3 phase

TABLE 9.4-14 (SHEET 3 OF 6)

<u>Shift supervisor's area (continued)</u>

Condensing unit	
No.	1
Size (% capacity)	100
Type	Water cooled, reciprocating
Capacity (tons)	8.7
Compressor motor	10 hp, 208 V/60 Hz/3 phase
Condenser cooling water flow (gal/min)	42
Cooling water source	PSW
Electric duct heater	
No.	1
Size (% capacity)	100
Rating (kW)	4
Kitchen exhaust fan	
No.	1
Type	Centrifugal roof fan
Capacity (ft^3/min)	225
Motor	0.03 hp, 120 V/60 Hz/1 phase

<u>Control building ventilation units</u>

Supply fans	
No.	3
Type of fan	Centrifugal, backward-inclined
Capacity (ft^3/min)	67,900
Motor	50 hp, 550 V/60 Hz/3 phase
Drive	V-belt
Exhaust fans	
No.	2
Type of fan	Vaneaxial
Capacity (ft^3/min)	56,000
Motor	50 hp, 550 V/60 Hz/3 phase
Drive	Direct
Heating coils	
No.	2
Type	Hot water
Capacity of first coil (Btu/h)	1.124×10^6
Capacity of second coil (Btu/h)	0.342×10^6

TABLE 9.4-14 (SHEET 4 OF 6)

LPCI inverter room essential coolers[a]

Equipment MPL no.	2Z41-B020A, B020B
Size/unit (% capacity)	100
Cooling coil	
Capacity (Btu/h)	90,000
No. of coils/unit	1
Design water flowrate (gal/min)	60
Design inlet water temperature (°F)	95
Water pressure drop (ft)	6.6
Cooling water source	PSW
Fan	
Capacity (ft^3/min)	9850
No./unit	1
Type	Vaneaxial
Motor	15 hp 550 V/60 Hz/3 phase

LPCI inverter room normal air-handling unit[a]

Equipment MPL no.	2Z41-B100
Design temperature (°F)	76 normal
Cooling coil	
Capacity of coil (Btu/h)	180,000
No. of coils per unit	1
Design pressure (psig)	150
Water pressure drop (ft)	9.63
Type of water	Control building chilled water system
Fan	
Capacity (ft^3/min)	6800
No.	1
Type	Forward curved centrifugal
Motor	Belt-drive, 5 hp, 550 V/60 Hz/3 phase
Filter	
Quantity	6 (16 x 20 in.)
Type	Roughing, 50% efficiency

TABLE 9.4-14 (SHEET 5 OF 6)

<u>Vital ac room air-handling unit</u>	
Equipment MPL no.	2Z41-B040
Design temperature (°F)	76 normal
Cooling coil	
Capacity of coil (Btu/h)	192,000
No. of coils per unit	1
Design pressure (psig)	150
Water pressure drop (ft)	8.33
Type of water	Control building chilled water system
Fan	
Capacity (ft^3/min)	6800
No.	1
Type	Forward curved centrifugal
Motor	Belt-drive, 5 hp, 550 V/60 Hz/3 phase
Filter	
Quantity	6 (16 x 20 in.)
Type	Roughing, 50% efficiency
<u>Control building RPS MG set room cooling coil module</u>	
No.	1
Type of fans	None
Capacity - flow (sf^3/min)	1800
Capacity - cooling (Btu/h)	97,200 (design)
Cooling source	Control building chilled water system
Accessories	Inlet damper, balancing damper two 1-in. 30% efficiency filters
<u>Control building chilled water system (2P67)</u>	
Chiller	
Equipment MPL no.	2P67-B001
Type	Reciprocating compression
Capacity (tons)	55 nominal
Motor	40 hp, 460 V/60 Hz/3 phase
Cooling media	Ambient, outdoor air
Chilled water flow (gal/min)	128

TABLE 9.4-14 (SHEET 6 OF 6)

Control building chilled water system (2P67) (continued)

Chilled water circulating pumps	
Equipment MPL nos.	2P67-C001A&B
Type	Centrifugal
Capacity (each) (gal/min)	160 sizing/ 120 actual
Head (ft)	86
Motor	7.5 hp, 460 V/60 Hz/3 phase
Chemical addition tank	
Equipment MPL no.	2P67-A003
Type	Vertical, without agitator
Capacity (gal)	5
Air separator	
Equipment MPL no.	2P67-A002
Capacity (gal/min)	180
Expansion tank	
Equipment MPL no.	2P67-A001
Capacity (gal)	24

a. HNP-1 and HNP-2 LPCI inverters were replaced with Class 1E power supplies backed by dedicated diesel generators (HNP-1-FSAR figure 8.5-1, HNP-2-FSAR figure 8.3-8). The PSW supply for the two essential LPCI inverter room coolers has been retired in place.

TABLE 9.4-15 (SHEET 1 OF 8)

CONTROL BUILDING HVAC SYSTEMS FAILURE ANALYSES

Components	Malfunction	Comments
		Computer Room HVAC
Fan	Failure of fan motor	An overload protection device trips the motor. A low-flow switch on the fan discharge initiates an alarm in the MCR. The operator starts the standby unit.
	Reduced flow	A low-flow switch on the fan discharge initiates an alarm in the MCR room. The operator starts the standby unit.
	LOSP	The computers operate for 1/2 h from self-contained batteries; during this period, the loss of HVAC will not harm the computers. Furthermore, the computers are not required for safe shutdown of the plant.
Refrigerating unit	Loss of one refrigerating unit	One of two operating units will still be operating to hold the temperature down until the operator can start the standby unit.
Reheat coils	Loss of heating coils	Room temperature is held to a minimum of 65°F, since the source of supply air (control building) is regulated down to 65°F.
	Loss of airflow through coils	A low-flow on the reheat coils automatically shuts off the power to the coils to prevent burnout. The low-flow switch on the fan discharge initiates an alarm in the MCR.
		Water Sampling Room HVAC
Fan	Failure of fan motor	An overload protection device trips the motor. Rising temperature in the room will not harm equipment or affect plant operation. The operator starts the standby unit.
	Reduced flow	Rising temperature in the room will not harm equipment or affect plant operation. The operator starts the standby unit.

TABLE 9.4-15 (SHEET 2 OF 8)

Components	Malfunction	Comments
	Water Sampling Room HVAC (continued)	
Fan	LOSP	Rising temperature in the room will not harm equipment or affect plant operation.
Refrigerating unit	Loss of active refrigerating unit	Rising temperature in the room will not harm equipment or affect plant operation. The operator starts the standby unit.
Reheat coils	Loss of heating coils	Room temperature is held to a minimum of 65°F, since the source of supply air (control building) is regulated down to 65°F. The operator starts the standby unit.
	Loss of airflow through coils	A low-flow switch on the reheat coils automatically shuts off power to the coils to prevent burnout. Room temperature is held to a minimum of 65°F. The operator starts the standby unit.
	Radio Chemistry Laboratory and Health Physics Area HVAC	
Fan	Failure of fan motor	An overload protection device trips the motor. Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
	Reduced flow	Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
	LOSP	Rising temperature in the room will not harm equipment or affect plant operation.
Refrigerating unit	Loss of active refrigerating unit	Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
Reheat coils	Loss of heating coils	Room temperature is held to a minimum of 65°F, since the source of supply air (control building) is regulated down to 65°F.

TABLE 9.4-15 (SHEET 3 OF 8)

Components	Malfunction	Comments
Radio chemistry Laboratory and Health Physics Area HVAC (continued)		
Reheat coils	Loss of airflow through coils	A low-flow switch on the reheat coils automatically shuts off power to the coils to prevent burnout. Room temperature is held to a minimum of 65°F.
Dampers	Fail closing of dampers	Rising temperature in the room will not harm equipment or affect plant operation. For cold weather, room temperature is held to a minimum of 65°F by supply air. Loss of air flow automatically shuts off power to the coils.
Cold Lab HVAC		
Fan	Failure of fan motor	An overload protection device trips the motor. Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
	Reduced flow	Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
	LOSP	Rising temperature in the room will not harm equipment or affect plant operation.
Refrigerating unit	Loss of active refrigerating unit	Rising temperature in the room will not harm equipment or affect plant operation. Partial air-conditioning is still provided by the other unit.
Reheat coil	Loss of heating coils	Room temperature is held to a minimum of 65°F, since the source of supply air (control building) is regulated down to 65°F.
	Loss of airflow through coils	A low-flow switch on the reheat coils automatically shuts off power to the coils to prevent burnout. Room temperature is held to a minimum of 65°F.

TABLE 9.4-15 (SHEET 4 OF 8)

Components	Malfunction	Comments
	Cable Spreading Area HVAC	
Supply fan	Loss of motor or reduced flow	Temperature in the room will rise to 111°F (maximum). The exhaust fan removes heat from the room.
Exhaust fan	Loss of motor or reduced flow	The temperature in the room will rise to 111°F (maximum). The supply fan adds cool air in the room and forces warm air out of the room.
Regulating dampers	Failure of damper control	The temperature in the room will rise to 111°F (maximum).
Power source	LOSP	The temperature in the room will rise to 111°F (maximum).
	Battery Room HVAC	
Exhaust fans	Failure of fan motor	The motor trips, and a low-flow switch on the fan discharge initiates an alarm in the MCR. Battery operation is shifted to the room with an operable exhaust fan.
	Reduce flow	A low-flow switch on the fan discharge initiates an alarm in the MCR. Battery operation is shifted to the room with an operable exhaust fan.
Power source	LOSP	The fans are automatically started and shifted to the emergency diesel power source.
	Shift Supervisor's Area HVAC	
AHU	Failure of fan motor	An overload protection device trips the motor. Rising temperature in the room will not harm equipment or affect plant operation.
	Reduced flow	Rising temperature in the room will not harm equipment or affect plant operation.
	LOSP	Rising temperature in the room will not harm equipment or affect plant operation.

TABLE 9.4-15 (SHEET 5 OF 8)

Components	Malfunction	Comments
	Shift Supervisor's Area HVAC (continued)	
Reheat coil	Loss of heating coil	Falling temperature in the room will not harm equipment or affect plant operation.
	Loss of airflow through coil	A low-flow switch on the reheat coil automatically shuts off power to the coil to prevent burnout. Falling temperature in the room will not harm equipment or affect plant operation.
Exhaust fan	Loss of motor or reduced flow	The supply fan adds cool air in the room and forces warm air out of the room.
	Control Building HVAC	
Supply fan	Failure of fan motor	An overload protection device trips the motor and automatically starts the standby fan. A low-flow switch initiates an alarm in the MCR.
	Reduced flow	A low-flow switch initiates an alarm in the MCR, and the operator starts the standby fan.
Heating coils	Loss of heating water	Fans may be shut down or operated on and off to maintain a comfortable atmosphere in the building.
Exhaust fan	Failure of fan motor	An overload protection device trips the motor and automatically starts the standby fan. A low-flow switch initiates an alarm in the MCR.
	Reduced flow	A low-flow switch initiates an alarm in the MCR, and the operator starts the standby fan.
Power source	LOSP	Rising temperature in the room will not harm equipment or affect plant operation. Battery room exhaust fans operate from the emergency power sources.

TABLE 9.4-15 (SHEET 6 OF 8)

Components	Malfunction	Comments
	LPCI Inverter Room Essential Coolers[a]	
Cooler	Failure of fan motor	An overload protection device trips the motor. Cooling capacity is provided by redundant unit.
	Reduced air flow	Cooling capacity is provided by redundant unit.
	Loss of service water	Cooling capacity is provided by redundant unit.
	LOSP	Coolers are transferred to the emergency diesels.
	LPCI Inverter Room AHU[a]	
Normal AHU	Failure of fan motor	An overload protection device trips the motor. A high-temperature switch in the room starts the emergency coolers.
	LOSP	AHU will automatically restart upon restoration of power. A high temperature switch in the room starts the emergency coolers.
	Loss of chilled water	Cooling coils are not required during or after a DBE or LOCA. The operator can rectify the problem and/or add temporary cooling units in the affected areas.
	Vital ac Room AHU	
AHU	Failure of fan motor	An overload protection device trips the motor. Ventilation will maintain some cooling in the room. The cooling coils are not required to mitigate a DBA.
	LOSP	AHU will automatically restart upon restoration of power. Ventilation will maintain some cooling in the room. The cooling coils are not required to mitigate a DBA.

TABLE 9.4-15 (SHEET 7 OF 8)

Components	Malfunction	Comments
		Vital ac Room AHU (continued)
AHU	Loss of chilled water	Cooling coils are not required during or after a DBE or LOCA. For normal operation, loss of the chiller actuates an alarm in the main control room. The operator can rectify the problem and/or add temporary cooling units in the affected areas.
		Control Building RPS M-G Set Room Cooling Coil Module
Cooling coil module	Loss of chilled water	Cooling is not required in the RPS M-G set rooms during and after a DBE or LOCA. Cooling is not required in the M-G set rooms during the winter months. During summer months and normal plant operation, operator rounds will detect increased temperature in the room and initiate corrective action.
		Control Building Chilled Water System
Chiller	Loss of chiller	An alarm is annunciated in the main control room. The operator can rectify the problem and/or add temporary cooling units in the affected areas.
	LOSP	Chiller will automatically restart, after a time delay, upon restoration of power. This time delay is internal to the chiller logic and is required to prevent unit damage.
Chilled water circulating pumps	Loss of operating pump	An alarm is annunciated in the MCR. The standby pump can be started locally. Loss of cooling water in the LPCI inverter room will cause the room temperature to rise. A high temperature switch within the room will then initiate an alarm in the MCR and start the emergency coolers. Cooling water to the vital ac rooms is not required during or after a DBE or LOCA.

TABLE 9.4-15 (SHEET 8 OF 8)

Components	Malfunction	Comments
Control Building Chilled Water System (continued)		
System fluid inventory	System leak	Level switch on expansion tank will initiate an alarm in the MCR. The operator can rectify the problem and/or add temporary cooling units in the affected areas.

a. HNP-1 and HNP-2 LPCI inverters were replaced with Class 1E power supplies backed by dedicated diesel generators (HNP-1-FSAR figure 8.5-1, HNP-2-FSAR figure 8.3-8). The PSW supply for the two essential LPCI inverter room coolers has been retired in place.

TABLE 9.4-16

WASTE GAS TREATMENT BUILDING HVAC SYSTEM EQUIPMENT LIST

Water chillers	
No.	2
Capacity (tons)	45
Chilled water flowrate (gal/min)	108
Compressor motor	60 hp, 550 V/60 Hz/3 phase
Chilled water recirculation pumps	
No.	2
Capacity (gal/min)	108
Total head (ft)	120
Type	Centrifugal
Motor	7.5 hp, 550 V/60 Hz/3 phase
Carbon adsorber vault AHU	
No.	2
Airflow (ft^3/min)	4000
Cooling capacity (Btu/h)	102,000
Electric heating capacity	18 kW, 550 V/60 Hz/3 phase
Waste gas treatment building AHU	
No.	1
Airflow (ft^3/min)	6000
Cooling capacity (Btu/h)	181,000
Electric heating capacity	20 kW, 550 V/60 Hz/3 phase
Exhaust fans	
No.	2
Capacity (ft^3/min)	2400
Type	Vaneaxial
Motor	2 hp, 208 V/60 Hz/3 phase

TABLE 9.4-17 (SHEET 1 OF 2)

WASTE GAS TREATMENT BUILDING HVAC SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments
Chillers	Failure of chillers	An alarm is annunciated in the MCR. The operator activates the standby chiller and the associated recirculating pump.
	Failure of isolation valve on chilled water line to AHUs	The isolation valves fail open; thus, chilled water flow to the AHUs remain open.
Recirculating pumps	Failure of pump motor	An overload protection device trips the motor, and a differential pressure switch across the chilled water lines initiates an alarm in the local control room. The operator activates the standby recirculating pump and associated chiller.
Vault AHUs	Failure of fan motor	An overload protection device trips the motor, and a low-flow switch initiates an alarm in the local control room and starts the standby AHU.
	Reduced flow	A low-flow switch initiates an alarm in the local control room and automatically starts the standby AHU.
	Loss of chilled water to cooling coils	See failure analysis for chillers and recirculating of chilled water pumps for causes of loss of chilled water and remedial action.
	Loss of heating coils	A drop in room temperature will not harm equipment or affect plant operation. The operator starts the standby AHU to obtain heating.
	Loss of airflow to heating coils	Loss of airflow automatically shuts off power to the coils to prevent burnout. The low-flow switch on the fan discharge initiates an alarm in the local control room and automatically starts the standby AHU.

TABLE 9.4-17 (SHEET 2 OF 2)

Component	Malfunction	Comments
Vault AHUs (cont)	Failure of makeup air damper	The damper will fail closed, thus preventing release of contaminated air outside the building. Normal recirculation and air conditioning are not affected. The operator may start the standby AHU to obtain makeup air.
	Failure of fan discharge air damper	The damper will fail open, thus permitting unrestricted recirculation and air-conditioning operation.
Building AHU	Failure of fan motor	An overload protection trips the motor and a low-flow switch initiates an alarm in the local control room. A rise or drop in building temperature will not harm equipment or affect plant operation.
	Reduced flow	A low-flow switch initiates an alarm in the local control room. A rise or drop in building temperature will not harm equipment or affect plant operation.
	Loss of chilled water to cooling coils	See failure analysis for chillers and recirculating pumps for causes of loss of chilled water and for remedial action. The manual chilled water isolation valve to the AHU is normally open.
	Loss of heating coils	A drop in room temperature will not harm equipment or affect plant operation.
	Loss of airflow to heating coils	A loss of airflow automatically shuts off power to the coils to prevent burnout. The low-flow switch on the fan discharge initiates an alarm in the local control room. A drop in room temperature will not harm equipment or affect plant operation.
Power source	LOSP	A rise or drop in room temperature will not harm equipment or affect plant operation.

TABLE 9.4-18 (SHEET 1 OF 2)

TSC HVAC SYSTEM EQUIPMENT LIST

AHU (X75-B001)	
Quantity	1
Size (% capacity)	100
Fan rating, (hp)	7.5
Type	Horizontal, draw through
Capacity (tons)	19.25
Fan capacity (ft^3/min)	5500 (4750 system)
Filter type	Roll filter
Condensing unit (X75-B002)	
Quantity	1
Size (% capacity)	100
Type	Air cooled, reciprocating
Fan motors (three) (amps)	1.9 (full load), each
Compressor motor (amps)	36
Silencer (X75-D006)	
Quantity	1
Size (% capacity)	100
Type	Rectangular
Capacity (ft^3/min)	4750
Filter train (X75-D001)	
Quantity	1
Size (% capacity)	100
Type	Horizontal, draw-through
Capacity (ft^3/min)	1000
Media	Activated, impregnated charcoal
HEPA efficiency (%)	99.97
Charcoal efficiency (%)	99.0
Charcoal banks	2
Test canisters/bank	5
Heater rating (kW)	5
Filter train fan (X75-C001)	
Quantity	1
Size (% capacity)	100
Type	Centrifugal
Capacity (ft^3/min)	1000
Motor (hp)	3

TABLE 9.4-18 (SHEET 2 OF 2)

Electric duct heater (X75-B003)	
No.	1
Size (% capacity)	100
Rating (kW)	2.5
Restroom exhaust fan (X75-C002)	
No.	1
Type	Inline, cabinet
Capacity (ft^3/min)	100
Motor (hp)	0.07
Electric duct heater (X75-B004)	
No.	1
Size (% capacity)	100
Rating (kW)	32.5

TABLE 9.4-19 (SHEET 1 OF 2)

TSC HVAC SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments
AHU	Failure of fan motor	An overload protection device trips the motor. A low airflow switch on the fan discharge initiates an alarm on the local panel.
	Reduced flow	A low airflow switch on the fan discharge initiates an alarm on the local panel.
Duct-mounted electric heater	Loss of electric heater	Drop in room temperature will not harm equipment or affect plant operation.
Condensing unit	Loss of condensing unit	Rise in room temperature will not harm equipment or affect plant operation.
Filter train	Obstruction of filter elements	High differential pressure across the filter elements will alarm on the local panel. The defective filter train will be isolated.
	High temperature in the charcoal bed	High temperature will alarm on the local panel, trip the filter train fan, and realign dampers for normal flow path. The filter deluge system will be manually activated as necessary.
	High radiation at discharge	High radiation will alarm on the local panel.

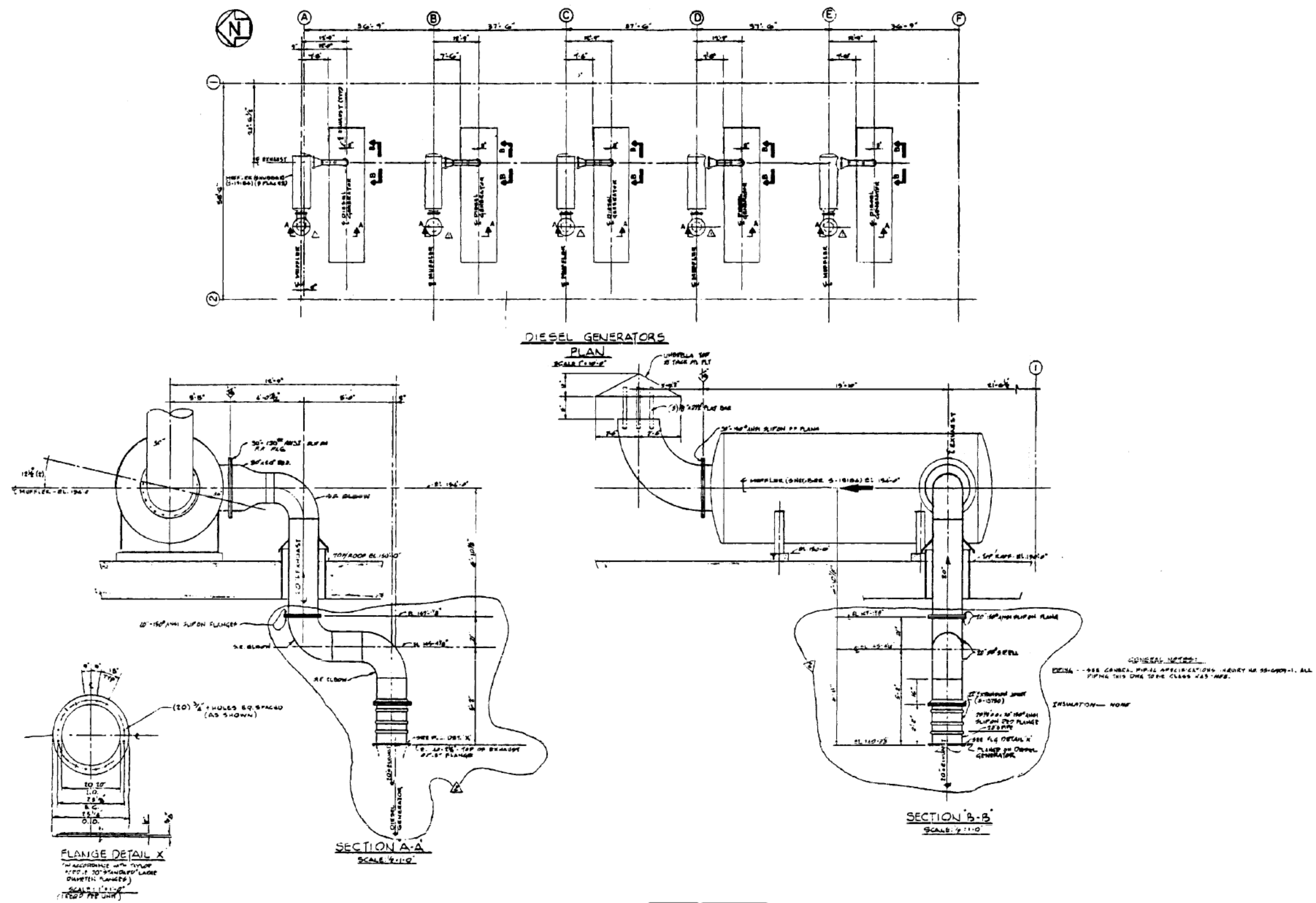
TABLE 9.4-19 (SHEET 2 OF 2)

Component	Malfunction	Comments
Filter train fan	Failure of fan motor	An overload protection device trips the fan motor. Low flow and/or high radiation will alarm on the local panel. TSC operations will be switched to the EOF, as required.
Dampers	Failure of dampers	Dampers will fail to the position required for the accident mode of operation.
Power source	LOSP	On loss of ventilation, TSC operations will be switched to the EOF, as required.

TABLE 9.4-20

RIVER INTAKE STRUCTURE VENTILATION SYSTEM FAILURE ANALYSIS

Components	Malfunction	Comments
Roof ventilator	Failure of one ventilator or loss of controls	Two other ventilators are available.
	Loss of one division power supply	This will result in the loss of one of the three ventilators.
Thermostat	Failure of the related ventilator	This can result in either the ventilator operating or not operating, depending on the failure mechanism of the thermostat. Ventilator operation due to thermostat failure during outside freezing temperatures will be monitored by the plant operator rounds procedure. Failure of a ventilator to operate due to thermostat failure will result in the loss of one of the three ventilators.



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UNIT 2

DIESEL GENERATOR EXHAUST

FIGURE 9.4-1

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 FIRE PROTECTION SYSTEM

The plant fire protection system is described in the **Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR)**.

9.5.2 PLANT COMMUNICATION SYSTEM (HNP-1 AND HNP-2)

9.5.2.1 Safety Objective

The plant communication system provides communication between all vital areas of the plant (figure 9.5-1).

9.5.2.2 Safety Design Basis

Internal and external communication is established by a public address system and a private, dial telephone system. These systems provide convenient, effective operational communications between various plant buildings and locations.

The private, automatic exchange dial telephone system provides onsite telephone communications and interfaces with several offsite communication systems.

The public address system provides communications by means of paging and two-way communications between onsite locations. The public address system is supplemented by visual indication in high noise level areas.

9.5.2.3 Description

The intrasite communication system consists of a public address system; a private, dial telephone system; and a two-way radio communication system provided for paging and communication in all important areas.

9.5.2.3.1 Public Address System

A public address system consisting of handsets, amplifiers, loudspeakers, multitone generator, and associated equipment provides convenient, effective paging and private conversational service to the plant. The system is transistorized utilizing multiple stations located throughout the plant such that, following an accident, there is no one area which has a communication requirement so critical that it cannot be met by going to an alternate location.

The public address system is designed to allow for expansion of the system without degrading communications capability. The failure of one or more station will not degrade communication capacity.

Public address handsets consist of a dual amplifier (one for the handset and the other to drive one or more paging speakers), associated speaker volume controls, page/party line controls, and a paging speaker. When a handset is used for paging, its associated speakers are muted to avoid acoustical coupling.

Two-way conversations are possible over the handset stations after the desired party has been paged via loud speakers and answered. It is possible for more than two handset stations to take part in a conversation.

Handset stations are designed for various mounting applications: wall, panel, desk top, desk edge, and portable (indoor and outdoor locations). The location of handsets relative to noise is not critical due to the use of noise canceling microphones.

In areas of low to medium noise levels, communications equipment is installed in half-length booths; and in areas of high noise levels, the equipment is installed in full-length booths. These booths minimize the undesirable background noises from being transmitted by the telephone or public address system so that intraplant communications is maintained when high noise levels occur. Tables 9.5-1 and 9.5-2 demonstrate the effectiveness of these booths to attenuate sound.

Paging amplifier stations consist of a speaker volume control and separately mounted speakers. There are four types of paging speakers:

- The 20-in. diameter horn which is the speaker generally used in areas where the ambient sound levels may range from 65 dB to over 100 dB.
- The 16-in. diameter horn which is used in areas of high density piping, cable trays, etc.
- The 8-in.-diameter horn which is used in shops, switchgear areas, etc.
- The 6-in.-diameter cone speaker which is used in finished areas where noise levels are minimal.

Speaker orientation is designed so that a person standing in the center of the work area to be covered can sight directly along the axis of speaker projection. The off-axis coverage is determined by the speaker dispersion angle and the ambient noise level.

The plant public address system is also used to alert station personnel during emergency conditions. Upon declaration of an Emergency, personnel will be notified by a page announcement. For declaration of an Alert, a Site Area Emergency, or a General Emergency, this notification will be preceded by a warning tone. Likewise, page announcements for a Fire will be preceded by a specific tone. A multitone generator produces distinct sounds over the public address paging line for the applicable conditions requiring the use of a warning tone.

For high ambient noise areas where speaker coverage is expected to be marginal during an alarm condition, the speakers are supplemented by flashing lights. Such lights are provided in the following areas:

- Diesel generator rooms.
- Residual heat removal and control rod drive areas.
- High-pressure coolant injection room.
- Condensate and condensate booster pump areas.
- The drywell for workers during shutdown conditions.

The HNP-1 and HNP-2 public address systems can be tied together.

9.5.2.3.2 Private, Automatic Exchange Dial Telephone System

The main telephone system at Plant Hatch is a Voice over Internet Protocol (VoIP) system. All phones in office locations use VoIP technology. All phones inside the plant are analog circuits connected to analog gateways that connect to the IP backbone. This system provides phone service to all areas of the plant.

The main system consists of the following major components:

- Call managers, gateways, analog gateways, and a combination of VoIP and analog phones.
- The servers for this system are powered VIA a UPS with battery backup that is rated to provide approximately 4 hours of runtime.
- A main distribution frame which is wall mounted and combines terminal and cross-connecting facilities.

Plant Hatch also has an independent phone system that provides phone service to designated phones in the Control Room and emergency facilities at the plant.

The independent system consists of the following major components:

- An independent phone switch and analog phones located in the control room and emergency facilities.
- A manual throw switch for selecting either a HNP-1 normal power source and emergency diesel generator or a HNP-2 normal power source and emergency diesel generator.

- A main distribution frame which is wall mounted and combines terminal and cross-connecting facilities.

Power is supplied to the telephone equipment located in the HNP-1 service building from HNP-1 essential ac cabinet 1R25-S036 or from HNP-2 essential ac cabinet 2R25-S036. Power to the equipment located in the IT computer room is powered VIA a UPS with battery backup that is rated to provide approximately 4 hours of runtime. The HNP-1 telephone terminal boards are in panel R51-P001 located on el 112 ft, control building. The HNP-2 telephone terminal boards are in panel R51-P002 located on el 112 ft, control building.

The location of handsets relative to noise is not critical due to the use of noise canceling microphones. In areas of low to medium noise levels, communications equipment is installed in half-length booths; and in areas of high noise levels, the equipment is installed in full-length booths. These booths minimize the undesirable background noises from being transmitted by the telephone or public address system so that intraplant communications are maintained when high noise levels occur. Tables 9.5-1 and 9.5-2 demonstrate the effectiveness of these booths to attenuate sound.

A separate intraplant telephone system is used for uninterrupted private communications between the control room and the reactor refueling area.

The telephone system interfaces with the following offsite communications systems:

- Baxley - Georgia exchange.
- Vidalia - Georgia exchange.
- Atlanta - Georgia exchange.
- Georgia Power Company (GPC) general office.
- Southern Bell system lines.
- Company microwave system.
- NRC Emergency Notification System (ENS).
- NRC Emergency Notification Network (ENN).

Refer to Section F of the Emergency Plan for the description of emergency communications system.

9.5.2.3.3 Two-Way Radio Communications

A separate, two-way radio communication system is provided to permit communications with GPC mobile units and base stations within the range of the plant.

9.5.2.4 Safety Evaluation

The public address system and the private, automatic exchange telephone system are not necessary items for the safe shutdown of the plant. However, these systems provide effective and reliable communications for the overall safe operation of the plant.

9.5.2.5 Inspection and Tests

All communications systems are in operation daily, which demonstrates system operability.

9.5.3 PLANT LIGHTING SYSTEM (HNP-1 AND HNP-2)

9.5.3.1 Safety Objective

The plant lighting system provides adequate illumination in all areas of the plant.

9.5.3.2 Safety Design Basis

Normal lighting and emergency lighting are provided for the plant with power utilized from normal ac sources, station battery system, or self-contained battery packs.

9.5.3.3 Description

The lighting system is divided into the following categories:
normal, security, and emergency.

A. Normal Lighting

The normal lighting system provides illumination for all plant areas.

B. Security Lighting

The security lighting system provides illumination for certain controlled and protected areas. Refer to section 3.2 of the Plant Security Plan.

C. Emergency Lighting

The emergency lighting system provides sufficient illumination in specific areas following a loss of normal lighting. The emergency lighting system is divided as follows:

1. Fire Protection Lighting (Appendix R), 10 CFR 50

   Fixed 8-h rated, sealed-beam, battery-operated fixtures are provided for all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.

2. Exit/Essential Lighting

   The exit/essential lighting is provided to meet the following criteria:

   a. To provide sufficient lighting (1 to 5 footcandles) so that an individual may exit the plant along designated paths.

   b. The lighting intensity for the required areas is listed below:

Area	Normal Lighting (footcandles)	Minimum Emergency Lighting (footcandles)
MCR	150	10
Diesel building	40-50	15
Essential switchgear	30	10

9.5.3.4 Safety Evaluation

The main control room (MCR) is provided with fluorescent luminaries. Areas where emergency lighting is provided are the MCR, turbine front standard, refueling floor, switchgear and control boards, reactor building, radwaste building, diesel building, river intake structure, service building, and other areas where illumination is required during emergencies.

9.5.3.5 Inspection and Tests

The normal ac lighting is normally energized and requires no periodic testing. The emergency dc lighting is inspected and tested periodically to ensure the operability of the automatic switches and other components in the system.

9.5.4 DIESEL GENERATOR FUEL OIL STORAGE AND TRANSFER SYSTEM

9.5.4.1 Safety Design Bases

A. The system is designed to supply fuel to at least two diesel generator units during emergency conditions despite any active or passive failure of one of its components.

B. The minimum required combined (HNP-1, HNP-2, and swing diesel generators) onsite storage capacity is sufficient for operating 4 diesel generators at 3250 kW for a duration of 7 days.

C. The design and construction of the diesel generator fuel oil system conforms to the criteria of Institute of Electrical and Electronics Engineers (IEEE) 308-1971, as well as to the applicable portions of:

- National Electrical Manufacturers Association (NEMA).
- National Fire Protection Association (NFPA).
- American Society of Testing Materials (ASTM).
- American Society of Mechanical Engineers (ASME).
- IEEE.
- American National Standards Institute (ANSI).
- Underwriters' Laboratories (UL).
- American Petroleum Institute (APM).

D. The safety-related components of this system are designed to withstand the design basis earthquake (DBE).

E. The system is protected from damage caused by missiles.

9.5.4.2 System Description

The diesel generator fuel oil system consists of five independent trains of equipment with each train supplying fuel oil to its respective diesel generator. A total of five diesel generators supply the emergency ac power for HNP-1 and HNP-2. The system is composed of storage tanks, day tanks, transfer pumps, and associated piping, valves, filters, and controls. (See drawing no. H-11037.) Transfer capability between storage tanks of different trains is provided by a transfer

header. Valving and physical arrangement are such that no single failure can prevent more than one train from performing its primary function.

Five equal-capacity (40,000 gal) horizontal-type main fuel oil storage tanks are located underground. Additionally, a 1000-gal-capacity day tank is provided for each DG. The 33,320 gal required to be maintained in each DGs' main fuel oil tank represent a total amount of oil sufficient to operate any 2 DGs at 3250 kW for a period of 7 days. In addition, this amount provides fuel to operate the required HNP-1 DGs at a load sufficient to maintain power to the components required to be operable by the HNP-2 Technical Specifications for 7 days. This onsite fuel oil capacity is sufficient to operate the diesel generators for longer than the time to replenish the onsite supply from outside sources.

Each day tank is housed in a separate room in the diesel generator building and has a fuel capacity for ~ 2 h of full-load operations. Fuel oil is transferred from storage tanks to the day tanks by either of two pumps located on each storage tank. Redundancy of pumps and piping will not allow the failure of one pump or the rupture of any pipe, valve, or tank to result in the loss of more than one diesel. In the event that the piping between the last isolation valve and the day tank breaks, the use of one diesel can be lost. This occurs only after the approximate 2-h supply of fuel in the day tank has been used. All outside tanks, pumps, and piping are underground.

During operation of the diesel generator, fuel oil pumps driven by the diesel engines transfer fuel from the day tanks to the diesel engine fuel manifolds. Level controls mounted on the day tanks automatically start and stop the storage tank transfer pumps.

9.5.4.3 Instrumentation Application

The level of the fuel supply in each tank is indicated in the MCR. In addition, alarms both locally and in the control room annunciate low level and high level in any day tank. Alarm systems for each train are independent from those of other trains such that a single failure would affect no more than one train.

9.5.4.4 Safety Evaluation

The diesel generator fuel oil system is designed so that failure of any one active component results in the loss of fuel supply to no more than one diesel generator. The loss of one diesel generator does not preclude adequate core cooling under accident conditions. Therefore, failure of any one active component of the diesel generator fuel oil system does not preclude safe shutdown of the plant following a loss-of-coolant accident (LOCA) and/or a loss-of-offsite power (LOSP). The component failure analysis of the diesel generator fuel oil system is given in table 9.5-3.

Additionally, a 1000-gal-capacity day tank is provided for each DG. The 33,320 gal required to be maintained in each DGs' main fuel oil tank represent a total amount of oil sufficient to operate any 2 DGs at 3250 kW for a period of 7 days. In addition, this amount provides fuel to operate the required HNP-1 DGs at a load sufficient to maintain power to the components

required to be operable by the HNP-2 Technical Specifications for 7 days. This onsite fuel oil capacity is sufficient to operate the diesel generators for longer than the time to replenish the onsite supply from outside sources. Additional fuel can be brought to the site by truck from fuel supplies in the local area. The capacity to transfer fuel from one storage tank to another storage tank also exists.

The present diesel fuel resupply consists of a minimum of 3 sources within a maximum distance of 125 miles from the plant site. The total normal storage of these 3 sources is more than 4,500,000 gal. The maximum delivery time is 24 h, and the minimum delivery time is 4 h.

During diesel operation, filling of the day tanks is automatically controlled by two level controllers, one for each storage tank transfer pump assigned to each day tank.

In the unlikely event of a failure in one of the supply trains, the associated day tank low-level alarm annunciates when the fuel oil level in the tank drops 2 in. below the transfer initiation setpoint, thus allowing the operator ~ 2 h of full-load operating time in which to take corrective action to prevent the loss of the diesel.

Protection against earthquake damage is assured by the Seismic Category I design of the system. Protection from hurricanes, tornadoes, and missiles is provided by locating system components either underground or within the diesel generator building.

Corrosion protection for the underground storage tanks and piping is provided by protective coating and wrapping. Aboveground components are located inside Seismic Category I structures that protect these components from detrimental environmental effects.

9.5.4.5 Tests and Inspections

The diesel generator fuel oil system operability is demonstrated during the regularly scheduled tests of the diesel generators.

Samples of fuel from all tanks are analyzed periodically to ensure that the fuel quality requirements of the diesel manufacturer are met.

9.5.5 DIESEL GENERATOR COOLING WATER SYSTEM

9.5.5.1 Safety Design Bases

The diesel generator cooling water system is designed to:

- Have the capability of removing sufficient heat by supplying the required quantity of cooling water, permitting continuous operation of the diesel engine at maximum load.

- Maintain the jacket coolant in a warmed condition while the diesel engine is in normal standby status to promote starting.

- Withstand the effects of a single failure and continue to supply adequate cooling water to at least two diesel generators.

- Meet Seismic Category I requirements.

9.5.5.2 System Description

The diesel generator cooling water system is shown schematically on drawing no. H-21074; it is also shown as part of the plant service water (PSW) system in figure 9.2-1.

The PSW pumps, piping, and valves that supply cooling water to the diesel heat exchangers are designed and constructed to meet quality group C requirements.

Each diesel engine is furnished with a closed-loop circulating-water cooling system. The system includes a pump, an expansion tank for makeup water, and a heat exchanger (shell and tube type). The heat exchanger is made up of three independent coolers: an air cooler, a lube oil cooler, and a jacket cooler. The shell sides of these coolers are independent, with fluids flowing through the shell sides controlled by thermostatic valves to maintain the temperatures at proper operating levels.

The tube sides of the coolers are arranged in series with cooling water supplied as follows

A. Diesel generators 2A and 2C are unique to HNP-2. The cooling water circulating in the tube side of the heat exchangers is supplied from the PSW system. Two 100% division I PSW pumps supply cooling water to diesel generator 2A. Two 100% division II PSW pumps supply cooling water to diesel generator 2C.

B. Diesel generator 1B is shared by HNP-1 and HNP-2, and the water circulating in the tube side of its heat exchanger is normally supplied from a completely independent water system by a standby service water pump. The capability exists to manually cross-connect the HNP-1 PSW system to supply cooling to diesel generator 1B during times when the standby service water pump is inoperable.

The engine coolant for all diesels is heated automatically during standby by an electric immersion heater and circulated through the diesel cooling system by a small circulating pump to maintain the jacket water at proper temperature for optimum standby starting conditions.

Electric power for the diesel generator cooling system is supplied from the 4160-V essential buses or from the control power transformers associated with the diesel generator. With an LOSP, the 3 diesels are automatically started and connected to their respective 4160-V buses. The load sequencers automatically start one cooling pump in each division and the diesel generator 1B cooling water pump.

Sufficient capacity in each diesel generator cooling water system is provided so that the unit may be started from the standby condition and operated at full load for at least 3 min without service water flow through the coolant heat exchanger before reaching an abnormally high temperature. Therefore, the time period involved in starting the diesels and pumps has no significance.

9.5.5.3 Instrumentation Application

Indications of system temperatures and coolant pump discharge pressures are provided in the diesel generator room and the main control room (MCR). Jacket coolant high and low service water pressure annunciation is also provided locally and remotely. All alarms prompt operator investigation and remedial action.

9.5.5.4 Safety Evaluation

The diesel generator units and diesel generator cooling water system are housed in Seismic Category I structures, protecting them against natural phenomena. All piping is located in the diesel generator building or buried with a minimum of 8 ft of cover. All valves are located inside the diesel generator building and are arranged so that the failure of any component associated with the diesel generator units does not jeopardize the capability of the remaining units to start and supply the minimum required engineered safety features (ESFs).

9.5.5.5 Tests and Inspections

Visual inspections, pressure and leak testing, and operational checks of the cooling system components were performed when the unit was installed.

The diesel generator cooling water system is operationally checked during periodic testing of the diesel generator system. During these tests, coolant pressures and temperatures are monitored to ensure that the heat exchangers, coolant pumps, and three-way thermostatic valves are functioning properly. The warming water system is operationally checked during diesel generator shutdown periods. The aging management program for the diesel generator skid-mounted components containing cooling water is described in subsection 18.2.18.

9.5.6 DIESEL GENERATOR STARTING SYSTEM

9.5.6.1 Safety Design Bases

The diesel generator starting system is designed to:

- Supply adequate compressed air at sufficient pressure to initiate an engine start such that within 12 s after receipt of the start signal, the diesel generator is operating at load speed and is ready to begin load sequencing.

- Provide two redundant air starting trains for each engine so that no single active failure renders the diesel generator starting system inoperable.

- Meet Seismic Category I requirements for the portions of the diesel generator starting system which are required to start the diesel upon receipt of an ESFs actuation signal.

9.5.6.2 System Description

The diesel generator starting system is shown schematically on drawing no. H-21074.

The diesel generator air starting piping on the compressor-receiver tank skid and from this skid to the generator set is designed, constructed, and tested as described in table 9.5-4, and is Seismic Category I. The air starting piping on the diesel generator set is Seismic Category I and is designed and fabricated to the diesel generator manufacturer's requirements. To ensure high reliability when starting the units, each diesel generator is equipped with a completely independent air starting system.

Each starting system consists of two redundant air compressors, two redundant air receivers, filters, and piping and valves to the diesel generator. The air compressors are motor-driven, conventional piston-type, air-cooled compressors. Each compressor is sized to completely charge either air receiver from the minimum required starting pressure in 30 min. Each compressor is designed to automatically start when air receiver pressure drops to 240 psig and stop when pressure is increased to 250 psig. At the Technical Specifications required minimum pressure of 225 psig, each air receiver has an adequate air capacity to provide five normal diesel generator starts without recharging.

The diesel generators receive an automatic start signal upon an LOSP, low reactor water level, or high drywell pressure. The units are also capable of being started manually from local control stations near the diesels or remotely from the control room for testing purposes. Each diesel generator has two separate starting circuits completely independent of offsite sources to ensure that the starting signal is received and that the diesel generator has its own battery for operating auxiliary motors and controls required for starting.

Each compressor motor in its respective starting system train is supplied power from a different essential bus.

The starting signal causes the engine solenoid-operated pilot valves to open. Thus, receiver air at high pressure is admitted to a starting air header and a starting air distributor. The air header supplies air to the air start check valves and then to the right side of the cylinder between the pistons. The starting air distributor is driven from the crank shaft, timing and delivering a pilot air charge through individual tubes to the cylinder air start check valves. In turn, each start check valve opens and allows air to enter the cylinders in the normal firing order, thus pushing

on the pistons and rotating the engine until it starts. Starting air flow is stopped when the diesel engine is running under its own power or when the diesel generator has failed to start in the allowable starting time.

9.5.6.3 Instrumentation Application

Each compressor and air receiver is furnished with instrumentation consisting of locally mounted pressure switches, pressure indicators, and automatic protection devices.

Low-starting air pressure at 200 psi and diesel start failure are annunciated locally and in the MCR.

9.5.6.4 Safety Evaluation

Compressed air for each diesel is stored in an individual storage and starting system. Each system holds sufficient air to start the diesel 10 times (5 times for each air receiver) under a no-load condition without compressor assistance. Since the air starting system is continuously available, the diesel engine starts immediately.

The solenoid air-start valve trains are installed in parallel within each system. If one valve train fails due to the blocking of an air filter or valve failure, the parallel valve train supplies starting air. A failure of the compressors is indicated by an air receiver low-pressure alarm; this alarm prompts the operator to take corrective action. A single active failure in either starting system does not compromise the ability of the system to accomplish its function.

The diesel engine starting system, exclusive of the air compressor, is designed in accordance with Seismic Category I requirements.

The following vessels located in the diesel generator building contain air under pressure:

The diesel generator air compressor starting air receiver tank has a design pressure of 275 psig but was tested up to 415 psig. The energy of gas expansion from the operating pressure to atmospheric pressure is 3.1×10^6 ft-lb. The operating temperature of this tank is well above the nil ductility transition temperature (NDTT) for carbon steel; therefore, brittle failure of this tank is not considered. Assuming a rupture of the largest line (2 1/2 in. in diameter) leading from the air receiver, calculations show forces resulting from the escaping air could not move the air receiver and resulting bending stress from such a failure is ~ 580 psi, well below the yield point for carbon steel.

9.5.6.5 Tests and Inspections

The air compressor for each diesel engine is test-started periodically to ensure continued operability. Compressor suction air filters are periodically checked for cleanliness. During preoperational testing of the diesel generator, the entire compressed air starting system is operated to ensure 100% capability.

Because of the redundance of the air starting system, all testing can be performed without affecting normal plant operations or safety systems.

9.5.7 DIESEL GENERATOR LUBRICATION SYSTEM

9.5.7.1 Safety Design Bases

The diesel generator lubrication system is designed to:

- Supply a continuous flow of oil to all surfaces requiring lubrication and to the pistons for cooling during diesel generator operation.
- Warm and circulate the oil in normal standby status to promote starting and prevent extreme lube oil viscosities.
- Meet the requirements of the single-failure criteria.
- Meet Seismic Category I requirements.

9.5.7.2 System Description

The diesel generator lubrication system is shown schematically on drawing no. H-21074.

Each diesel generator is provided with a positive full-pressure lubrication system designed and constructed in accordance with NEMA specifications. Major components of the system include an engine-driven pump, a lube oil collection sump, a full-flow filter with an internal valve, a full-flow strainer, a lube oil cooler, an electric immersion heater and electric circulating pump, an electric prelube pump, and associated piping and valves.

When the engine is operating, a built-in lubricating oil pump driven from the engine drivegear draws oil through a mesh intake screen from the sump and before distribution in the engine, passes it through a full-flow filter, an external lube oil cooler, and a full-flow strainer. Oil is circulated from the upper and lower headers to the main bearings and crankpins and passes through the connecting rods to the piston insert passages where it cools the pistons. Oil then flows back to the engine sump by gravity drain. All heat transferred to the lube oil is given up through the diesel heat exchanger to the PSW system. To keep the oil at a constant temperature, a three-way thermostatic bypass valve maintains a sufficient flow through the cooler.

During standby periods, an electric motor-driven circulating pump draws oil from the engine sump, pumps it through an electric immersion heater, and discharges it into the front end of the engine sump. The pump runs continuously whenever the engine is shut down, and the heater cycles under control of a thermostat, ensuring a fairly even temperature of the lube oil at any point in the sump.

The engine is also furnished with an electric motor-driven prelube pump controlled by a momentary pushbutton for use before any start other than automatic. The prelube oil pump draws oil from the sump and forces it into the oil header.

9.5.7.3 Instrumentation Application

Instrumentation provided for the diesel generator lubrication system includes pressure and temperature switches, indicators, and automatic protection devices. The temperature and pressure switches support the automatic control modes of lubrication operation. High crankcase pressure, low lube oil pressure, and high and low lube oil temperatures are alarmed in the MCR and in the diesel generator room.

A start-failure relay functions to interrupt starting of the diesel generator if lube oil pressure is not established within a predetermined time interval following the start initiation. Signals that initiate diesel engine trips are discussed in chapter 8.

9.5.7.4 Safety Evaluation

The engine-driven pump provides oil to the engine bearings during engine operational periods. Oil is kept at a constant pressure and temperature by use of regulating valves, recirculation lines, and a lube oil cooler. During starting or operation of the diesel generator, failure of the lubrication system engine-driven pump or three-way thermostatic valve could result in an unsatisfactory low lube oil pressure or high lube oil temperature.

The diesel generator lubrication system is provided with an electric pump and an immersion heater unit that circulates warmed lube oil in the sump. Extreme lube oil viscosities accompanying low lube oil temperatures are prevented, and quick starting of the diesel engine is assured. Failure of the warming unit is indicated by the low lube oil temperature alarm; this annunciation prompts operator investigation and remedial action. Finally, failure of the warming unit will not adversely affect the diesel generator system since the unit may be readily replaced and the large mass of the diesel generator and lube oil retains heat for lengthy periods.

Since the lubricating oil systems for the diesels are completely independent of each other, and since two of the three available diesel generator units are necessary for the safe shutdown of HNP-2 following a design basis accident and an LOSP, a failure of one component of the lubricating oil system will not affect the availability of onsite generation for safe shutdown requirements.

The diesel generator lubrication system is designed in accordance with Seismic Category I requirements.

9.5.7.5 Tests and Inspections

The diesel generator lubrication system is operationally tested during the monthly startup and checkout of the diesel generator. Lube oil pressure and temperature are monitored to ensure

operability of the engine-driven pump and the recirculation lines. Operation of the electric pump and heater is evidence of their ability to function properly. Strainers are cleaned and filters are periodically replaced. Inspection and testing of the system is performed without disturbing normal plant operations. The aging management program for the skid-mounted diesel generator components containing lube oil is described in subsection 18.2.18.

9.5.8 TURBINE BUILDING CRANE

The turbine building crane provides the capability to move major components for maintenance.

9.5.8.1 Design Bases

The turbine building crane is designed to:

- Have the capability to handle loads up to 180 tons using the main hook.

- Have the capability to move equipment along the length and breadth of the turbine deck up to the control building in the HNP-2 turbine building and from grade elevation up to the turbine deck through the service opening.

- Have the capability to perform its required function in the safest possible manner while maintaining reliability and optimum control.

9.5.8.2 Description

The turbine building crane consists of electric-powered hoisting machinery attached to a trolley platform for raising and lowering loads by wire rope reeving through blocks. The loads are secured to the load block by lifting devices. The structural frame support for the hoisting machinery is the trolley which moves by tractive power on trucks over rails secured to the top of the two parallel matched-crane girders. These are held together with structural end beams. These two end beams are supported by wheeled trucks (two pair on each side) that travel on top of the runway rail. The runway rail is structurally supported by foundations. The crane is designed to be controlled from a cab located at the west end of the bridge or by radio control from the operating floor. However, the radio control equipment has been abandoned in place and is no longer utilized to control the crane.

The main hook is a two-pronged sister hook with a bail hole. It is designed with a safety factor of 5 when loaded equally on each prong with a maximum included sling angle of 60 degrees. The rated load may also be handled using the bail hole.

The reeving system consists of two separate ropes attached to an equalizing bar which provides for equal division of the load between the two ropes. With both ropes functioning and equalized, the safety factor of the ropes is 5 on a static basis. If one rope fails, the remaining rope can support the load with a residual safety factor of 2.5 on a static basis.

Codes and Standards

The turbine building overhead crane complies with the intent of Crane Manufacturers' Association of America (CMAA) Specification No. 70, Class A1 (Standby Service). This meets the intent of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," Guideline 7. This service class covers cranes used in installations where precise handling of valuable machinery at slow speeds with long idle periods between lifts is required and where capacity loads may be handled for initial installation of machinery or for infrequent maintenance.

The turbine building overhead crane complies with the Occupational Safety and Health Administration (OSHA) Subpart N - Materials Handling and Storage - 29 CFR Part 1910, Section 1910.179 - "Overhead and Gantry Cranes" (insofar as it is applicable to indoor powerhouse cranes).

The operating practices, as well as the qualifications and training of those persons operating or directing the operation of the turbine building crane conform with the intent of the requirements of Chapter 2-3.1, "Operation - Overhead and Gantry Cranes," USAS B 30.2-167, as developed by the American National Standard Safety Code for Cranes, Derricks, Hoists, Jacks, and Slings.

The turbine building crane, consisting of structural girders, end beams, trucks, trolley machinery bed and trucks which support the mechanical traction drive, hoisting machinery, reeving system and lifting devices, was designed, fabricated, installed, and tested to the following codes and standards:

- American Gear Manufacturer Association (AGMA) - for defining and calculating the gear durability and strength horsepower requirements.

- Anti-Friction Bearing Manufacturers Association (AFBMA) - for bearing load limits and expected bearing life calculations.

- Association of Iron and Steel Engineers (AISE) - for providing the basic outline of mechanical components such as drum grooving, drive systems, electrical horsepower calculations, and reeving efficiency calculations.

- American Society of Civil Engineers (ASCE) - for providing rules for designing the structure, bolting, and connections that are not fully covered in CMAA Specification No. 70.

- American Society for Testing Materials (ASTM) - for specifying the grades of material and material testing procedures.

- American Iron and Steel Institute (AISI) - for specifying general materials such as shafting and forgings.

- American Welding Society (AWS) - for providing AWS D14.01 or D2.0 used for welding procedures.

- Crane Manufacturers Association of America (CMAA) - for specifying basic parameters and structural, mechanical, and electrical features.

- National Electric Manufacturers Association (NEMA) - for specifying electrical equipment such as controls and panels.

- Steel Structures Painting Council (SSPC) - for cleaning and painting specifications.

- American National Standards Institute (ANSI) - for providing the B30.2.0 safety code for electric overhead bridge cranes.

- National Fire Protection Association (NFPA) - for specifying electric safety codes which are also part of OSHA.

- National Electrical Code (NEC) - for specifying the wiring, insulation, and fastenings.

- Institute of Electrical and Electronics Engineers (IEEE) - for specifying industrial controls and recommended practices.

- Occupational Safety and Health Administration (OSHA) - for specifying safety requirements for walkways, guardrails, switchgear, clearances, and checkout and testing procedures for maintenance and operation.

- American Society of Mechanical Engineers (ASME) - for defining nondestructive testing and supplements ASTM and AWS, and for assisting in design of machinery components.

- American Institute of Steel Construction (AISC) - for defining specifications for rails and structural methods, covering the details only referenced in the CMAA Specification No. 70.

- Society of Automotive Engineers (SAE) - for defining shafting and machinery fittings not contained in AISI and AISC.

- Local and State codes, such as Southern States Building Code, were complied with in accordance with loading and impact considerations.

<u>Crane Design Features</u>

The design includes safety factors and features and considers modes of failure as follows:

A. The design rated capacity is 180 tons, and the crane is mechanically designed to a balanced factor of safety in which all components have a minimum safety factor of 5.

B. The reeving system consists of two separate ropes reeved between load and head block and secured to an equalizing bar which provides for equal division of the load between the two ropes. Rigid inspection and checking of the top ensures dependable service and reliability. The rope has a safety factor of 5 as a minimum.

C. The sister hook with bail hole is forged to ASTM specifications and tested to a 200% design capacity. Each prong and the cored bail hole have a design rated capacity of 180 tons. The conservative safety factor to ultimate is > 5. The load block, reeving rope, head block, drum, gear reducer, couplings, and motor shaft comprising the basic hoisting systems all have a safety factor to ultimate in excess of 5.

D. The hoisting operation is protected by an eddy-current braking system and electric holding brakes. The electric brakes are a safety automatic type that set should power fail; they are only released during operations in which the system is energized. The eddy-current regenerative brake system is a control type which prevents overspeed and is used to regulate load-lowering speed. The holding brake system will stop and hold the rated load. Each brake is sized to excess of 125% full-load motor torque as a minimum.

E. Should hoisting operation continue without operator control, two limit switches are provided, and either one will prevent the load block from contacting the head block. One limit switch is actuated by drum rotation and the other on mechanical rise of the load block.

F. The trolley and bridge travel have a five-step variable speed control on travel speed from starting to full design speed, providing for low impact due to acceleration. The trolley and bridge each have a rectified dc magnetic holding brake system which sets should power fail and which must be energized for operation. The bridge motor also has an electric hydraulic foot brake. Brake systems are sized to 50% full-motor torque for trolley and 150% full-motor torque for bridge. The bridge and trolley are provided with track-type limit switches to prevent overtravel in either direction. Movement of heavy loads close to the control room wall by overriding the limit switches is controlled by operational procedures and strict adherence to the established load paths.

G. Thermal overload protection is provided for all electric power circuits, preventing continuation of motor-stalling torque.

9.5.8.3 Safety Evaluation

The turbine building crane is shared on a limited basis with HNP-1. To prevent hazardous conditions from being created when the crane passes over the control room roof, the following features have been incorporated into the design:

A. A reinforced concrete wall around the perimeter of the control room extends above the reinforced concrete control room roof to el 192 ft 0 in. and houses a portion of the control building ventilation and air-conditioning equipment. The ventilation ducts extend above this concrete wall and do not permit clearance through the area below el 194 ft 0 in. The maximum lift of the crane hooks is el 209 ft 0 in. This limited clearance with the crane passing over the control room will not permit transporting a load from the HNP-2 turbine area to the HNP-1 turbine Area. To exclude any such possibility, operational procedures forbid moving a load from the HNP-2 turbine area to the HNP-1 turbine area.

B. Although the turbine building is a Category II structure, it is designed to prevent failure due to the seismic events described for Seismic Category I structures as well as failure due to the tornado criteria.

C. A full-load turbine building crane is installed in each unit; therefore, the need to move a crane from one unit to the other is limited. When such a move is required, an operational procedure describes the precautions and procedure to be followed. It is necessary to bypass the breaker trip switches once when entering the zone over the control building, and the crane-bridge motor-track switches are bypassed twice at each unit's track switches adjacent to the control building. Once within either turbine room, all controls can be returned to normal. Either or both cranes can then be operated independently within the allowed zone.

   Movement of portions of the control building ventilation and air-conditioning equipment located on top of the control room is controlled by an operational procedure, and strict adherence to established safe load paths is observed.

All the structural components and machinery of the turbine building crane are designed for a full capacity of 180 tons with a minimum safety factor of 5 against ultimate failure for the load-carrying parts and the machinery. The structural components are designed in accordance with CMAA Specification No. 70, Section 70-3.

The crane runway (supporting structure and rails), an integral part of the superstructure of the turbine building, is designed in accordance with design methods of applicable codes and standards.

The crane design provides a safety factor of 5 for mechanical machinery. All lifting devices, slings, and load connections also have a minimum safety factor of 5.

9.5.8.4 Tests and Inspections

The performance and acceptance testing of the turbine building crane systems include:

- *Detailed checking of the installed runway and assembled crane.*

- *Performance test with the 180-ton rated load and the 125% test load.*

Detailed instructions and procedures for operating, servicing, and maintaining the crane were prepared prior to and used during the performance and acceptance testing period. Records of the performance testing and adjustments made to system controls provide the basis for detailed operating procedures, instructions for handling specific loads, servicing requirements, and the maintenance program.

Following overhauls and major repairs to components of the crane, a complete performance and 125% proof test is conducted to verify and prove the integrity of the crane.

9.5.9 GEZIP PASSIVE ZINC INJECTION SYSTEM

General Electric developed the General Electric Zinc Injection Passivation (GEZIP) process to control radiation buildup in boiling water reactors. Soluble zinc in the reactor feedwater inhibits the corrosion of stainless steel. Soluble zinc in the reactor water also inhibits the transport and the deposition of Cobalt-60 from the fuel to the reactor coolant pressure boundary surfaces, thereby reducing radiation buildup on these surfaces.

The passive zinc injection system is designed to continuously inject a dilute solution of ionic zinc in water into the reactor feedwater. A stream of water taken from the common reactor feedwater pump discharge is routed through a column containing zinc oxide pellets. The dissolution of sintered zinc oxide pellets into the diverted feedwater stream provides the ionic zinc. The dissolved zinc oxide in the stream leaving the dissolution column is returned to the common reactor feedwater pump suction and is blended with the main feedwater flow.

Reactor water zinc levels are measured periodically. Based upon the results of these measurements, the flow through the passive zinc injection system can be adjusted to maintain the reactor water zinc concentration at the desired level.

The injection rate of the zinc into the feedwater is adjusted by controlling the rate of water flow through the dissolution column and varying the amount of zinc oxide pellets in the column, with the primary means of control being water flowrate through the column. The water flowrate through the dissolution column is controlled by the manual positioning of the opening of a flow control valve. The dissolution column is filled with sufficient zinc oxide to last through one complete fuel cycle.

The zinc oxide dissolution rate is naturally reduced during reactor power reduction since the rate is a function of temperature. As reactor power is reduced, feedwater temperature decreases, reducing the rate of zinc dissolution into the diverted feedwater stream passing through the dissolution column.

The GEZIP passive zinc injection system is not safety related because it is not required for safe operation or shutdown of the plant, and it does not impact the operation, function, or integrity of any safety-related equipment or systems.

9.5.10 MAIN STEAM ISOLATION VALVE LEAKAGE TREATMENT SYSTEM (HNP-1 and HNP-2)

As part of the implementation of an alternative source term (AST) (reference subsection 15.1.11), the main steam isolation valve (MSIV) leakage treatment system was implemented for HNP-1. The same system had previously been implemented for HNP-2 but was modified (some boundary valves were supplied with a diesel-backed power source) to support AST. The below description applies to both HNP-1 and HNP-2.

The MSIV leakage treatment system consists of the main steam lines between the outboard MSIVs and the turbine stop valve, the main steam drain line, and the isolated condenser. The objective of the leakage treatment system is to provide a method to hold up any MSIV leakage and allow the iodine and radioactive particulates to decay off and plate out on the internal surfaces of the steam piping and condenser following a potential LOCA. The main steam piping, drains, and main condenser are used to mitigate the consequences of a LOCA that could lead to potential exposures in excess of 10 CFR Part 50.67 limits. Treatment of MSIV leakage using this nonsafety-related, passive system was recommended by the BWROG MSIV Leakage Closure Committee after extensive evaluation of the MSIV leakage issue.

Immediately following a LOCA, the MSIVs isolate, the turbine control valves close, the turbine stop valves close, and the turbine bypass valves close. In addition, specified boundary valves in main steam line connecting piping close. Some of those valves are closed automatically, some of the boundary valves are closed from the control room, and some require manual action. As necessary, some boundary valves are supplied with a diesel-backed power source. The boundary valve design assures that all boundary valves can be closed in the event of a LOCA with a loss of offsite power (LOSP).

The boundary valves were established in the connecting lines to limit the piping and components required to be evaluated for seismic adequacy. After the system is isolated as described above, the only action required to initiate the leakage treatment system is the opening of MOV 2B21-F021 in the steam drain line header. That valve is on emergency power and can be opened during a loss of offsite power. To further assure operability, MOV 2B21-F021 is tested quarterly as a part of the inservice testing program. In addition, the main steam drain line that originates at the main steam drain pots has been determined to be an effective alternate drain line to convey the MSIV leakage to the isolated condenser in the event that MOV 2B21-F021 fails to open.

While the main steam lines were seismically designed, the drain lines, the condenser, and the connecting lines beyond the first isolation valve were not seismically designed. However, a seismic walkdown and evaluation were performed to verify the seismic adequacy of all the piping and equipment that constitute the leakage treatment system. The seismic evaluation compared the HNP installed piping and equipment to a large earthquake experience data base. A walkdown verified that none of the deficiencies that allowed isolated failures of piping or equipment, which were in the data base and had been installed in industrial plants during actual earthquakes, existed at HNP. If any conditions were identified that indicated a failure could potentially occur, they were designated as outliers, and further evaluations or modifications were made to assure seismic adequacy. The process employed to verify the seismic adequacy of the leakage treatment system satisfied the intent of 10 CFR 100, Appendix A.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.

TABLE 9.5-1

NOISE ATTENUATION CHARACTERISTICS OF FULL-LENGTH BOOTHS (HNP-1 AND HNP-2)

Outside Noise Frequency (Hz)	Percent Reduction in Noise Level Inside Booth
150 - 300	25
300 - 600	38
600 - 1200	38
1200 - 2400	34
2400 - 4800	43

TABLE 9.5-2

NOISE ATTENUATION CHARACTERISTICS OF SCOUT SHELF BOOTHS (HNP-1 AND HNP-2)

Outside Noise Frequency (Hz)	Percent Reduction in Noise Level Inside Booth
150 - 300	16
300 - 600	38
600 - 1200	29
1200 - 2400	29
2400 - 4800	34

TABLE 9.5-3

FAILURE ANALYSIS OF DIESEL GENERATOR FUEL OIL SYSTEM

Component	Malfunction	Effect on System
Storage tanks (one per diesel)	Leakage	Loss of insignificant oil volume. Credited oil volume assured by periodic inspections of level indication.
Day tanks (one per diesel)	Loss of one tank	The fuel supply to one of the five diesels is lost; however, only two diesels for each unit are required for a safe shutdown following a LOCA and an LOSP.
Transfer pumps (two per diesel)	Loss of one pump	Each tank has redundant pumps so there is no loss of fuel supply.
Line between day tank and supply line isolation valve (one per diesel)	Line fails (rupture of pipe or component)	The effect is the same as that for day tanks.
Line between storage tank and supply line isolation valve (two per diesel)	Rupture of pipe or component	There is no loss of fuel supply since there are redundant lines from each tank up to the isolation valve.
Fuel oil pump (engine-driven) (one per diesel)	Pump fails	The effect is the same as that for day tanks.

TABLE 9.5-4 (SHEET 1 OF 2)

DIESEL GENERATOR
AUXILIARY SYSTEMS QUALITY GROUP DATA[c] (HNP-2)

System/Component	Provided By	Design Code	Design Pressure and Temperature	Comments
Air starting system				
On skid	FM[a]	None	250 psi, 300°F	
Off skid				
Piping	SCS[b]	B31.1.0	Pressure test at 275 psi with system	2 1/2-in. piping ASTM A-106, Grade B, Schedule 40 with butt-welded ASTM A-234, Grade WPB Schedule 40 fittings 2-in. and under ASTM A-106, Grade B, Schedule 80 with 3000-lb socket-welded ASTM A-181 Grade 11 fittings
Tubing	SCS	B31.1 B31.1		3/8 in. Type K ASTM B-88 solder joint 3/8 in. SA 213 GR TP304L stainless steel
Valves				
F034A, F035A	FM	ANSI B16.5 (1968)	425-psi hydro test shell	Carbon steel valves
F026A, F027A	FM	ANSI B16.5 (1968)	pressure	
F022A, F023A	FM	ASME Section VIII	Set at 260 psi in shop	AISI 304 stainless-steel relief valves
F032A, F033A	FM	ASME Section VIII		
Globe valves				
F030A, F031A,	SCS	ANSI B16.5 (1968)	1100-psi hydro test	ASTM A-105, Grade II carbon steel
Comp. discharge			shell pressure	valves to B16.5 (1968)
F181A, C		B31.1	225 psi, 122°F	ASTM A479 Type 316 stainless steel
Check valves				
F024A, F025A, F095A, F029A	Bechtel	B31.1	3000 psi, 400°F	ASTM A-479, Type 316 stainless steel
Ball valves F171A	Bechtel	B31.1	300 psi, 422°F	ASTM A-351, Grade CF3M, stainless steel
Air receiver tanks	FM	ASME Section VIII	Pressure test at 415 psi	Shell metal SA-455A, Head metal SA-515-70, welder qualification ASME Section IV

TABLE 9.5-4 (SHEET 2 OF 2)

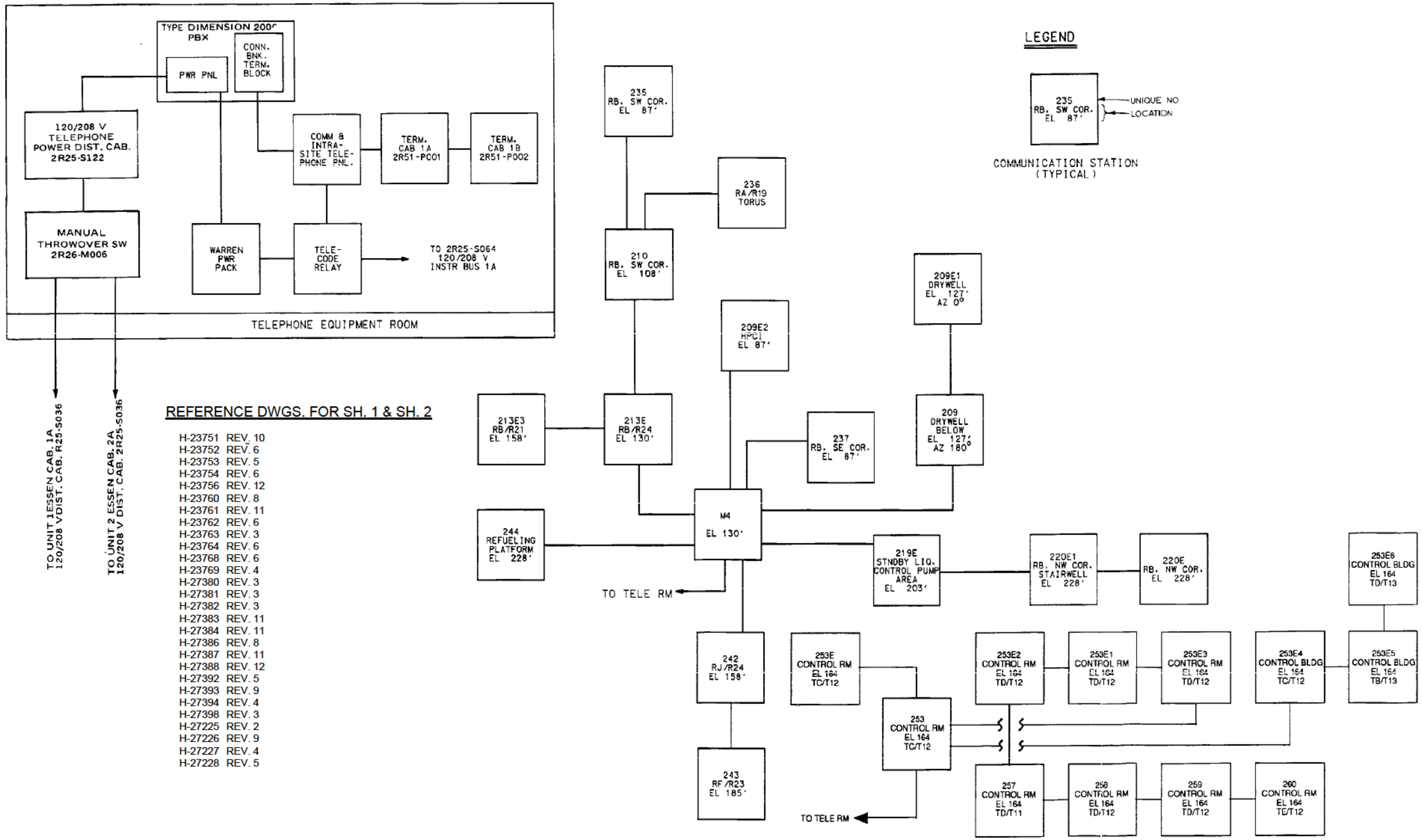
System/Component	Provided By	Design Code	Design Pressure and Temperature	Comments
Jacket cooling water				
On skid	FM	B31.1.0	Pressure test at 60 psi (design pressure 40 psi)	
Off skid				
Piping	SCS	B31.1.0	150 psig, 100°F for supply tank to skid; no test	2-in. and under ASTM A-106, Grade B, Schedule 80 with 3000-lb socket-welded ASTM A-181, Grade II fittings
Valves				
Solenoid-F081A	FM	UL 429, UL 1002	125 psi, 180°F	ASCO brass valve
F081A bypass-F082A	SCS	ANSI B16.5 (1968)	1100-psi hydro test shell pressure	ASTM A-105, Grade II carbon steel valves to B16.5 (1968)
Expansion tank drain	SCS	ANSI B16.5 (1968)		ASTM A-105, Grade II carbon steel valves to B16.5 (1968)
Expansion tank	FM	ASME Section VIII	Pressure test at 23 psi	Welder qualification, ASME Section IX, Metals; approved Section III

a. Fairbanks Morse.
b. Southern Company Services, Inc.
c. This table shows equipment associated with diesel generator 2A. Equipment associated with diesel generator 2C is the same except that all the MPL nos. have the suffix C.

TABLE 9.5-5

DOSES RESULTING FROM MSIV LEAKAGE FOLLOWING A LOCA

This table has been deleted.



REFERENCE DWGS. FOR SH. 1 & SH. 2

H-23751 REV. 10
H-23752 REV. 6
H-23753 REV. 5
H-23754 REV. 6
H-23756 REV. 12
H-23760 REV. 8
H-23761 REV. 11
H-23762 REV. 6
H-23763 REV. 3
H-23764 REV. 6
H-23768 REV. 6
H-23769 REV. 4
H-27380 REV. 3
H-27381 REV. 3
H-27382 REV. 3
H-27383 REV. 11
H-27384 REV. 11
H-27386 REV. 8
H-27387 REV. 11
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H-27394 REV. 4
H-27398 REV. 3
H-27225 REV. 2
H-27226 REV. 9
H-27227 REV. 4
H-27228 REV. 5

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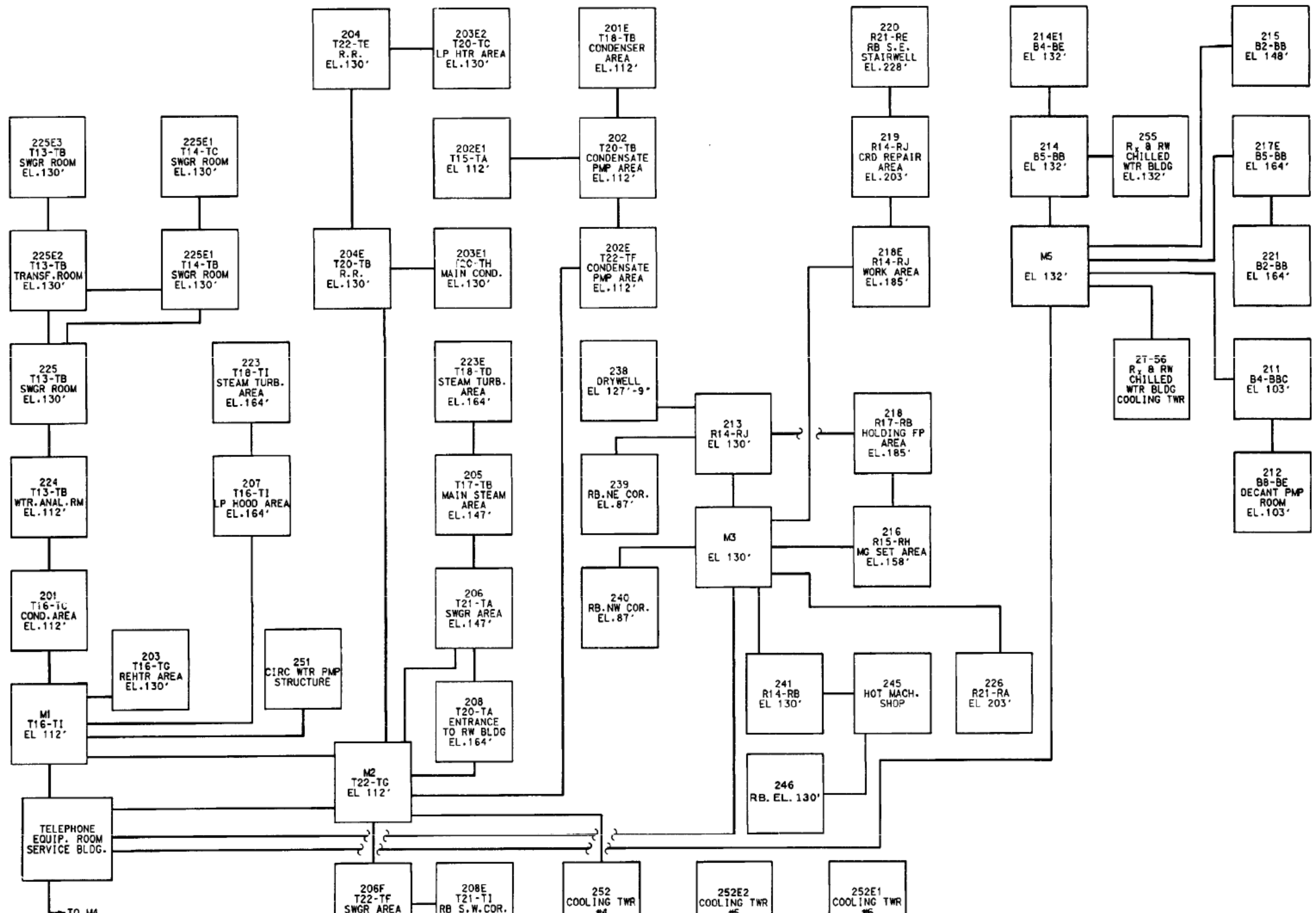
INTRAPLANT COMMUNICATION SYSTEM BLOCK DIAGRAM

FIGURE 9.5-1 (SHEET 1 OF 2)



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INTRAPLANT COMMUNICATION SYSTEM BLOCK DIAGRAM

FIGURE 9.5-1 (SHEET 2 OF 2)

10.0 STEAM AND POWER CONVERSION SYSTEMS

10.1 SUMMARY DESCRIPTION

Power conversion systems are designed to produce electrical energy through conversion of a portion of thermal energy contained in the steam supplied from the reactor; condense the turbine exhaust steam into water; and return the water to the reactor as heated feedwater, with a major portion of its gaseous, dissolved, and particulate impurities removed.

The major components of the power conversion system are:

- Turbine generator (one high-pressure turbine, two low-pressure turbines, one generator).
- Main condenser.
- Condensate pumps.
- Air ejectors.
- Turbine gland-seal system.
- Turbine bypass system.
- Condensate demineralizer.
- Condensate booster pumps.
- Reactor feed pumps.
- Feedwater heaters.
- Condensate storage system.

The heat rejected to the main condenser is removed by the circulating water system, using cooling towers. These major components are shown on drawing nos. H-21001 through H-21004, H-21006, and H-21007.

The saturated steam produced by the boiling water reactor is passed through the high-pressure turbine where the steam is expanded and then exhausted through the moisture separators. Moisture is removed and reheated in the moisture-separator reheaters, and the steam is then passed through the low-pressure turbines where the steam is again expanded. From the low-pressure turbines, the steam is exhausted into the condenser where the steam is condensed and deaerated, and then returned to the cycle as condensate. A small part of the main steam supply is used continuously by the steam jet air ejectors. The condensate pumps, taking suction from the condenser hotwell, deliver the condensate through the air ejector

condensers, turbine gland-seal condenser, condensate demineralizer, and off-gas condenser to the condensate booster pumps, and then through five stages of low-pressure feedwater heaters to the reactor feed pumps. The reactor feed pumps supply feedwater through one stage of the high-pressure feedwater heaters to the reactor. Steam for heating the feedwater in the heating cycle is supplied from turbine extractions. The feedwater heaters also provide the means of handling the moisture separated from the steam in the turbine and the moisture separators. Normally, the turbine uses all the steam being generated by the reactor; however, an automatic pressure-controlled steam bypass system is provided to discharge excess steam up to ~ 20% of the 100% RTP steam flowrate directly to the condenser.

The power conversion systems are suitable for operation at current 100% rated conditions at 2804 MWt and 1060 psia reactor pressure as demonstrated in the safety analysis report for thermal power optimization(1) and the reactor operating pressure increase reviews.(2) Except for portions of the main steam and feedwater lines from the reactor pressure vessel to the outermost isolation valves and for the turbine trip circuitry, no other portions of the steam and power conversion systems are safety-related.

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. RER 03-254, Reactor Operating Pressure Increase From 1050 psia to 1060 psia, Engineering Evaluations.

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASES AND OBJECTIVE

The function of the turbine-generator is to receive steam from the boiling water reactor, to economically convert a portion of the thermal energy contained in the steam to electric energy, to provide extraction steam for feedwater heating, and to provide extraction steam for driving the reactor feed pump turbines.

The turbine-generator and associated systems and their control characteristics are integrated with the features of the reactor and associated nuclear systems to obtain an efficient and safe power-generating unit.

The turbine-generator is designed to meet the conditions listed in table 10.2-1, which shows conditions at 100% reactor steam flow. The heat balance for this case is provided in figure 1.2-5.

In special cases, the operations department at Hatch Nuclear Plant (HNP) can be requested by the Southern electric system control center to vary the output of HNP-2, as required, to support system needs. Normally, the unit is operated at baseload but is designed to take its operational share of system control and regulation. In the baseload mode, power is essentially constant, being affected only by fluctuations in reactor pressure and system frequency.

The nuclear steam supply system (NSSS) and turbine have the ability to provide continuous load-following capability over a range of ~ 35% of rated power; however, this capability is not used by the plant. Step-change electrical load reductions which do not exceed ~ 20% of rated power are handled by operation of the main steam bypass system without requiring an associated change in reactor power.

The turbine is considered a machine, and General Electric Corporation (GE) developed their own internal proprietary standards and specifications which are continually updated in comparison with American Society of Mechanical Engineers (ASME) codes and standards.

10.2.2 SYSTEM DESCRIPTION

The turbine-generator consists of a turbine, generator, exciter, controls, and required subsystems.

The turbine is a tandem-compound, 1800-rpm reheat unit with 43-in. last-stage buckets.

Saturated steam is supplied to the turbine throttle from the reactor through four stop valves and four control valves. The steam flows through a two-flow, high-pressure turbine and then through four combination moisture-separator reheaters in parallel to two double-flow, low-pressure turbines which exhaust to the main condenser. The moisture-separator reheaters have two stages of reheating, one supplied with steam from before the stop and control valves and the other supplied with steam from the second stage of the high-pressure turbine. There are two

stages of feedwater reheating off the high-pressure turbine and four stages of feedwater reheating off the low-pressure turbines.

The generator is a direct-coupled, three-phase, 60-Hz, 24,000-V, conductor-cooled synchronous generator, rated 1,050,000 kVA, with a short-circuit ratio of 0.58 and a maximum hydrogen pressure of 60 psig.

The exciter system is EX2100 multibridge static excitation system. The power for the generator field is drawn from 24 – 0.8-kV, 5600-kVA power potential transformer (PPT) at the generator terminals. The primary side of the PPT is connected by a tap off of the existing generator isophase bus. The secondary side of the PPT is connected through isophase bus to the EX2100 AC termination, which supplies power to the exciter bridge input. The AC power from PPT secondary side is converted to DC by a three-phase, full-wave, inverting thyristor bridge (SCR) to provide rated field current to the generator field.

The turbine uses an electrohydraulic control system consisting of normal governing devices and emergency devices for turbine and plant protection and special control and test devices. The electrohydraulic control system operates the main stop valves, control valves, bypass valves, crossover combination stop-intercept valves, and other protective devices. Turbine governor functions and turbine control and effects on the reactor coolant systems are covered more fully in subsection 7.7.4.

The overspeed controls consist of redundant and independent mechanical and electrical overspeed trips that will trip the turbine at 110% rated speed and an electrical backup overspeed trip that will trip the turbine at about 112% speed. The overspeed trips can be tested separately while the unit is operating and maintain overspeed protection. A description of the turbine overspeed protection is provided in supplement 10.2A. A list of the various turbine trips is provided in subsection 7.7.4.

Fifteen hydrogen storage cylinders containing hydrogen for generator cooling in HNP-1 and HNP-2 are located ~ 500 ft northeast of the HNP-2 reactor building. Each cylinder contains ~ 6968 ft^3 of hydrogen at 2300 psi. The cylinders are filled to a pressure of 2300 psi, the design pressure is 2450 psi (the cylinders are designed with a safety factor of 3) and they are tested at 3675 psi. The cylinders are designed according to ASME UPV Code, Section VIII and Code Case 1205, for temperatures from -20 to 200°F and are of seamless-type construction of ASME SA372, Class IV carbon steel, with swaged ends. The cylinders are ~ 24 in. in diameter and 20 ft in length. A spring-loaded safety relief valve set at 2450 psi and a rupture disc designed to rupture at a pressure between 3305 and 3675 psi are provided. The cylinders are located in an open area ~ 500 ft northeast of the HNP-2 reactor building, 320 ft east of the diesel building, and 800 ft southeast of the intake structure. The energy released in an isentropic expansion of the hydrogen in one cylinder is 55,928 Btu. The cylinders are bolted into racks in three rows. The racks are designed to prevent movement of any cylinder due to any forces that may result from the breaking of any line connected to a cylinder. These cylinders are separated from safety-related equipment by a minimum distance of 320 ft and a barrier of 18 in. of reinforced concrete. Since the storage cylinders are located on an open air concrete pad which provides excellent ventilation, there is no possibility of quantities of hydrogen collecting in explosive mixtures and being detonated.

10.2.3 TURBINE MISSILES

10.2.3.1 Turbine-Missile Analysis and Evaluation

The methodology for missile generation probability includes consideration of the probability of unit overspeed, wheel materials, inservice inspection capabilities, and the potential for wheel containment by stationary turbine structures. The analysis methodology considers two fundamental failure modes that can lead to missile generation, brittle fracture failures, and ductile tensile failures. These two failure modes are statistically independent.[9]

The brittle-fracture failure mechanism is due to the initiation and growth of keyway stress corrosion cracks to critical size. Since the monoblock rotors contain no wheel keyways, no missile generation will occur due to brittle fracture. The monoblock rotors do not have shrunk-on wheels, therefore, only the ductile failure portion of the methodology is used.

The probability of ductile failure is a function of speed, temperature, and material tensile strength. The turbine control system is designed to limit peak overspeed to 120 percent of rated. Under 120-percent speed, rotor design stresses are below the ultimate material strength, thus the probability of a ductile failure is negligible at speeds under 120 percent. The GE probabilistic analysis of turbine overspeed was documented in the GE 1984 NRC report and referenced in Supplementary Report GET-8039, dated September 1993, and is applicable to units with low-pressure monoblock rotors. The overspeed analysis considers the characteristics of the turbine control system, the unit configuration, and test requirements for the steam valves and other overspeed protection devices. This overspeed analysis showed that the probability of attaining a given overspeed decreases rapidly as the overspeed value increases. As long as the control system is maintained in accordance with GE's recommendations, the annual probability of attaining an overspeed of 120 percent or greater is at or below 1.71×10^{-6}.[10]

All of the rotating components of the monoblock rotors have sufficient margin to tensile strength (at design component temperatures) to support operating speeds well in excess of 120 percent of normal. The limiting components, per design, for the low-pressure rotors are the last stage low-pressure buckets, which have overspeed capability of 174 percent.

Since ductile failure is only possible at speeds significantly greater than 120 percent and since the turbine control system keeps the probability of speeds over 120 percent below 1.71×10^{-6}, the probability of missile generation is well below 1.71×10^{-6}.

The turbine missile analysis considers the following probabilities:

P_1 = annual probability of turbine failure resulting in the ejection of turbine rotor (or internal structure) fragments through the turbine casing.

P_2 = the probability that a turbine missile strikes a critical plant target.

P_3 = the probability that the critical target is unacceptably damaged.

P_4 = annual probability of unacceptable damage resulting from a turbine missile.

The probability that a particular safety-related or important-to-safety target suffers unacceptable consequences because of turbine failure is:

$P_4 = P_1 \times P_2 \times P_3$

Therefore, for the monoblock rotor design, the value of P_1 is:

$P_1 = 1.71 \times 10^{-6}$

Since the probability of missile generation (P_1) is sufficiently low that, when combined with P_2 and P_3, would result in a value of P_4 that meets the NRC acceptance criteria of 1×10^{-7} for target damage with unacceptable consequences, GE does not calculate values for P_2 and P_3. In NUREG-1048, Safety Evaluation Report related to the operation of Hope Creek Generating Station, Supplement 6, July 1986, the NRC makes the following statements in Appendix U, Probability of Missile Generation in General Electric Nuclear Turbines[11].

"…in the evaluation of P_4 ($P_1 \times P_2 \times P_3$) the probability of unacceptable damage to safety-related systems from potential turbine missiles, the NRC staff is giving credit for the product of the strike and damage probabilities of $10^{-3}yr^{-1}$ for a favorably oriented turbine and $10^{-2}yr^{-1}$ for an unfavorably oriented turbine, and is discouraging the elaborate calculation of these values.

The NRC staff believes that maintaining an initial small value of P_1 through turbine testing and inspection is a reliable means of ensuring that the objectives precluding turbine missiles and unacceptable damage to safety-related structures, systems, and components can be met. It simplifies and improves procedures for evaluating turbine missile risks and ensures that the public health and safety is maintained."

The above reference provides generic NRC acceptance regarding the use of a nominal value in lieu of plant specific values for the strike and damage probability in the calculation of the overall probability of unacceptable damage due to a turbine missile. Since Hatch is an unfavorably oriented unit, the product of P_2 and P_3 is taken to be $10^{-2}yr^{-1}$. Therefore, the value of P_4 for the monoblock rotors will be:

$P_4 = P_1 (1 \times 10^{-2})$

$P_4 = 1.71 \times 10^{-8}$

The value of P_4 is below the NRC limit of 1×10^{-7} for unfavorable orientation.

10.2.3.2 Turbine Wheel Cracks and Missile Prevention

Thorough examinations are made of each turbine wheel at the time of manufacture. Most wheels used have no indications. If indications are detected, these indications are assumed to be cracks. Conservative assumptions are applied to the indications such as maximum size and most critical orientation for their locations. The growth of these assumed cracks is calculated

for the maximum number of cycles. If these calculations show that any assumed cracks might grow to critical size during the lifetime of the unit, the wheel is rejected.

The potential for missile generation was reviewed as part of the extended power uprate program.[6] The results which showed a minimal effect on missile probability or consequences were determined as part of the thermal power optimization and reactor operating pressure increase reviews[7] [8] to bound the effects of the new operating conditions at 2804 MWt.

The turbine is disassembled at ~ 10-year intervals, during plant shutdown coinciding with the inservice inspection schedule required by ASME Boiler and Pressure Vessel Code, Section XI, and all normally inaccessible parts such as couplings, coupling bolts, turbine shafts, low-pressure turbine buckets, and high-pressure rotors are inspected. The base set of inspections consists of visual and surface examination as required.

10.2.4 SAFETY EVALUATION

The primary source of activity in the steam- and power-conversion system is radiation from nitrogen-16 (N-16), formed by activation in the reactor. N-16 has a half life of ~ 7 s. The activated nitrogen is carried with the steam to the turbine. Fission-product noble gases and other activation gases, such as oxygen-19 (O-19), nitrogen-17 (N-17), and nitrogen-13 (N-13), are also carried with the steam to the turbine. Some nongaseous fission and activation products are present in the turbine as a result of moisture carryover in the steam from the NSSS.
The activity entering the low-pressure turbine is reduced because of the presence of moisture separation and transit time between the high-pressure and low-pressure turbines, which permits the N-16 to decay.

Most of the noncondensable gases in the condenser are removed by the steamjet air ejectors to the off-gas system for processing holdup prior to release to the environs; the off-gas system is described in section 11.3.

The activity remaining in the condensate is reduced significantly by the 3-min (minimum) holdup time in the condenser hotwell.

Shielding requirements and expected radiation levels are provided in subsection 12.3.2 and drawing nos. H-25993 through H-25996. The turbine-generator is in an administratively controlled access area.

REFERENCES

1. (Deleted)

2. (Deleted)

3. (Deleted)

4. (Deleted)

5. (Deleted)

6. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 and 2," NEDC-32749P, General Electric Company, July 1997.

7. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

8. RER 03-254, Reactor Operating Pressure Increase From 1050 psia to 1060 psia, Engineering Evaluations.

9. General Electric, “Probability of Missile Generation in General Electric Nuclear Turbines,” January 1984, Proprietary Document.

10. S-63950, Turbine Missile Analysis Statement, General Electric Company, June 2010.

11. NUREG-1048, Safety Evaluation Report related to the operation of Hope Creek Generating Station, Supplement 6, July 1986; Appendix U: Probablilty of Missile Generation in General Electric Nuclear Turbines, Proprietary Document.

TABLE 10.2-1

TURBINE-GENERATOR DESIGN CONDITIONS

Turbine-generator output (kW) at:	
100% reactor steam flow	946,170
Steam conditions at turbine throttle valves	
Flow (lb/h)	
100% flow	11,601,280
Pressure (psia)	999.4
Temperature (°F)	544.5
Moisture content (%)	0.45
Exhaust pressure (in Hg. abs.)	3.5
Final feedwater temperature (°F)	
100% flow	425.7
Stages of feedwater heating	6
Stages of steam reheating	2
Generator power factor (100% flow)	0.90
Generator rating (kVA)	1,050,000
Voltage	24,000
Hydrogen pressure (psig)	60

TABLE 10.2-2

This table has been deleted.

TABLE 10.2-3

THICKNESS OF PROTECTIVE CONCRETE FOR VITAL AREAS OF PLANT[c]

Area	Thickness (in.)
Reactor building refueling floor (5000 psi concrete)	14
Reactor building west wall	24
Control room roof	30
Intake structure roof and wall	30
Diesel generator building roof	24
Diesel generator building wall	30
Radiation shield wall around turbine	42

a. Deleted.

b. Deleted.

c. The turbine-missile methodology utilized in subsection 10.2.3 does not involve calculation of turbine missile penetration depth. The calculated penetration depths previously presented in this table are historical and are no longer applicable.

THIS FIGURE HAS BEEN DELETED.

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SWING ANGLE AND GRAVITY PARABOLA

FIGURE 10.2-1

THIS FIGURE HAS BEEN DELETED.

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DESCRIPTIVE COORDINATES FOR
TURBINE MISSILE TRAJECTORIES

FIGURE 10.2-2

10.2A.0 GENERAL ELECTRIC TURBINE OVERSPEED PROTECTION

10.2A.1 INTRODUCTION

The purpose of the protection system is to detect undesirable or dangerous operating conditions associated with the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the subsequent action.

Any trip action for the Mark VI control system results in dumping the emergency trip system (ETS) hydraulic fluid pressure, thereby causing rapid closure of all ETS controlled steam admission valves. The ETS pressure is the fundamental permissive for the control system to be reset and allow the turbine steam admission valves to be opened. Provisions are also made to test most of the components in the trip system while the turbine-generator unit is online.

Other protective functions like power load unbalance and intercept valve trigger act on fast-acting solenoid valves of the primary steam valves to permanently or momentarily trip the valves closed. These fast-acting solenoid valves cause rapid steam valve closure by depressurizing the ETS header locally at the valve actuator.

Sections 10.2A.6 through 10.2A.7 describe technical details of some of the major components.

10.2A.2 OVERSPEED PROTECTION

The Mark VI's electronic overspeed system is designed to protect the steam turbine against possible damage caused by excessive turbine shaft speed. Under normal operation, the speed/load loop controls the shaft's speed. This overspeed system would be called upon only if that control loop, or a decive contained therein, failed.

The overspeed protection system consists of a primary and an emergency overspeed protection system. The primary overspeed system is part of the normal speed control system and uses magnetic pickups to sense turbine speed, speed-detection software, and associated logic circuits.

The emergency or backup overspeed system consists of an independent two-out-of-three voting electronic overspeed protection <P> module that has replaced the original mechanical overspeed bolt.

10.2A.3 EMERGENCY TRIP SYSTEM

Emergency turbine tripping action protects the turbine-generator against damage from uncontrolled overspeed or other potentially damaging conditions.

The original equipment, front standard mounted, master trip solenoid arrangement was replaced by dual two-out-of-three trip manifold assemblies. In essence there are two identical hydraulic trip manifolds, each with the capability to completely dump the hydraulic trip header to the hydraulic tank reservoir. The design is based on the two-out-of-three voting logic concept, i.e.,

for a trip to occur, two of the three controlling solenoids and valves on a single manifold must move to the trip position in order to depressurize the hydraulic trip header and complete the turbine trip process. The trip solenoids are deenergized to trip.

10.2A.4 (Deleted)

10.2A.5 (Deleted)

10.2A.6 TURBINE STEAM VALVES

Turbine steam valves are provided, two in series, in all major steam lines which have a steam supply potential capable of driving the turbine to dangerous speed levels. On figure 10.2A-5 is shown schematically a main steam lead equipped with a main stop valve followed by a control valve, as well as a reheat steam line equipped with an intercept valve followed by a reheat stop valve. The two latter valves are normally built into a common casing to form a combined intermediate valve.

A large nuclear turbine is normally equipped with four main stop valves in parallel, followed by four control valves, as shown in figure 10.2A-5. To permit testing of individual valves during service, an equalizer is provided between the main stop valves and the control valves. Two combined intermediate valves are provided to each low-pressure turbine, as also shown on figure 10.2A-5, to permit testing of one combined intermediate valve without significant reduction in steam flow to a low-pressure turbine.

Due to the parallel arrangement of valves, it is necessary for all valves of a specific group, control valves, intercept valves, etc. to close completely to interrupt the steam flow from a source.

Extraction lines from the turbine are each similarly equipped with positive-closing nonreturn valves to interrupt backflow of steam into the turbine.

10.2A.7 HYDRAULIC POWER SUPPLY

The hydraulic supply is common to all EHC controlled steam valves and the emergency trip system. The hydraulic power unit operates with phosphate ester-type, fire-resistant fluid pressurized to 1600 psig. Two identical variable-displacement pumps can pump into a common supply manifold. Normally, only one pump is required, with the other in active standby ready to start automatically on a preset drop in manifold pressure. Hydraulic accumulators help support a transient flow demand which exceeds the delivery capacity of a pump.

The hydraulic power unit is equipped with full-flow filtration (5-μm rating) in the high-pressure discharge line from each pump. The filters are equipped with collapse-proof cartridges (design pressure 3000 psig differential) and warning devices for excess pressure drop due to clogging

of filters. There is no bypass around a filter. Filters in a pumping system can be serviced while the other pumping system is operating.

A bypass filtering system operates continuously to condition the fluid through the filtration of acid, water, and very fine particles. The condition of the fluid is monitored through a prescribed sampling schedule to keep the characteristics of the fluid (particle count, total acid number, H_2O content, etc.) within specified limits.

The entire overspeed protection system is designed so that loss-of-fluid pressure causes automatic shutdown of the turbine. This is achieved as follows:

A. If the operating pump fails to maintain the hydraulic pressure at a level sufficient for normal and accurate control of the turbine, the standby pump is started automatically.

B. Should this pump also fail to maintain pressure, a further decay initiates an electrical turbine trip.

C. Finally, on radical loss of hydraulic pressure, the EHC controlled steam valves are forced closed by steam and spring forces, and loss of emergency trip signal pressure initiates rapid valve closure by release of the disk dump valves on the individual valve actuators.

10.2A.8 Deleted

This figure has been deleted.

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EHC TURBINE NORMAL OVERSPEED PROTECTION SYSTEM

FIGURE 10.2A-1

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EHC TURBINE EMERGENCY OVERSPEED PROTECTION SYSTEM

FIGURE 10.2A-2

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EHC TURBINE ADDITIONAL PROTECTION SYSTEM

FIGURE 10.2A-3

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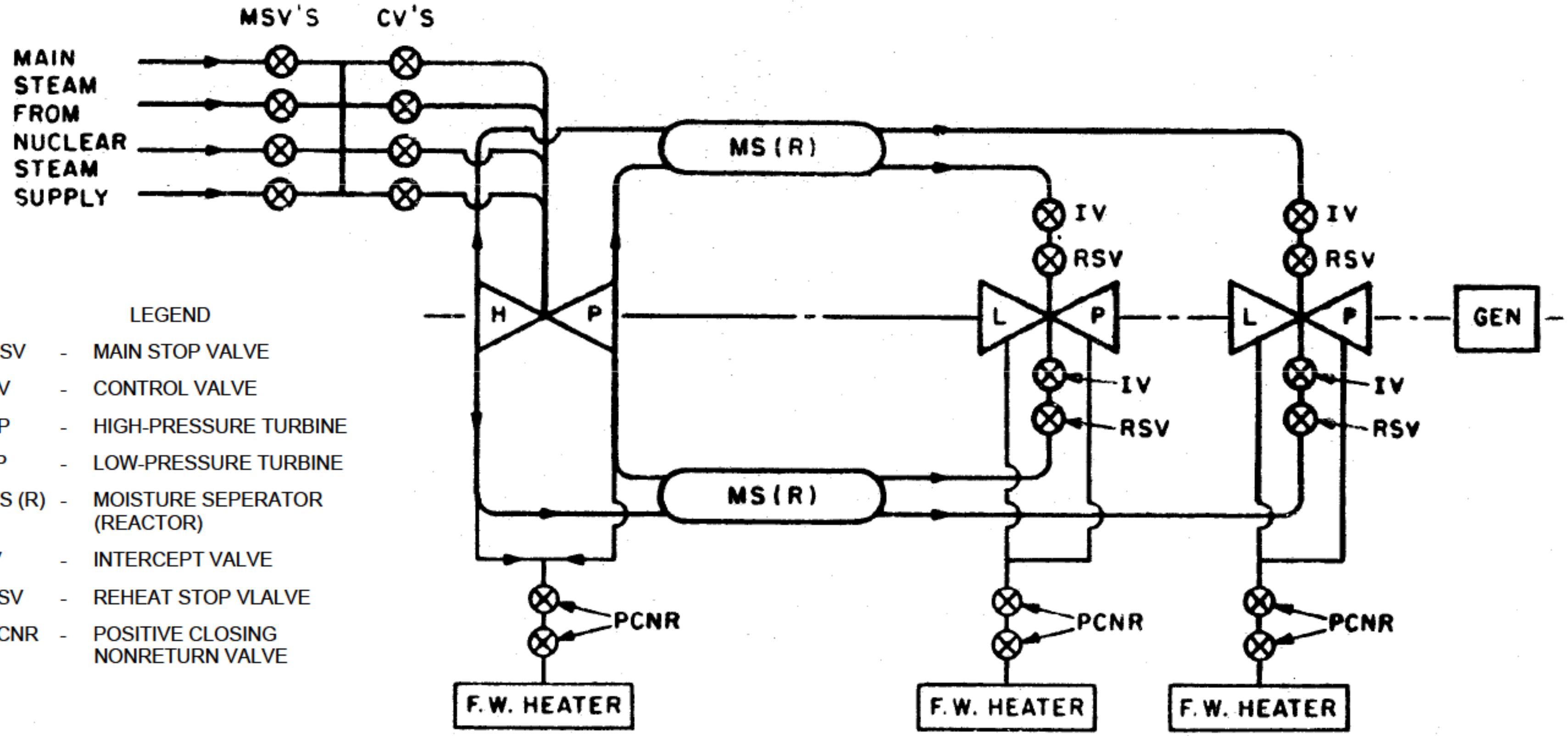
EHC TURBINE OVERSPEED PROTECTION SYSTEM

FIGURE 10.2A-4



LEGEND

MSV	-	MAIN STOP VALVE
CV	-	CONTROL VALVE
HP	-	HIGH-PRESSURE TURBINE
LP	-	LOW-PRESSURE TURBINE
MS (R)	-	MOISTURE SEPERATOR (REACTOR)
IV	-	INTERCEPT VALVE
RSV	-	REHEAT STOP VLALVE
PCNR	-	POSITIVE CLOSING NONRETURN VALVE

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TYPICAL ARRANGEMENT OF STEAM VALVES IN MAIN AND EXTRACTION LINE OF NUCLEAR TURBINE

FIGURE 10.2A-5

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 DESIGN BASES

The main steam supply system is designed to perform the following functions:

A. Deliver steam from the reactor to the turbine-generator from warmup to full-power operation.

B. Provide steam for the second-stage reheater, steam jet air ejectors, turbine steam sealing system, low-load operation of the reactor feed pump turbines, and off-gas system preheaters.

C. Provide a means of heat dissipation for heat generated by the nuclear steam supply system in the event the heat generated is in excess of that required for turbine-generator operation.

10.3.2 DESCRIPTION

The main steam supply system is shown on drawing nos. H-21012 and H-21056. The main steam piping consists of four 24-in. outside diameter lines from the outermost main steam isolation valves (MSIVs) to the main turbine stop valves. The use of four main steam lines permits tests of the turbine stop valves and MSIVs during plant operation, with only minimum load reduction.

The main steam line nuclear pressure relief system, main steam line flow restrictors, and MSIVs are described in subsections 5.2.2, 5.5.4, and 5.5.5, respectively.

10.3.3 SAFETY EVALUATION

To satisfy safety requirements, the main steam lines and valves are designed as follows:

A. The main steam line piping from the outer isolation valve up to the turbine stop valves, including all branch lines 2 1/2 in. in diameter and larger up to the first valve capable of timely actuation, are Seismic Category I and American Society of Mechanical Engineers (ASME) Section III, Class 2 (Quality Group B) piping.

B. Inservice inspection requirements for the main steam supply system are performed in accordance with the specifications set forth in the ASME Boiler and Pressure Vessel Code, Section XI.

C. The steam lines from the branch line isolation valves to the reactor feed pump turbines are nonseismic and American National Standards Institute B31.1.0 Code piping. The main turbine stop valves and bypass valves are not Seismic Category I.

The main steam line piping from the outer MSIV up to the turbine stop valves and all branch lines 2 1/2 in. in diameter and larger up to the first valve capable of timely actuation are designed by the use of an appropriate dynamic seismic system analysis to withstand the operating basis earthquake (OBE) and design basis earthquake (DBE) loads in combination with other appropriate loads within the limits specified for Class 2 pipe in the ASME Section III piping code. The mathematical model for the dynamic seismic analyses of the main steam line and branch line piping includes the stop valves, piping beyond the stop valves, and piping to the turbine casing. The dynamic input loads for design of the main steam line are derived from a time-history model analysis (or an equivalent method) of the reactor building, control building, and applicable portions of the turbine building.

The portions of the turbine building housing the main steam lines may undergo some plastic deformation under the DBE; however, the plastic deformation is limited to a ductility factor of 2, and an elastic multidegree of freedom system analysis is used to determine the input to the main steam line. The allowable stress and associated deformation limits for piping are in accordance with Group B requirements for OBE and DBE loading combinations. The main steam line supporting structures (those portions of the turbine building) are such that the main steam line and its supports can maintain their integrity within Group B requirements under Seismic Category I loading conditions.

All main steam lines and components are designed in accordance with the requirements defined in section 3.2. The design of the main steam lines allows for inservice inspection, as discussed in paragraph 10.3.4.

10.3.4 INSPECTION AND TESTING

The main steam line was hydrostatically tested to confirm leaktightness. Before placing the systems into service, all foreign material and loose oxides were flushed from the lines.

The main steam lines are designed to provide for inservice inspection in accordance with ASME Code Section XI.

At ~ 6 calendar year intervals (equivalent to ~ 5 years of operation), during refueling or maintenance shutdowns coinciding with the inservice inspection schedule required by ASME Code Section XI, at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve are dismantled, and visual and surface examinations are performed for valve seats, disks, and stems. If unacceptable flaws or excessive corrosion are found in a valve, all valves of its type are inspected and cleaned, and bore diameter is checked for proper clearance. Georgia Power Company (GPC) found through experience in other GPC generating plants that these intervals are completely satisfactory for disassembly and inspection of steam stop and control valves. Effective March 22, 1997, Southern Nuclear Operating Company has adopted these intervals as the exclusive operating licensee.

Main steam stop and reheat stop and intercept valves are exercised at least once per 31 days by cycling each valve through at least one complete cycle of full travel. Each main turbine control valve is cycled at least once per 92 days through at least one cycle of travel from its open position to full closed.

10.3.5 WATER CHEMISTRY (PRESSURIZED WATER REACTOR)

This subsection is not applicable to the Hatch Nuclear Plant-Unit 2.

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

10.4.1.1 Design Bases

A. The main condenser is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 6.515 x 10^9 Btu/h, an inlet water temperature of 90°F, and an average backpressure of 3.5-in. Hg absolute.

B. The condenser is designed to accept up to ~ 20% of 100% RTP rated main steam flow through the turbine bypass without increasing backpressure beyond the turbine trip setpoint or exceeding turbine exhaust temperature.

C. The condenser is designed to deaerate the condensate, provide feedwater of required quality, and provide for removal of noncondensable gases from the condensing steam and from air inleakage.

D. The condenser is designed to store condensate in sufficient volume to provide at least 2-min retention time of the condensate for radioactive decay of short-lived radioactive isotopes.

10.4.1.2 System Description

During planned operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows, such as exhaust steam from feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents.

Other flows occur periodically; they originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate.

During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge (from feedwater heater shells, steam-seal regulator, and various steam supply lines).

The main condenser is a two-shell, single-pass, single-pressure, deaerating type with a reheating-deareating hotwell and divided water boxes. The condenser consists of two sections, and each section is located below one of two low-pressure elements of the turbine. The condensers are supported on the turbine room foundation mat, with stainless steel expansion joints provided between each turbine exhaust opening and the steam inlet connections in the condenser shells.

The condenser hotwells have horizontal and vertical baffles to ensure a minimum retention of 2 min for condensate from the time it enters the hotwell until it is removed by the condensate pumps.

The inlet and outlet waterboxes of the condenser shells are each provided with circulating water valves, permitting either half of each condenser shell to be removed from service.

Conductivity elements detect tube sheet inleakage of circulating water into the condenser steam space.

Should the control, bypass, or turbine stop valves fail to close on loss of condenser vacuum, two rupture diaphragms on each turbine exhaust to the condenser to protect the condenser and turbine exhaust hoods against overpressure.

Deaeration in the condenser removes normal inleakage of air plus hydrogen and oxygen gases contained in the turbine steam due to dissociation of water in the reactor. Anticipated air inleakage to the main condenser is expected to be < 20 sf^3/min, based on operational experience. The design inleakage is 40 sf^3/min.

The noncondensable gases are concentrated in the air cooling section of the condenser, from which they are removed by the mechanical vacuum pump at startup and by the steam jet air ejectors (SJAEs) during normal operation.

10.4.1.3 <u>Safety Evaluation</u>

During operation, radioactive gases and condensate are present in the shells of the main condenser. The inventory of radioactive contaminants during operation and during shutdown is discussed in sections 11.1 and 11.3. Necessary shielding and controlled access for the main condenser is provided as discussed in subsection 12.3.2.

The main condensers are not required for safe shutdown of the reactor.

Loss of condenser vacuum causes the turbine-generator to trip. The turbine trip is discussed in section 15.2; the turbine-generator control system is discussed in subsection 7.7.4.

10.4.1.4 <u>Tests and Inspections</u>

Each condenser shell has received a field hydrostatic test prior to initial operation, and surfaces have been inspected for visible leakage and/or excessive deflection.

Each condenser water box has received a shop hydrostatic test and a field hydrostatic test, inspecting all joints and external surfaces.

After the completion of tubing of the condenser, all tube joints were leak tested.

10.4.1.5 Instrumentation Application

Each condenser shell is provided with local and remote hotwell level and pressure indication. The remote indication is by means of indicators and alarms in the main control room (MCR). The condensate level in the condenser hotwell is maintained within proper limits by automatic controls which provide for transfer of condensate to and from the condensate storage tank as needed to satisfy the requirements of the steam system. Water box pressure and temperature measurements are provided.

A temperature well is provided in the hotwell supply line to the condensate pumps so that condensate temperature can be measured when required.

Turbine exhaust hood temperature is monitored and controlled with water sprays to provide protection from exhaust hood overheating.

A high condenser backpressure alarm is provided at ~ 5-in. Hg absolute. The turbine trip is activated on loss of main condenser vacuum, with condenser backpressure reaching or exceeding a setpoint of ~ 7-in. Hg absolute.

Conductivity elements detect leakage of circulating water into the condenser steam space.

Air leakage is monitored at the SJAEs.

At startup, steam is admitted to each condenser shell to assist in condensate deaeration. Steam admission is regulated by means of a control valve which receives its control signal from the MCR.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

10.4.2.1 Design Bases

The main condenser gas-removal system has been designed to remove all noncondensable gases from the condenser, including air inleakage and dissociation products originating in the reactor, and exhaust them to the off-gas system.

10.4.2.2 System Description

For planned operation, the main condenser gas-removal system includes two 100% capacity, 3-stage, SJAE units, complete with intercondensers and aftercondensers. These units remove air and noncondensable gases from the main condenser during normal plant operation. (See drawing no. H-21056.) A mechanical vacuum pump is provided for startup and shutdown.

The basic criterion for design of the gas-removal systems is that radioactive gases released to the environment through the main stack will not exceed the offsite doses permitted by 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

When the desired rate of air and gas removal exceeds the capacity of the SJAEs (i.e.,when reactor power is < 5%), or when the steam supply to the SJAEs is not adequate to provide for their operation, the mechanical vacuum pump is used to evacuate the condenser. Discharge gases from the mechanical vacuum pump are vented to the environment via the steam packing gland exhaust system discharge line to the main stack. (See drawing no. H-21030.)

The SJAE may be placed into operation when a condenser vacuum of ~ 20-in. Hg (gauge) has been established. Main steam, reduced in pressure by an automatic steam pressure reducing station, is the motive flow for the SJAEs. The first-stage air ejector takes suction directly on the condenser air-cooling section and discharges to the first intercondenser. The second-stage air ejector takes suction on the first intercondenser and discharges to the second intercondenser. The third-stage SJAE takes suction on the second intercondenser and exhausts/discharges the gas vapor mixture to the off-gas system. The intercondensers are cooled by condensate, and condensation occurring in the intercondensers is returned to the condenser hotwell for reuse.

10.4.2.3 Safety Evaluation

The waste gas from the main condenser is one source of radioactive gas in the plant. This gas normally consists of the following activation products: nitrogen-16, oxygen-19, nitrogen-13, and flourine-18, as well as noble gas fission products. The largest contribution to the main condenser waste gas activity comes from the nitrogen-16 source. An inventory of radioactive contaminants in the effluent from the SJAEs is found in section 11.3.

Decay of short-lived radioisotopes prior to release is assured by providing sufficient holdup time in the off-gas system. The system pipes and charcoal vessels are large enough to permit the appropriate holdup time. The possibility of ignition of hydrogen in the off-gas mixture is minimized by use of a catalytic hydrogen recombiner as discussed in section 11.3. Off-gas pipes and components are shielded as required and as discussed in subsection 12.3.2.

The radiological consequences of a failure of the SJAE lines are evaluated in section 15.4.

10.4.2.4 Tests and Inspections

All tests and inspections of the equipment and parts of the main condenser evacuation system have been performed in accordance with applicable codes. Preoperational testing of the system was conducted to the extent possible prior to the introduction of main steam to the system.

10.4.2.5 Instrumentation Application

Instrumentation permits monitoring and recording of flowrate and radioactivity in the off-gas system. Shutoff valves automatically isolate the system if radioactivity level is high. Gas release rates are indicated from radiation and flowrate measurements.

10.4.3 TURBINE GLAND-SEALING SYSTEM

10.4.3.1 Design Bases

The turbine-sealing system is designed to provide a means of sealing with steam the turbine shaft glands and the valve stems (main stop, control, combined intercept, and bypass valves).

Condensed steam from the sealing system is returned to the main condenser, and the noncondensable gases are exhausted to the gland-seal off-gas holdup system.

10.4.3.2 System Description

The turbine-sealing system consists of a seal steam pressure regulator feed and unloader system, a 100% steam packing gland-seal condenser, two 100% steam packing exhaust fans, and associated piping and isolation valves.

During initial evacuation of the condenser, seal steam is supplied to the turbine shaft glands from the main steam system pressure reducing station via the system steam seal feed valve (and the steam seal feed valve bypass valve) as required to maintain a steam-seal header pressure of ~ 4.5 psig. Simultaneously, the steam packing exhauster fans and condenser provide removal capability of excess sealing steam from the turbine glands. Condensate in the steam packing gland-seal condenser is routed to the main condenser hotwell for return to the reactor.

At loads $>$ 25%, the turbine becomes self-sealing, providing sealing steam to the steam-seal header via leakoff from the high-pressure packings. Excess seal steam leakoff during self-sealing operation is returned to the condenser via the seal steam unloading valve.

The gland-seal condenser is cooled by the main condensate after the main condensate has passed through the SJAE condensers.

The steam packing exhaust fans remove noncondensable gases from the gland-seal condenser and discharge the gases to the main vent stack for release to atmosphere via a 1.75-min holdup line.

In the unlikely event of failure of either the gland-seal condenser or both steam packing exhauster fans, the gland exhaust will be directed to the main condenser.

The steam packing exhauster fans are stopped automatically in the event of a high main steam line radiation signal.

10.4.3.3 Safety Evaluation

The system provided for sealing the turbine glands to prevent air inleakage and/or steam outleakage is not unlike sealing systems provided for conventional equipment and is, therefore, considered to be of satisfactory design to perform the turbine sealing function.

Detailed information regarding gaseous waste releases during normal operation is provided in section 11.3.

The radiological consequences of the failure of the gland-seal off-gas line are evaluated in chapter 15.

10.4.3.4 Tests and Inspections

All tests and inspections of equipment that is part of the turbine sealing system have been performed in accordance with applicable codes. The system underwent preoperational testing prior to being operated with steam from the reactor.

10.4.3.5 Instrumentation Application

Liquid seal in the gland-seal condenser is maintained by a loop seal and an atmospheric drain tank between the gland-seal condenser and the main condenser. Pressure and temperature instrumentation is provided to monitor overall system performance. Main steam line radiation detectors are used to provide automatic isolation of the gland-seal exhaust fans.

10.4.4 TURBINE BYPASS SYSTEM

10.4.4.1 Design Bases

The objective of the turbine bypass system is to dissipate up to ~ 20% of the energy of main steam generated by the reactor which cannot be utilized by the turbine.

The turbine bypass system is designed to control reactor pressure:

- During reactor heatup to rated pressure.
- While the turbine is brought up to speed and the generator synchronized.
- During power operation when the reactor system generation exceeds the transient turbine steam requirements and limitations.
- During cooldown of the reactor.

The turbine bypass system capacity was originally based on 23.5% of the turbine design flow. At current 100% power conditions (2804 MWt) the bypass valve capacity is calculated to be ~ 20% of the rated steam flow.

10.4.4.2 System Description

The turbine bypass system consists of three automatically and sequentially operated regulating valves mounted on a valve manifold. The manifold is connected to the main steam lines upstream of the turbine main stop valves. The bypass valve outlets are piped to the main condenser, and pressure reducing orifices are located at the condenser connection.

Basic operation of the turbine bypass system consists of receiving a signal from the turbine control system (initial pressure regulator) to open the bypass valves whenever actual steam pressure exceeds the preset steam pressure by a small margin. This occurs whenever the amount of steam generated by the reactor cannot be entirely absorbed by the turbine.

The bypass valves are tripped closed whenever the vacuum in the main condenser falls below a preset value.

10.4.4.3 Safety Evaluation

The effects of a malfunction of the turbine bypass system valves, and the effects of such failures on other systems and components, are evaluated in chapter 15, Safety Analysis.

10.4.4.4 Tests and Inspections

Opening and closing of the turbine bypass system valves was checked during initial startup and shutdown for performance and timing. The bypass steam line was hydrostatically tested up to the bypass valve chest to confirm leaktightness. Main steam piping up to the main steam bypass valves was tested and inspected in accordance with the American Society of Mechanical Engineers (ASME) Section III, Code for Class 2 Piping.

10.4.4.5 Instrumentation Application

Instrumentation applicable to the control of the turbine bypass system is discussed in subsections 7.7.2 and 7.7.4.

10.4.5 CIRCULATING WATER SYSTEM (HNP-1 AND HNP-2)

The circulating water systems described in this section are applicable to HNP-1 and HNP-2 unless specified otherwise.

10.4.5.1 Design Bases

The circulating water system is designed:

- To circulate the flow required to remove the design heat load from the main condenser.

- For closed cycle operation, using mechanical draft cooling towers.

- To remove the design heat load from the circulating water for all weather conditions at or below the design wet bulb temperature.

HNP-1 and HNP-2 circulating water systems are shown on drawings H-11036 and H-21026, respectively.

10.4.5.2 System Description

The circulating water system is a closed loop system consisting of a main condenser, cooling towers, and circulating water pumps (CWPs). Two 50% capacity motor-driven, vertical CWPs are located in a separate structure between the turbine building and the cooling towers. Fixed screens located at the pump structure prevent possible debris from entering the CWPs, piping, and the main condenser.

The circulating water transport system is constructed of open concrete flumes, reinforced concrete pipe, large diameter steel pipe, rubber expansion joints, and butterfly valves. Circulating water enters and leaves the turbine building through reinforced concrete tunnels which are constructed below, but integral with, the turbine building base slab. The circulating water flows vertically from the concrete tunnel through four steel pipes which extend above the turbine building base slab at el 112 ft. A motor-operated butterfly valve is located in each of the lines at a position ~ 12 in. above the floor. The bottom of the valve motor is located 30 in. above the floor. These four lines are connected to the condenser water boxes by expansion joints. The piping and valve arrangements on the inlet and outlet sides of the condenser are similar. (See HNP-1 drawings H-11126 and H-12626 and HNP-2 drawings H-21001 and H-21114).

The normal discharge pressure of the two CWPs is 27 psig with a maximum pump shutoff head pressure of 40.5 psig. The expansion joints are designed for 55 psig with a test pressure of 83 psig. The circulating water system piping is designed for 75 psig in HNP-1 and 125 psig in HNP-2. The circulating water system is designed to supply the main condenser with cooling water at temperatures ranging from 37° to 86°F on HNP-1 and 37°F to 90°F on HNP-2.

Evaporation, drift, and blowdown losses are compensated for by makeup water taken from the Altamaha River via the plant service water system. The maximum rate at which water is taken from the river is 32,000 gal/min for HNP-1 and 34,000 gal/min for HNP-2, of which ~ 20,000 gal/min are returned to the river by each unit. For a more detailed discussion see section 2.4 and subsection 9.2.5.

HNP-1: The cooling towers consist of four mechanical draft counter-flow cooling towers designed for a wet bulb temperature of 80°F. Three of the towers are designed to cool the circulating water by 20°F (range), with the cooled water temperature within 7°F of the design wet bulb. The fourth cooling tower is designed to cool the circulating water by 20.6°F (range), with the cooling water temperature within 6°F of the design wet bulb.

HNP-2: The cooling towers consist of three mechanical draft cross-flow cooling towers designed for a wet bulb temperature of 78°F and a fourth cooling tower, a counter-flow mechanical draft tower, designed for an 80°F wet bulb temperature. The three cross-flow HNP-2 towers are designed to cool the circulating water 20.6°F (range), with the cooled water temperature within 12°F of design wet bulb temperature (approach). The fourth counter-flow cooling tower is designed to cool the circulating water by 20.6°F (range), with the cooling water temperature within 6°F of the design wet bulb.

A blowdown system is provided on the circulating water system since the evaporative processes in the cooling towers tend to increase the dissolved solids content in the circulating waters. The cooling tower blowdown system is operated in proportion to the circulating water flume level and radwaste dilution flow. Blowdown at a normal rate of 8915 gal/min is accomplished downstream of the circulating water pump discharge to decrease the dissolved solids content in the circulating water. Blowdown is discharged to the Altamaha River.

Sodium hypochlorite is utilized to treat the circulating water system, the sanitary water system, and the service water system. (See subsection 15.4.4.)

10.4.5.3 Safety Evaluation

Liquid radioactive wastes are discharged to the river a considerable distance downstream of the intake. Considering the small portion of the flow being taken from the river, no recirculation of the discharged water back to the intake is considered feasible. Therefore, the liquid radioactive wastes discharged from the plant are not taken into the cooling tower system and are not available for release to the environment through the cooling towers.

Passage of condensate from the condenser to the circulating water through a condenser tube leak is not considered to be possible during circulating water system operation since the circulating water system is at a higher pressure than the condenser and any leakage is into the condenser. However, the circulating water is sampled and monitored on a routine basis.

Should abnormal conditions exist during shutdown which would make it possible for condensate to leak through to the circulating water, the circulating water is sampled and monitored prior to resuming circulating water system operation.

10.4.5.3.1 Circulating Water Inlet/Outlet Valve Failure

The circulating water valves on the inlet and outlet of the condensers have slow acting motor operators and require ~ 60 s to move from the full-open to the full-closed position. Their normal operating position is full open, and their positions are not normally changed during operation.

A malfunction of one of these valves resulting in its inadvertent closure during operation would not result in a significant increase in pressure since the other three parallel flow paths would still be available. Inadvertent closure of one of the two valves in each of the four parallel flow paths would be required to completely stop water flow through the system; however, because the valves close slowly, the resulting pressure rise in the system would not exceed the pump shutoff pressure of 40.5 psig.

While sudden closure of one of these valves can be postulated, with higher than normal pressure resulting in a portion of the system, this is considered to be very unlikely since a gross failure of the valve disc shaft or the motor drive gear train would have to occur to permit rapid closure.

10.4.5.3.2 Circulating Water Flooding in HNP-1 and HNP-2 Turbine Buildings

Assuming a gross circulating water system failure occurs in the turbine building which exceeds the 500 gal/min capacity of the drain system, water would flow into HNP-1 and HNP-2 turbine buildings and the control building due to communication between these areas via the east corridor and the west cableway. Initial indication of this type of failure would be audible alarms in the MCR actuated by the level switches in the turbine buildings and control building drain sumps. Failure of the expansion joint is the most probable type of failure for the circulating water system.

The control functions associated with the HNP-1 and HNP-2 level switches (set at 3 in. of water level) in the condenser bay rooms are as follows:

- Remove power from the CWP motors.
- Annunciate in the MCR.
- Isolate the turbine building service water.
- Initiate closure of the CWP discharge valves (HNP-1).
- Initiate closure of inlet and outlet isolation valves on condenser (HNP-2).

A. Flooding Assuming Condenser Water Box Expansion Joint Failure and CWP Runout

Initial conditions and assumptions are as follows:

• Normal flow from two CWPs	561,000 gal/min
• Combined runout of both CWPs	640,000 gal/min
• Closing time for circulating water valves	60 s
• Time from level switch actuation until power is removed from CWP motors	< 0.2 s
• Coastdown time for CWPs	~ 80 s
• Total floor area for HNP-1 and HNP-2 turbine buildings and control building at el 112 ft.	113,009 ft^2
• Total floor area, assuming interior walls, equipment, etc., displace ~14% of total area	97,188 ft^2
• Turbine building level switches set to trip	3 in. above el 112 ft
• Flood waters travel to HNP-1 and HNP-2 turbine buildings and control building via the condenser bay access door and equalize immediately, that is, the entire floor area is available to dissipate the water and it will not rise any higher in the condenser bay faster than the entire area.	

Results are summarized below:

• Rate of water rise in buildings	0.18 in./s
• Time to reach 3-in. level switches	16.6 s
• Time required to isolate circulating water system	76.6 s
• Termination level assuming runout flow during coastdown period	13.8 in

B. Flooding Assuming Condenser Water Box Expansion Joint Failure and Isolation Valve Failure

The most conservative assumption for evaluating the effects of circulating water flooding is to assume that a failure occurs that allows the total volume of water contained within the circulating water flumes and the cooling tower basins to equalize at a level common to the inside of the turbine and control buildings and outside in the circulating water canals.

1. HNP-2 Condenser Water Box Expansion Joint Failure

Expansion joint failure consequences are limited due to the following:

- The HNP-2 condenser bay 3-in. level switches initiate closure of the HNP-2 condenser inlet and outlet isolation valves.

- The HNP-2 condenser bay 3-in. level switches initiate closure of the HNP-2 CWP discharge valves by removal of power to the CWP motors.

Thus, assuming circulating water expansion joint failure occurs in the HNP-2 turbine building and allowing for a single failure, the 3-in. level switches will isolate either the condenser inlet and outlet isolation valves or the CWP discharge valves. Therefore, condenser water box expansion joint failure is not analyzed for HNP-2.

2. HNP-1 Condenser Water Box Expansion Joint Failure

Initial conditions and assumptions for HNP-1 expansion joint failure are as follows:

• Failure occurs and CWP discharge valves fail to close.	
• Total floor area for HNP-1 and HNP-2 turbine buildings and control building	113,009 ft^2
• Total floor area, assuming interior walls displace 14% of total area	97,188 ft^2
• Turbine building level switches set to trip	3 in. above el 112 ft
• HNP-1 and HNP-2 battery pads are 5 ft 11 in. high	el 117 ft 11 in.
• Maximum circulating water flume level	118 ft 9 in.

- Total capacity in tower basins, canals, pump structure, and helper tower at el 118 ft 9 in. 798,316 ft^3

- Volume of water will equalize at a level (between el 112 ft and 118 ft 9 in.) common to area inside buildings and outside in circulating water canals.

Water flows from the flumes into HNP-1 and HNP-2 turbine buildings and control building until the level in the three buildings and the level in the flumes and basins equalize at el 117 ft.

Drawings H-12626 and H-22802 show a plan view of the HNP-1 and HNP-2 turbine and control buildings at el 112 ft. The HNP-1 and HNP-2 station batteries are housed in rooms with normally shut doors, which would minimize the ingress of floodwater to the space. If the doors are open and the floodwaters flow into the space, the batteries will remain unaffected. The batteries are mounted on racks that are fastened to pads 5 ft 11 in. high (el 117 ft 11 in.). Therefore, even with the water level at its maximum elevation of 117 ft, the water is 11 in. below the top of the battery pad. (See figure 10.4-1.)

<u>HNP-1</u>: All other safety-related equipment, including cables and junction boxes, is located at elevations higher than el 117 ft. Cable trays containing safety-related cables are located at el 121 ft 11 in. (1 tray) and 123 ft 3 in. (2 trays). Even if these cables were submerged in water, they would continue to perform their function. All junctions in the onsite emergency ac power cables are above el 130 ft. Other safety-related equipment in the control building is located at el 130 ft or above, including the 600 V-ac switchgear and the dc switchgear, which are located at el 130 ft.

<u>HNP-2:</u> The station batteries and certain cables in the cableways are the only safety-related equipment located in the spaces affected by the circulating water flooding. When the water reaches el 117 ft, some safety-related power cables are submerged. However, no malfunction of safety-related equipment due to submerged cables is postulated.

In addition to the circulating water system, there are other systems whose failure would result in water flowing into the turbine and control buildings. These systems include potable water, demineralized water, condensate storage, fire protection, reactor building closed cooling water, and the condensate and feedwater systems. The largest of these is the fire protection system, which has a maximum inventory of 600,000 gal. Assuming that this total inventory is pumped into the turbine and control buildings, the water level would be < el 114 ft. This is well below the top of the battery pads at el 117 ft 11 in.

10.4.5.4 <u>Tests and Inspections</u>

All major components of the system (except the main condensers and the circulating water tunnel) are accessible for inspection during station operation. The cooling towers are tested in

accordance with the ASME Power Test Code for Atmospheric Water Cooling Equipment, PTC-23.

The CWPs were hydrostatically tested prior to shipment. Performance tests are conducted in accordance with the standards of the Hydraulic Institute.

Performance, hydrostatic, and leakage tests are conducted on the circulating water system butterfly valves in accordance with American Water Works Association (AWWA) C-504.

10.4.5.5 Instrumentation Application

The CWPs are individually equipped with isolation valves which permit either pump to be isolated. The isolation valves also prevent vapor binding of the pumps when starting up after isolation.

Each of the eight condenser waterboxes is equipped with isolation valves which enable any of the four parallel condenser tube/waterbox/expansion joint sections to be isolated from the circulating water system. All isolation valves are operated by remote manual switches. After detection and isolation of a condenser tube leak or a waterbox expansion joint failure, circulating water from the affected condenser section may be transferred to unaffected sections by the condenser waterbox drain pump. Temperature and pressure are measured on each condenser. Level alarms to protect the circulating water pumps are provided. The cooling tower blowdown system is operated in proportion to the circulating water flume level and radwaste dilution flow.

10.4.6 CONDENSATE POLISHING DEMINERALIZER SYSTEM

10.4.6.1 Design Bases

The condensate polishing demineralizer system is designed to:

A. Maintain the quality of the feedwater at all flows.

B. Remove suspended and dissolved solids from the feedwater to meet the following criteria:

• Specific conductivity at 25°C (μho/cm)	< 0.1
• Chlorides (as Cℓ) (ppb)	< 10
• pH at 25°C	6.5 to 7.5

- Metallic impurities (ppb) < 30 (of which copper shall not exceed 2 ppb)

- Oxygen (ppb) ≤ 200

C. Piping for the system is designed in accordance with American National Standards Institute (ANSI) B31.1.0, while the tanks are designed in accordance with ASME Section VIII.

It is recognized that, during initial startup and restart conditions, higher than normal concentrations of metallic impurities may be found in the feedwater.

10.4.6.2 System Description

The condensate polishing demineralizer system is shown on drawing nos. H-21018 and S-60192. The system consists of seven filter-demineralizers which operate in parallel to maintain the reactor feedwater quality. The filter-demineralizers are of the precoatable, backwashable type, using powdered cation anion resins as the coating media. The system includes all necessary controls, piping, valves, pumps, and vessels required for operation, as well as a body feed system. With the filter-demineralizer operating, the body feed system adds resin to the filter-demineralizer vessels. The purpose of the resin addition is to increase the operation time of the filter-demineralizer before the backwash and precoating is required. This system is skid mounted and includes an enclosed mixing tank with nitrogen inerting, a recirculation pump, two feed pumps (one spare), the required valves and piping, and a control panel. The condensate polishing demineralizer system is remotely operable, controlled from a locally mounted panel. An automatic bypass maintains condensate flow in the event of high differential pressure across the filter-demineralizers.

10.4.6.3 Safety Evaluation

The condensate cleanup system removes some radioactive material created by corrosion, fission products, and carryover from the reactor. While radioactive effects from these sources do not affect the capacity of the resin, the concentration of such radioactive material requires shielding. (See subsection 12.3.2.) Waste sludge and vent gases from the condensate cleanup system are sent automatically to the radwaste system for cleanup and/or disposal. Chapter 11 describes the activity level and removal of radioactive material from the system.

10.4.6.4 Tests and Inspections

The condensate cleanup system was proven operable by its use during normal plant operation. Each vessel of the system is separately isolated for testing to ensure operability and integrity of the system.

10.4.6.5 Instrumentation Application

Instrumentation includes an automatic flow balancing control for each demineralizer which maintains equal flow through each unit by regulating a valve downstream of the unit. A flow indicator is provided for each filter-demineralizer. As indicated on drawing nos. H-21018 and S-60192, conductivity elements are located on the filter-demineralizer influent header and on each filter-demineralizer's effluent line to permit evaluation of its ion-exchange capacity and to provide a means for alarming in the event of either high influent or effluent conductivity; readout and alarm is provided in the MCR. Differential pressure is also measured across each filter-demineralizer to permit corrosion product removal. In addition to the above described instrumentation, a means is provided for sampling the influent and effluent streams from each filter-demineralizer. These sample points are indicated on drawing nos. H-21018 and S-60192.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

10.4.7.1 Design Bases

The condensate and feedwater system is designed as follows:

A. The system is designed to provide a dependable supply of feedwater to the reactor, to provide feedwater heating, and to maintain high feedwater quality.

B. The feedwater equipment provides the required flow at required pressure to the reactor, allowing sufficient margin to provide continued flow under anticipated operational occurrences (AOOs) in which the condensate and feedwater system remains available.

C. The feedwater heaters are designed to provide the required feedwater temperature to the reactor with six stages of closed feedwater heating.

D. A prestartup recirculation line from the reactor feedwater supply line is provided to recirculate one third of the design flow back through the condenser and polishing system to minimize the amount of corrosion products entering the reactor.

E. The condensate and feedwater system piping and equipment to the outermost isolation valve is ANSI B31.1.0, and the feedwater heaters are ASME Section VIII.

F. The condensate and feedwater system is isolated from the reactor coolant system by air-operated check valves.

10.4.7.2 System Description

The vertical condensate pumps take the condensate from the condenser hotwells and pump it through the air ejector condensers, gland-seal condenser, condensate demineralizer, and the off-gas condenser. The horizontal condensate booster pumps take the condensate after it

passes through the off-gas condenser and pump it through two parallel streams, each with five low-pressure heaters, to the suction of the reactor feed pump. The reactor feed pumps then pump the feedwater through two parallel streams, each with one high-pressure heater, to the reactor. (See drawing nos. H-21037 and H-21038.)

10.4.7.2.1 Vertical Condensate Pumps

There are three condensate pumps. Each condensate pump is a multistage vertical, canned suction type, motor-driven, centrifugal unit. The pumps are installed at an elevation which permits full-capacity operation down to extreme low level in the condenser hotwell. The pumps provide maximum design flow plus design margins at the required pressure to overcome system resistance and provide the required suction pressure at the horizontal condensate booster pumps.

10.4.7.2.2 Horizontal Condensate Booster Pumps

There are three condensate booster pumps. Each horizontal condensate booster pump is a single-stage, double-suction, motor-driven, centrifugal unit. The pumps provide maximum design flow plus design margins at the required pressure to overcome system resistance, and provide the required suction pressure at the reactor feed pumps. A two-out-of-two logic is provided with a delay to trip each condensate booster pump on low-suction pressure and autostart the standby condensate pump. This delay allows the system to recover from short-term, low suction pressures during a plant transient. The trip time delays are staggered to prevent the condensate booster pumps from tripping simultaneously.

10.4.7.2.3 Feedwater Heaters

There are two parallel trains of heaters, each consisting of six feedwater heaters. The first five heaters are located before the reactor feed pumps and after the condensate booster pumps. The last heater is a high-pressure heater located after the reactor feed pump. All the feedwater heaters have stainless steel tubes and welded tube to tube sheet joints.

10.4.7.2.4 Reactor Feed Pumps

Two turbine-driven, reactor feed pumps are provided. Each reactor feed pump is a horizontal, centrifugal unit. The feed pumps operate in series with the condensate and condensate booster pumps and provide maximum design flow plus design margins at the required pressure at the reactor inlet nozzles. A two-out-of-three logic is provided with a delay to trip each reactor feed pump on low suction pressure and autostart the standby condensate booster pump. This delay allows the system to recover from short-term, low suction pressures during a plant transient. The trip time delays are staggered to prevent both reactor feed pumps from tripping simultaneously.

10.4.7.2.5 Pump Recirculation

Recirculation control valves are provided on all pump discharge lines to permit direct recirculation of feedwater to the main condenser, thus assuring required minimum flows are maintained.

10.4.7.2.6 Reactor Feed Pump Turbine Drive

Individual steam turbines drive the feedwater pumps. The turbine drives are of dual-admission type, and each is equipped with two sets of main stop and control valves. One set admits high-pressure steam from the reactor, and the other set admits low-pressure steam from the main steam crossaround piping. Under normal operating conditions, the turbine drives run on the low-pressure crossover steam. Reactor steam is used during plant startup, low-load, or transient conditions, when crossover steam is not available or insufficient.

10.4.7.3 <u>Feedwater Controls</u>

The feedwater control system is described in subsection 7.7.3.

10.4.7.4 <u>Safety Evaluation</u>

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Shielding and controlled access are provided as necessary. (See subsection 12.3.2.) The condensate and feedwater system is designed to minimize leakage, with welded construction used where practical.

The condensate and feedwater system is not required to affect or support the safe shutdown of the reactor or perform in the operation of reactor safety features.

One condensate pump, one condensate booster pump, and one reactor feedwater pump, operating in series, are capable of maintaining sufficient flow to the reactor to prevent scramming on loss of any one pump in the stream while operating with two streams.

The standby condenser pump is automatically started prior to receiving a booster pump suction drop.

A bypass is provided around the reactor feed pumps for startup and shutdown operations, using the motor-driven condensate pumps for feeding the reactor.

An AOO analysis of the loss of feedwater heating is included in section 15.2.

10.4.7.5 Tests and Inspections

Each feedwater heater, pump, and valve received a shop hydrostatic test which was performed in accordance with applicable codes. All tube joints of feedwater heaters are shop leak tested. Prior to initial operation, the completed condensate and feedwater system received a field hydrostatic test and inspection in accordance with the applicable code.

Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages.

10.4.7.6 Instrumentation Application

Feedwater flow control instrumentation measures the feedwater flowrate from the condensate and feedwater system. This measurement is used by the feedwater control system which regulates the feedwater flow to the reactor to meet system demands.

Instrumentation and controls are provided for regulating the pump recirculation flowrate for the condensate pumps, condensate booster pumps, and reactor feed pumps.

Points for measurement of pump suction and discharge pressures are provided for all pumps in the system.

Sampling means are provided for monitoring the quality of the final feedwater. In the feedwater heating portion of the system, temperature measurements are provided for each stage of heating. These measurements include the flow temperature into and out of each feedwater heater.

10.4.8 HYDROGEN WATER CHEMISTRY SYSTEM (HNP-1 AND HNP-2)

The information provided in this subsection is applicable to both HNP-1 and HNP-2 unless specified otherwise.

10.4.8.1 Power Generation Objective

The purpose of the hydrogen water chemistry (HWC) system is to eliminate, in a timely manner, the chemical conditions in the recirculation water that allow intergranular stress corrosion cracking (IGSCC). Boiling water reactors use high purity water as the primary recirculation coolant in the direct cycle production of steam. Because of radiolytic decomposition of the water in the core, the reactor and recirculation water contains a steady-state concentration of 100-300 ppb of dissolved oxygen. This is a sufficient amount of oxygen to cause IGSCC of highly stressed, sensitized stainless steel. Other regions of the reactor, such as components in the vessel lower plenum, can also be protected from IGSCC by increasing hydrogen injection rates.

Noble metal compounds have been injected into the reactor vessel to prevent crack initiation and mitigate any existing crack growth due to IGSCC in the reactor vessel surfaces, internal components, and piping. This process is commonly called the NobleChem^{TM} process, which reduces the amount of hydrogen injection required to mitigate IGSCC.

10.4.8.2 Power Generation Design Basis

The HWC system injects hydrogen into the feedwater at the suctions of the condensate booster pumps to mitigate IGSSC in the recirculation piping and regions of the reactor vessel. The injected hydrogen forces a reduction in dissolved oxygen within these areas and lowers the radiolytic production of the hydrogen and oxygen in the vessel core region. The concentration of hydrogen and oxygen exiting the vessel (main steam) and eventually in the main condenser is altered in this process. Lowering the main condenser oxygen level can reduce the feedwater dissolved-oxygen concentration. The injected hydrogen mostly passes through the coolant cycle unreacted, leaving in the main condenser an "excess" of hydrogen not having equivalent oxygen with which to recombine in the off-gas system. To maintain the offgas system near its normal operating characteristics, a flowrate of oxygen equal to one-half the injected hydrogen flowrate is put into the offgas system upstream of the recombiner.

10.4.8.3 Description

The majority of the HWC system process valving is grouped into two modules, one module for the hydrogen injection subsystem and the other for the oxygen injection subsystem.

A. Automatic or Control Features in the HWC System

1. Automatic Oxygen Injection Rate Change Delay

   This function is also augmented as a function of reactor power level.

2. Automatic Shutdown on Several Alarms

   Shutdown and alarm capabilities are listed below:

Shutdowns	Alarms
Control room demand	Hydrogen flow error
Low off-gas % oxygen	Low hydrogen pressure
High-high hydrogen area monitors	High hydrogen area monitors
High hydrogen flow	Low oxygen pressure
Local panel demand	High oxygen pressure
High hydrogen pressure	
Off-gas train/recombiner train trip	

Shutdowns	Alarms
Reactor mode switch taken out of Run position	Hydrogen/oxygen supply alarm Off-gas sample alarm (Low off-gas sample flow, high or low off-gas sample pressure) Hydrogen guard pipe alarm (HNP-1 only) Oxygen guard pipe alarm (HNP-1 only) HWC injection system trouble (remote) HWC supply system trouble remote High off-gas % oxygen

3. Flow Control Automatic Isolation Valves Closure on System Power Loss

4. Reprogrammable Alarms and Controller Electronics

5. Hydrogen and Oxygen Flow Monitor Correction Functions to Compensate for Nonlinearities

B. Safety Features in the HWC System

1. Nonflammable Off-gas

Oxygen is injected into the off-gas system upstream of the recombiner in stoichiometric proportion to the hydrogen present to produce a nonflammable offgas through catalytic recombination of hydrogen.

A built-in delay and lag in the oxygen flow control system ensure changes in the oxygen injection rate lag changes in the hydrogen rate. This ensures sufficient oxygen in the off-gas for recombination with the hydrogen. This delay period is automatically adjusted for power level.

2. Automatic Reset of Hydrogen and Oxygen Flowrates to Zero During Shutdown

The hydrogen external and internal setpoints are disabled and are immediately given a zero value on system shutdown. The oxygen flow will automatically follow the hydrogen flowrate with a delay and decay. A zero setpoint value is also input to the hydrogen rate limiter on shutdown, so system restart with an external or internal setpoint proceeds from zero flow. Restart of the system can proceed only if the shutdown condition is cleared and the annunciator panel is reset.

When the off-gas trip signal is received, the oxygen and hydrogen flow control valves are immediately closed, and the oxygen setpoints are disabled and given a zero value to prevent oxygen injection into an isolated off-gas system.

3. Valves

The flow control and air-operated isolation valves fail closed upon loss of instrument air or control power, ensuring flow does not proceed in an uncontrolled fashion. Excess flow check valves in the hydrogen and oxygen supply lines ensure the injection rates do not exceed a maximum rate.

The cryogenic storage facility supplied for the HWC system consists of a [redacted] The liquid nitrogen tank is mounted with [redacted] and supplies nitrogen gas for purge applications and operation of valve actuators. The cryogenic storage facility meets all the design requirements of the EPRI NP-5283-SR-A, Guidelines for Permanent BWR HWC Installations-1987 Revision.[1]

10.4.8.4 Safety Evaluation

The HWC system is not safety related; however, the installation and operation of the system substantially increase the carryover of N-16 from the reactor to the steam system (tables 11.1-6 and 11.1-7). This increase results in a measurable increase in the gamma dose rate both inside and outside the radiation controlled area. The radiation levels around the plant were measured during the dual unit mini-test of July 27, 1991. Survey data indicated that compliance with Nuclear Regulatory Commission (NRC) regulation Title 10 Code of Federal Regulations (CFR) Part 20 will be maintained during operation of the HWC system. The HWC system design includes a high hydrogen flowrate signal as a system shutdown function to ensure the hydrogen injection rate does not exceed a maximum rate.

The use of the HWC system does require that the main steam line radiation setpoints be increased while the HWC system is in operation. The change to the main steam line radiation setpoints is required due to the increase in main steam line radiation above normal due to N-16 carryover. No design basis accidents take credit for these setpoints.

Also, HWC system operation may cause a slight increase in offgas flow to the off-gas recombiner, depending on the hydrogen injection rate. However, this does not lead to any safety concern, since the increased off-gas flow is within the design specifications for the recombiner flow capacity and temperature.

The operation of the HWC system does not lead to any safety concerns related to the installation of the hydrogen, oxygen, and nitrogen storage tanks and transfer system, since they are installed in accordance with acceptable industry practices and designed to the appropriate codes and standards. In addition, all storage and gas-handling equipment is located in areas where hydrogen- and oxygen-assisted fires would have no impact on safety-related equipment. The storage facility, in compliance with the safety-related structure separation criteria of EPRI NP-5283-SR-A, has been located [redacted]. No fire protection is specifically required for this application by the NRC or by Nuclear Mutual Limited.

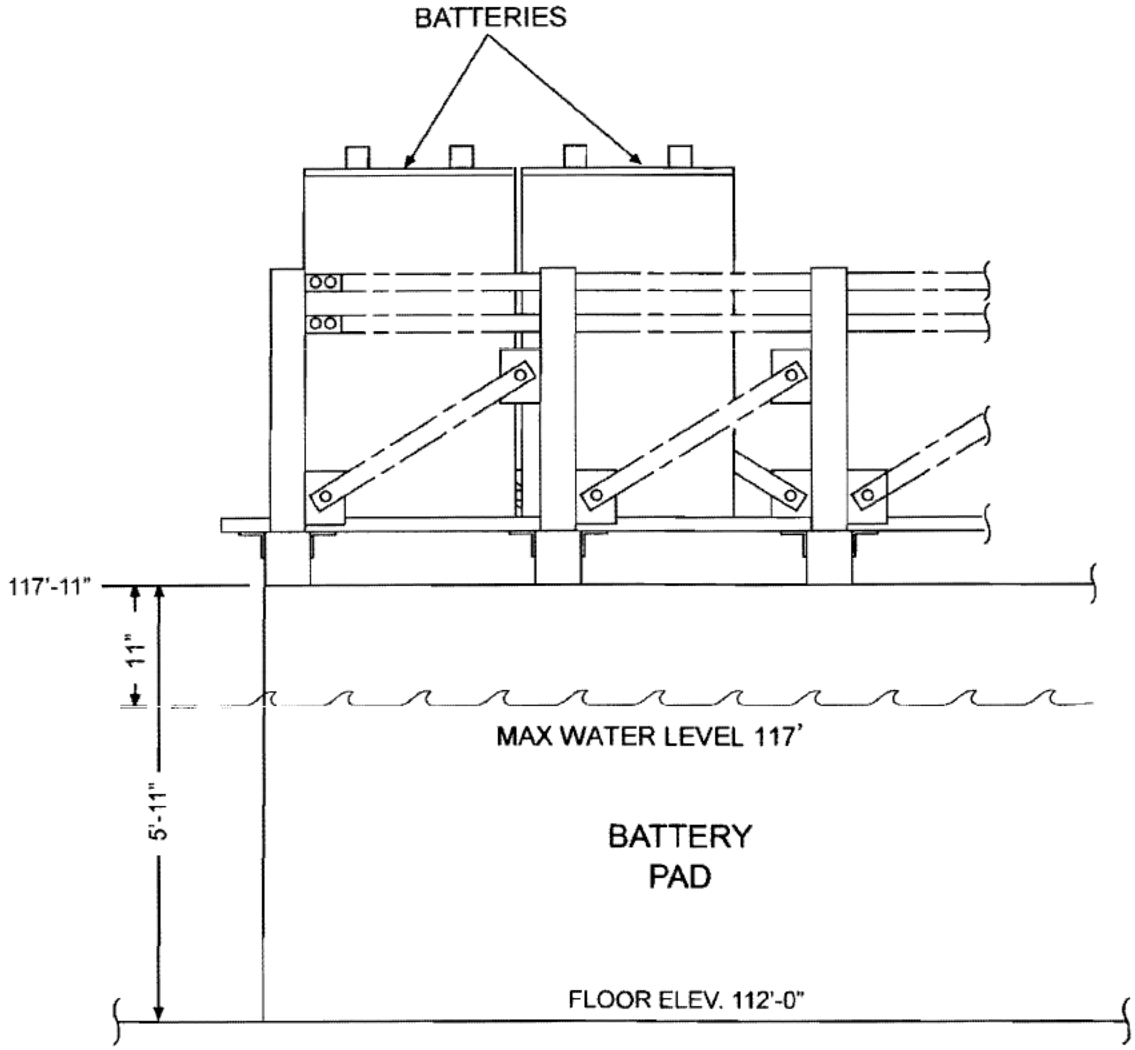
REFERENCES

1. "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations - 1987 Revision," EPRI NP-5283-SR-A, September 1987.

2. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

3. RER 03-254, Reactor Operating Pressure Increase From 1050 psia to 1060 psia, Engineering Evaluations.

4. EPRI BWRVIP-156: BWR Vessel and Internals Project (Generic Guidelines for Improvement in HWC System Availability).



REV 24 9/06

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

MAXIMUM WATER LEVEL IN STATION BATTERY ROOMS WITH CIRCULATING WATER SYSTEM EXPANSION JOINT FAILURE

FIGURE 10.4-1

11.0 RADIOACTIVE WASTE MANAGEMENT

11.1 SOURCE TERMS

Two source terms are presented in this section. The first is a conservative design base that utilizes a conventional fuel clad defect model. This design model serves as a basis for system and shielding requirements.

The second source term is a realistic model used to predict expected long-term average concentrations of radionuclides in the primary and secondary fluid stream and an average plant's environmental releases over its lifetime. This realistic model, based on available measured nuclide concentrations during normal operation, was formulated as a standard for the American National Standard Source Term Specifications (ANSI) and American Nuclear Society (ANS), ANSI N237/ANS 18.1-1976,[7] and is the source term model used in the BWR GALE Code-NUREG-0016.[8]

11.1.1 REACTOR COOLANT AND SECONDARY SIDE ACTIVITY

11.1.1.1 Design Basis Model

The General Electric Company (GE) has evaluated radioactive material sources (activation products and fission product release from fuel) in operating boiling water reactors (BWRs) over the past decade. These source terms are reviewed and periodically revised to incorporate up-to-date information. Release of radioactive material from operating BWRs has generally resulted in doses to offsite persons which have been only a small fraction of permissible or natural background doses.

The information provided in this section defines the design basis radioactive material levels in the reactor water, steam, and off-gas. The various radioisotopes listed have been grouped as coolant activation products, noncoolant activation products, and fission products. The fission product levels are based on measurements of BWR reactor water and off-gas at several stations through mid-1971. Emphasis was placed on observations made at KRB[a] and Dresden 2. The design basis radioactive material levels do not necessarily include all the radioisotopes observed or theoretically predicted to be present. The radioisotopes included are considered significant to one or more of the following criteria:

- Plant equipment design.
- Shielding design.
- Understanding system operation and performance.
- Measurement practicability.

a. Kernkraftwerk FEW Bayerwerk, 237 MW(e) BWR, Gundremmingen, West Germany.

For halogens, radioisotopes with half-lives of < 3 min were omitted. For other fission product radioisotopes in reactor water, radioisotopes with half-lives of < 10 min were not considered.

11.1.1.1.1 Fission Products

11.1.1.1.1.1 <u>Noble Radiogas Fission Products</u>. The noble radiogas fission product source terms observed in operating BWRs are generally complex mixtures whose sources vary from minuscule defects in cladding to "tramp" uranium on external cladding surfaces. The relative concentrations or amounts of noble radiogas isotopes can be described as follows:

- Equilibrium = $R_g \approx k_1 y$ (1)
- Recoil = $R_g \approx k_2 y$ (2)

The nomenclature in paragraph 11.1.1.4 defines the terms in these and succeeding equations. The constants k_1 and k_2 describe the fractions of the total fission product that are involved in each of the releases.

The equilibrium and recoil mixtures are the two extremes of the mixture spectrum that are physically possible. The equilibrium mixture results when a sufficient time delay occurs, between the fission event and the time of release of the radiogases from the fuel to the coolant, for the radiogases to approach equilibrium levels in the fuel. When there is no delay or impedance between the fission event and the release of the radiogases, the recoil mixture is observed.

Prior to Vallecitos BWR and Dresden 1 experience, it was assumed that noble radiogas leakage from the fuel would be the equilibrium mixture of the noble radiogases present in the fuel.

Vallecitos BWR and early Dresden 1 experience indicated that the actual mixture most often observed approached a distribution which was intermediate in character to the two extremes. This intermediate decay mixture was termed the diffusion mixture. It must be emphasized that this diffusion mixture is merely one possible point on the mixture spectrum ranging from the equilibrium to the recoil mixture, and it does not have the absolute mathematical and mechanistic basis for the calculational methods possible for equilibrium and recoil mixtures. However, the diffusion distribution pattern which has been described is as follows.[1]

Diffusion = $R_g \approx k_3 y \lambda^{0.5}$ (3)

The constant k_3 describes the fraction of total fissions that are involved in the release. As can be seen, the value of the exponent of the decay constant, λ, is midway between that of equilibrium (0) and recoil (1). The diffusion pattern value of 0.5 was originally derived from diffusion theory, but the assumptions have been discredited.

Although the previously described diffusion mixture has been used by GE as a basis for design since 1963, the design basis release magnitude used has varied from 0.5 Ci/s to 0.1 Ci/s as measured after 30-min decay (t = 30 min).[(a)]

Since about 1967, the design basis release magnitude used, including the 1971 source terms, was established at an annual average of 0.1 Ci/s at t = 30 min. This design basis is considered as an annual average with some time above and some time below this value.

This design value was selected on the basis of operating experience rather than predictive assumptions. Several judgment factors, including the significance of environmental release, reactor water radioisotope concentrations, liquid waste handling and effluent disposal criteria, building air contamination, shielding design, turbine, and other component contamination affecting maintenance have been considered in establishing this level.

Experience in the operation of open-cycle BWRs has indicated that in-plant contamination and other operating restrictions may limit plant operation at levels well below emission rates which would correspond to 10 CFR 20.1001-20.2402 dose limits.

Although noble radiogas source terms from fuel above 0.1 Ci/s at t = 30 min can be tolerated for reasonable periods of time, long-term operation at such levels may be undesirable. Continual assessment of this value is made on the basis of actual operating experience in BWRs. There is no experimental or operational basis for changing this design basis value because of increased reactor size or fuel power density and since limiting conditions are largely independent of these parameters.

While the noble radiogas source term magnitude was established at 0.1 Ci/s at t = 30 min, it was recognized that there may be a more statistically applicable distribution for the noble radiogas mixture. Sufficient data were available from KRB operations from 1967 to mid-1971, along with Dresden 2 data from 1970 and several months in 1971, to more accurately characterize the noble radiogas mixture pattern for an operating BWR.

The basic equation for each radioisotope used to analyze the collected data is:

$$R_g = K_g y \lambda^m \left(1 - e^{-\lambda T}\right)\left(e^{-\lambda t}\right) \tag{4}$$

With the exception of Kr-85 with a half-life of 10.74 years, the noble radiogas fission products in the fuel are essentially at an equilibrium condition after an irradiation period of several months. (Rate of formation is equal to the rate of decay.) Therefore, for practical purposes, the term $\left(1 - e^{-\lambda T}\right)$ approaches unity and can be neglected when the reactor has been operating at a steady state for long periods of time. The term ($e^{-\lambda t}$) is used to adjust the releases from the fuel at t = 0 to the decay time for which values are needed. Historically, t = 30 min has been used. When discussing long steady-state operation and leakage from the fuel, the following simplified form of equation 4 can be used to describe the leakage of each noble radiogas isotope:

a. The noble radiogas source term rate after 30-min decay has been used as a conventional measure of the design basis fuel leakage rate, since it is conveniently measurable and was consistent with the nominal design basis 30-min, off-gas holdup system used on a number of plants.

$$R_g = K_g y \lambda^m \tag{5}$$

The constant K_g describes the magnitude of leakage. The relative rates of leakage of the different noble radiogas isotopes is accounted for by the variable m and the exponent of the decay constant, λ.

Dividing both sides of equation 5 by the variable y and taking the logarithm of both sides result in the following equation:

$$\log\left(R_g / y\right) = m \log(\lambda) + \log\left(K_g\right) \tag{6}$$

Equation 6 represents a straight line when $\log(R_g/y)$ is plotted versus $\log(\lambda)$; variable m is the slope of the line. This straight line is obtained by plotting R_g/y versus λ on logarithmic graph paper. By fitting actual data from KRB and Dresden 2 and applying least squares techniques to the equation, the slope m can be obtained. This can be estimated on the plotted graph. With radiogas leakage at KRB over the nearly 5-year period varying from 0.001 to 0.056 Ci/s at t = 30 min, and with radiogas leakage at Dresden 2 varying from 0.001 to 0.169 Ci/s at t = 30 min, the average value of m was determined. The value for m is 0.4 with a $\overline{\text{s}}$tandard deviation of ± 0.07. This is illustrated on figure 11.1-1 as a frequency histogram. As can be seen from this figure, variations in m were observed in the range m = 0.1 to m = 0.6.

After establishing the value of $\overline{m}$ = 0.4, the value of K_g can be calculated by selecting a value from R_g or, as has been done historically, by setting the total design basis source term magnitude at t = 30 min. With ΣR_g at 30 min equal to 100,000 μCi/s, K_g can be calculated as being 2.6 x 10^7. Equation 4 then becomes:

$$R_g = 2.6 \times 10^7 y \lambda^{0.4} \left(1 - e^{-\lambda T}\right)\left(e^{-\lambda t}\right) \tag{7}$$

This updated noble radiogas source term mixture has been termed the 1971 mixture to differentiate it from the diffusion mixture. The noble gas source term for each radioisotope can be calculated from equation 7. The resultant source terms are presented in table 11.1-1 as leakage from fuel (t = 0) and after 30-min decay. While Kr-85 can be calculated using equation 7, the number of confirming experimental observations was limited by the difficulty of measuring the very low release rates of this isotope. Therefore, the table provides an estimated range for Kr-85 based on a few actual measurements.

11.1.1.1.1.2 Radiohalogen Fission Products. Historically, the radiohalogen design basis source term was established by the same equation as that used for noble radiogases. In a fashion similar to that used with gases, a simplified equation can be shown to describe the release of each halogen radioisotope:

$$R_h = K_h y \lambda^n \tag{8}$$

The constant, K_h, describes the magnitude of leakage from fuel. The relative rates of halogen radioisotope leakage are expressed in terms of n, the exponent of the decay constant, λ. As was done with the noble radiogases, the average value was determined for n. The value for n is 0.5 with a standard deviation of ± 0.19. This is illustrated on figure 11.1-2 as a frequency histogram. As can be seen from this figure, variations in variable n were observed in the range of n = 0.1 to 0.9.

It appeared that the use of the previous method of calculating radiohalogen leakage from fuel was overly conservative. Figure 11.1-3 relates KRB and Dresden 2 noble radiogas and I-131 leakage. From Dresden 2 data during the period August 1970 to January 1971, a relationship between noble radiogas and I-131 leakage under one fuel condition can be seen. However there was no simple relationship for all fuel conditions experienced. Also, it can be seen that during this period, high radiogas leakages were not accompanied by high radioiodine leakage from the fuel. Except for one KRB data point, all steady-state I-131 leakages observed at KRB or Dresden 2 were ≤ 505 µCi/s. Even at Dresden 1 in March 1965 when severe defects were experienced in stainless-steel-clad fuel, I-131 leakages > 500 µCi/s were not experienced. Figure 11.1-3 shows that these higher radioiodine leakages from the fuel were related to noble radiogas source terms of less than the design basis value of 0.1 Ci/s at t = 30 min. This may be partially explained by inherent limitations due to internal plant operational problems that caused plant derating.

In general, it would not be anticipated that operation at full power would continue for any significant time period with fuel-cladding defects, which would be indicated by I-131 leakage from the fuel in excess of 700 µCi/s. When high radiohalogen leakages are observed, other fission products will be present in greater amounts. This may increase potential radiation exposure to operating and maintenance personnel during plant outages following such operation.

Using these judgment factors and experience to date, the design basis radiohalogen source terms from fuel were established based on an I-131 leakage of 700 µCi/s. This value, as seen on figure 11.1-3, accommodates the experience data and the design basis noble radiogas source term of 0.1 Ci/s at t = 30 min. With the I-131 design basis source term established, K_h can be calculated as being 2.4×10^7, and halogen radioisotope release can be expressed by the following equation:

$$R_h = 2.4 \times 10^7 \, y \lambda^{0.5} \left(1 - e^{-\lambda T}\right)\left(e^{-\lambda t}\right) \qquad (9)$$

Concentrations of radiohalogens in reactor water can be calculated using the following equation:

$$C_h = \frac{R_h}{(\lambda + \beta + \gamma)M} \qquad (10)$$

Although carryover of most soluble radioisotopes from reactor water to steam is observed to be < 0.1% (< 0.001 fraction), the observed carryover for radiohalogens has varied from 0.1% to ~ 2% on new plants. The average of observed radiohalogen carryover measurements has been

1.2% by weight of reactor water in steam with a standard deviation of ± 0.9. In our present source term definition, a radiohalogen carryover of 2% (0.02 fraction) was used.

The halogen release rate from the fuel can be calculated from equation 9. Concentrations in reactor water can be calculated from equation 10. The resultant concentrations are presented in table 11.1-2.

11.1.1.1.1.3 Other Fission Products. The observations of other fission products and transuranic nuclides, including Np-239, in operating BWRs are not adequately correlated by simple equations. For these radioisotopes, design basis concentrations in reactor water were estimated conservatively from experience data and are presented in table 11.1-3. Carryover of these radioisotopes from the reactor water to the steam is estimated to be < 0.1% (< 0.001 fraction). In addition to carryover, however, decay of noble radiogases in the steam leaving the reactor results in production of noble gas daughter radioisotopes in the steam and condensate systems.

Some daughter radioisotopes, such as yttrium and lanthanum, were not listed as being in reactor water. Their independent leakage to the coolant is negligible. However, these radioisotopes may be observed in some samples in equilibrium or approaching equilibrium with the parent radioisotope.

Except for Np-239, trace concentrations of transuranic isotopes have been observed in only a few samples where extensive and complex analyses were carried out. The predominant alpha emitter present in reactor water is Cm-242 at an estimated concentration of $\leq 10^{-6}$ µCi/g which is below the maximum permissible concentration in potable water applicable to continuous use by the general public as stated in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), Appendix B, table II, column 2. The concentration of alpha-emitting plutonium radioisotopes is more than one order of magnitude lower than that of Cm-242. Pu-241, a beta emitter, may also be present in concentrations comparable to the Cm-242 level.

11.1.1.1.1.4 Nomenclature. The following nomenclature defines the terms used in equations for source term calculations:

R_g = leakage rate of a noble gas radioisotope (µCi/s).

R_h = leakage rate of a halogen gas radioisotope (µCi/s).

y = fission yield of a radioisotope (atoms/fission).

λ = decay constant of a radioisotope (s^{-1}).

T = fuel irradiation time (s).

t = decay time following leakage from fuel (s).

m = noble radiogas decay constant exponent (dimensionless).

n = radiohalogen decay constant exponent (dimensionless).

K_g = a constant establishing the level of noble radiogas leakage from fuel.

K_h = a constant establishing the level of radiohalogen leakage from fuel.

C_h = concentration of a halogen radioisotope in reactor water (μCi/g).

M = mass of water in the operating reactor (g).

β = reactor water cleanup (RWC) system removal constant (s^{-1}).

$$\beta = \frac{\text{RWC system flowrate (g/s)}}{M} \qquad (11)$$

γ = halogen steam carryover removal constant (s-1)

$$\gamma = \frac{\left[\dfrac{\text{conc. of halogen radioisotope in steam } (\mu\text{Ci/g})}{C_h}\right]\left[\text{steam flow (g/s)}\right]}{M} \qquad (12)$$

11.1.1.1.2 Activation Products

11.1.1.1.2.1 <u>Coolant Activation Products</u>. The coolant activation products are not adequately correlated by simple equations. Design basis concentrations in reactor water and steam have been estimated conservatively from experience data. The resultant concentrations are presented in table 11.1-4.

11.1.1.1.2.2 <u>Noncoolant Activation Products</u>. The activation products formed by activation of impurities in the coolant or corrosion of irradiated system materials are not adequately correlated by simple equations. The design basis source terms of noncoolant activation products have been estimated conservatively from experience data. The resultant concentrations are presented in table 11.1-5. Carryover of these isotopes from the reactor water to the steam is estimated to be < 0.1 % (< 0.001 fraction).

11.1.1.1.3 Tritium

In a BWR, tritium is produced by three principal methods:

- Activation of naturally occurring deuterium in the primary coolant.

- Nuclear fission of UO_2 fuel.

- Neutron reactions with boron used in reactivity control rods.

Tritium may be released from a BWR in liquid or gaseous effluents. The tritium formed in control rods which is released is believed to be negligible. A prime source of tritium available for release from a BWR is that produced from activation of deuterium in the primary coolant. Some fission product tritium may also transfer from fuel to primary coolant. This discussion is limited to the uncertainties associated with estimating the amounts of tritium generated in a BWR which are available for release.

All of the tritium produced by activation of deuterium in the primary coolant is available for release in liquid or gaseous effluents. The tritium formed in a BWR can be calculated using the following equation:

$$R_{act} = \frac{\Sigma \phi V \lambda}{3.7 \times 10^4 P} \qquad (13)$$

where:

R_{act} = tritium formation rate by deuterium activation (μCi/s/MWt).

Σ = macroscopic thermal neutron cross-section (cm^{-1}) for deuterium.

ϕ = thermal neutron flux (neutrons/cm^2/s).

V = coolant volume incore (cm^3).

λ = tritium radioactive decay constant ($1.78 \times 10^{-9} s^{-1}$).

P = reactor power level (MWt).

For recent BWR designs, R_{act} is calculated to be $1.3 \pm 0.4 \times 10^{-4}$ μCi/s/MWt. The uncertainty indicated is derived from the estimated errors in selecting values for the coolant volume in the core, coolant density in the core, abundance of deuterium in light water (some additional deuterium will be present because of the H(n, λ) D reaction), thermal neutron flux, and microscopic cross-section for deuterium.

The fraction of tritium produced by fission, which may transfer from fuel to the coolant and will then be available for release in liquid and gaseous effluents, is much more difficult to estimate. However, since Zircaloy-clad fuel rods are used in BWRs, essentially all fission product tritium remains in the fuel rods unless defects are present in the cladding material.(2)

The study made at Dresden 1(3) in 1968 by the United States Public Health Service suggests that essentially all of the tritium released from the plant could be accounted for by the deuterium activation source. For purposes of estimating the leakage of tritium from defective fuel, the assumption can be made that it leaks in a manner similar to the leakage of noble radiogases.

Thus, the empirical relationship described as the diffusion mixture can be used for predicting the source term of individual noble gas radioisotopes as a function of total noble gas source term. The equation which describes this relationship is:

$$R_{dif} = Ky\sqrt{\lambda} \tag{14}$$

where:

R_{dif}	=	leakage rate of the radioisotope (µCi/s).
y	=	fission yield fraction.
λ	=	radioactive decay constant (s^{-1}).
K	=	a constant related to total leakage rate.

If the total noble radiogas source term is 105 µCi/s after a 30-min decay, leakage from fuel is calculated to be ~ 0.24 µCi/s of tritium. To place this value in perspective, in the United States Public Health Service study, the observed rate of Kr-85, which has a half-life similar to that of tritium, was 0.06 to 0.4 times that calculated using the diffusion mixture relationship. This would suggest that the actual tritium leakage rate might range from 0.015 to 0.10 µCi/s. Since the annual average noble radiogas leakage from a BWR is expected to be < 0.1 µCi/s at t = 30 min, the annual average tritium release rate from the fission source can be conservatively estimated at 0.12 $\pm$ 0.12 µCi/s or 0-to-0.24 µCi/s. The calculated tritium release rate for operation at 2763 MWt is shown in table 11.2-4.

Tritium formed in the reactor is generally present as tritiated oxide and to a lesser degree as tritiated gas. Tritium concentration in the steam formed in the reactor is the same as that in the reactor water at any given time. This tritium concentration is also present in condensate and feedwater. Since radioactive effluents generally originate from the reactor and power cycle equipment, radioactive effluents also have this tritium concentration. Condensate storage receives treated water from the radwaste system and rejects water from the condensate system, thus all plant process water should have a common tritium concentration. Off-gases released from the plant contain tritium which is present as tritiated gas resulting from reactor water radiolysis, as well as tritiated water vapor. In addition, a lesser amount present in ventilation air due to process steam leaks or evaporation from sumps, tanks, and spills on floors also contains tritium. The remainder of the tritium leaves the plant in liquid effluents.

Recombination of radiolysis gases in the off-gas system forms water which is condensed and returned to the main condenser. This tends to reduce the amount of tritium leaving in gaseous effluents. Reducing the gaseous tritium release results in a slightly higher tritium concentration in the plant process water. Reducing the amount of liquid effluent discharged also results in a higher process coolant equilibrium tritium concentration.

Essentially all tritium entering the primary coolant is eventually released to the environs either as water vapor and gas to the atmosphere or as liquid effluent to the plant discharge. Reduction due to radioactive decay is negligible due to the 12-year half-life of tritium. The

United States Public Health Service study at Dresden 1 estimated that ~ 90% of the tritium release was observed in liquid effluent with the remaining 10% leaving as gaseous effluent.[3] Efforts to reduce the volume of liquid effluent discharges may change this distribution so that a greater amount of tritium leaves as gaseous effluent. The fraction of tritium leaving as liquid effluent may vary between 60 and 90% with the remainder leaving in gaseous effluent.

11.1.1.1.4 Fuel Fission Product Inventory and Fuel Experience

11.1.1.1.4.1 Fuel Fission Product Inventory. Fuel rod and fuel plenum radioisotopic inventory, along with escape rate coefficients and release fractions, is not used in establishing BWR design basis source term coolant activities. Fuel fission product inventory information is used in establishing fission product source terms for accident analyses and is discussed in chapter 15.

11.1.1.1.4.2 Fuel Experience. A discussion of fuel experience gained for BWR fuel, including failure experience, burnup experience, and thermal conditions under which the experience was gained, is available in two GE topical reports.[4,5]

11.1.1.1.5 Process Leakage Sources

Process leakage results in potential release paths for noble gases and other volatile fission products via ventilation systems. Liquid from process leaks are all collected and routed to the liquid-solid radwaste system. Radionuclide releases via ventilation paths are at extremely low levels and have been insignificant compared to process off-gas from operating BWR plants. Because the implementation of improved process off-gas treatment systems make the ventilation release relatively significant, GE has implemented an intensive measurement program to identify and qualify low-level release paths.

Concurrently, analytical and mathematical model studies are being performed to provide a description of the transport, residence, and release of various radionuclides in and from an operating BWR. The BWR radiochemical model has been supplied in a GE topical report.[6]

Process leakage measurements and control methods are further discussed in subsections 9.3.3, 5.2.7, 7.6.4, and 7.6.9.

11.1.1.1.6 Process System Inventories

The radioisotope inventories for the liquid, gaseous, and solid radwaste system components are provided in sections 11.2, 11.3, and 11.5, respectively.

11.1.1.1.6.1 Main Steam and Condensate Systems. The inventories of the major groups of radioisotopes exiting with the main steam at the reactor nozzle are given in table 11.1-6.

Similarly, the inventories of major groups of radioisotopes in the main condenser are given in table 11.1-7.

With regard to table 11.1-6, the noble gas release rate is taken from table 11.1-1. For other groups of activities, group totals are determined from tables 11.1-2 through 11.1-5.

Decay of the isotopes having half-lives < 1 min was estimated and deducted from the group totals. In general, the activity entering the main condenser was assumed to be composed of 50% of the activity shown in table 11.1-6. This activity was decayed for 6 s (3 s from reactor pressure vessel (RPV) to turbine and 3 s in the turbine) and 20% of the same activity was decayed for 28 s (3 s from RPV to turbine and 25 s in the turbine). The condenser inventories given in table 11.7-7 were calculated by accumulating the input as described above for the 0.5-s steam transit time through the main condenser assuming no further decay. No credit is taken for removal of condensables and particulates due to steam condensation in the main condenser.

After entering the main condenser, the radioactivity can be transported to either the off-gas system via the steam jet air ejector (SJAE) or to the condensate. All noble gases and volatile coolant activation products are assumed to be transported with other noncondensibles to the off-gas system. The gaseous activity transported to the SJAE would essentially be at the same rate as that given in table 11.1-6 with the appropriate decay times assumed above. Halogen carryover to the off-gas system is negligible compared to the fraction remaining with the condensate; however, the carryover fraction has been assumed as 1/140 (~ 0.7%) of the total being transported to the main condenser. All of the noncoolant activation products and the solid fission products are assumed to be transported with the condensate.

Prior to condensate return as feedwater to the reactor, the condensate polishing system removes fission products and the noncoolant activation products with an overall decontamination factor (DF) conservatively assumed to be 10.

11.1.1.1.6.2 Reactor Water Cleanup System. The RWC system draws reactor water at a flowrate of 100,000 lb/h through a filter-demineralizer and then returns the water to the reactor via the feedwater line. The radioisotope inventories would be the reactor water inventories provided in tables 11.1-2 through 11.1-5 with the following reductions due to decay, filtration, or demineralization:

- From reactor recirculation loop to filter-demineralizer - transit time of 192 s for decay.
- Filter-demineralizer DF for all isotopes is conservatively estimated as 100.
- From filter-demineralizer to feedwater header – transit time of 184 s for (including filter-demineralizer residence time of 46 s) for decay.

The above transit times account for residence times in the heat exchanger.

Radioisotope inventories for the cleanup phase separators are given in section 11.2, table 11.2-2.

11.1.1.1.6.3 Residual Heat Removal System (RHR) (Shutdown Cooling Mode). Transport of radioactive materials by the RHR system applies only when this system is operated in the reactor shutdown cooling mode. In this mode, the system is placed in operation to recirculate reactor water and remove decay heat during a period of hours after reactor shutdown. During RHR system operation, the primary source of radioactivity is from long-lived radioactive fission products and noncoolant activation products.

11.1.1.1.6.4 Spent-Fuel Pool and Spent-Fuel Pool Cooling and Cleanup System (SFPCCS). The amount of radioactivity in the spent-fuel pool is dependent upon the amount of stored spent fuel, the time since the fuel was removed from the reactor, the amount of fission product leakage from the fuel, and the radioactivity removal rate of the SFPCCS. The radiation source for spent-fuel is given in table 11.1-8 in terms of MeV/s/MWt. The design calculation basis for the tabulated values is a mean fuel element of 24 h after shutdown. The number of variables involved preclude determining inventories for the components of the SFPCCS components. See paragraph 9.1.3.4 for the results of an analysis of fuel pool boiling.

11.1.1.1.6.5 Condensate Storage Tank (CST). The CST contains high-purity demineralized water with a maximum expected gross activity concentration of 5×10^{-3} µCi/cm^3. The principal sources of water for storage in the CST are:

- Radwaste system recycled water - maximum activity above 5×10^{-3} µCi/cm^3.
- Demineralized makeup water - no activity.
- Condenser hotwell reject - same as condensate polisher effluent.

11.1.1.1.6.6 Other Process Systems. The high-pressure coolant injection and reactor core isolation cooling systems contain main steam up to their respective turbines during normal operation even through these systems are not normally in operation. The core spray and standby liquid control systems are also not normally in operation, thus radioactivity inventories are expected to be negligible. Various cooling water systems do not process liquids containing radioactivity unless minor leakage occurs in heat exchangers served by these systems.

Portions of the control rod drive hydraulic system will also be in contact with reactor water. Activity in this system will be mainly due to long-lived noncoolant activation products. The amount of water processed through these lines is small, and experience has shown that radioactivity inventories are not significant.

11.1.1.1.7 Containment Sources

Expected gamma ray and neutron fluxes outside the RPV are provided in table 11.1-9.

11.1.1.2 Realistic Model

The realistic source term model is provided by the gaseous and liquid effluents (GALE) computer code for boiling water reactors. The calculations performed by the BWR-GALE CODE are based on (1) standardized coolant activities derived from the ANSI N237/ANS 18.1-1976 recommendations, (2) release and transport mechanisms that result in the appearance of radioactive material in liquid and gaseous waste streams, and (3) plant-specific design features used to reduce the quantities of radioactive materials ultimately released to the environs.

The parameters used to describe the realistic model are given in table 11.1-10 together with the range of values utilized by ANSI N237/ANS 18.1-1976. Regulatory Guide 1.112, Appendix A, recommends using the ANSI N237/ANS 18.1 BWR-GALE CODE methodology and lists plant-specific input parameters needed to execute the GALE computer code for boiling water reactors.(9) The specific activity source term normal operation values associated with the BWR realistic model are listed in table 11.1-11.

The liquid and gaseous source term derivations using the BWR-GALE CODE methodologies in conjunction with specific plant parameters are discussed in further detail in sections 11.2 and 11.3, respectively.

REFERENCES

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4. Williamson, H. E., and Ditamore, D. C., "Current State of Knowledge of High Performance BWR Zircaloy Clad UO_2 Fuel," NEDO-10173, General Electric, May 1970.

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6. Skarpelos, J. M., and Gilbert, R. S., "Technical Derivation of BWR 1971 Design Basis Radioactive Material Source Terms," NEDO-10871, General Electric, March 1973.

7. American National Standard Source Term Specification, ANSI N237-1976/ANS-18.1, approved May 11, 1976.

8. U. S. Nuclear Regulatory Commission, “Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Boiling Water Reactors (BWR-GALE CODE),” NUREG-0016, Office of Standard Development, April 1976.

9. U. S. NRC Regulatory Guide 1.112, Revision 0-R, “Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Light-Water-Cooled Power Reactors,” April 1976.

TABLE 11.1-1

NOBLE RADIOGAS SOURCE TERMS

Isotope	Half-Life	Source Term[a] at t = 0 (µCi/s)	Source Term[a] at t = 30 min (µCi/s)
Kr-83m	1.86 h	3.4(3)	2.9(3)
Kr-85m	4.4 h	6.1(3)	5.6(3)
Kr-85	10.74 h	10 to 20[b]	10 to 20[b]
Kr-87	76 min	2.0(4)	1.5(4)
Kr-88	2.79 h	2.0(4)	1.8(4)
Kr-89	3.18 min	1.3(5)	1.8(2)
Kr-90	32.3 s	2.8(5)	- - -
Kr-91	8.6 s	3.3(5)	- - -
Kr-92	1.84 s	3.3(5)	- - -
Kr-93	1.29 s	9.9(4)	- - -
Kr-94	1.0 s	2.3(4)	- - -
Kr-95	0.5 s	2.1(3)	- - -
Kr-97	1.0 s	1.4(1)	- - -
Xe-131m	11.96 days	1.5(1)	1.5(1)
Xe-133m	2.26 days	2.9(2)	2.8(2)
Xe-133	5.27 days	8.2(3)	8.2(3)
Xe-135m	15.7 min	2.6(4)	6.9(3)
Xe-135	9.16 h	2.2(4)	2.2(4)
Xe-137	3.82 min	1.5(5)	6.7(2)
Xe-138	14.2 min	8.9(4)	2.1(4)
Xe-139	40 s	2.8(5)	- - -
Xe-140	13.6 s	3.0(5)	- - -
Xe-141	1.72 s	2.4(5)	- - -
Xe-142	1.22 s	7.3(4)	- - -
Xe-143	0.96 s	1.2(4)	- - -
Xe-144	9.0 s	5.6(2)	- - -
TOTALS		~ 2.5(6)	~ 1.0(5)

a. 3.4(3) = 3.4 x 10^3
b. Estimated from experimental observations.

TABLE 11.1-2

HALOGEN ISOTOPES IN REACTOR WATER

Isotope	Half-Life	Concentration[a][b] (μCi/g)
Br-83	2.40 h	2.0(-2)
Br-84	31.8 min	3.5(-2)
Br-85	3.0 min	2.1(-2)
I-131	8.065 days	1.8(-2)
I-132	2.284 h	1.6(-1)
I-133	20.8 h	1.2(-1)
I-134	52.3 min	3.1(-1)
I-135	6.7 h	1.7(-1)

a. 2.0(-2) = 2.0×10^{-2}

b. Concentrations increase ~ 14.5% above the values shown for plant operation at a rated thermal power (RTP) of 2804 MWt.

TABLE 11.1-3 (SHEET 1 OF 2)

OTHER FISSION PRODUCT ISOTOPES IN REACTOR WATER

Isotope	Half-Life	Concentration[a][b] (µCi/g)
Sr-89	50.8 days	4.1(-3)
Sr-90	28.9 years	3.1(-4)
Sr-91	9.67 h	9.1(-2)
Sr-92	2.69 h	1.4(-1)
Zr-95	65.5 days	5.4(-5)
Zr-97	16.8 h	4.2(-5)
Nb-95	35.1 days	5.5(-5)
Mo-99	66.6 h	3.0(-2)
Tc-99m	6.007 h	3.7(-1)
Tc-101	14.2 min	1.7(-1)
Ru-103	39.8 days	2.6(-5)
Ru-106	368 days	3.5(-6)
Te-129m	34.1 days	5.3(-5)
Te-132	78 h	6.5(-2)
Cs-134	2.06 years	2.1(-4)
Cs-136	13 days	1.4(-4)
Cs-137	30.2 years	3.2(-4)
Cs-138	32.2 min	2.4(-1)
Ba-139	83.2 min	2.1(-1)
Ba-140	12.8 days	1.2(-2)

TABLE 11.1-3 (SHEET 2 OF 2)

Isotope	Half-Life	Concentration[(a)(b)] (µCi/g)
Ba-141	18.3 min	2.2(-1)
Ba-142	10.7 min	2.1(-1)
Ce-141	32.53 days	5.3(-5)
Ce-143	33.0 h	4.6(-5)
Ce-144	284.4 days	4.7(-5)
Pr-143	13.58 days	5.1(-5)
Nd-147	11.06 days	1.9(-5)
Np-239	2.35 days	3.2(-1)

a. 4.1(-3) = 4.1 x 10^{-3}
b. Concentrations increase ~ 14.5% above the values shown for plant operation at an RTP level of 2804 MWt.

TABLE 11.1-4

COOLANT ACTIVATION PRODUCTS IN REACTOR WATER AND STEAM

Isotope	Half-Life	Steam Concentration (μCi/g)	Reactor Water Concentration (μCi/g)
N-13	9.99 min	6.9(-3)[a]	5.2(-2)
N-16[b]	7.13 s	50.0	47.0
N-17	4.14 s	1.6(-2)	1.2(-2)
O-19	26.8 s	2.3(-1)	0.73
F-18	109.8 min	4.0(-3)	4.0(-3)

a. 6.9(-3) = 6.9 x 10^{-3}

b. Steam concentration increases by a factor of 5.5 above the value shown for plant operation at an RTP of 2804 MWt and hydrogen injection at a maximum rate of 65 sf^3/min. Water concentration increases ~ 14.5% above the value shown for plant operation at an RTP of 2804 MWt.

TABLE 11.1-5

NONCOOLANT ACTIVATION PRODUCTS IN REACTOR WATER

Isotope	Half-Life	Concentration[(a)(b)] (µCi/g)
Na-24	15 h	2(-3)
P-32	14.31 days	2(-5)
Cr-51	27.8 days	5(-4)
Mn-54	313 days	4(-5)
Mn-56	2.582 h	5(-2)
Co-58	71.4 days	5(-3)
Co-60	5.258 year	5(-4)
Fe-59	45 days	8(-5)
Ni-65	2.55 h	3(-4)
Zn-65	243.7 days	2(-6)
Zn-69m	13.7 h	3(-5)
Ag-110m	253 days	6(-5)
W-187	23.9 h	3(-3)

a. 2(-3) = 2×10^{-3}
b. Concentrations increase ~ 14.5% above the values shown for plant operation at an RTP of 2804 MWt.

TABLE 11.1-6

MAJOR RADIOISOTOPES IN STEAM AT REACTOR NOZZLE

Coolant Activation Products

N-13	9.5×10^3 μCi/s
N-16	6.9×10^7 μCi/s[a]
N-17	2.2×10^4 μCi/s
O-19	3.2×10^5 μCi/s
F-18	5.5×10^3 μCi/s

Halogens ~ 2.4×10^4 μCi/s
(2% carryover)

Noncoolant activation products ~ 8.5×10^1 μCi/s
(0.1% carryover)

Solid fission products ~ 2.9×10^3 μCi/s
(0.1% carryover)

Noble gases ~ 2.5×10^6 μCi/s
(Design basis off-gas rate - 1×10^5 μCi/s per reactor of a diffusion mixture of noble gases referenced to 30-min decay)

a. May increase up to 4.2×10^8 μCi/s for plant operation at an RTP of 2804 MWt and hydrogen injection at a maximum rate of 65 sf^3/min.

TABLE 11.1-7

MAJOR RADIOISOTOPES IN MAIN CONDENSER

Coolant Activation Products	
N-13	3.3×10^3 μCi
N-16	1.0×10^7 μCi[(a)]
N-17	2.1×10^3 μCi
O-19	8.5×10^4 μCi
F-18	1.9×10^3 μCi

Halogens ~ 8.4×10^3 μCi
(2% carryover)

Noncoolant activation products ~ 3.0×10^1 μCi
(0.1% carryover)

Solid fission products ~1.0×10^3 μCi
(0.1% carryover)

Noble gases ~ 4.6×10^5 μCi
(Design basis off-gas rate - 1×10^5 μCi/s per reactor of a diffusion mixture of noble gases referenced to 30-min decay)

a. May increase up to 6.1×10^7 μCi for plant operation at an RTP of 2804 MWt and hydrogen injection at a maximum rate of 65 sf^3/min.

TABLE 11.1-8

POST-OPERATION GAMMA SOURCES IN CORE[a][b]
(MeV/s/W)

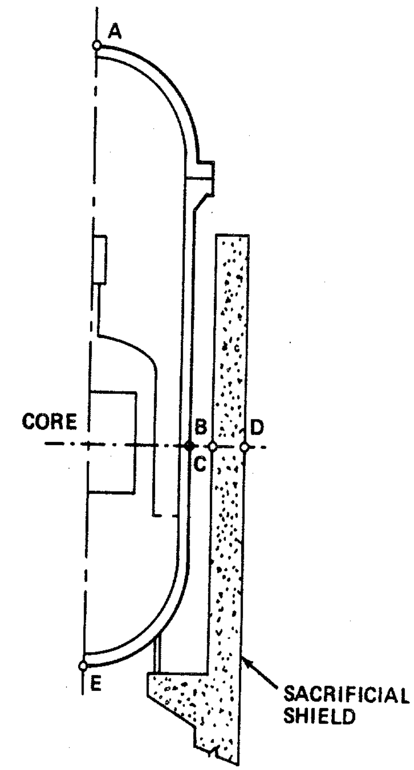
Energy Bounds	Time After Shutdown 0 s	1 Day	1 Week	1 Month
6.0 MeV – 4.0 MeV	8.2 E + 10	< 1.0 E + 6	< 1.0 E + 6	< 1.0 E + 6
4.0 MeV – 3.0 MeV	1.8 E + 10	7.0 E + 6	4.6 E + 6	< 1.0 E + 6
3.0 MeV – 2.6 MeV	1.1 E + 10	5.7 E + 6	3.7 E + 6	< 1.0 E + 6
2.6 MeV – 2.2 MeV	1.7 E + 10	2.9 E + 8	1.7 E + 8	< 1.0 E + 6
2.2 MeV – 1.8 MeV	2.1 E + 10	4.5 E + 8	4.0 E + 7	5.2 E + 6
1.8 MeV – 1.35 MeV	3.3 E + 10	3.1 E + 9	2.1 E + 9	6.4 E + 8
1.35 MeV – 0.9 MeV	3.7 E + 10	2.3 E + 9	1.6 E + 9	1.1 E + 9
0.9 MeV – 0.4 MeV	5.1 E + 10	7.5 E + 9	3.8 E + 9	2.1 E + 9
0.4 MeV – 0.1 MeV	1.2 E + 10	1.8 E + 9	8.7 E + 8	3.6 E + 8

a. Operating history of 3.2 years.
b. May increase ~ 14.5% above the values shown for plant operation at an RTP of 2804 MWt.

TABLE 11.1-9

FAST NEUTRON AND MULTIGROUP GAMMA FLUXES OUTSIDE THE RPV

	Gamma Flux (MeV/cm^2-s)[a]						Fast Neutron[a] Flux (≥ 1 MeV) (n/cm^2-s)
Key	1 MeV	1.5 MeV	2.3 MeV	3 MeV	5 MeV	7 MeV	
A	1.1 x 10^3	8.5 x 10^3	1.2 x 10^5	1.3 x 10^6	1.5 x 10^6	5.9 x 10^6	6.6 x 10^{-1}
B	7.7 x 10^7	3.7 x 10^8	2.2 x 10^9	1.3 x 10^{10}	3.7 x 10^9	7.2 x 10^9	2.7 x 10^7
C	5.3 x 10^7	2.6 x 10^8	1.6 x 10^9	1.0 x 10^{10}	2.8 x 10^9	5.5 x 10^9	2.1 x 10^7
D[b]	4.7 x 10^2	1.9 x 10^4	5.9 x 10^5	1.1 x 10^7	1.1 x 10^7	3.7 x 10^7	2.1 x 10^4
E	5.3 x 10^{-3}	1.5	4.2 x 10^2	1.3 x 10^4	8.8 x 10^4	6.5 x 10^5	2.4 x 10^{-6}



a. The flux levels represent direct core fluxes. Contributions caused by scattering from walls and surfaces outside the reactor vessel are not included.
b. Assumes a sacrificial shield of 0.25-in.-thick steel plate, 25.75-in. concrete (density 2.3 g/cm^2), and 1.75-in. steel plate.

TABLE 11.1-10

PARAMETERS USED TO DESCRIBE THE BOILING WATER REACTOR SYSTEM – REALISTIC BASIS

Parameter	Symbol	Units	Nominal Value	ANSI N237 Range Maximum	ANSI N237 Range Minimum
Thermal power	P	MWt	3400	3800	3000
Weight of water in reactor vessel	WP	lb	3.8×10^5	4.2×10^5	3.4×10^5
Flow through the purification system cation demineralizer	FA	lb/h	1.3×10^5	1.5×10^5	1.1×10^5
Steam flowrate	FS	lb/h	1.5×10^7	1.7×10^7	1.3×10^7
Ratio of condensate demineralizer flowrate to the total stream flowrate	NC	-	1.0	1.0	0.8

TABLE 11.1-11 (SHEET 1 OF 4)

SPECIFIC ACTIVITIES IN PRINCIPAL FLUID STREAMS – REALISTIC BASIS

Normal BWR Plant Operation Source Terms (uCi/gm)
(based on ANSI N237/ANS 18.1)

Class 1 – Noble Gases

Nuclide	Reactor Water Activity	Reactor Stream Activity
Kr-83m		1.1×10^{-3}
Kr-85m		1.9×10^{-3}
Kr-85		6.0×10^{-6}
Kr-87		6.6×10^{-3}
Kr-88		6.6×10^{-3}
Kr-89		4.1×10^{-2}
Kr-90		9.0×10^{-2}
Kr-91		1.1×10^{-1}
Kr-92		1.1×10^{-1}
Kr-93		2.9×10^{-2}
Kr-94		7.2×10^{-3}
Kr-95		6.6×10^{-3}
Kr-97		4.4×10^{-6}
Xe-131m		4.7×10^{-6}
Xe-133m		9.0×10^{-5}
Xe-133		2.6×10^{-3}
Xe-135m		8.4×10^{-3}
Xe-135		7.2×10^{-3}
Xe-137		4.7×10^{-2}
Xe-138		2.8×10^{-2}
Xe-139		9.0×10^{-2}
Xe-140		9.6×10^{-2}
Xe-141		7.8×10^{-2}
Xe-142		2.3×10^{-2}
Xe-143		3.8×10^{-3}
Xe-144		1.8×10^{-4}

Class 2 – Halogens

Nuclide	Reactor Water Activity	Reactor Stream Activity
Br-83	3.0×10^{-3}	6.0×10^{-5}
Br-84	5.0×10^{-3}	1.0×10^{-4}

TABLE 11.1-11 (SHEET 2 OF 4)

Class 2 – Halogens (con't)

Nuclide	Reactor Water Activity	Reactor Stream Activity
Br-85	5.0×10^{-3}	6.0×10^{-5}
I-131	3.0×10^{-2}	1.0×10^{-4}
I-132	2.0×10^{-2}	6.0×10^{-4}
I-133	5.0×10^{-2}	4.0×10^{-4}
I-134	2.0×10^{-2}	1.0×10^{-3}
I-135		4.0×10^{-4}

Class 3 – Cesium and Rubidium

Nuclide	Reactor Water Activity	Reactor Stream Activity
Rb-89	5.0×10^{-3}	5.0×10^{-6}
Cs-134	3.0×10^{-5}	3.0×10^{-8}
Cs-136	2.0×10^{-5}	2.0×10^{-8}
Cs-137	7.0×10^{-5}	7.0×10^{-8}
Ba-138	1.0×10^{-2}	1.0×10^{-5}

Class 4 – Water Activation Products

Nuclide	Reactor Water Activity	Reactor Stream Activity
N-13	5.0×10^{-2}	7.0×10^{-3}
N16	6.0×10^{1}	5.0×10^{1}
N-17	9.0×10^{-3}	2.0×10^{-2}
O-19	7.0×10^{-1}	2.0×10^{-1}
F-18	4.0×10^{-3}	4.0×10^{-3}

Class 5 – Tritium

Nuclide	Reactor Water Activity	Reactor Stream Activity
H-3	1.0×10^{-2}	1.0×10^{-2}

TABLE 11.1-11 (SHEET 3 OF 4)

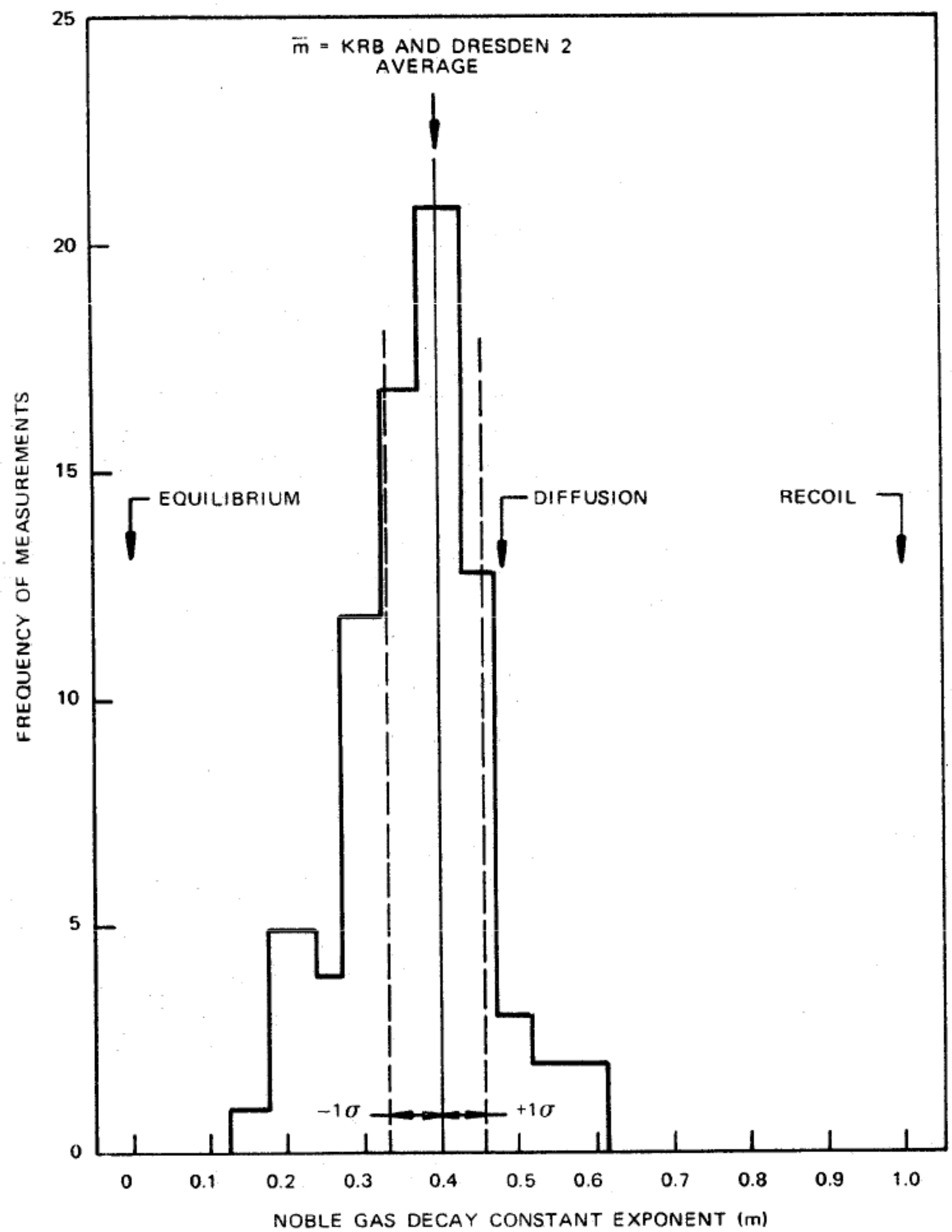
Class 6 – Miscellaneous Isotopes

Nuclide	Reactor Water Activity	Reactor Stream Activity
Na-24	9.0×10^{-3}	9.0×10^{-6}
P-32	2.0×10^{-4}	2.0×10^{-7}
Cr-51	5.0×10^{-3}	5.0×10^{-6}
Mn-54	6.0×10^{-5}	6.0×10^{-8}
Mn-56	5.0×10^{-2}	5.0×10^{-5}
Fe-55	1.0×10^{-3}	1.0×10^{-6}
Fe-59	3.0×10^{-5}	3.0×10^{-8}
Co-58	2.0×10^{-4}	2.0×10^{-7}
Co-60	4.0×10^{-4}	4.0×10^{-7}
Ni-63	1.0×10^{-6}	1.0×10^{-9}
Ni-65	3.0×10^{-4}	3.0×10^{-7}
Cu-64	3.0×10^{-2}	3.0×10^{-5}
Zn-65	2.0×10^{-4}	2.0×10^{-7}
Zn-69m	2.0×10^{-3}	2.0×10^{-6}
Sr-89	1.0×10^{-4}	1.0×10^{-7}
Sr-90	6.0×10^{-6}	6.0×10^{-9}
Sr-91	4.0×10^{-3}	4.0×10^{-6}
Sr-92	1.0×10^{-2}	1.0×10^{-5}
Y-91	4.0×10^{-5}	4.0×10^{-8}
Y-92	6.0×10^{-3}	6.0×10^{-6}
Y-93	4.0×10^{-3}	4.0×10^{-6}
Zr-95	7.0×10^{-6}	7.0×10^{-9}
Zr-97	5.0×10^{-6}	5.0×10^{-9}
Nb-95	7.0×10^{-6}	7.0×10^{-9}
Nb-98	4.0×10^{-3}	4.0×10^{-6}
Mo-99	2.0×10^{-3}	2.0×10^{-6}
Tc-99m	2.0×10^{-2}	2.0×10^{-5}
Tc-101	9.0×10^{-2}	9.0×10^{-5}
Tc-104	8.0×10^{-2}	8.0×10^{-5}
Ru-103	2.0×10^{-5}	2.0×10^{-8}
Ru-105	2.0×10^{-3}	2.0×10^{-6}
Ru-106	3.0×10^{-6}	3.0×10^{-9}
Ag-110m	1.0×10^{-6}	1.0×10^{-9}
Te-129m	4.0×10^{-5}	4.0×10^{-8}
Te-131m	1.0×10^{-4}	1.0×10^{-7}
Te-132	1.0×10^{-5}	1.0×10^{-8}
Ba-139	1.0×10^{-2}	1.0×10^{-5}
Ba-140	4.0×10^{-4}	4.0×10^{-7}
Ba-141	1.0×10^{-2}	1.0×10^{-5}

TABLE 11.1-11 (SHEET 4 OF 4)

Class 6 – Miscellaneous Isotopes(cont'd)

Nuclide	Reactor Water Activity	Reactor Stream Activity
Ba-142	6.0×10^{-3}	6.0×10^{-6}
La-142	5.0×10^{-3}	5.0×10^{-6}
Ce-141	3.0×10^{-5}	3.0×10^{-8}
Ce-143	3.0×10^{-5}	3.0×10^{-8}
Ce-144	3.0×10^{-6}	3.0×10^{-9}
Pr-143	4.0×10^{-5}	4.0×10^{-8}
Nd-147	3.0×10^{-6}	3.0×10^{-9}
W-187	3.0×10^{-4}	3.0×10^{-7}
Np-239	7.0×10^{-3}	7.0×10^{-6}



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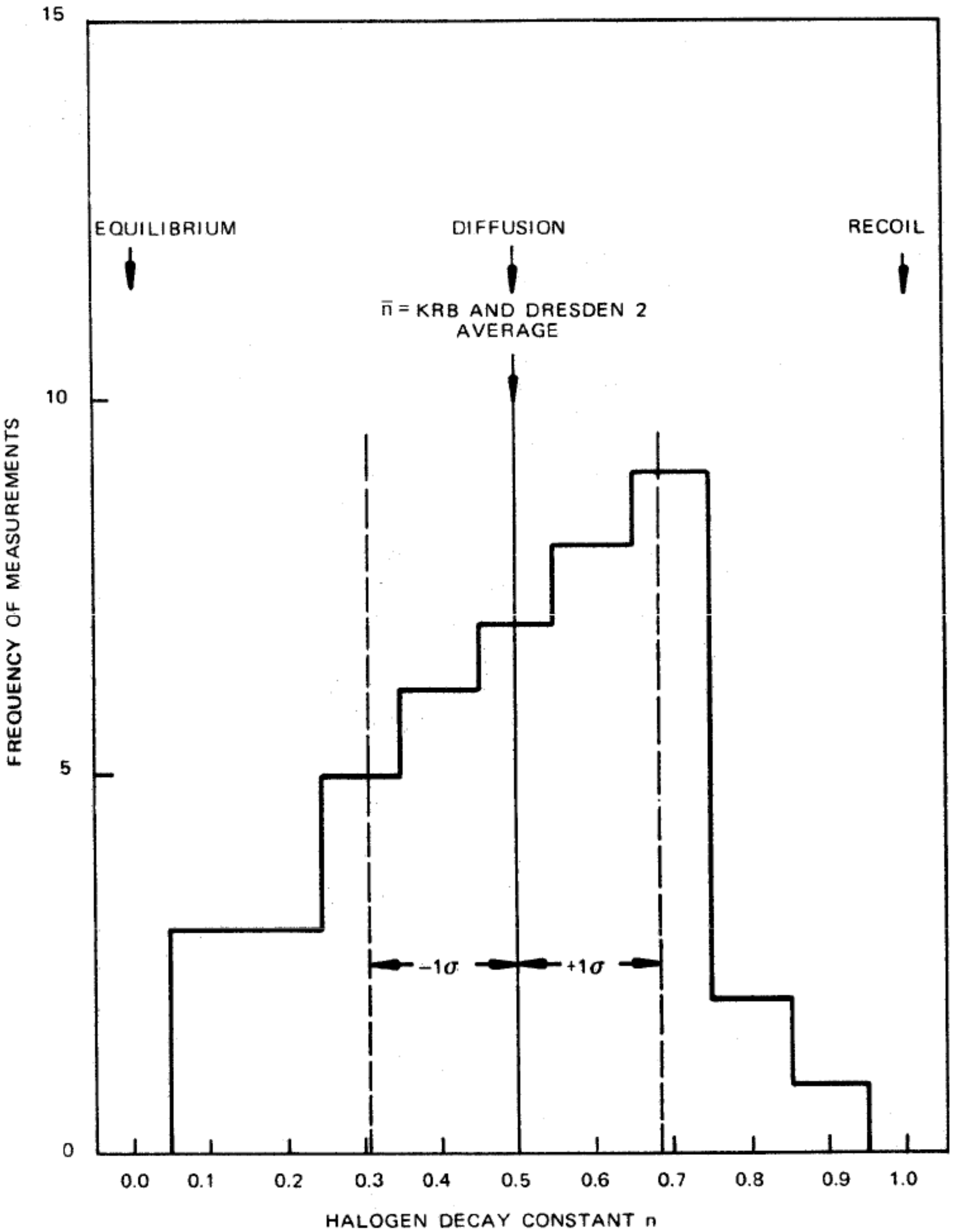
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NOBLE RADIOGAS CONSTANT EXPONENT FREQUENCY HISTOGRAM

FIGURE 11.1-1



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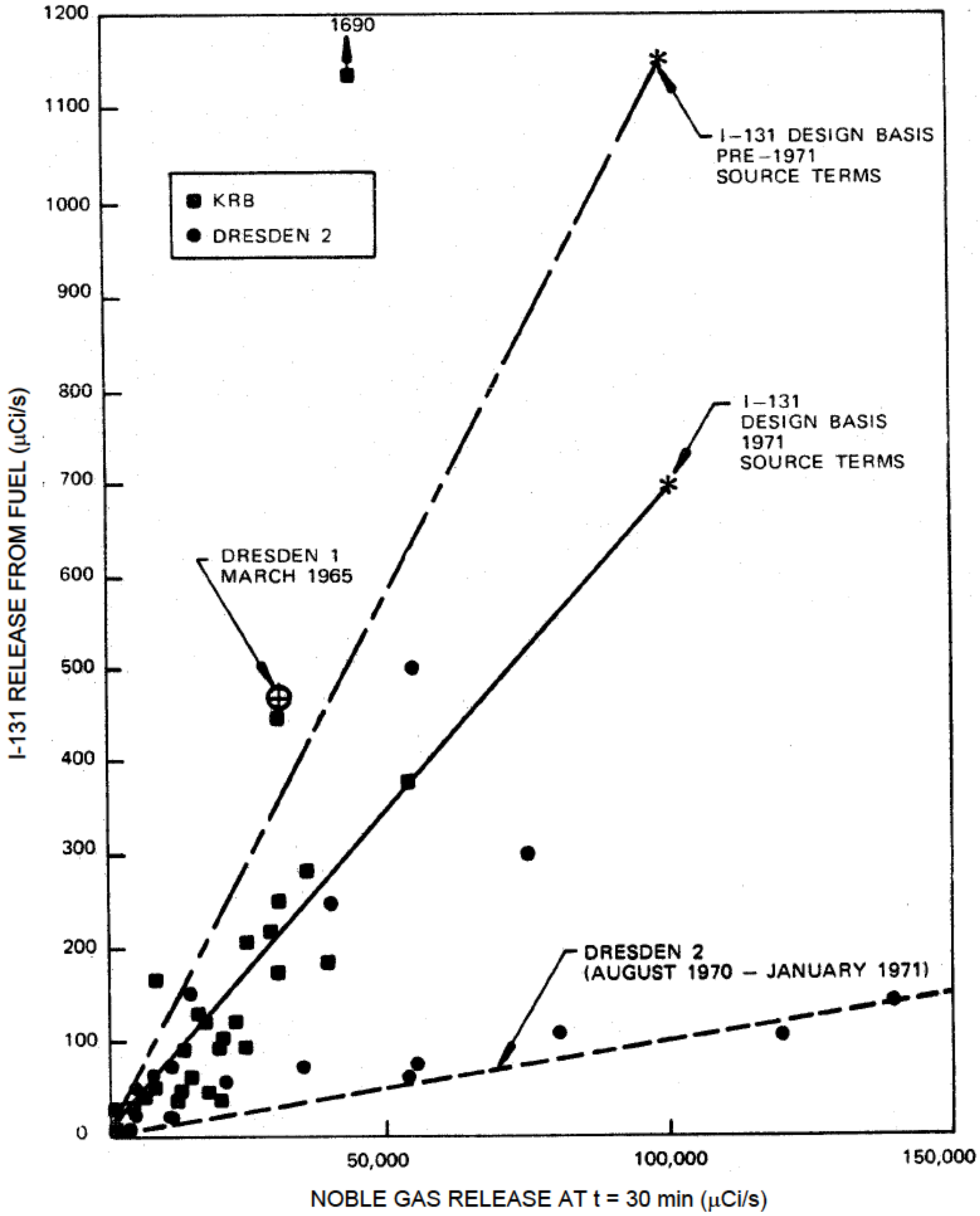
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RADIOHALOGEN DECAY CONSTANT EXPONENT FREQUENCY HISTOGRAM

FIGURE 11.1-2



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NOBLE RADIOGAS VERSUS I-131 LEAKAGE

FIGURE 11.1-3

11.2 LIQUID RADWASTE SYSTEM

The liquid radwaste system is designed to process and recycle the liquid waste collected to the extent practicable. During normal plant operation, the annual radiation doses to individuals from each reactor on the site, resulting from these routine liquid waste discharges, are below the guidelines set forth in 10 CFR 50, Appendix I.[1] The design further ensures that releases from the plant are within the applicable 10 CFR 20 limits. Liquid effluents are continuously monitored and discharges are terminated if the effluents exceed preset radioactivity levels. Subsection 3.8.7 provides seismic evaluations of the radwaste facility buildings.

11.2.1 DESIGN BASES AND OBJECTIVES

A. Liquids that potentially contain radioactive material are collected and processed in the radwaste system.

B. The liquid radwaste treatment system is designed to limit effluent releases during normal plant operation and anticipated operational occurrences (AOOs) to concentrations below those specified in applicable sections of 10 CFR 20 and which result in doses to individuals below the as low as reasonably achievable (ALARA) guidelines set forth in 10 CFR 50, Appendix I.

C. The system has the capability to process the anticipated quantities of liquid wastes without impairing operation or availability of the plant during both normal and AOO conditions.

D. The various types of liquid wastes are treated to recycle the maximum amount of water to the plant for reuse within the limitations of water inventory balance and reactor water quality specifications.

E. Portions of the system containing unprocessed wastes are designed and installed in accordance with American Society of Mechanical Engineers (ASME) Code, Section III, Class 3 requirements. Piping and valves to the exterior fill station are designed and installed in accordance with American National Standards Institute (ANSI) Standard B31.1. Replacement components may be procured in accordance with the requirements of Table 1 of Regulatory Guide 1.26, September 1974,[2] and Table 1 of Regulatory Guide 1.143, October 1979,[3] as summarized in table 11.2-1.

F. The accidental release of radioactivity caused by a system gross equipment failure is limited so that the resulting radiation exposure of the public is within the annual exposure limit of 10 CFR 20.1001-20.2402 .

11.2.2 SYSTEM DESCRIPTION

The liquid radwaste system collects, monitors, processes, stores, and disposes of radioactive liquid wastes. The liquid radwaste system piping, equipment, instrumentation, and flow paths are given on drawing nos. H-26026 through H-26032 and H-26035. Included in the system are:

- Piping and equipment drains carrying potentially radioactive wastes.

- Floor drain systems in controlled access areas which contain potentially radioactive wastes.

- Tanks and sumps used to collect potentially radioactive wastes.

- Tanks, sumps, piping, pumps, process equipment, instrumentation, and auxiliaries necessary to collect, process, store, and dispose of potentially radioactive wastes.

Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance with acceptable personnel exposures. For example, sumps, pumps, valves, and instruments which contain radioactivity are located in controlled access areas. Tanks and processing equipment that contain significant quantities of radioactive material are shielded. Operation of the radwaste system is essentially manual start, automatic stop.

Protection against accidental discharge is provided by instrumentation for detection and alarm of abnormal conditions and by procedural controls. The radwaste facility arrangement and the methods of waste processing provide a substantial degree of immobility of the wastes within the plant. These provisions ensure that, in the event of a failure of the liquid waste system equipment or errors in operation of the system, the potential for inadvertent release of liquids is small. Immobility of wastes is further accomplished by collecting solids on filters and demineralizer resins. The arrangement of radwaste system equipment is shown on drawing nos. H-26097 through H-26100 and H-26106.

The liquid radwaste system is divided into several subsystems so that the liquid wastes from various sources can be kept segregated and processed separately. Cross connections between the subsystems provide additional flexibility for processing of the wastes by alternate methods. The liquid radwastes are classified, collected, and treated as high purity, low purity, chemical, or sludge. The terms high purity and low purity refer to the conductivity and not radioactivity.

11.2.2.1 Liquid Radwaste Subsystems

11.2.2.1.1 High-Purity Wastes

High-purity (low-conductivity) liquid wastes are collected in the waste collector tank from the following sources:

- Drywell equipment drain sump.
- Reactor building equipment drain sumps.
- Radwaste building equipment drain sump.
- Turbine building equipment drain sump.
- Reactor water cleanup (RWC) system.
- Residual heat removal (RHR) system.
- Decantate from cleanup phase separators.
- Spent-fuel pool cooling and demineralizer system.
- Decantate from condensate phase separators.
- Decantate from waste sludge phase separator.
- Off-gas equipment process sump.
- Waste gas treatment building equipment drain sump.

The high-purity wastes are processed by filtration and ion exchange through the waste filter and waste demineralizer. After processing, the liquid is received in the waste sample tank where it is sampled. Then, if it is satisfactory for reuse, it is transferred to the condensate storage tank (CST) as makeup water.

If the analysis of the sample reveals water not meeting specification for reuse, it is returned to the system for additional processing by the waste filter-demineralizer train. Occasionally, water quality below Technical Specifications limits for disposal after dilution may be discharged from the plant because of excess water inventories or unexpected occurrences.

11.2.2.1.2 Low-Purity Wastes

Low-purity (moderate-conductivity) liquid wastes are collected in the floor drain collector tank from the following sources:

- Off-gas pipe trench floor drain sump.

- RHR system drain.
- Drain from reactor building ventilation room.
- Drywell floor drain sump.
- Reactor building floor drain sumps.
- Radwaste building floor drain sumps.
- Turbine building floor drain sump.

These wastes generally have low concentrations of radioactive impurities. Processing consists of filtration, ion exchange, and subsequent transfer to floor drain sample tanks for sampling and analysis.

Treated low-purity wastes below Technical Specifications limits are discharged from the plant after dilution with cooling tower blowdown. However, if the treated wastes meet the specifications of water quality used in the plant and if the water inventory of the plant permits their recycle, they are returned to the CST for reuse.

11.2.2.1.3 Chemical Wastes

Chemical wastes collected in the chemical waste tank come from the following sources:

- Reactor water cleanup flow glass drain.
- Fuel pool filter-demineralizer drain.
- Fuel pool chemical cleaning drain.
- Cask cleaning drains.
- Reactor and turbine building decontamination drains.
- Chemical addition system overflow and drains.

When the laboratory drains or other drains containing chemicals are received by and accumulated in the chemical waste tank, these wastes are processed by filtration (after being neutralized, if required). A chemical addition system made up of a storage tank and addition pump is provided to neutralize the contents of the waste storage tank prior to processing. If a decision is made to reuse the water, it is treated through an ion exchange unit and sent to the condensate storage tank. Alternately, if the sampling and analysis indicate that the radioactivity concentrations are low enough to meet discharge criteria, the water in the sample tank is released to the discharge pipe. Wastes received in this subsystem generally represent excess inventory, and the processing method will generally produce treated waste of radioactivity

content equal to or less than that of the high- and low-purity subsystems. Thus, release of this water is for inventory control and results in minimal activity discharge from the plant. Laundry and hot shower wastes are treated in the HNP-1 radwaste system as are laboratory drains.

11.2.2.1.4 Sludges

Expended filter-demineralizer ion exchange resins from the cleanup and condensate filter-demineralizer are removed when necessary by backwashing. Cleanup system sludges and sludges from the condensate polishing system are collected in the respective phase separators where excess backwash water is decanted to the waste collector tank and the sludge is accumulated. The fuel pool filter-demineralizer and waste filters are backwashed to the waste sludge phase separator. The accumulated resins and sludges are processed through the solid radwaste system after a suitable decay period.

11.2.2.1.5 Spent Resins

Expended ion-exchange resins from waste demineralizers are backwashed to spent resin tanks where the spent resins are stored for a suitable decay period. The resins are then sent to the solid radwaste system discussed in section 11.5.

11.2.2.2 <u>Process Equipment Description</u>

Major components of the liquid radwaste system are described below. A summary of the design codes for major components is provided in table 11.2-1.

11.2.2.2.1 Pumps

A. Sump Pumps

   All radwaste system sump pumps are vertical, centrifugal-type pumps. With the exception of one sump pump located in the turbine building sub-basement, all sump pumps were designed to ASME Code, Section III, Class 3 design criteria and are constructed of stainless steel. Sumps are provided with one or two pumps, depending on expected usage. Replacement pumps may be designed to the manufacturer's standard code.

   When two pumps are provided, the first pump starts on rising water level in the sump and, if it is unable to handle the flow, the second pump will start. The duty of each pump is automatically switched after a start/stop cycle to evenly distribute run time between pumps in order to extend the time between maintenance requirements. The pumps are also provided with water-lubricated bearings to minimize routine maintenance.

B. Process Pumps

With the exception of the chemical addition pump, which is a sealed-diaphragm positive-displacement type, all liquid radwaste process pumps are the horizontal, centrifugal type. All pumps which process potentially radioactive liquids were originally procured to ASME Code, Section III, Class 3 design criteria and/or manufacturer's standards. Material of construction for pumps which process chemical wastes is stainless steel. Material of construction for the remaining pumps is carbon steel or stainless steel. Replacement pumps may be designed to the manufacturer's standards.

Process pumps are separated from adjacent storage tanks by shield walls in order to minimize personnel exposure during maintenance periods. Pump design was selected on the basis of minimizing the amount of routine maintenance requirements.

11.2.2.2.2 Tanks

A. Waste Collector Tank and Waste Surge Tank

The waste collector tank and the waste surge tank are constructed of carbon steel and were designed to the requirements of ASME Code, Section III, Class 3. Replacements may be designed to the requirements of American Petroleum Institute (API) No. 650.

The waste collector tank capacity is based on the normal expected input rate of the waste collection subsystem while the surge tank capacity is sufficient to contain a 1-day input of the system to allow maintenance of the rest of the subsystem.

Tank capacities and expected radioactive isotope content are given in table 11.2-2.

B. Floor Drain Collector Tank and Sample Tank

The floor drain collector tank and the sample tank are constructed of carbon steel and were designed to meet the requirements of ASME Code, Section III, Class 3. Replacements may be designed to the requirements of API No. 650.

The floor drain collector tank capacity is based on expected normal daily input of the floor drain subsystem. The floor drain sample tank is sized identically to the floor drain collector tank.

Tank capacities and expected radioactive isotope content are given in table 11.2-2.

C. Chemical Waste Tank

In keeping with the design objectives, the chemical waste tank is constructed of stainless steel and was designed to meet the requirements of ASME Code,

Section III, Class 3. Replacements may be designed to meet the requirements of API No. 650.

The chemical waste tank capacity is based on an expected quantity of decontamination solutions plus an additional volume sufficient to provide two flushings of the decontamination equipment for maintenance.

Tank capacity and expected radioactive isotope content are given in table 11.2-2.

D. Spent-Resin Tank

The spent-resin tank is constructed of carbon steel and was designed to meet the requirements of ASME Code, Section III, Class 3. Replacements may be designed to meet the requirements of API No. 650.

The spent-resin tank capacity is based on the quantity of resin from the waste demineralizer plus resin transfer water volume.

The tank overflow line is equipped with a fine mesh screen to prevent resins from getting into other portions of the radwaste system.

Tank capacity and expected radioactive isotope content are given in table 11.2-2.

E. Chemical Waste and Floor Drain Neutralizer Tank

The chemical waste and floor drain neutralizer tank is constructed of stainless steel and was designed to meet the requirements of ASME Code, Section III, Class 3. Replacements may be designed to meet the requirements of API No. 650.

Tank capacity and radioactive isotope content are given in table 11.2-2.

11.2.2.2.3 Filters

The waste collector filter and the floor drain collector filter are pressure precoat filters of identical design and differ only in capacity. Both filters are equipped with a common precoating tank and pump and individual filter holding pumps.

Filter media lifetime is based on a pressure drop across the filter and not specific radioactive content. Both filters are backwashed to the waste sludge phase separators.

The filter vessels are constructed of carbon steel and were designed to meet the requirements of ASME Code, Section III, Class 3. Replacement filter vessels may be designed to meet the requirements of ASME Code, Section VIII, Division 1. A corrosion-resistant lining is provided to minimize erosion of the carbon-steel vessels.

Each filter is housed in a separate shielded room to minimize exposure to personnel during routine maintenance. Use of condensate water for backwashing and design of the filter internals ensure a minimum accumulation of radioactive material in the filters.

11.2.2.2.4 Demineralizers

The waste and floor drain demineralizers are deep-bed, mixed-cation and anion type, with flowrate capacities consistent with their associated filters.

The resin bed lifetime is based on demineralizer effluent chemistry parameters. A resin bed is generally replaced when effluent parameters exceed established values, or on high differential pressure.

The demineralizer vessels are constructed of carbon steel, were designed to meet the requirements of ASME Code, Section III, Class 3, and are equipped with a rubber lining. Replacement vessels may be designed to meet the requirements of ASME Code, Section VIII, Division 1. Fine mesh strainers are provided in the demineralizer vessel discharge and in the piping downstream to prevent resin fines from being transferred to other portions of the system.

Both demineralizers are backwashed to a common spent-resin tank.

Each demineralizer is housed in a separate shielded room to minimize exposure to personnel during routine maintenance.

11.2.2.2.5 Phase Separators

A. Condensate Phase Separators

   The two carbon steel condensate phase separators are sized to contain a volume sufficient to contain 1 backwash from the condensate polishing demineralizers in addition to the accumulation of 10 volumes of sludge from previous backwashes or the amount of sludge that would accumulate in 1 day of operation, including startup, whichever is greater. These tanks were designed to the requirements of ASME Code, Section III, Class 3. Replacements may be designed to meet the requirements of API No. 650.

   Provisions are made for the injection of a flocculent into the separators after receiving a backwash to promote settling of the sludge. The tanks are also provided with an internal sparger system for mixing the contents to a homogeneous mixture prior to transfer.

   Tank capacity and expected radioactive isotope content are given in table 11.2-2.

B. Cleanup Phase Separators

Two stainless steel cleanup phase separators are provided to receive the backwash from the RWC system demineralizers. Each is sized to contain sufficient volume for 2 backwash cycles plus a 2-month accumulation of settled sludge from previous backwashes. Two phase separators are provided to allow for decay in one while the other is being filled. These tanks were designed to the requirements of ASME Code, Section III, Class 3. Replacements may be designed to meet the requirements of API No. 650.

Provisions are made for the injection of a flocculent into the phase separators after receiving a backwash to promote settling of the sludge. The tanks are also provided with an internal sparger system for mixing the contents to a homogeneous mixture prior to transferring the sludge to the dewatering facility.

Tank capacity and expected radioactive isotope content are given in table 11.2-2.

C. Waste Sludge Phase Separators

Two carbon steel waste sludge phase separators are provided to receive the backwash from the waste collector and floor drain filters. These tanks were designed to the requirements of ASME Code, Section III, Class 3, and are rubber lined. Replacements may be designed to meet the requirements of API No. 650.

Each waste sludge phase separator is sized to contain two backflushes from the largest radwaste filter. Two phase separators are provided to allow for decay in one while the other is being filled.

The waste sludge phase separators are provided with flocculent addition and an internal sparger system as described for the condensate and cleanup phase separators.

Tank capacity and expected radioactive isotope content are given in table 11.2-2.

11.2.2.3 <u>Design for Keeping Activity Discharges ALARA</u>

Liquid radwastes are received and processed in the subsystems described in paragraph 11.2.2.1. To ensure operability of each of these systems so the wastes are processed by the treatment methods provided, the following system features are included:

A. Processing equipment is designed and selected so maintenance requirements are minimized and is shielded so it can be maintained.

B. Floor drain and waste filters and demineralizers are cross-connected so each filter or demineralizer can be used in place of the other, if necessary, to maintain process continuity.

C. Major liquid subsystem pumps are cross-connected for maintainability and so that outage of a pump does not prevent subsystem continuity.

D. Because the subsystems are batch systems rather than continuous systems and are preceded by collection tanks, time is available to accumulate wastes during maintenance of subsequent equipment or during filter backwashing and resin replacement. The waste surge tank is also provided to accumulate certain wastes and thus provide time for maintenance.

E. Certain operations are also subject to scheduling and can be delayed in the event of mechanical problems. Examples are:

1. Transfer of liquid from cleanup phase separators to waste collector tank and transfer of solids for solid waste processing.

2. Transfer to and from the waste sludge phase separator and spent-resin tank.

3. Chemical waste/floor drain neutralizer tank is sized to hold 2 days of normal daily low-purity (floor drain) volume, and is capable of holding either filtered but otherwise untreated wastes or off-standard recycle wastes which have been treated but require further processing.

F. Filter backwashing and precoating are part of the normal operating procedure for which cycle time has been allowed in the design.

G. Waste and floor drain demineralizer resin replacement is an infrequent operation, normally about once a month. The essential factor to minimizing outage time is to maintain an appropriate resin inventory at the station for resin replacement. Resins can be replaced in less than one shift, the major task being to transfer resins from container to demineralizer.

The principal administrative areas involved in maintaining an operational system are planning radwaste processing, controlling the reactor water inventory, and carrying out a preventive maintenance program.

Radwaste system planning ensures that wastes are processed in a timely manner. Timeliness ensures that reactor operations and maintenance activities (draining, flushing, decontamination, etc.) are coordinated so as not to impose unusual, unexpected quantities of water on the radwaste system.

The reactor water inventory is controlled to minimize the need for discharging waste water because of excessive inputs via the makeup system. The planning and water inventory control activities are also useful in detecting abnormal inputs to radwaste and thus revealing causes of such inputs for correction.

The preventive maintenance program has the obvious objective of minimizing unplanned equipment conditions that would affect radwaste performance. The cross-connections (noted above) accommodate such outages in critical flow paths.

11.2.3 INSTRUMENTATION APPLICATION

System operation is controlled from a local control panel in the radwaste building. Instrumentation, including alarms, is provided for both process control and for detection and alarm of abnormal conditions. The various alarms located at the local control panel provide signals of specific conditions. Indications and general alarms are also provided in the main control room (MCR). In general, the control scheme employed in the radwaste system is manual start and automatic shutoff, to avoid unintentional or uncontrolled discharge.

11.2.3.1 System Performance Instrumentation

As indicated on drawing nos. H-26026 through H-26032 and H-26035, instrumentation for measuring system performance is provided. The performance of the filters is measured by pressure drop across the filter. The performance of the demineralizers is measured by the conductivity cell located downstream of the demineralizer, and, should the conductivity be higher than the preset level, an alarm is given and the liquid is automatically diverted (bypassing the sample tank) to the appropriate storage tank for reprocessing.

11.2.3.2 Drywell Sumps Control

There are two sumps within the drywell that collect waste water which is pumped out to the liquid radwaste system collector tanks. Each sump is equipped with two pumps that automatically start and stop on high- and low-sump level, respectively. The pumps are alternately started on each high-level signal. Each pump is equipped with a separate float switch in a separate float well and is electrically connected to provide level backup for the other pump if one float device should fail. A high-high level is provided by each float switch which will start both pumps and annunciate an alarm in the MCR. The liquid discharge lines to the radwaste collector tanks are provided with two ASME Section III, Class 2 and Seismic Category I isolation valves. When either isolation valve is closed, the sump pumps are interlocked to prevent their operation. The closing of these valves is necessary for sealing the primary containment under postulated accident conditions. The initiating isolation signal is from the primary containment and reactor vessel isolation and control system described in subsection 7.3.2.

The discharge lines are provided with radiation monitors which automatically shut off the associated sump pumps on high radiation. This prevents pumping of high level contaminants into the radwaste building.

11.2.3.3 Reactor and Turbine Building Sumps Control

These sumps collect waste water from their respective areas and automatically pump out the sumps on level control. These are not safety systems and an alarm and annunciation in the radwaste control room will occur on a high-high sump level to allow the operator to take corrective action.

11.2.3.4 Control of Discharge to the Environment

Offsite discharge is under operator control. Two console-operated parallel flow-control valves control flow at fast and slow rates. Console-operated, fail-closed shutoff valves are provided in the sample tank effluent line and in the discharge line to the conduit to the river. Activity in the effluent from the sample tank above a preset level will initiate automatic isolation of the discharge line. Discharge to the conduit is prevented if there is not sufficient dilution water flow available from the cooling tower. This was done by interlocking the cooling tower discharge flow with the shutoff valves. The sample tank cannot empty by gravity flow or by siphoning because of the relative elevations of the sample tank and the discharge exits to the conduit.

The ultimate control over the decision for the final destination of the liquid effluent from a given batch rests with the sampling and analyses performed by the plant laboratory. The guideline used by the laboratory personnel in making this decision is water inventory in the plant, water quality for reuse, consideration for instantaneous and annual average activity concentration in the discharge conduit, and annual total activity release.

The liquid radwaste radiation monitor provides automatic isolation of the radwaste discharge and is discussed in detail in section 11.4.

11.2.4 SAFETY EVALUATION

11.2.4.1 Normal Operation

Treated high-purity radwastes normally are routed to condensate storage for reuse. Treated floor drain wastes also can be routed to condensate storage to the extent practical, consistent with reactor water inventory and reactor water quality requirements. Treated floor drain and chemical wastes are discharged into the cooling tower blowdown discharge pipe after sampling of treated wastes to ensure discharge pipe concentrations are within Technical Specifications limits after dilution.

The effluent from the plant to the discharge pipe, all of which must pass through a sample tank, is monitored by taking batch samples; records of the volumes and concentration levels are retained. A process monitoring system is provided to indicate high-radiation levels in the release to the discharge pipe. On the annunciation of the high-radiation level alarm, the release of the liquid radwastes will be terminated.

The processing equipment is located within a concrete building to provide secondary enclosures for the wastes in the event of leaks or overflows. Tanks and equipment that may contain significant quantities of radioactivity are shielded. Except where flanges are required for maintenance, all pipe connections are welded to reduce the probability of leaks. Process lines that penetrate shield walls are routed to prevent a direct radiation path from the tanks or equipment for which shielding is required. The waste system is controlled from a local panel in the radwaste control room.

The radioactivity concentrations in the discharge system are well within the Technical Specifications limits. The components of the liquid radwaste system are sized to collect and process the volume of liquid radwaste generated from the reactor under normal power operation and expected occurrences.

11.2.4.1.1 Estimate of Radionuclides Released

To ensure that radioactive liquid releases from normal operation of the nuclear plant will result in doses to individuals below the guidelines given in Appendix I to 10 CFR 50, an estimate of the quantity of annual radioactive effluents was performed using the BWR-GALE Code given in reference 4. This GALE model is applicable to HNP-1 and HNP-2.

Liquid releases were recalculated in 1993 using the GALE Liquid Code in conjunction with the deletion of the evaporator from service. A single GALE model was developed, and one run was performed for HNP-1 and HNP-2. HNP-2-FSAR figure 11.5-1 and HNP-1-FSAR figure 9.2-1 show the liquid radwaste processing system diagram as used in the development of the GALE model based upon the utilization of powdered resin on the precoat filters and utilization of all installed demineralizers. Although utilization of all installed demineralization capability may not be necessary for all processing, the design basis case was analyzed with all capability in service to demonstrate compliance with 10 CFR 50, Appendix I.

The model also included the laundry wastes associated with HNP-1 and are thus slightly conservative for HNP-2. (For a discussion of laundry waste processing, see HNP-1-FSAR paragraph 9.2.1.4.)

Table 11.2-3 lists the input data required for the BWR-GALE Code. The annual expected releases of activity to the environment in liquid effluents (including tritium) are presented in table 11.2-4. These releases are obtained directly for the BWR-GALE Code's output and include the increment of 0.15 Ci/year to account for anticipated operational occurrences, such as operator errors, which may result in unplanned releases.

11.2.4.1.2 Release Points

Liquid effluents are discharged through a 3-in.-diameter line which feeds into a 42-in.-diameter pipe which has an average flowrate of 26.8 ft^3/s. The submerged pipe discharges at a point ~ 100 ft from shore at a pipe centerline depth of ~ 5 ft below the normal surface of the river. The downstream site boundary is ~ 4900 ft from the discharge point. The river width and depth near the site are ~ 560 ft and 9 ft, respectively. The release point from the liquid radwaste system is shown on drawing no. H-26028. The relative location of the discharge point to the site boundary is shown in figure 11.2-3.

11.2.4.1.3 Dilution Factors

The mixing ratio (inverse of the dilution factor) was taken as 0.2 for all pathways evaluated in accordance with recommendations in reference 1, Table A-1. Resultant concentrations correspond roughly to those at the edge of the initial mixing zone. Discharge characteristics are discussed in Subsection 3.4.3 of the HNP-2 Environmental Report (ER) - Operating License Stage, and in the response to Question 3.4-1 of Supplement 1 to the ER.

11.2.4.1.4 Estimated Doses

Using the methodology of NUREG/CR-1276 (LADTAP II)[5] which implements the dose models described in reference 1 with the annual releases given in table 11.2-4 and the mixing ratio of 0.2, maximum annual doses to individuals offsite were estimated. The pathways evaluated include fish ingestion, shoreline recreation, boating, and swimming. The standard reference 1 values for usage rates, holdup times, and other parameters were used. Table 11.2-5 gives the maximum annual doses from liquid effluents. There are no public water supply intakes downstream of the plant and there are no known plans to construct any. The resulting doses (including a hypothetical drinking water pathway) are below the objectives of Appendix I to 10 CFR 50.

11.2.4.2 Accident Analysis

11.2.4.2.1 Identification of Causes and Accident Description

Although not analyzed for the requirements of Seismic Category I equipment, the liquid radwaste tanks are constructed in accordance with sound engineering principles and current ASME codes. Therefore, simultaneous failure of all tanks is not considered credible, though conservatively analyzed herein. In most cases, the tanks are individually, or in small groups, located in shielded areas; therefore, the probability of a missile striking and rupturing all of the tanks is remote. The only event which might cause failure of all radwaste tanks is an earthquake sufficient in magnitude to exceed the design capabilities.

11.2.4.2.2 Analysis of Effects and Consequences

The concrete radwaste building retains and returns any spills or leaks from the liquid radwaste system to the system for additional processing. The radwaste building has the capacity to handle a major leak in the largest tank without permitting significant quantities of the liquid to escape offsite.

None of the radioactive waste system tanks are located outside. The only tank which is located outside and which does contain radioactive materials is the CST. A Seismic Category I concrete structure is provided around the CST. This structure is of sufficient size to retain the contents of the tank in the unlikely event of damage to the tank and will prevent release of

radioactive materials to unrestricted areas exceeding the limits of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), Appendix B, table II, column 2.

All the radwaste tanks, with the exception of the cleanup phase separators for HNP-2, are contained in the radwaste building. The cleanup phase separators are in the reactor building, which is a Seismic Category I structure, and will contain the contents of the phase separators in the event of their failure. If an accident occurred to cause all the contents of the tankage in the radwaste building to be spilled, it would flow to the bottom floor of the building by way of stairways and openings and would be contained there. If the integrity of the floor or walls is broken by a seismic event, the liquid would slowly permeate into the surrounding soil.

To evaluate the consequences of such an event, it has been conservatively assumed that the entire contents of the radwaste tankage comes into immediate contact with the soil below the radwaste building. The activity estimated to be contained in the various radwaste tanks is shown in table 11.2-2. The total activity contained in the radwaste building is ~ 52 Ci. The worst case is assumed to be the contents of the radwaste building moving as a body toward the river and then mixing with the river at a rate consistent with the rate of travel through the soil.

A discussion of soil permeability and travel time to the Altamaha River is provided in paragraph 2.4.13.3, Accident Effects. This discussion indicates that the travel time of groundwater from the HNP-2 radwaste building to the Altamaha River through the minor confined aquifer is 230 years. With an annual average river flow of 1300 ft^3/s and a total activity of ~ 62 Ci dispersed over a period of 1 year, the average concentration in the river would be ~ 5×10^{-8} µCi/cc, which is considerably below that concentration which could cause doses to people approaching 10 CFR 100 guidelines and is also below the permissible concentration given in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), Appendix B, table II, column 2. It was also assumed that the radioactive liquid uniformly mixes with the river water. Approximately 2 1/2 miles downstream of the site, there are two sharp turns in the river, and it is believed that any radioactivity released into the river will be completely mixed beyond these turns. No credit has been taken for radioactive decay which would be substantial during seepage of the water to the river or for retention of the radioactive material by the soil.

The evaluation of site boundary dose due to a puff release from failure of radwaste tanks is discussed in subsection 15.4.14.

11.2.4.2.3 Identification of Operator Actions

In the event of this accident, certain measures could be taken to remove much of the water in the basement of the radwaste building before it could seep into the soil beneath the building.

The rupture of the liquid radwaste tanks would leave little recourse to the operator. No methods of recontaining the discharge are available; however, isolation of the radwaste area would minimize the results. High-radiation alarms, both in the radwaste building ventilation exhaust and in the radwaste areas, would alert the operator to a failure. No credit for operator action has been taken in evaluating this event.

11.2.4.2.4 Conclusions

Because leaks or spills from the liquid radwaste system go into the radwaste building and/or the reactor building, they do not cause doses at the plant boundary exceeding the limits of 10 CFR 20; because the system is monitored for inadvertent discharge of high-level waste, the liquid radwaste system fulfills the design basis and adheres to the guidelines of 10 CFR 20.

11.2.5 TESTS AND INSPECTIONS

The liquid radwaste system is normally operating on an as-required basis during operation of the nuclear plant, thereby demonstrating operability without any special inspections or testing. Data from equipment operation logs, records, and from laboratory testing of samples taken from the radwaste sampling tanks reflects day-to-day performance of the various radwaste subsystems. Abnormal conditions such as high-volume throughputs, short-filter or demineralizer runs, and high-effluent conductivity or activity, dictate special performance testing or analysis that may be required.

Overall decontamination factors, crud-loading capacities, and contamination concentrations in waste water, such as turbidity and conductivity, are used in the design of the system. These design values are based upon operating plant data taken during both preoperational plant testing and actual plant waste treatment.

REFERENCES

1. "Calculation of Annual Doses to Man from Radioactive Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," USNRC Regulatory Guide 1.109, Revision 0, March 1976.

2. "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," USNRC Regulatory Guide 1.26, Revision 1, September 1974.

3. "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants," USNRC Regulatory Guide 1.143, Revision 1, October 1979.

4. "Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors," (BWR-GALE Code) USNRC NUREG-0016, April 1976.

5. "User's Manual for LADTAP II - A Computer Program for Calculating Radiation Exposure to Man from Routine Release of Nuclear Reactor Liquid Effluents," USNRC NUREG/CR-1276, March 1980.

TABLE 11.2-1

DESIGN CODES FOR MAJOR LIQUID RADWASTE SYSTEM COMPONENTS

Component	Original Code(s)	Replacement Code
Piping	ASME Section III, Class 3 and ANSI B31.1.0	ANSI B31.1[a]
Valves	ASME Section III, Class 3 and ANSI B31.1.0	ANSI B31.1[a]
Pumps	ASME Section III, Class 3 and/or manufacturer's standard	Manufacturer's standard
Tanks	ASME Section III, Class 3	
Pressure vessels		ASME Section VIII, Division 1
0-15 psig tanks		API No. 620
Atmospheric tanks		API No. 650
Filter vessels	ASME Section III, Class 3	ASME Section VIII, Division 1
Demineralizers	ASME Section III, Class 3	ASME Section VIII, Division 1
Condensate phase separators	ASME Section III, Class 3	API No. 650
Cleanup phase separators	ASME Section III, Class 3	API No. 650
Waste sludge phase separators	ASME Section III, Class 3	API No. 650

a. Primary containment isolation valves and associated piping from these valves to the containment penetrations remain ASME Section III, Class 2.

TABLE 11.2-2 (SHEET 1 OF 3)

CAPACITY AND MAXIMUM ACTIVITY CONTAINED IN LIQUID RADWASTE TANKS

	Waste Collector Tank	Floor Drain Collector Tank	Chemical Waste Tank	Chemical Waste Floor Drain Neutralizer Tank	Waste Sample Tank	Floor Drain Sample Tank	Chemical Waste Sample Tank	Condensate Backwash Receiving Tank	Condensate Phase Separator	Cleanup Phase Separator	Waste Sludge Tank	Spent-Resin Tank	Waste[(a)] Surge Tank
No. of tanks	1	1	1	1	2	1	2	1	2	2	1	1	1
Volume of each tank (gal)[(b)]	12,000	12,000	4500	15,000	12,000	12,000	7500	8500	13,500	4500	7500	1200	65,000
Isotopic concen-tration (µCi/cc)[(c)]													
Br-83	3.1E-3	5.8E-5	1.3E-5	↑ SAME AS CHEMICAL WASTETANK ↓	3.1E-5	8.1E-8	1.8E-9	2.6E-6	↑ SAME AS CONDENSATE BACKWASH RECEIVING TANK ↓	4.5E-3	↑ SAME AS CONDENSATE BACKWASH RECEIVING TANK ↓	↑ SAME AS CONDENSATE BACKWASH RECEIVING TANK ↓	
Br-84	5.7E-3	1.1E-4	2.3E-5		5.7E-5	(e)	(e)	4.6E-6		8.1E-3			
Br-85	3.5E-3	6.3E-5	1.4E-5		3.5E-5	0	0	2.8E-6		4.9E-3			
I-131[(d)]	2.9E-3	5.3E-5	1.2E-5		2.9E-5	2.3E-6	5.0E-8	2.4E-6		4.2E-3			
I-132	2.7E-2	4.8E-4	1.1E-4		2.7E-4	5.6E-7	1.2E-8	2.1E-5		3.7E-2			
I-133[(d)]	2.0E-2	3.6E-4	7.9E-5		2.0E-4	1.1E-6	2.3E-7	1.6E-5		2.8E-2			
I-134	5.3E-2	9.3E-4	2.1E-4		5.3E-4	2.9E-9	(e)	4.2E-5		7.3E-2			
I-135[(d)]	2.9E-2	5.2E-4	1.2E-4		2.9E-4	6.7E-6	1.5E-7	2.3E-5		4.1E-2			
Sr-89[(d)]	6.6E-4	1.2E-5	2.7E-6		6.6E-6	5.4E-7	1.2E-8	5.4E-7		9.5E-4			
Sr-90[(d)]	5.3E-5	9.3E-7	2.1E-7		5.3E-7	4.1E-8	(e)	4.1E-8		7.2E-5			
Sr-91[(d)]	1.5E-2	2.7E-4	6.1E-5		1.5E-4	5.1E-6	1.1E-7	1.2E-5		2.1E-2			
Sr-92	2.4E-2	4.3E-4	9.5E-5		2.4E-4	8.0E-7	1.9E-8	1.8E-5		3.3E-2			
Zr-95	9.0E-6	1.6E-7	3.6E-8		9.0E-8	7.0E-9	(e)	7.1E-9		1.2E-5			
Zr-97	6.6E-6	1.3E-7	2.8E-8		6.6E-8	3.5E-9	(e)	5.6E-9		9.9E-6			
Nb-95	9.2E-6	1.7E-7	3.7E-8		9.2E-8	7.2E-9	(e)	7.4E-9		1.3E-6			
Mo-99[(d)]	5.0E-3	8.9E-5	2.0E-5		5.0E-5	3.5E-5	7.7E-8	4.0E-6		6.9E-3			
Tc-99m	6.3E-2	1.1E-3	2.5E-4		6.3E-4	1.2E-5	2.7E-7	4.9E-5		8.6E-2			
Tc-101	2.7E-2	5.1E-4	1.1E-4		2.7E-4	(e)	(e)	2.3E-5		4.0E-2			
Ru-103	4.3E-6	7.8E-8	1.7E-8		4.3E-8	3.4E-9	(e)	3.4E-9		6.0E-6			
Ru-106	5.7E-7	1.0E-8	2.3E-9		5.7E-9	(e)	(e)	-		8.0E-7			
Te-129	8.8E-6	1.6E-7	3.5E-8		8.8E-8	6.9E-9	(e)	7.0E-9		1.2E-5			

TABLE 11.2-2 (SHEET 2 OF 3)

	Waste Collector Tank	Floor Drain Collector Tank	Chemical Waste Tank	Chemical Waste Floor Drain Neutralizer Tank	Waste Sample Tank	Floor Drain Sample Tank	Chemical Waste Sample Tank	Condensate Backwash Receiving Tank	Condensate Phase Separator	Cleanup Phase Separator	Waste Sludge Tank	Spent-Resin Tank	Waste[(a)] Surge Tank
Te-134	1.1E-2	1.9E-5	4.3E-5		1.1E-4	7.7E-6	1.7E-7	8.6E-6		1.5E-2			
Cs-134[(d)]	3.5E-5	6.4E-7	1.4E-7		3.5E-7	2.8E-8	(e)	2.8E-8		5.0E-5			
Cs-136	2.3E-5	4.2E-7	9.4E-8		2.3E-7	1.8E-8	(e)	1.9E-8		3.3E-5			
Cs-137[(d)]	5.3E-5	9.6E-7	2.1E-7		5.3E-7	4.3E-8	(e)	4.3E-8		7.5E-5			
Cs-138	4.0E-2	7.1E-4	1.6E-4		4.0E-4	(e)	(e)	3.2E-5		5.5E-2			
Ba-139	3.5E-2	6.2E-4	1.4E-4		3.5E-4	6.7E-8	1.5E-9	2.7E-5		4.8E-2			
Ba-140[(d)]	2.0E-2	3.6E-5	7.9E-5		2.0E-4	1.5E-6	3.4E-8	1.6E-6		2.8E-3			
Ba-141	3.7E-2	6.6E-4	1.5E-4		3.7E-4	(e)	(e)	3.0E-5		5.2E-2			
Ba-142	3.5E-2	6.4E-4	1.4E-4		3.5E-4	(e)	(e)	2.8E-5		5.0E-2			
Ce-141	8.7E-6	1.6E-7	3.5E-8		8.7E-8	6.9E-9	(e)	7.0E-9		1.2E-5			
Ce-143	7.8E-6	1.4E-7	3.1E-8		7.8E-8	4.8E-9	(e)	6.2E-9		1.1E-5			
Ce-144[(d)]	7.8E-6	1.4E-7	3.1E-8		7.8E-8	6.2E-9	(e)	6.2E-9		1.1E-5			
Pr-143	8.6E-6	1.5E-7	3.4E-8		8.6E-8	6.5E-9	(e)	6.7E-9		1.2E-5			
Nd-147	3.0E-6	5.6E-8	1.2E-8		3.0E-8	2.4E-9	(e)	2.5E-9		4.4E-6			
Np-239	5.5E-2	9.7E-4	2.2E-4		5.5E-4	3.7E-5	8.2E-7	4.3E-5		7.5E-2			
Na-24	(e)	6.0E-6	1.3E-6	6.5E-6	(e)	1.5E-7	3.4E-9	2.7E-7		4.7E-4			
P-32[(d)]	(e)	6.0E-8	1.3E-8	6.5E-8	(e)	2.6E-9	(e)	2.7E-9		4.7E-6			
Cr-51	(e)	1.5E-6	3.3E-7	1.7E-6	(e)	6.5E-8	1.4E-9	6.7E-8		1.2E-4			
Mn-54	(e)	1.2E-7	2.7E-8	1.4E-7	(e)	5.3E-9	(e)	5.3E-9		9.3E-6			
Mn-56	(e)	1.5E-4	3.3E-5	1.7E-4	(e)	2.6E-7	5.9E-9	6.7E-6		1.2E-2			
Co-58[(d)]	(e)	1.5E-5	3.3E-6	1.7E-5	(e)	6.6E-7	1.5E-8	6.7E-7		1.2E-3			
Co-60[(d)]	(e)	1.5E-6	3.3E-7	1.7E-6	(e)	6.6E-8	1.5E-9	6.7E-8		1.2E-4			
Fe-59	(e)	2.4E-7	5.3E-8	2.7E-7	(e)	1.1E-9	(e)	1.1E-8		1.9E-5			
Ni-65	(e)	9.0E-6	2.0E-6	1.0E-5	(e)	1.5E-8	(e)	4.0E-7		7.0E-4			
Zn-65	(e)	3.0E-9	(e)	(e)	(e)	(e)	(e)	(e)		2.3E-7			
Zn-69m	(e)	9.0E-8	2.0E-8	1.0E-7	(e)	2.2E-9	(e)	4.0E-9		7.0E-6			
Ag-110m[(d)]	(e)	1.8E-7	4.0E-8	2.0E-7	(e)	7.9E-9	(e)	8.0E-9		1.4E-5			
W-187	(e)	9.0E-6	2.0E-6	1.0E-5	(e)	3.0E-7	6.6E-9	4.0E-7		7.0E-4			
Maximum activity concen-tration (100,000 μCi/s, off-gas) (μCi/cc)	5E-1	9E-3	2E-3	2E-2	5E-3	9E-5	2E-6	4E-4	4E-4	8E-1	4E-4	4E-4	

TABLE 11.2-2 (SHEET 3 OF 3)

	Waste Collector Tank	Floor Drain Collector Tank	Chemical Waste Tank	Chemical Waste Floor Drain Neutralizer Tank	Waste Sample Tank	Floor Drain Sample Tank	Chemical Waste Sample Tank	Condensate Backwash Receiving Tank	Condensate Phase Separator	Cleanup Phase Separator	Waste Sludge Tank	Spent-Resin Tank	Waste[(a)] Surge Tank
Total maximum activity in all full tanks (μCi)	2.3E+7	4.1E+5	3.4E+4	1.1E+6	2.3E+5	4.1E+3	1.1E+2	1.3E+4	4.1E+4	2.7E+7	2.3E+4	3.6E+3	
Assumed type of liquid present in tank	Equip-ment drain (dilute reactor water)	Floor drain (dilute reactor water)	Labora-tory drain (dilute reactor water)	Filtered floor drain (dilute reactor water)	Pro-cessed equip-ment drain	Pro-cessed floor drain	Pro-cessed labora-tory drain	Conden-sate	Conden-sate	Conden-sate and reactor water	Conden-sate	Conden-sate	
Decay time applied (hours)	0	0	0	0	0	12	12	0	0	0	0	0	
Location	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg	Turbine bldg	Rad-waste bldg	Reactor bldg	Rad-waste bldg	Rad-waste bldg	Rad-waste bldg

a. The waste surge tank is normally kept empty, not included in the total.
b. Total liquid wastes in all tanks associated with radwaste system = 147,700 gal.
c. Total activities contained in all tanks at the maximum concentration in each tank = 52 Ci. Read 1.3E-3 as 1.3×10^{-3}.
d. Those radionuclides listed in the table 11.2-4.
e. < 10E-9.

TABLE 11.2-3

GALE INPUT DATA
(BWR GALE Code Input Data File)

CARD	1	NAME	NAME OF REACTOR HNP-1 & 2 EXTENDED POWER UPRATE CASE WITH TB FILTER	TYPE = BWR
CARD	2	POWTH	THERMAL POWER LEVEL (MEGAWATTS)	2804
CARD	3	GTO	TOTAL STEAM FLOW (MILLION LBS/HR)	12.2
CARD	4	WL1Q	MASS OF WATER IN REACTOR VESSEL (MILLION LBS)	0.493
CARD	5	GDE	CLEANUP DEMINERALIZER FLOW (MILLION LBS/HR)	0.1
CARD	6	REGENT	CONDENSATE DEMINERALIZER REGENERATION TIME (DAYS)	0.0
CARD	7	FFCDM	FRACTION FEED WATER THROUGH CONDENSATE DEMIN	1.00
CARD	8		HIGH PURITY WASTE INPUT 21000. GPD AT .23 PCA	
CARD	9		DFI= 1.0E03DFCS= 2.0E01DFO = 1.0E03	
CARD	10		COLLECTION .23 DAYS PROCESS .03 DAYS FRACT DISCH	0.01
CARD	11		LOW PURITY WASTE INPUT 6000. GPD AT .003	
CARD	12		DFI= 1.0E03DFCS= 4.0E00DFO = 1.0E03	
CARD	13		COLLECTION 0.8 DAYS PROCESS .07 DAYS FRACT DISCH	1.0
CARD	14		CHEMICAL WASTE INPUT 500. GPD AT .005 PCA	
CARD	15		DFI= 1.0E03DFCS= 4.0E00DFO = 1.0E03	
CARD	16		COLLECTION 3.6 DAYS PROCESS .03 DAYS FRACT DISCH	1.0
CARD	17		REGENERATION SOLTNS INPUT GPD	0.0
CARD	18		DFI= 1.0E00DFCS= 1.0E00DFO = 1.0E00	
CARD	19		COLLECTION 0.0 DAYS PROCESS .00 DAYS FRACT DISCH	1.0
CARD	20	GGS	GLAND SEAL STEAM FLOW (THOUSAND LBS/HR)	12.2
CARD	21	T1M3	GLAND SEAL HOLDUP TIME (HOURS)	0.029
CARD	22	TIM4	AIR EJECTOR OFFGAS HOLDUP TIME (HOURS)	.5
CARD	23		CONTAINMENT BLDG. CHARCOAL 00.0 HEPA?99.0	
CARD	24		TURBINE BLDG. CHARCOAL 90.0 HEPA?99.0	
CARD	25	FIL3	GLAND SEAL VENT, IODINE PF	0.0
CARD	26	FIL4	AIR EJECTOR OFFGAS IODINE PF	1.0
CARD	27		AUXILIARY BLDG. CHARCOAL 00.0 HEPA?99.0	
CARD	28		RADWASTE BLDG. CHARCOAL 00.0 HEPA?99.0	
CARD	29	KCHAR	CHARCOAL DELAY SYSTEM 0=NO,1=YES, 2=CRYOGENIC DISTILL	1
CARD	30	KKR	KRYPTON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)	18.50
CARD	31	KXE	XENON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)	330.0
CARD	32	KMASS	MASS OF CHARCOAL (THOUSAND LBS)	73.89
CARD	33	PFLAUN	DETERGENT WASTE DECONTAMINATION FACTOR	1.0

TABLE 11.2-4 (SHEET 1 OF 4)

EXPECTED ANNUAL RELEASES
(BWR GALE Code Output Data File)

1.5% Power
Uprate Case with TB Filter

THERMAL POWER LEVEL (megawatts)	2804.00000
PLANT CAPACITY FACTOR	.80
TOTAL STEAM FLOW (million lb/h)	12.2000
MASS OF WATER IN REACTOR VESSEL (million lb)	0.49300
FISSION PRODUCT CARRYOVER FRACTION	0.0010
HALOGEN CARRYOVER FRACTION	0.0200
CLEANUP DEMINERALIZER FLOW (million lb/h)	0.10000
CONDENSATE DEMINERALIZER REGENERATION TIME (days)	0.00000
FRACTION FEEDWATER THROUGH CONDENSATE DEMIN	1.00000

LIQUID WASTE INPUTS

STREAM	FLOWRATE (gal/day)	FRACTION OF PCA	FRACTION DISCHARGED	COLLECTION TIME (days)	DECAY TIME (days)	DECONTAMINATION FACTORS I	CS	OTHERS
HIGH PURITY WASTE	2.10E+04	0.230	0.010	0.230	0.030	1.00E+03	2.00E+01	1.00E+03
LOW PURITY WASTE	6.00E+03	0.003	1.000	0.800	0.070	1.00E+03	4.00E+00	1.00E+03
CHEMICAL WASTE	5.00E+02	0.005	1.000	3.600	0.030	1.00E+03	4.00E+00	1.00E+03
REGENERANT SOLS	0.00E+00		1.000	0.000	0.000	1.00E+00	1.00E+00	1.00E+00

GASEOUS WASTE INPUTS

GLAND SEAL STEAM FLOW (thousand lb/h)		12.2000
GLAND SEAL HOLDUP TIME (hours)		0.02900
AIR EJECTOR OFFGAS HOLDUP TIME (hours)		0.50000
CONTAINMENT BLDG.	IODINE RELEASE FRACTION	1.00000
	PARTICULATE RELEASE FRACTION	0.01000
TURBINE BLDG.	IODINE RELEASE FRACTION	0.10000
	PARTICULATE RELEASE FRACTION	0.01000
GLAND SEAL VENT, IODINE PF		1.00000
AIR EJECTOR OFFGAS IODINE PF		0.00000
AUXILIARY BLDG.	IODINE RELEASE FRACTION	0.10000
	PARTICULATE RELEASE FRACTION	0.01000
RADWASTE BLDG.	IODINE RELEASE FRACTION	0.10000
	PARTICULATE RELEASE FRACTION	0.01000

TABLE 11.2-4 (SHEET 2 OF 4)

GASEOUS WASTE INPUTS

THERE IS A CHARCOAL DELAY SYSTEM

KRYPTON HOLDUP TIME (days)	0.87751
XENON HOLDUP TIME (days)	15.65287
KRYTON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)	18.5000
XENON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)	330.000
MASS OF CHARCOAL (thousand lb)	73.89

HNP-1&2 EXTENDED POWER UPRATE CASE WITH TB FILTER
LIQUID EFFLUENTS ANNUAL RELEASES TO DISCHARGE CANAL

NUCLIDE	HALF LIFE (days)	CONCENTRATION IN PRIMARY COOLANT (micro ci/ml)	HIGH PURITY (curies)	LOW PURITY (curies)	CHEMICAL (curies)	TOTAL LWS (curies)	ADJUSTED TOTAL (ci/yr)	DETERGENT WASTES (ci/yr)	TOTAL (ci/yr)
CORROSION AND ACTIVATION PRODUCTS									
NA 24	6.25E-01	9.06E-03	0.00052	0.00014	0.00001	0.00066	0.00412	0.00000	0.00410
P 32	1.43E+01	1.93E-04	0.00001	0.00000	0.00000	0.00002	0.00011	0.00000	0.00011
CR 51	2.78E+01	5.79E-03	0.00038	0.00014	0.00002	0.00055	0.00340	0.00000	0.00340
MN 54	3.03E+02	6.76E-05	0.00000	0.00000	0.00000	0.00001	0.00004	0.00100	0.00100
MN 56	1.07E-01	3.849E-02	0.00112	0.00012	0.00000	0.00124	0.00771	0.00000	0.00770
FE 55	9.50E+02	9.66E-04	0.00006	0.00002	0.00000	0.00009	0.00057	0.00000	0.00057
FE 59	4.50E+01	2.90E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
CO 58	7.13E+01	1.93E-04	0.00001	0.00000	0.00000	0.00002	0.00011	0.00400	0.00410
CO 60	1.92E+03	3.87E-04	0.00003	0.00001	0.00000	0.00004	0.00023	0.00870	0.00890
NI 65	1.07E-01	2.33E-04	0.00001	0.00000	0.00000	0.00001	0.00005	0.00000	0.00005
CU 64	5.33E-01	2.69E-02	0.00149	0.00038	0.00002	0.00189	0.01177	0.00000	0.01200
ZN 65	2.45E+02	1.93E-04	0.00001	0.00000	0.00000	0.00002	0.00011	0.00000	0.00011
ZN 69M	5.75E-01	1.80E-03	0.00010	0.00003	0.00000	0.00013	0.00080	0.00000	0.00080
ZN 69	3.96E-02	0.00E+00	0.00009	0.00003	0.00000	0.00012	0.00074	0.00000	0.00074
ZR 95	6.50E+01	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00140	0.00140
NB 95	3.50E+01	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00200	0.00200
W187	9.96E-01	2.8E-04	0.00002	0.00001	0.00000	0.00002	0.00014	0.00000	0.00014
NP239	2.35E+00	6.63E-03	0.00042	0.00014	0.00001	0.00058	0.00362	0.00000	0.00360
FISSION PRODUCTS									
BR 83	1.00E-01	4.2E-03	0.00012	0.00001	0.00000	0.00013	0.00083	0.00000	0.00083
BR 84	2.21E-02	4.70E-03	0.00002	0.00000	0.00000	0.00002	0.00011	0.00000	0.00011
RB 89	1.07E-02	3.25E-03	0.00010	0.00000	0.00000	0.00011	0.00068	0.00000	0.00068
SR 89	5.20E+01	9.65E-05	0.00001	0.00000	0.00000	0.00001	0.00006	0.00000	0.00006

TABLE 11.2-4 (SHEET 3 OF 4)

HNP-1&2 EXTENDED POWER UPRATE CASE WITH TB FILTER
LIQUID EFFLUENTS ANNUAL RELEASES TO DISCHARGE CANAL

NUCLIDE	HALF LIFE (days)	CONCENTRATION IN PRIMARY COOLANT (micro ci/ml)	HIGH PURITY (curies)	LOW PURITY (curies)	CHEMICAL (curies)	TOTAL LWS (curies)	ADJUSTED TOTAL (ci/yr)	DETERGENT WASTES (ci/yr)	TOTAL (ci/yr)
FISSION PRODUCTS									
SR 91	4.03E-01	3.52E-03	0.00018	0.00004	0.00000	0.00023	0.00142	0.00000	0.00140
Y 91M	3.47E-02	0.00E+00	0.00010	0.00003	0.00000	0.00013	0.00080	0.00000	0.00080
Y 91	5.88E+01	3.86E-05	0.00000	0.00000	0.00000	0.00000	0.00003	0.00000	0.00003
SR 92	1.13E-01	7.83E-03	0.00023	0.00003	0.00000	0.00026	0.00161	0.00000	0.00160
Y 92	1.47E-01	4.83E-03	0.00032	0.00006	0.00000	0.00038	0.00234	0.00000	0.00230
Y 93	4.25E-01	3.54E-03	0.00019	0.00004	0.00000	0.00023	0.00145	0.00000	0.00140
NB 98	3.54E-02	2.81E-03	0.00002	0.00000	0.00000	0.00002	0.00015	0.00000	0.00015
MO 99	2.79E+00	1.90E-03	0.00012	0.00004	0.00000	0.00017	0.00105	0.00000	0.00100
TC 99M	2.50E-01	1.69E-02	0.00080	0.00016	0.00001	0.00098	0.00608	0.00000	0.00610
TC101	9.72E-03	5.91E-02	0.00003	0.00000	0.00000	0.00003	0.00018	0.00000	0.00018
RU103	3.96E+01	1.93E-05	0.00000	0.00000	0.00000	0.00000	0.00001	0.00014	0.00015
RH103M	3.96E-02	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
TC104	1.25E-02	5.30E-02	0.00005	0.00000	0.00000	0.00005	0.00033	0.00000	0.00033
RU105	1.85E-01	1.65E-03	0.00007	0.00001	0.00000	0.00008	0.00047	0.00000	0.00047
RH105M	5.21E-04	0.00E+00	0.00007	0.00001	0.00000	0.00008	0.00048	0.00000	0.00047
RH105	1.50E+00	0.00E+00	0.00001	0.00000	0.00000	0.00001	0.00005	0.00000	0.00006
RU106	3.67E+02	2.90E-06	0.00000	0.00000	0.00000	0.00000	0.00000	0.00240	0.00240
AG110M	2.53E+02	9.66E-07	0.00000	0.00000	0.00000	0.00000	0.00000	0.00044	0.00044
TE129M	3.40E+01	3.86E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
TE129	4.79E-02	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
TE131M	1.25E+00	9.33E-05	0.00001	0.00000	0.00000	0.00001	0.00005	0.00000	0.00005
I131	8.05E+100	3.12E-03	0.00021	0.0007	0.00001	0.00029	0.00180	0.00006	0.00190
I132	9.58E-02	4.41E-02	0.00114	0.00011	0.00000	0.00127	0.00792	0.00000	0.00790
I133	8.75E-01	4.11E-02	0.00245	0.00072	0.00005	0.00321	0.01999	0.00000	0.02000
I134	3.67E-02	6.89E-02	0.00059	0.00003	0.00000	0.00062	0.00389	0.00000	0.00390
CS134	7.49E+02	2.90E-05	0.00010	0.00018	0.00002	0.00030	0.00188	0.01300	0.01500
I135	2.79E-01	3.94E-02	0.00184	0.00036	0.00001	0.00223	0.01387	0.00000	0.01400
CS136	1.30E+01	7.68E-05	0.00025	0.00047	0.00006	0.00078	0.00484	0.00000	0.00480
CS137	1.10E+04	1.93E-05	0.00006	0.00012	0.00002	0.00020	0.00125	0.02400	0.02500
BA137M	1.77E-03	0.00E+00	0.00006	0.00011	0.00002	0.00019	0.00117	0.00000	0.00120
CS138	2.24E-02	6.62E-03	0.00122	0.00019	0.00002	0.00143	0.00892	0.00000	0.00890

TABLE 11.2-4 (SHEET 4 OF 4)

HNP-1&2 EXTENDED POWER UPRATE CASE WITH TB FILTER
LIQUID EFFLUENTS ANNUAL RELEASES TO DISCHARGE CANAL

NUCLIDE	HALF LIFE (days)	CONCENTRATION IN PRIMARY COOLANT (micro ci/ml)	HIGH PURITY (curies)	LOW PURITY (curies)	CHEMICAL (curies)	TOTAL LWS (curies)	ADJUSTED TOTAL (ci/yr)	DETERGENT WASTES (ci/yr)	TOTAL (ci/yr)
FISSION PRODUCTS									
BA139	5.76E-02	7.32E-03	0.00012	0.00001	0.00000	0.00012	0.00077	0.00000	0.00077
BA140	1.28E+01	3.85E-04	0.00003	0.00001	0.00000	0.00004	0.00022	0.00000	0.00022
LA140	1.67E+00	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
BA141	1.25E-02	6.63E-03	0.00001	0.00000	0.00000	0.00001	0.00004	0.00000	0.00004
LA141	1.63E-01	0.00E+00	0.00002	0.00000	0.00000	0.00002	0.00015	0.00000	0.00015
CE141	3.24E+01	2.89E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
LA142	6.39E-02	3.64 9E-03	0.00007	0.00001	0.00000	0.00008	0.00050	0.00000	0.00050
CE143	1.38E+00	2.81E-05	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
PR143	1.37E+01	3.85E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
CE144	2.84E+02	2.90E-06	0.00000	0.00000	0.00000	0.00000	0.00000	0.00520	0.00520
ALL OTHERS		5.88E-03	0.00001	0.00000	0.00000	0.00001	0.00005	0.0	0.00005
TOTAL (EXCEPT TRITIUM)		4.87E-01	0.01496	0.00388	0.00032	0.01915	0.11915	0.06234	0.18000

TRITIUM RELEASE 21 CURIES PER YEAR

TABLE 11.2-5

MAXIMUM INDIVIDUAL DOSES FROM LIQUID EFFLUENTS (mrem/year)
(LADTAP Output File)

* * * AS LOW AS REASONABLY ACHIEVABLE * * *

A D U L T   D O S E S

				DOSE (MREM PER YEAR INTAKE)				
PATHWAY	SKIN	BONE	LIVER	TOTAL BODY	THYROID	KIDNEY	LUNG	GI-LLI
FISH		1.40E+00	1.81E+00	1.31E+00	1.82E-02	6.02E-01	1.96E-01	3.04E-01
DRINKING		2.06E-03	4 98E-03	4 04E-03	5.22E-03	2.71E-03	1.88E-03	2.90E-03
SHORELINE	1.69E-03	1.45E-03	1.45E-03	1.45E-03	1.45E-03	1.45E-03	1.45E-03	1.45E-03
TOTAL	1.69E-03	1.40E+00	1.81E+00	1.32E+00	2.49E-02	6.07E-01	1.99E-01	3.09E-01
	USAGE (KG/YR,HR/YR)		DILUTION	Time (HR)			SHOREWIDTH FACTOR=0.2	
FISH	21.0		5.0	24.01				
DRINKING	730.0		45.0	36.00				
SHORELINE	12.0		5.0	0.01				

T E E N A G E R   D O S E S

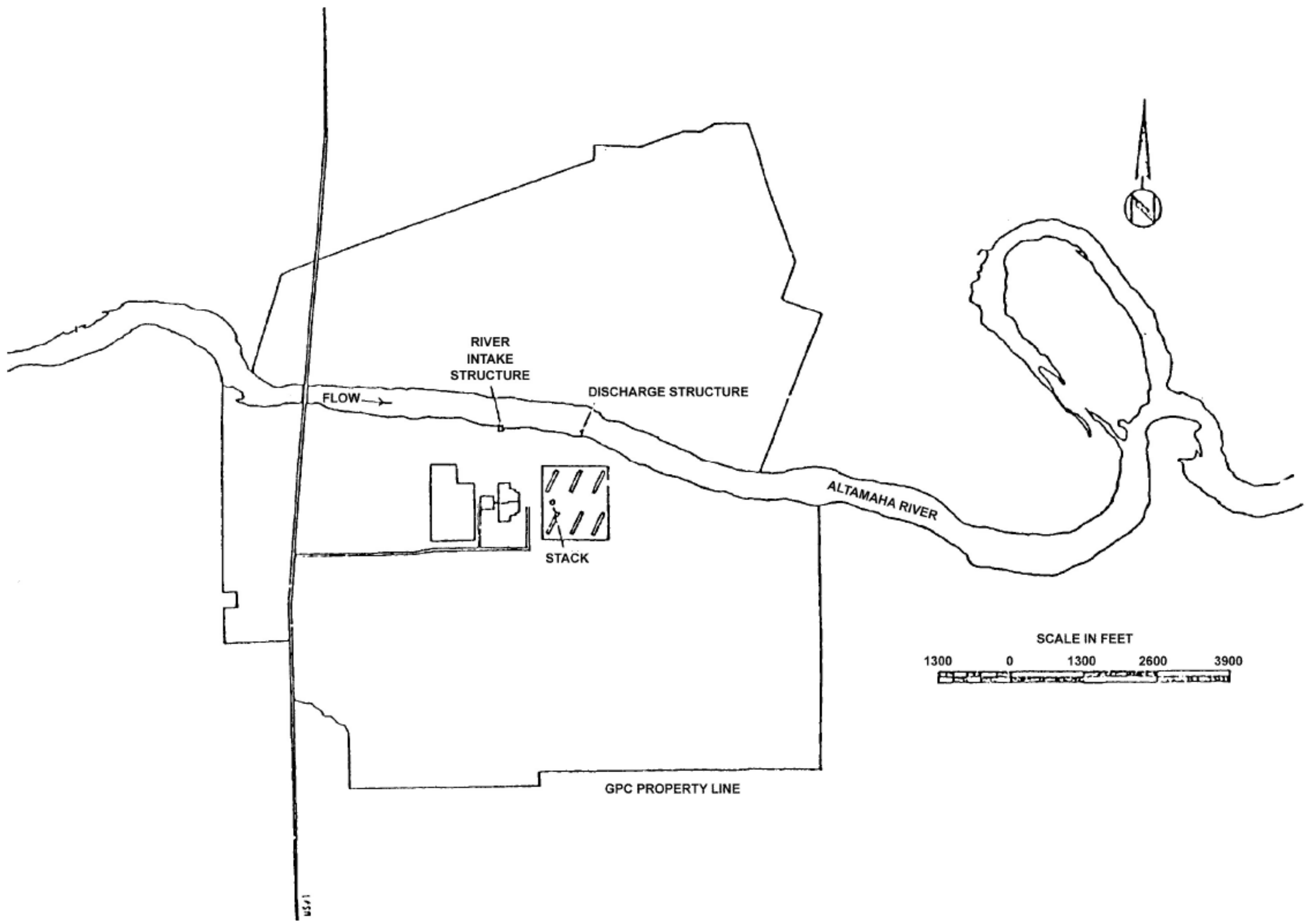
				DOSE (MREM PER YEAR INTAKE)				
PATHWAY	SKIN	BONE	LIVER	TOTAL BODY	THYROID	KIDNEY	LUNG	GI-LLI
FISH		1.49E+00	1.86E+00	7 59E-01	1.75E-02	6.15E-01	2.32E-01	2.22E-01
DRINKING		1.99E-03	4 34E-03	2.41E-03	4.33E-03	2.19E-03	1.47E-03	2.06E-03
SHORELINE	9.44E-03	8.07E-03	8 07E-03	8.07E-03	8.07E-03	8.07E-03	8.07E-03	8.07E-03
TOTAL	9.44E-03	1.50E+00	1.87E+00	7.70E-01	2.99E-02	6.25E-01	2.42E-01	2.32E-01
	USAGE (KG/YR,HR/YR)		DILUTION	TIME(HR)			SHOREWIDTH FACTOR=0.2	
FISH	16.0		5.0	24.01				
DRINKING	510.0		45.0	36.00				
SHORELINE	67.0		5.0	0.01				

C H I L D   D O S E S

				DOSE (MREM PER YEAR INTAKE)				
PATHWAY	SKIN	BONE	LIVER	TOTAL BODY	THYROID	KIDNEY	LUNG	GI-LLI
FISH		1.86E+00	1.63E+00	3.16E-01	1.98E-02	5.20E-01	1.83E-01	8.28E-02
DRINKING		5.74E-03	8.69E-03	3 34E-03	1.05E-02	4.25E-03	2.78E-03	2.97E-03
SHORELINE	1.97E-03	1.69E-03	1.69E-03	1.69E-03	1.69E-03	1.69E-03	1.69E-03	1.69E-03
TOTAL	1.97E-03	1.87E+00	1.64E+00	3 21E-01	3.20E-02	5.26E-01	1.88E-01	8.75E-02
	USAGE (KG/YR,HR/YR)		DILUTION	TIME(HR)			SHOREWIDTH FACTOR=0.2	
FISH	6.9		5.0	24.01				
DRINKING	510.0		45.0	36.00				
SHORELINE	14.0		5.0	0.01				

I N F A N T   D O S E

				DOSE (MREM PER YEAR INTAKE)				
THWAY	SKIN	BONE	LIVER	TOTAL BODY	THYROID	KIDNEY	LUNG	GI-LLI
FISH		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
DRINKING		5.99E-03	1 02E-02	2.83E-03	1.53E-02	4.26E-03	2.86E-03	2.59E-03
SHORELINE	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
TOTAL	0.00E+00	5.99E-03	1 02E-02	2.83E-03	1.53E-02	4.26E-03	2.86E-03	2.59E-03
	USAGE (KG/YR,HR/YR)		DILUTION	TIME(HR)			SHOREWIDTH FACTOR=0.2	
FISH	0.0		5.0	24.01				
DRINKING	330.0		45.0	36.00				



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UNIT 2

RELATIVE LOCATION OF INTAKE AND DISCHARGE STRUCTURES

FIGURE 11.2-3

11.3 GASEOUS EFFLUENT TREATMENT SYSTEMS

The gaseous effluent treatment systems are designed to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to individuals outside the controlled area is as low as reasonably achievable (ALARA) and does not exceed applicable regulations.

11.3.1 DESIGN BASES AND OBJECTIVES

A. The gaseous effluent treatment systems are designed to limit offsite concentrations from routine station releases to significantly less than the limits specified in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) and to stay within the limits established in the plant operating license.

B. A noble gas input equivalent to an annual average off- gas rate (based on 30-min decay) of 100,000 μCi/s of the "1971 mixture" (table 11.3-1) has been used as a design basis. A conservative value of 40 sf^3/min for condenser air inleakage has been used as a design basis.

C. Process and control the release of gaseous radioactive effluents to the site environs so as to maintain ALARA the exposure of persons in unrestricted areas to comply with Appendix I to 10 CFR 50.

D. The radiation dose design basis for the treated off-gas is to delay the gas until the required fraction of the radionuclides has decayed. The daughter products are retained by the charcoal and the high-efficiency particulate air (HEPA) filters. Subsection 3.8.7 provides seismic evaluations of the radwaste facilities buildings.

11.3.2 SYSTEM DESCRIPTIONS

11.3.2.1 Off-Gas Recombiner Charcoal (RECHAR) System

Noncondensible radioactive off-gas is continuously removed from the main condenser by the air ejector during plant operation. This is the major source and is larger than all other sources combined. The air ejector off-gas normally contains activation gases, principally N-16, O-19, and N-13. The N-16 and O-19 have short half-lives and are readily decayed. The 10-min N-13 is present in small amounts that are further reduced by decay. The air ejector off-gas also contains the radioactive noble gas parents of biologically significant Sr-89, Sr-90, Ba-140, and Cs-137. The concentration of these noble gases depends on the amount of tramp uranium in the coolant and on the cladding surfaces (usually extremely small) and the number and size of fuel-cladding leaks. An off-gas RECHAR system is provided to treat this source; the system utilizes catalytic recombination and charcoal adsorption as discussed below. The major system components are located in the turbine building at el 112 ft (drawing no. H-21001) and in the waste gas treatment building (drawing no. H-16536).

11.3.2.1.1 Process Description

The condenser off-gas RECHAR system (figure 11.3-1) uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen from the air ejector system. After cooling (to ~ 130°F) to strip the condensibles and reduce the volume, the remaining noncondensibles (principally kryptons, xenons, and air) are delayed in the 30-min holdup system. The gas is cooled to 45°F and reheated to 74°F for humidity control before reaching the adsorption bed. The charcoal adsorbs and delays the xenons and kryptons from the bulk carrier gas (principally air). This delay on the charcoal permits the Xe and Kr to decay in place. This system results in a reduction of the off-gas activity (Ci) released by a factor of ~ 14 relative to a 30-min holdup system and based on a "1971 mixture." Table 11.3-1 shows the estimated annual release rates from the charcoal adsorbers of various isotopes of krypton and xenon compared to a system releasing 100,000 μCi/s after a 30-min delay.

The adsorption of noble gases on charcoal primarily depends on gas flowrate, mass of charcoal, and gas-unique coefficients known as the dynamic adsorption coefficients. The parametric interrelationships and governing equations are well proved from 7 years of operation of a similar unit at Kernkraftwerk FWE Bayermwerk (KRB) in Germany.

The Kr and Xe holdup times are closely approximated by the following equation:

$$T = \frac{K_D M}{V}$$

where:

T = holdup time of a given gas.

K_D = dynamic adsorption coefficient for the given gas.

M = weight of charcoal.

V = flowrate of the carrier gas.

in consistent units.

Dynamic adsorption coefficient values for xenon and krypton, as reported by Browning,[(1)] are 330 cc/g and 18.5 cc/g, respectively. General Electric (GE) has performed pilot plant tests at their Vallecitos Laboratory and the results were reported at the 12th Atomic Energy Commission (AEC) Air Cleaning Conference.[(2)] Further GE data on a similar system operating at ambient temperatures have been reported in the GE Company proprietary topical report, "Experimental and Operational Confirmation of Off-Gas System Design Parameters;"[(3)] nonproprietary portions of this information are reported in reference 2.

Carrier gas is the air in-leakage from the main condenser after the radiolytic hydrogen and oxygen are removed by the recombiner. The air in-leakage design basis is conservatively sized at 40°sf^3/min total. The sixth edition of Heat Exchange Institute Standards for Steam Surface Condensers,[(4)] paragraph S-16(c) (2) indicates that with certain conditions of stable operation

and suitable construction, noncondensibles (not including radiological decomposition products) should not exceed 6 sf^3/min for large condensers. Dresden 2, Monticello, Fukushima 1, Tsuruga, and KRB have all operated at 6 sf^3/min or below after initial startup (table 6 of reference 3). Dilution air is not added to the system unless the air in-leakage is less than about 4 sf^3/min. In that event, 6 sf^3/min is added to provide for dilution of residual hydrogen from the recombiner. An initial bleed of oil-free air is added on startup until the recombiner comes up to temperature.

The system is mechanically capable of processing 3 times the source term quantities of table 11.3-1 without affecting delay time of the noble gases. With an air in-leakage of 40 sf^3/min, this treatment system results in a delay of 9 h for Kr and 6.8 days for Xe.

Hydrogen concentration of gases from the air ejector is kept below the flammable limit by maintaining adequate process steam flow for dilution at all times. This steam flow is monitored and alarmed in the main control room (MCR). The basis for sizing the catalytic recombiner is to maintain the hydrogen concentration below 4% (including steam) at the inlet using the dilution flow and below 4% at the outlet on a dry basis. The exit hydrogen concentration is normally well below the 4% maximum allowed.

Figure 11.3-1 is the process flow diagram for the system, and drawing no. H-26045 is the P&ID. Table 11.3-2 is a list of isotopic inventories of equipment in the RECHAR system.

11.3.2.1.2 Equipment Description

A listing of the off-gas system major equipment items which includes materials, rated process conditions, number of units supplied, and the design codes is provided in table 11.3-3. Equipment and piping are designed and constructed in accordance with the requirements of the applicable codes as given in table 11.3-3 and comply with the welding and material requirements and the system construction and testing requirements discussed below.

11.3.2.1.2.1 **<u>Construction</u>**. Pressure-retaining components of the off-gas system utilize welded construction to the maximum practicable extent. Process piping systems include the first root valve on sample and instrument lines. Process lines are not less than 3/4-in. nominal pipe size. Sample and instrument lines are not considered as portions of the process systems. Flanged joints or suitable rapid disconnect fittings are not used except where maintenance requirements clearly indicate that such construction is preferable. Screwed connections in which threads provide the only seal are not used. Screwed connections backed up by seal welding or mechanical joints are used only on lines of 3/4-in. nominal pipe size. In lines 3/4 in. or greater, but < 2 1/2-in. nominal pipe size, socket-type welds are used. In lines 2 1/2-in. nominal pipe size and larger, pipe welds are of the butt-joint type.

11.3.2.1.2.2 <u>Operating Procedure</u>

A. Prestartup Preparations

Prior to starting the main steam jet air ejectors (SJAEs), the charcoal vault is temperature controlled to near 77°F, the glycol cooler is chilled to near 35°F, and glycol is circulated through the cooler condenser, the off-gas condenser cooling water is valved in, and the recombiner heaters are turned on.

B. Startup

As the reactor is pressurized, preheater steam is supplied and air is bled through the preheater and recombiner. The recombiner is preheated to at least 225°F with this air bleed and/or by admitting steam to the final SJAE. With the recombiners preheated and the charcoal adsorbers valved in, the SJAE string is started. The bleed air is terminated. As the condenser is pumped down and the reactor power increases, the recombiner inlet stream is diluted to less than 4% H_2 by volume by a fixed steam supply, and the off-gas condenser outlet is maintained at $<$ 4% hydrogen by volume.

C. Normal Operation

After startup, the noncondensibles pumped by the SJAE stabilize. Recombiner performance is closely followed by the recorded temperature profile in the recombiner catalyst bed. The hydrogen effluent concentration is measured by a hydrogen analyzer.

Normal operation is terminated following a normal reactor shutdown or a scram by terminating steam to the SJAEs and the preheater.

11.3.2.2 <u>Other Gaseous Effluent Treatment Systems</u>

Some radioactive gas may be released from other deliberate ventilation paths such as from the reactor building, turbine building, or radwaste building. Iodine and particulate monitors are installed at the points of deliberate release of ventilation air which could have potentially significant amounts of radioactive material. Treatment involving holdup or filtration has been provided for each potential path for gaseous release as discussed for each source below.

11.3.2.2.1 Mechanical Vacuum Pump Off-Gas

During startup of the plant and before operation of the SJAE is achieved, a mechanical vacuum pump is utilized for evacuation of the main turbine condenser. The mechanical vacuum pump exhaust is discharged to the main stack via the gland-seal holdup line. The main condenser mechanical vacuum pump normally is in service during startup: a time when little or no radioactive gas is present. The pump is isolated from the off-gas system whenever the main steam line monitor system indicates high radiation.

11.3.2.2.2 Drywell Ventilation

Activity can be introduced into the drywell atmosphere through venting of the primary system relief valves into the suppression chamber and as a result of release of activity from system leaks and drywell sumps. The drywell forms a closed system that can be purged with normal reactor building air, if necessary, when personnel access is required. The drywell also can be vented during plant startup to accommodate the expansion of the atmosphere that occurs with increasing temperature or during plant operation if the oxygen content should reach specified limits. Air vented during startup and air purged during or after operation is discharged through the standby gas treatment system (SGTS) and its filters to remove airborne radioactivity.

11.3.2.2.3 Gland-Seal Condenser Off-Gas

After condensation of bulk moisture during normal operation, the gland-seal system off-gas is held up for a minimum of 1.75 min. This allows for the decay of short-lived activation gases before discharging to the main stack where additional holdup is afforded by the stack design.

11.3.2.2.4 Turbine Building

The turbine building ventilation system was designed to minimize the potential for releasing airborne radioactivity from the turbine building to the environs. A chilled water system supplying area fan coil units is used to help remove the heat load in the building. The balance of the system supplies outside air and exhausts turbine building air in quantities consistent with established ventilation criteria.

The turbine building exhaust air flows in the building from low-radiation areas to high-radiation areas. This air is then ducted to filter banks and released via the reactor building vent plenum. The filter banks employ HEPA and charcoal filters to minimize particulate and halogen releases. Radiation monitors survey the bank performance with high-level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe. A detailed discussion of this system is provided in subsection 9.4.4.

The charcoal filters contain charcoal impregnated with TEDA with a minimum expected efficiency of 99%. This type of impregnant is used to increase charcoal efficiency at low concentrations; and because of its favorable weathering characteristics, it is suitable for a continuously operated system.

11.3.2.2.5 Radwaste Building

The radwaste building ventilation system was designed to minimize the potential for releasing airborne radioactivity from the radwaste building to the environs. The ventilation system includes redundant supply fans, supply air filters, exhaust air filter trains, and redundant exhaust fans.

The supply air is ducted to the different areas of the radwaste building. The exhaust air is ducted to the filter trains and released via the reactor building vent plenum. The filter train consists of a bank of carbon adsorbers and a bank of HEPA filters to minimize particulate and halogen releases. Radiation monitors survey the bank performance with high level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe. A detailed discussion of this system is provided in subsection 9.4.3.

The charcoal filters contain charcoal impregnated with TEDA with a minimum expected efficiency of 99%. This type of impregnant is used to obtain increased charcoal adsorption efficiency at low concentrations and because of its favorable weathering characteristics for a continuously operated system.

11.3.2.2.6 Other Potentially Radioactive Gases

All tanks expected to contain radioactive material are vented through the ventilation system of the building housing the tanks.

11.3.3 INSTRUMENTATION APPLICATION

The off-gas system is monitored by flow, temperature, pressure, and humidity instrumentation, and by hydrogen analyzers to ensure correct operation and control and to ensure that hydrogen concentration is maintained below the flammable limit. Table 11.3-4 lists the process parameters that are instrumented to alarm in the MCR. It also indicates whether the parameters are recorded or just indicated. The operator is in control of the system at all times.

The instruments are not designed to be explosion proof; this implies requirements far in excess of those necessary for this system. The off-gas system is designed with:

- Dilution steam and redundant catalytic recombiners such that normally no part of the system downstream of the SJAE contains a detonable gas mixture.

- Extremely stringent leaktightness characteristics, so in the event of a recombiner failure, virtually none of the resulting detonable gas mixture downstream of the off-gas condenser could escape the system.

- Redundant hydrogen analyzers, and numerous other flow, temperature, and pressure-drop readings, which would provide indication of a failed recombiner, and of an internal hydrogen explosion, should one occur as a result of the failed recombiner in spite of designing to eliminate ignition sources.

- Equipment, piping, and inline instruments which form a fully detonation-resistant pressure boundary and offline instrument connections which are detonation-resistant to the first root valve.

Sensor checks and instrument calibrations are governed by the use of appropriate operational procedures.

The hydrogen analyzer is provided for process information only and is not required for safe system operation. The requirement for a gas analysis when the hydrogen analyzer is inoperable depends on how long this instrument remains inoperable. It is not anticipated that such gas analysis would normally be required.

11.3.3.1 Off-Gas System Performance Instrumentation

A. Catalytic Recombiner

The catalytic recombiner vessel temperatures are monitored by thermocouples and recorded. High or low temperature is annunciated in the MCR. The standby recombiner is temperature controlled, maintained, monitored, and recorded. Any low temperature is annunciated in the MCR. Inlet process gas is monitored for temperature, and if low temperatures are obtained, they are annunciated in the MCR.

B. Off-Gas Condenser

The off-gas condenser condensate level is maintained at a given level within the condenser shell. A level control system is used to provide drainage of condensate from the condenser shell. High and low level and high gas discharge temperature are annunciated locally (table 11.3-4).

C. Charcoal Vessels and Vaults and Particulate Filters

The first charcoal vessels are temperature-monitored and recorded. High vessel temperature is alarmed at 80°F in the MCR. The charcoal vessel vault is also temperature-monitored and recorded in the MCR along with a high-temperature alarm. Two independent refrigeration units with independent temperature controls maintain the vault at a temperature of 77°F with a ± 2°F variation.

Differential pressure measurements are made across the charcoal vessel train and the after filters. High differential pressure is annunciated in the MCR.

D. Hydrogen Analyzer

Hydrogen analyzers are used to measure the hydrogen content of the off-gas process stream. The hydrogen concentration percentage output from each analyzer is indicated and recorded in the MCR along with alarm annunciation for high hydrogen concentration percentage in the off-gas process stream.

The hydrogen analyzer system continuously withdraws a sample of the process off-gas, analyzes the hydrogen content, and returns the sample gas to the main condenser. During normal plant operation, the main turbine condenser vacuum provides the pumping force to move the sample gas from the off-gas process line, through the hydrogen analyzer system. A hydrogen level of 1% alarms and annunciates in the MCR.

The hydrogen analyzers used in the off-gas system operate on an electrolytic cell principle and do not present an ignition source if the hydrogen concentration in the sensed gas reaches detonable levels. Furthermore, the sample-conditioning equipment incorporates a bubble pot designed to serve as a flame arrester so that even if a sensor which inherently presents an ignition source in the sample chamber, i.e., a heated wire or catalyst bead-type sensor, should be substituted for the present unit, an ignition could not propagate from the sensor back into the process piping.

11.3.3.2 Off-Gas System Flow Measurements

Off-gas system flow measurements are made just downstream of the charcoal adsorbers. Startup and normal range flows are recorded in the MCR and displayed on a local gauge. Normal range high and low flows are recorded and annunciated in the MCR. The MCR recorder keeps a record of all discharge volumes.

11.3.3.3 Off-Gas System Radiation Measurements

A radiation monitor placed after the off-gas condenser continuously monitors radioactivity release from the reactor and, therefore, continuously monitors the degree of fuel leakage and input to the charcoal adsorbers. This radiation monitor is used to provide an alarm on high radiation in the off-gas.

A radiation monitor is also provided at the outlet of the charcoal adsorbers to continuously monitor the release rate from the adsorber beds. This radiation monitor is used to isolate the off-gas system on high radioactivity to prevent treated gas of unacceptably high activity from entering the main stack. Therefore, the activity of the gas entering and leaving the off-gas system is continuously monitored; thus, system performance is known to the operator at all times. Provision is made for sampling and periodic analysis of the influent and effluent gases for purposes of determining their compositions. This information is used in calibrating the monitors and in relating the release to calculated environs dose. Off-gas system process radiation instrumentation is further discussed in section 11.4.

11.3.4 SAFETY EVALUATION

11.3.4.1 <u>Normal Operation</u>

11.3.4.1.1 Off-Gas System Safety Design Evaluation

The following design features or evaluations ensure that the off-gas system performs its intended function:

A. Explosion Resistance

The pressure boundary of the system is designed to be explosion resistant. The pressure vessels are designed to withstand 350-psig static pressure, and piping and valving are designed to resist dynamic pressures encountered in long runs of piping at the design temperature. This analysis is covered in a proprietary report submitted to the Nuclear Regulatory Commission (NRC).[5]

An equivalent detonation-containing-static pressure is then derived for which the component can be rated, based upon the wall thickness calculated per the above procedure.

B. Charcoal and Charcoal Vault Temperature

The charcoal adsorbers operate at essentially room temperature so that, on system shutdown, radioactive gases in the adsorbers are subject to the same holdup time as during normal operation, even in the presence of continued air flow. The charcoal adsorbers are designed to limit the temperature of the charcoal (~ 77°F) to well below the charcoal ignition temperature, thus precluding overheating or fire and consequent escape of radioactive material. The adsorbers are located in a shielded room, and maintained at a constant temperature by an air-conditioning system that removes the decay heat generated in the adsorbers. Failure of the air-conditioning system causes an alarm in the MCR. In addition, a radiation monitor is provided to monitor the radiation level in the charcoal bed vault. High radiation causes an alarm in the MCR.

During a plant outage when the condenser is not maintained at vacuum, there is no gas flow through the charcoal. Maximum mid-line temperature in the charcoal vessel would rise < 12°F if flow were stopped. The decay heat at the design basis of 100,000 μCi/s is insignificant compared to the thermal mass of the charcoal vault.

C. Liquid Seals

There are several liquid seals to prevent gas escape through drains. These seals are protected against permanent loss of liquid by an enlarged section downstream of the seal that can hold the seal volume and drains by gravity back into the loop

after the momentary pressure surge has passed. Each seal has a manual valve that can be used to fill the loop. Seals are also equipped with solenoid valves that close if release from this system exceeds established limits.

D. Leakage of Radioactive Gases

Leakage of radioactive gases from the system is limited by welding piping connections where possible and using valves with liquid seals, bellows stem seals, or equivalent valving. The system operates at a maximum of 7 psig during startup and $<$ 2 psig during normal operation so that the differential pressure to cause leakage is small.

E. Gas Channeling in the Charcoal Adsorber

Channeling in the charcoal adsorbers is prevented by supplying an effective flow distributor on the inlet, having long columns, and having a high bed-to-particle diameter ratio of ~ 500. Underhill has stated that channeling or wall effects may reduce efficiency of the holdup bed if this ratio is not $>$ 12.[4] During transfer of the charcoal into the charcoal adsorber vessels, radial sizing of the charcoal is minimized by pouring the charcoal (by gravity or pneumatically) over a cone or other instrument to spread the granules over the surface.

F. Charcoal Bypass Mode

A valve is provided to bypass the charcoal adsorbers. The main purpose of this bypass is to protect the charcoal during preoperation and startup testing when gas activity is zero or very low. It may be desirable to use the bypass for short periods during startup or normal operations. This bypass mode would not be used for normal operation unless some unforeseen system malfunction would necessitate shutting down the power plant or operating in the bypass mode and remaining within the Technical Specifications limits. The activity release is controlled by a process monitor, located upstream of the vent isolation valve, that causes the bypass valve to close on a high-radiation alarm. This interlock can be defeated only by a keylock switch. The alarm setting is defeated only by a keylock switch. The alarm setting is covered in paragraph 7.6.1.3. In addition, there is a high-high-high alarm on the same monitor that causes the off-gas system to be isolated from the stack if established release limits are exceeded.

G. Shielding

Shielding is provided for off-gas system equipment to maintain safe radiation exposure levels for plant personnel. The equipment is principally operated from the MCR.

H. Malfunction Analysis

Malfunction analysis, indicating consequences and design precautions taken to accommodate failure of various components of the system, is given in table 11.3-5.

I. Seismic Design

Conservative analyses similar to those presented in reference 6 demonstrate that equipment failure does not result in doses exceeding the guidelines of Regulatory Guide 1.29; thus, the off-gas system equipment and components, and the buildings housing the equipment are not designed to meet Seismic Category I requirements.

11.3.4.1.2 Estimate of Radionuclides Expected to be Released (HNP-1 and HNP-2)

Estimates of the annual particulate and gaseous releases to the environment were recalculated for the extended power uprate to 2763 MWt core thermal power using an updated version of the BWR-GALE Code.(7) Input parameters for the BWR-GALE Code are presented in table 11.3-6. This single GALE model was developed to be applicable to both Hatch units.

The calculated annual releases of activity to the environment in gaseous effluents are also presented in table 11.3-6. They include releases of tritium, noble gases, iodine, and particulates from ventilation systems of the containment, auxiliary, turbine, and radwaste buildings; from operation of the mechanical vacuum pump gland seal system; and from the condenser off-gas treatment system.

11.3.4.1.3 Release Points

Gaseous effluents are only released from two points: the main stack and the reactor building vent plenum. All gaseous effluents other than ventilation releases are released from the main stack. Reactor, turbine, and radwaste building ventilation releases are discharged from the reactor building vent plenum. The reactor building vent plenum release is elevated above the reactor building roof which is the tallest plant structure in the power block; however, releases are assumed to be at ground level and entrapped within the building wake.

11.3.4.1.4 Dilution Factors

The long-term (annual average) atmospheric dispersion factors (χ/Q) and deposition factors (D/Q) were estimated based on 4 years of onsite meteorological data. The data and models used to estimate the χ/Qs and D/Qs are presented in subsection 2.3.5. The χ/Qs and D/Qs at the nearest site boundary, residence, vegetable garden, milk cow, and meat animal, for each of 16 radial sectors, out to 8000 m, are given in tables 2.3-23 and 2.3-24 for elevated releases (from main stack) and ground-level releases (from reactor building vent), respectively.

11.3.4.1.5 Estimated Doses

Using the methodology of NUREG-0597, the GASPAR Code,(9) which implements the dose models described in Regulatory Guide 1.109,(8) in conjunction with the annual releases given in table 11.3-6 and the dispersion and deposition factors given in tables 2.3-23 and 2.3-24,

maximum annual offsite doses to air and to individuals are estimated. The standard reference 8 values for uptake rates, holdup times, and other default parameters are used.

Table 11.3-7 provides the maximum air dose (gamma and beta) and a breakdown by organ and pathway, and individual doses that include the summation from both plant discharge vents. Estimated maximum dose totals are compared to the 10 CFR 50, Appendix I, design objective dose criteria given in table 11.3-10. All estimated doses are below the Appendix I values.

11.3.4.2 <u>Accident Analysis</u>

The failure of the off-gas system is analyzed in section 15.4. The related failures of the SJAE lines and the turbine gland-seal off-gas lines are also analyzed in section 15.4.

11.3.5 TESTS AND INSPECTIONS

The gaseous waste disposal systems are used on a routine basis and do not require specific testing to assure operability. Monitoring equipment is calibrated and maintained on a specific schedule and on indication of malfunction. The particulate filters were tested using a dioctylphthalate (DOP) smoke test or equivalent.

Experience with BWRs has shown that the calibration of the off-gas and stack effluent monitors changes with isotopic content. Isotopic content can change depending on the presence or absence of fuel-cladding leaks in the reactor and the nature of the leaks. Because of this, the monitors are calibrated against grab samples periodically and when there appears to be a significant change in the station operations.

The off-gas RECHAR system was pressure tested to the maximum practicable extent. Piping was hydrostatically or pneumatically tested in their entirety, utilizing available valves or temporary plugs at atmospheric tank connections. Hydrostatic testing of piping was performed at a pressure 1.5 times the design pressure, but in no case at < 75 psig. The test pressure was held for a minimum of 30 min with no leakage indicated. Pneumatic testing may be substituted for hydrostatic testing in accordance with the applicable codes.

The following tests were performed for off-gas system components:

A. Charcoal Performance

The ability of the charcoal to delay the noble gases can be continuously evaluated by comparing activity measured and recorded by the process activity monitors at the exit of the off-gas condenser and at the exit of the charcoal adsorbers. Grab sample points are located upstream and downstream of the first charcoal bed and downstream of the last charcoal bed and can be used for periodic sampling if the monitoring equipment indicates degradation of system delay performance.

B. Post-Filter

On installation, replacements, and at periodic intervals during operation, these particulate filters are tested using a DOP test or equivalent.

REFERENCES

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3. Miller, C. W., "Experimental and Operational Confirmation of Off-Gas System Design Parameters," NEDO-10751, Proprietary, January 1973.

4. Standards for Steam Surface Condensers, Sixth Edition, Heat Exchange Institute, New York, New York, 1970.

5. Nesbitt, L. B., "Design Basis for New Gas Systems," NEDE-11146, Proprietary, July 1971.

6. Miller, C. W., et. al., "A General Justification for Classification of Effluent Treatment System Equipment as Group D," NEDO-10734, February 1973.

7. "Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors," USNRC NUREG-0016, (BWR-GALE Code), Revision 1, January 1979.

8. "Calculation of Annual Doses to Man from Radioactive Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," USNRC Regulatory Guide 1.109, Revision 1, October 1977.

9. "User's Guide to GASPAR Code," USNRC NUREG-0597, June 1980.

TABLE 11.3-1

ESTIMATED PROCESS OFF-GAS RELEASE RATES FROM MAIN CONDENSER (WITH 40 sf^3/min IN-LEAKAGE AND BASED ON A 1971 MIXTURE)

Isotope	Discharge Rate from 30-min Holdup Line (µCi/s)	Discharge Rate from Charcoal Adsorbers (µCi/s)	Annual Discharge from Charcoal Adsorbers (Ci/year)[a]	Inventory at End of 1 Year due to 1 Year of Operation (Ci)[a]
Kr-83m	2880	103	2762	1
Kr-85m	5690	1380	37,015	28
Kr-85	10 - 20[b]	10 - 20	268 - 536	275 - 550
Kr-87	15,000	110	2950	1
Kr-88	17,900	1920	51,499	25
Kr-89	185			
Xe-131m	15	10	268	14
Xe-133m	276	35	939	9
Xe-133	8150	3360	90,123	1989
Xe-135m	7010			
Xe-135	21,400			
Xe-137	673			
Xe-138	20,800			
Halides	negligible	negligible	negligible	negligible
TOTAL	~ 100,000	~ 6900	~ 186,000	~ 2500

a. At 85% plant capacity factor.
b. Estimated from experimental observations.

TABLE 11.3-2 (SHEET 1 OF 4)

INVENTORY ACTIVITIES FOR OFF-GAS RECHAR EQUIPMENT (μCi)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser	Moisture Separator	Reheater	Charcoal Vessels (Train)	Charcoal Vessels (First)	Afterfilter
Residence Times											
Gas	8.00-1S	9.40-1S	5.00+1S	1.57 S	3.00+1M	5.47+1S	2.00 S	4.46 S 1	2.32+1M	1.95 M	1.34+1S
Kr	0.	0.	0.	0.	0.	0.	0.	0.	8.98 H	4.48+1M	0.
Xe	0.	0.	0.	0.	0.	0.	0.	0.	6.76 D	1.35+1H	0.
Operation time	0.	0.	0.	0.	0.	0.	0.	0.	1.00+1Y	1.00+1Y	1.00 Y
Solid daughter capture	0	0	100	100	60	0	0	0	100	100	100
Solid daughter washout			100	100	100				0	0	0
Isotope											
N-13	6.73+3	7.90+3	4.08+5	1.24+4	5.98+6	5.20+4	1.84+3	4.09+3	6.33+5	1.11+5	2.39+3
N-17	4.34+3	4.41+3	2.60+4	1.42	4.72	0.	0.	0.	0.	0.	0.
O-19	6.99+5	8.03+5	2.37+7	3.56+5	8.57+6	0.	0.	0.	0.	0.	0.
Kr-83M	2.77+3	3.26+3	1.73+5	5.41+3	5.67+6	1.56+5	5.70+3	1.27+4	2.66+7	6.72+6	1.36+1
Kr-85	1.90+1	2.24+1	1.19+3	3.74+1	4.28+4	1.30+3	4.76+1	1.06+2	7.74+5	6.44+4	3.22+2
Kr-85M	4.92+3	5.78+3	3.07+5	9.63+3	1.06+7	3.10+5	1.13+4	2.52+4	9.78+7	1.44+7	1.84+4
Kr-87	1.57+4	1.85+4	9.79+5	3.06+4	3.07+7	8.08+5	2.94+4	6.56+4	9.60+7	3.26+7	1.44+3
Rb-87	0.	0.	0.	0.	0.	0.	0.	0.	1.34-2	4.66-3	0.
Kr-88	1.61+4	1.90+4	1.01+6	3.16+4	3.40+7	9.69+5	3.54+4	7.88+4	2.28+8	4.35+7	2.54+4
Rb-88	4.21	1.57+1	1.74+4	1.62+1	8.55+6	2.95+5	1.12+4	2.51+4	2.37+8	5.22+7	2.54+4
Kr-89	9.67+4	1.13+5	5.50+6	1.57+5	2.75+7	7.19+3	2.37+2	5.22+2	3.20+4	3.20+4	0.
Rb-89	2.94+1	1.10+2	1.14+5	9.38+1	1.12+7	1.44+5	5.14+3	1.14+4	3.40+6	3.40+6	0.
Sr-89	1.24-5	1.15-5	3.17-1	7.76-6	1.65+3	6.51+1	2.40	5.36	1.09+7	1.09+7	0.
Y-89M	0.	0.	1.23-1	0.	1.61+3	6.46+1	2.38	5.32	1.09+7	1.09+7	0.
Kr-90	1.67+5	1.93+5	6.23+6	1.07+5	3.12+6	0.	0.	0.	0.	0.	0.

TABLE 11.3-2 (SHEET 2 OF 4)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser	Moisture Separator	Reheater	Charcoal Vessels (Train)	Charcoal Vessels (First)	Afterfilter
Rb-90	2.87+2	1.06+3	7.96+5	3.61+2	1.87+6	1.47+2	4.74	1.04+1	5.41+2	5.41+2	0.
Sr-90	0.	0.	1.16-2	0.	2.16	5.19-2	1.90-3	4.23-3	2.95-4	2.95-4	0.
Y-90	0.	0.	0.	0.	5.06-3	2.41-4	8.98-6	2.01-5	2.92+4	2.92+4	0.
Kr-91	8.62+4	9.45+4	1.18+6	2.54+3	1.88+4	0.	0.	0.	0.	0.	0.
Rb-91	4.17+2	1.50+3	5.11+5	2.42+1	1.13+4	1.77-6	0.	0.	1.76-6	1.76-6	0.
Sr-91	2.23-3	2.02-2	2.36+2	2.55-4	3.76+2	7.91	2.89-1	6.44-1	7.26+3	7.26+3	0.
Y-91	0.	0.	1.31-6	0.	5.23-3	3.33-4	1.25-5	2.81-5	7.41+3	7.41+3	0.
Y-91M	0.	2.15-6	8.30-1	0.	6.52+1	2.63	9.74-2	2.17-1	7.47+3	7.47+3	0.
Kr-92	1.41+3	1.20+3	2.81+3	8.19-6	1.01-5	0.	0.	0.	0.	0.	0.
Rb-92	8.82+1	2.67+2	5.07+3	1.01-6	6.08-6	0.	0.	0.	0.	0.	0.
Sr-92	1.74-3	1.42-2	1.65+1	0.	0.	0.	0.	0.	3.56-6	3.56-6	0.
Y-92	0.	0.	1.97-2	0.	0.	0.	0.	0.	4.03-6	4.03-6	0.
Kr-93	4.54+1	3.35+1	5.10+1	0.	0.	0.	0.	0.	0.	0.	0.
Rb-93	2.22	6.47	1.21+2	0.	0.	0.	0.	0.	0.	0.	0.
Sr-93	9.51-4	7.53-3	8.01	0.	0.	0.	0.	0.	0.	0.	0.
Y-93	0.	0.	3.30-3	0.	0.	0.	0.	0.	0.	0.	0.
Zr-93	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Nb-93M	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Kr-94	1.20	7.77-1	8.46-1	0.	0.	0.	0.	0.	0.	0.	0.
Rb-94	1.27-1	3.30-1	2.37	0.	0.	0.	0.	9.	9.	9.	9.
Sr-94	3.22-4	2.37-3	9.57-1	0.	0.	0.	0.	0.	0.	0.	0.
Y-94	0.	0.	1.35-2	0.	0.	0.	0.	0.	0.	0.	0.
Kr-95	7.16-6	2.56-6	0.	0.	0.	0.	0.	0.	0.	0.	0.
Rb-95	3.99-6	4.24-6	2.44-6	0.	0.	0.	0.	0.	0.	0.	0.
Sr-95	0.	0.	7.71-6	0.	0.	0.	0.	0.	0.	0.	0.
Y-95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Zr-95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Nb-95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Kr-97	7.22-4	4.66-4	5.08-4	0.	0.	0.	0.	0.	0.	0.	0.
Rb-97	5.68-4	5.37-4	5.90-4	0.	0.	0.	0.	0.	0.	0.	0.

TABLE 11.3-2 (SHEET 3 OF 4)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser	Moisture Separator	Reheater	Charcoal Vessels (Train)	Charcoal Vessels (First)	Afterfilter
Sr-97	2.40-4	5.57-4	8.99-4	0.	0.	0.	0.	0.	0.	0.	0.
Y-97	3.44-5	2.29-4	1.43-4	0.	0.	0.	0.	0.	0.	0.	0.
Zr-97	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Nb-97	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Nb-97M	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Xe-131M	1.21+1	1.42+1	7.56+2	2.38+1	2.72+4	8.27+2	3.02+1	6.74+1	7.30+6	7.23+5	1.37+2
Xe-133	6.61+3	7.76+3	4.13+5	1.30+4	1.48+7	4.50+5	1.65+4	3.67+4	3.22+9	3.86+8	4.62+4
Xe-133M	2.22+2	2.61+2	1.39+4	4.35+2	4.97+5	1.51+4	5.51+2	1.23+3	6.78+7	1.23+7	4.64+2
Xe-135	1.78+4	2.09+4	1.11+6	3.49+4	3.98+7	1.20+6	4.38+4	9.76+4	1.05+9	6.72+8	1.39
Xe-135M	2.09+4	2.45+4	1.28+6	3.94+4	2.50+7	3.57+5	1.28+4	2.85+4	8.65+6	8.65+6	0.
Cs-135	0.	0.	0.	0.	2.06-4	8.63-6	0.	0.	3.17+3	2.03+3	0.
Xe-137	1.18+5	1.39+5	6.85+6	1.99+5	4.16+7	2.77+4	9.30+2	2.05+3	1.51+5	1.51+5	0.
Cs-137	3.45-5	1.28-4	1.37-1	1.13-4	2.68+1	6.63-1	2.42-2	5.41-2	4.08+5	4.08+5	0.
Ba-137M	0.	0.	1.02-2	0.	2.28+1	6.57-1	2.41-2	5.37-2	4.08+5	4.08+5	0.
Xe-138	7.11+4	8.35+4	4.35+6	1.34+5	8.04+7	1.05+6	3.76+4	8.37+4	2.30+7	2.30+7	0.
Cs-138	1.02+1	3.81+1	4.18+4	3.77+1	1.54+7	4.37+5	1.62+4	3.62+4	4.57+7	4.57+7	0.
Xe-139	1.76+5	2.03+5	7.18+6	1.40+5	5.08+6	0.	0.	0.	0.	0.	0.
Cs-139	8.73+1	8.23+2	2.72+5	1.37+2	2.70+6	1.54+4	5.44+2	1.21+3	2.18+5	2.18+5	0.
Ba-139	3.24-3	3.00-2	7.01+2	9.97-3	3.98+5	1.17+4	4.27+2	9.53+2	1.76+6	1.76+6	0.
Xe-140	1.21+5	1.36+5	2.64+6	1.84+4	2.30+5	0.	0.	0.	0.	0.	0.
Cs-140	5.28+2	1.92+3	9.11+5	1.59+2	1.38+5	1.60-4	4.24-6	9.14-6	1.83-4	1.83-4	0.
Ba-140	8.87-5	8.11-4	1.23+1	5.25-5	1.46+2	3.16	1.15-1	2.57-1	9.21+4	9.21+4	0.
La-140	0.	0.	6.69-4	0.	5.92-1	2.59-2	9.61-4	2.15-3	9.22+4	9.22+4	0.
Xe-141	7.19+2	5.96+2	1.29+3	1.08-6	1.22-6	0.	0.	0.	0.	0.	0.
Cs-141	8.45	2.68+1	1.92+3	0.	0.	0.	0.	0.	0.	0.	0.
Ba-141	1.46-3	1.22-2	3.68+1	0.	0.	0.	0.	0.	0.	0.	0.
La-141	0.	0.	3.34-2	0.	0.	0.	0.	0.	0.	0.	0.
Ce-141	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Xe-142	2.20+1	1.58+1	2.24+1	0.	0.	0.	0.	0.	0.	0.	0.
Cs-142	3.47	8.82	4.80+1	0.	0.	0.	0.	0.	0.	0.	0.

TABLE 11.3-2 (SHEET 4 OF 4)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser	Moisture Separator	Reheater	Charcoal Vessels (Train)	Charcoal Vessels (First)	Afterfilter
Ba-142	1.06-3	7.77-3	3.01	0.	0.	0.	0.	0.	0.	0.	0.
La-142	0.	0.	9.05-3	0.	0.	0.	0.	0.	0.	0.	0.
Xe-143	4.17-1	2.63-1	2.71-1	0.	0.	0.	0.	0.	0.	0.	0.
Cs-143	6.68-2	1.61-1	7.23-1	0.	0.	0.	0.	0.	0.	0.	0.
Ba-143	1.10-3	7.60-3	8.81-1	0.	0.	0.	0.	0.	0.	0.	0.
La-143	0.	3.25-6	2.45-2	0.	0.	0.	0.	0.	0.	0.	0.
Ce-143	0.	0.	2.73-6	0.	0.	0.	0.	0.	0.	0.	0.
Pr-143	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
Xe-144	1.55+2	1.70+2	2.22+3	5.49	4.27+1	0.	0.	0.	0.	0.	0.
Cs-144	3.35+1	9.64+1	2.41+3	2.04	2.56+1	0.	0.	0.	0.	0.	0.
Ba-144	5.38-1	4.15	2.18+3	6.60-2	2.56+1	0.	0.	0.	0.	0.	0.
La-144	1.87-3	3.46-2	7.74+2	4.61-4	2.56+1	0.	0.	0.	0.	0.	0.
Ce-144	0.	0.	3.86-4	0.	1.24-3	2.64-5	0.	2.15-6	1.01+1	1.01+1	0.
Pr-144	0.	0.	3.20-6	0.	4.99-4	1.81-5	0.	1.49-6	1.01+1	1.01+1	0.
Nd-144	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
I-131	0.	0.	0.	0.	0.	0.	0.	0.	3.30+5	3.30+5	0.
I-132	0.	0.	0.	0.	0.	0.	0.	0.	3.50+4	3.50+4	0.
I-133	0.	0.	0.	0.	0.	0.	0.	0.	2.40+5	2.40+5	0.
I-134	0.	0.	0.	0.	0.	0.	0.	0.	2.60+4	2.60+4	0.
I-135	0.	0.	0.	0.	0.	0.	0.	0.	1.10+5	1.10+5	0.
Total	1.64+6	1.89+6	6.60+7	1.29+6	3.74+8	6.31+6	2.30+5	5.12+5	5.14+9	1.33+9	1.20+5
Gas (N + O)	7.10+5	8.15+5	2.41+7	3.68+5	1.45+7	5.20+4	1.84+3	4.09+3	6.33+5	1.11+5	2.39+3
Gas (Kr + Xe)	9.24+5	1.06+6	3.92+7	9.23+5	3.19+8	5.36+6	1.94+5	4.33+5	4.87+9	1.20+9	9.24+4
Solid daughter	1.50+3	5.38+3	2.68+6	8.31+2	4.02+7	9.02+5	3.35+4	7.49+4	3.11+8	1.26+8	2.54+4
Cr Gas	3.91+5	4.49+5	1.54+7	3.44+5	1.12+8	2.25+6	8.21+4	1.83+5	4.49+8	9.73+7	4.56+4
Xe Gas	5.32+5	6.16+5	2.38+7	5.78+5	2.08+8	3.10+6	1.12+5	2.50+5	4.37+9	1.10+9	4.68+4

TABLE 11.3-3 (SHEET 1 OF 2)

OFF-GAS SYSTEM MAJOR EQUIPMENT ITEMS[(a)]

Off-Gas Preheaters - two required.

Construction: Stainless-steel tubes and carbon steel shell. 350-psig shell design pressure, 1000-psig tube design pressure. 400°F shell design temperature, 575°F tube design temperature.

Catalytic Recombiners - two required.

Construction: Stainless-steel cartridge, Cr-Mo steel shell. Catalyst cartridge containing a precious metal catalyst on nichrome strips. Catalyst cartridge to be replaceable without removing vessel. 350-psig design pressure. 900°F design temperature.

Off-Gas Condenser - one required.

Construction: Cr-Mo steel shell. Stainless steel tubes. 350-psig shell design pressure. 250-psig tube design pressure. 900°F design temperature.

Water Separator - one required.

Construction: Carbon steel shell, stainless steel wire mesh. 350-psig design pressure. 250°F design temperature.

30-min-Holdup Piping

Construction: Carbon steel. Radiographed, buried, with the outside wrapped and coated for corrosion protection. Ends and elbows reinforced to 1000-psig design pressure. 150°F design temperature.

Cooler-Condenser - two required.

Construction: Stainless-steel shell. Stainless steel tubes. 100-psig tube design pressure. 350-psig shell design pressure. 150°F tube design temperature. 150°F shell design temperature.

Moisture Separators (downstream of cooler-condenser) - two required.

Construction: Carbon steel shell, stainless-steel wire mesh. 350-psig design pressure. 150°F design temperature.

Off-Gas Reheater - one required.

Construction: Carbon steel pipe. Electrical resistance heaters on outside of pipe.

TABLE 11.3-3 (SHEET 2 OF 2)

Glycol tank - one required.

Construction: Carbon steel. 3000 gal. Water-filled hydrostatic design pressure. 0°F design temperature.

Glycol Refrigeration Machines and Motor Drives - two required.

Construction: Conventional refrigeration units. Glycol exit solution temperature 35°F.

Glycol Pumps and Motor Drives - two required.

Construction:[b] Carbon steel. 1 1/2-in. suction x 3-in. discharge connections. 85-ft total head. 0°F design temperature.

After Filters - two required.

Construction: Carbon steel shell. HEPA, moisture-resistant filter element. Flanged shell. 350-psig design pressure. 130°F design temperature.

Carbon Bed Adsorbers - 12 beds.

Construction:[c] Carbon steel. 4-ft ID x 21-ft vessels, each with a 16-ft packed section containing ~ 3 tons of 8-14 mesh carbon, Columbia G or equivalent. 350-psig design pressure. Design temperature 130°F.

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a. Design codes and standards are provided in chapter 3, table 3.2-1.
b. For HNP-1: 3-in. connections and 50-ft total head.
c. For HNP-1: each vessel contains a 19-ft packed section of 8-14 mesh carbon.

TABLE 11.3-4 (SHEET 1 OF 2)

OFF-GAS SYSTEM PROCESS INSTRUMENT ANNUNCIATORS IN MCR[a]

	Indicator	Recorder
Recombiner inlet temperature - low	X	
Recombiner catalyst temperature - high/low		X
Off-gas condenser water (dual) level - high/low		
Off-gas condenser gas outlet temperature - high		
H_2 analyzer off-gas condenser discharge - (dual) - high		X
Refrigeration machine inoperable		
Pretreatment off-gas condenser discharge radiation - high		X
Gas flow (carbon bed discharge) - high/low		X
Gas reheater inlet temperature - high/low		X
Glycol storage tank temperature - high/low		X
Glycol tank level - low		
Gas reheater outlet dewpoint temperature - high		X
Adsorber vessel temperature - high		X
Adsorber vault temperature - high/low		X
Adsorber inlet/outlet pressure - high	X	
Post-treatment off-gas radiation - high		X
Prefilter differential pressure - high	X	

a. All listed parameters provide input to MCR annunciators, and selected parameters are provided with indicators or recorders as shown

TABLE 11.3-4 (SHEET 2 OF 2)

	Indicator	Recorder
After filter differential pressure - high	X	
Adsorber vault radiation - downscale	X	
Off-gas carbon bed bypassed		
Adsorber vault radiation - high	X	
Instrumentation elements:		
Temperature - thermocouple		
Level - differential pressure diaphragm		
Hydrogen - electrochemical galvanic sensor		
Gas flow - thermal mass flow element		
Differential pressure - differential pressure diaphragm		
Humidity - moisture element		
Radiation - sample chambers and detectors		

TABLE 11.3-5 (SHEET 1 OF 3)

OFF-GAS SYSTEM EQUIPMENT MALFUNCTION ANALYSIS

Equipment Item	Malfunction	Consequences	Design Precautions
Preheaters	Steam leak	Would further dilute process off-gas. Steam consumption would increase.	Spare preheater
	Low-pressure steam supply	Recombiner performance would fall off at low power level, and hydrogen content of recombiner gas discharge would increase, eventually to a combustible mixture.	Low-temperature alarms on preheater exit and recombiner inlet. Recombiner H_2 analyzer.
Recombiners	Catalyst gradually deactivates	Temperature profile changes through catalyst. Eventually excess H_2 would be detected by H_2 analyzer or by gas flowmeter. Eventually the gas could become combustible.	Temperature probes in recombiner and H_2 analyzer provided. Spare recombiner.
	Catalyst gets wet at start	H_2 conversion falls off and H_2 is detected by downstream analyzers. Eventually the gas could become combustible.	Condensate drains, temperature probes in recombiner. Air bleed system at startup. Recombiner thermal blanket, spare recombiner, and heater. Hydrogen analyzer.
Off-Gas condenser	Cooling water leak	The coolant (reactor condensate) would leak to the process gas (shell) side. This would be detected if drain well liquid level increases. Moderate leakage would be of no concern from a process standpoint. (The process condensate drains to hotwell.)	None
Drain well	Liquid level instruments fail	If both drain valves fail to open, water builds up in the condenser and pressure drop increases. The high ΔP, if not detected by instrumentation, could cause pressure buildup in the main condenser and eventually initiate a reactor scram. If a drain valve fails to close, gas will recycle to the main condenser, increase the load of the SJAE, and cause back pressure on the main condenser, eventually causing a reactor scram.	Two separate drain systems, each, provided with high- and low-level alarms.

TABLE 11.3-5 (SHEET 2 OF 3)

Equipment Item	Malfunction	Consequences	Design Precautions
Water separator	Corrosion of wire mesh element	Higher quantity of water collected in 30-min holdup line and routed to radwaste.	Stainless-steel mesh specified.
146-min holdup line	Corrosion of line	Leakage to soil of gaseous and liquid fission products.	Outside of pipe dipped and wrapped.
Cooler-condensers	Corrosion of finned tube	Glycol-water solution would leak into process (shell) side and be discharged to clean radwaste. If not detected at radwaste, the glycol solution would discharge to the reactor condensate system.	Stainless-steel-finned tubes specified. The inventory of glycol-water can be observed in tank. A002 - spare cooler provided.
	Icing up of finned tube	Shell side of cooler could plug up with ice, gradually building up pressure drop. If this happens, the spare unit could be activated. Complete blockage of <u>both</u> units would increase ΔP and lead to a reactor scram.	Design glycol-H_2O solution temperature of 35°F to 40°F. Spare unit provided. Redundant temperature indication and alarm systems.
Moisture separators	Corrosion of wire mesh element	Increased moisture would be retained in the process gas routed to charcoal adsorbers. Over a long period, the charcoal performance would deteriorate as a result of moisture pickup.	Stainless steel mesh specified. Relative humidity instrumentation provided. Spare unit provided.
Charcoal absorbers	Charcoal gets wet	Charcoal performance deteriorates gradually as charcoal gets wet. Holdup times for krypton and xenon decrease, and plant emissions increase.	Highly instrumented, mechanically simple gas dehumidification system with redundant equipment.
Vault air conditioning units	Mechanical failure	If ambient temperature exceeds ~ 80°F, increased emission could occur.	Spare air-conditioning unit provided.
		If ambient temperature is below ~ 60°F, charcoal could pick up additional moisture	Vault temperature alarms provided.
Afterfilters	Hole in filter media	Probably of no real consequence. The charcoal media itself should be a good filter at the low air velocity.	ΔP instrumentation provided. Spare unit provided.
Glycol refrigeration machines	Mechanical failure	If spare unit fails to operate, the glycol solution temperature rises and the dehumidification system performance will deteriorate. This causes gradual buildup of moisture on the charcoal, with increased plant emissions.	Spare refrigerator provided. Glycol solution temperature alarms provided.

TABLE 11.3-5 (SHEET 3 OF 3)

Equipment Item	Malfunction	Consequences	Design Precautions
SJAE	Low flow of motive high-pressure steam	When the H_2 and O_2 concentrations exceed 4- and 5-volume percent, respectively, the process gas becomes flammable.	Alarms provided on steam for low steam flow and low steam pressure.
		Inadequate steam flow causes overheating and deterioration of the catalyst.	Steam flow to be held at constant maximum flow regardless of plant power level.
	Wear of steam supply nozzle of ejector	Increased steam flow to recombiner. This could reduce degree of recombination at low power levels.	

TABLE 11.3-6 (SHEET 1 OF 3)

GALE CODE DATA (HNP-1 AND HNP-2)

GALE CODE INPUT

CARD 1	NAME	NAME OF REACTOR HNP-1&2 1.5% Power Uprate Case with TB Filter	TYPE =	BWR
CARD 2	POWTH	THERMAL POWER LEVEL (MEGAWATTS)		2804
CARD 3	GTO	TOTAL STEAM FLOW (MILLION LBS/HR)		12.2
CARD 4	WL1Q	MASS OF WATER IN REACTOR VESSEL (MILLION LBS)		0.493
CARD 5	GDE	CLEAN-UP DEMINERALIZER FLOW (MILLION LBS/HR)		0.1
CARD 6	REGENT	CONDENSATE DEMINERALIZER REGENERATION TIME (DAYS)		0.0
CARD 7	FFCDM	FRACTION FEED WATER THROUGH CONDENSATE DEMIN		1.00
CARD 8		HIGH PURITY WASTE INPUT 21000. GPD AT .23 PCA		
CARD 9		DFI= 1.0E03DFCS= 2.OEO1DFO = 1.0E03		
CARD 10		COLLECTION .23 DAYS PROCESS .03 DAYS FRACT DISCH		0.01
CARD 11		LOW PURITY WASTE INPUT 6000. GPD AT .003		
CARD 12		DFI= 1.0E03DFCS= 4.0E00DFO = 1.0E03		
CARD 13		COLLECTION 0.8 DAYS PROCESS .07 DAYS FRACT DISCH		1.0
CARD 14		CHEMICAL WASTE INPUT 500. GPD AT .005 PCA		
CARD 15		DFI= 1.0E03DFCS= 4.0E00DFO = 1.0E03		
CARD 16		COLLECTION 3.6 DAYS PROCESS .03 DAYS FRACT DISCH		1.0
CARD 17		REGENERATION SOLTNS INPUT GPD		0.0
CARD 18		DFI= 1.0E00DFCS= 1.0E00DFO = 1.0E00		
CARD 19		COLLECTION 0.0 DAYS PROCESS .00 DAYS FRACT DISCH		1.0
CARD 20	GGS	GLAND SEAL STEAM FLOW (THOUSAND LBS/HR)		12.2
CARD 21	T1M3	GLAND SEAL HOLDUP TIME (HOURS)		0.029
CARD 22	T1M4	AIR EJECTOR OFFGAS HOLDUP TIME (HOURS)		.5
CARD 23		CONTAINMENT BLDG.CHARCOAL 00.0 HEPA?99.0		
CARD 24		TURBINE BLDG. CHARCOAL 90.0 HEPA?99.0		
CARD 25	FIL3	GLAND SEAL VENT, IODINE PF		0.0
CARD 26	FIL4	AIR EJECTOR OFFGAS IODINE PF		1.0
CARD 27		AUXILIARY BLDG. CHARCOAL 00.0 HEPA?99.0		
CARD 28		RADWASTE BLDG. CHARCOAL 00.0 HEPA?99.O		
CARD 29	KCHAR	CHARCOAL DELAY SYSTEM 0=NO, 1=YES, 2=CRYOGENIC DISTILL		1
CARD 30	KKR	KRYPTON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)		18.50
CARD 31	KXE	XENON DYNAMIC ADSORPTION COEFFICIENT (CM3/GM)		330.0
CARD 32	KMASS	MASS OF CHARCOAL (THOUSAND LBS)		73.89
CARD 33	PFLAUN	DETERGENT WASTE DECONTAMINATION FACTOR		1.0

TABLE 11.3-6 (SHEET 2 OF 3)

GALE CODE OUTPUT
ANNUAL RELEASES OF GASEOUS EFFLUENTS

NUCLIDE	COOLANT CONC. (MICROCURIES/G)	GASEOUS RELEASE RATE (curies/year) CONTAINMENT BLDG.	TURBINE BLDG.	AUXILIARY BLDG.	RADWASTE BLDG.	GLAND SEAL	AIR EJECTOR	MECH VAC PUMP	TOTAL
I-131	3.450E-03	2.0E-02	5.9E-03	4.0E-02	2.1E-02	2.8E-03	0.0E+00	4.3E-02	1.3E-1
I-133	4.514E-02	2.7E-01	7.7E-02	5.3E-01	2.7E-01	1.0E-02	0.0E+00	4.5E-01	1.6E+00

H-3 RELEASED FROM TURBINE BLDG. VENTILATION SYSTEM 2.1E+01
H-3 RELEASED FROM CONTAINMENT BLDG. VENTILATION SYSTEM 2.1E+01
TOTAL H-3 RELEASED VIA GASEOUS PATHWAY 4.3E+01
C-14 RELEASED VIA MAIN CONDENSER OFFGAS SYSTEM = 9.5 CI/YR

NUCLIDE	COOLANT CONC. (MICROCURIES/G)	GASEOUS RELEASE RATE (CURIES/YEAR) CONTAINMENT BLDG.	TURBINE BLDG.	AUXILIARY BLDG.	RADWASTE BLDG.	GLAND SEAL	AIR EJECTOR	MECH VAC PUMP	TOTAL
AR-41	0.000E+00	1.5E+01	0.0E+00	0.0E+00	0.0E+00	0.0E+00	5.2E+01	0.0E+00	6.7E+01
KR-83M	9.100E-03	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.5E+02	1.1E+02	0.0E+00	4.6E+02
KR-85M	1.600E-03	1.0E+00	2.5E+01	3.0E+00	0.0E+00	6.2E+01	2.1E+03	0.0E+00	2.2E+03
KR-85	5.000E-06	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.9E+02	0.0E+00	1.9E+02
KR-87	5.500E-03	0.0E+00	6.1E+01	2.0E+00	0.0E+00	2.1E+02	2.0E+00	0.0E+00	2.7E+02
KR-88	5.500E-03	1.0E+00	9.1E+01	3.0E+00	0.0E+00	2.1E+02	1.0E+03	0.0E+00	1.3E+03
KR-89	3.400E-02	0.0E+00	5.8E+02	2.0E+00	2.9E+01	9.0E+02	0.0E+00	0.0E+00	1.5E+03
XE-131M	3.900E-06	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	6.0E+01	0.0E+00	6.0E+01
XE-133M	7.500E-05	0.0E+00	0.0E+00	0.0E+00	0.0E+00	3.0E+00	2.4E+01	0.0E+00	2.7E+01
XE-133	2.100E-03	2.7E+01	1.5E+02	8.3E+01	2.2E+02	8.0E+01	1.0E+04	1.3E+03	1.2E+04
XE-135M	7.000E-03	1.5E+01	4.0E+02	4.5E+01	5.3E+02	2.5E+02	0.0E+00	0.0E+00	1.2E+03
XE-135	6.000E-03	3.3E+01	3.3E+02	9.4E+01	2.8E+02	2.3E+02	0.0E+00	5.0E+02	1.5E+03
XE-137	3.900E-02	4.5E+01	1.0E+03	1.3E+02	8.3E+01	1.1E+03	0.0E+00	0.0E+00	2.4E+03
XE-138	2.300E-02	2.0E+00	1.0E+03	6.0E+00	2.0E+00	8.2E+02	0.0E+00	0.0E+00	1.8E+03
TOTAL	NOBLE CASES								2.5E+04

0.0 APPEARING IN THE TABLE INDICATES RELEASE IS < 1.0 CI/YR FOR NOBLE GAS.

TABLE 11.3-6 (SHEET 3 OF 3)

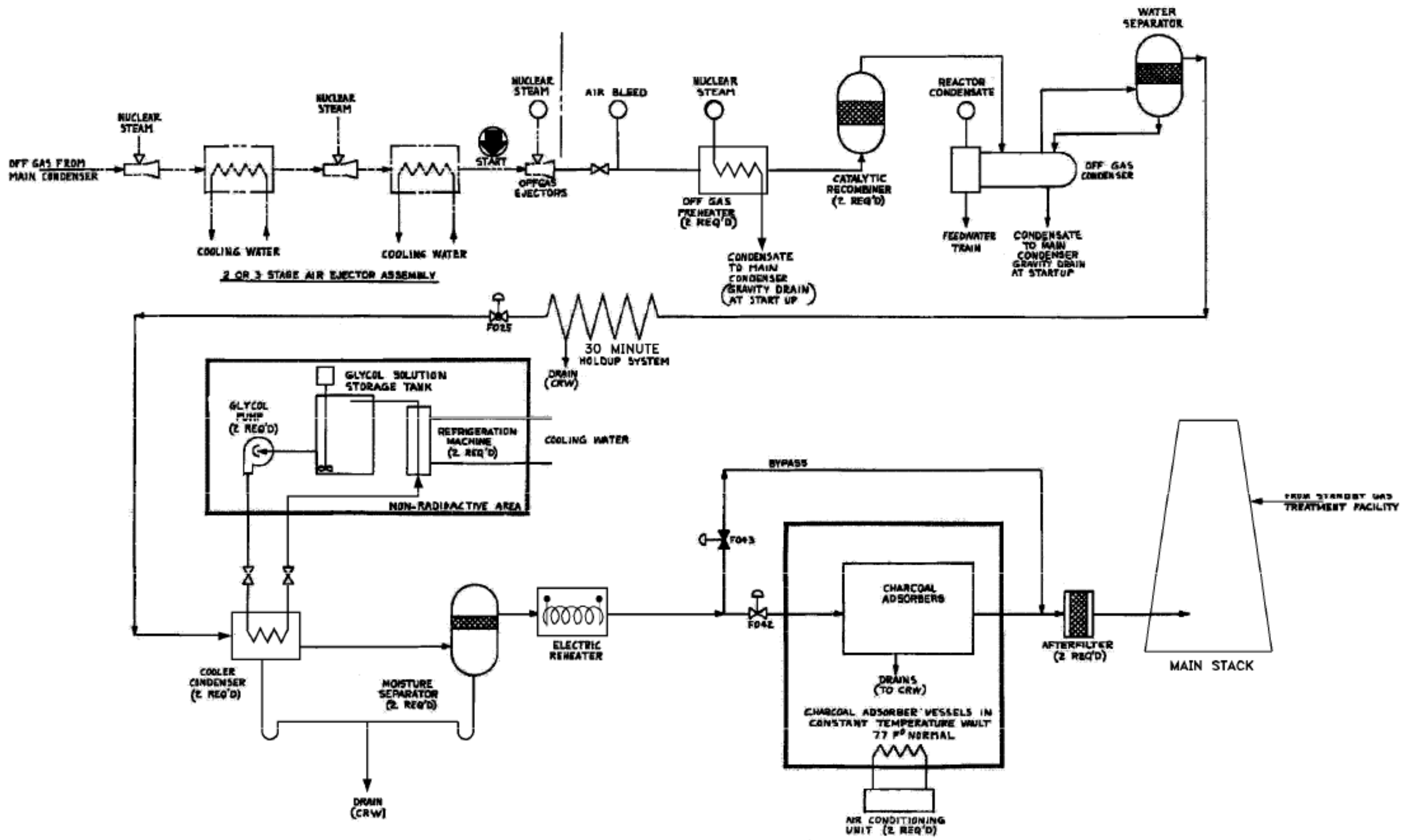
AIRBORNE PARTICULATE RELEASE RATE
(curies/year)

NUCLIDE	CONTAINMENT BLDG.	TURBINE BLDG.	AUXILIARY BLDG.	RADWASTE BLDG.	MECH VAC PUMP	TOTAL
R-51	2.0E-06	9.0E-06	9.0E-06	7.0E-06	1.0E-06	2.8E-05
MN-54	4.0E-06	6.0E-06	1.0E-05	4.0E-05	0.0E+00	6.0E-05
CO-58	1.0E-06	1.0E-05	2.0E-06	2.0E-06	0.0E+00	1.5E-05
FE-59	9.0E-07	1.0E-06	3.0E-06	3.0E-06	0.0E+00	7.9E-06
CO-60	1.0E-05	1.0E-05	4.0E-05	7.0E-05	5.6E-07	1.3E-04
ZN-65	1.0E-05	6.0E-05	4.0E-05	3.0E-06	3.4E-07	1.1E-04
SR-89	3.0E-07	6.0E-05	2.0E-07	0.0E+00	0.0E+00	6.1E-05
SR-90	3.0E-08	2.0E-07	7.0E-08	0.0E+00	0.0E+00	3.0E-07
NB-95	1.0E-05	6.0E-08	9.0E-05	4.0E-08	0.0E+00	1.0E-04
ZR-95	3.0E-06	4.0E-07	7.0E-06	8.0E-06	0.0E+00	1.8E-05
MO-99	6.0E-05	2.0E-05	6.0E-04	3.0E-08	0.0E+00	6.8E-04
RU-103	2.0E-06	5.0E-07	4.0E-05	1.0E-08	0.0E+00	4.3E-05
AG-110M	4.0E-09	0.0E+00	2.0E-08	0.0E+00	0.0E+00	2.4E-08
SB-124	2.0E-07	1.0E-06	3.0E-07	7.0E-07	0.0E+00	2.2E-06
CS-134	7.0E-06	2.0E-06	4.0E-05	2.4E-05	3.2E-06	7.6E-05
CS-136	1.0E-06	1.0E-06	4.0E-06	0.0E+00	1.9E-06	7.9E-06
CS-137	1.0E-05	1.0E-05	5.0E-05	4.0E-05	8.9E-06	1.2E-04
BA-140	2.0E-05	1.0E-04	2.0E-04	4.0E-08	1.1E-05	3.3E-04
CE-141	2.0E-06	1.0E-04	7.0E-06	7.0E-08	0.0E+00	1.1E-04

TABLE 11.3-7

MAXIMUM DOSES FROM GASEOUS EFFLUENTS (HNP-1 AND HNP-2)

Effluent	Applicable Organ	Estimated Doses/Year	Appendix I Objective/Year
Noble gas	Air dose (Gamma)	6.4 mRad/unit	10 mRad/unit
	Air dose (Beta)	7.1 mRad/unit	20 mRad/unit
Noble gas	Total body	4.3 mrem/unit	5 mrem/unit
	Skin	11.5 mrem/unit	15 mrem/unit
Airborne iodine and particulate	Any organ (child's thyroid)	4.4 mrem/unit	15 mrem/unit



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UNIT 2

OFF-GAS SYSTEM PROCESS
FLOW DIAGRAM

FIGURE 11.3-1

11.4 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING

The process and effluent radiological monitoring systems, including the primary containment radiation monitor system, are contained in the process radiation monitoring system (PRMS). The PRMS furnishes information to operations personnel regarding radioactivity levels in principal plant process and effluent streams to assist in maintaining radiation levels as low as reasonably achievable (ALARA) and to verify compliance with applicable governmental regulations for the containment, control, and release of radioactive liquids, gases, and particulates generated as a result of normal or emergency operations of the plant.

The PRMS is composed of the following process and effluent radiological monitors:

A. Gaseous Monitors

- Main steam line radiation monitors.
- Refueling floor ventilation exhaust radiation monitors.
- Reactor building ventilation exhaust radiation monitors.
- Main control room (MCR) air intake radiation monitors.
- Off-gas radiation monitor system.
- Main stack (off-gas vent pipe) radiation monitor (shared with HNP-1).
- Reactor building vent stack radiation monitor.
- Radwaste building ventilation radiation monitors.
- Turbine building ventilation radiation monitors.
- Standby gas treatment system (SGTS) radiation monitors.
- Primary containment purge radiation monitor.
- Fission products (leak detection) radiation monitors.
- Primary containment normal and post-accident radiation monitors.

B. Liquid Monitors

- Liquid radwaste effluent radiation monitor.
- Plant service water (PSW) effluent radiation monitor.
- Reactor building closed cooling water (RBCCW) process radiation monitor.

Those monitors with a safety function (A1, A2, A3, and A4) are discussed in subsection 7.6.3. The other PRMS monitors are described in the following paragraphs and serve in conjunction with a comprehensive sampling program. The sampling program is the primary method for quantitatively evaluating system and effluent activity levels.

11.4.1 DESIGN OBJECTIVES

The PRMS is designed to measure and record radioactivity levels, to alarm on high radioactivity levels, and to control, as required, the release of radioactive liquids, gases, and particulates produced in the operation of the plant. It is also designed to comply with the requirements of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) and the appropriate General Design Criteria (GDC) in 10 CFR 50, Appendix A. The PRMS aids in the protection of the general public and plant personnel from exposure to radiation or radioactive materials in excess of those allowed by the applicable regulations of governmental agencies.

The design objectives of this system for normal operation are to:

- Provide surveillance of radioactivity levels in process and effluent streams from minimum detectable levels to levels commensurate with Technical Specifications limits by indicating and recording these levels, alarming at abnormal activity levels, and initiating or causing the initiation of corrective action when applicable

- Provide data for estimating total released activity.

For some anticipated operational occurrences (AOOs), accidents, or malfunctions, the PRMS activates necessary isolation or diversion valves, thereby terminating releases if radioactivity levels exceed radiation alarm high-high (RAHH) setpoints, as indicated in tables 11.4-1 and 11.4-2.

11.4.2 CONTINUOUS MONITORING

11.4.2.1 <u>General Design Criteria</u>

The design of the continuous monitoring systems is described below.

A. Use of a radiation alarm high (RAH) setpoint gives early warning of increasing radioactivity levels indicative of equipment failure, filter failure, system malfunction, or deteriorating system performance. Corrective action is taken upon receipt of an RAH if an RAHH setpoint is not used.

B. Use of an RAHH setpoint initiates prompt corrective action, either automatically or through operation response, on high radioactivity level.

C. Monitors and detectors were selected with sensitivities and ranges in accordance with radiation levels anticipated at specific detector locations to facilitate compliance with applicable regulations.

D. All monitors must register full scale if exposed to radiation levels exceeding full-scale indication.

E. Independence of safety-related redundant monitors is maintained by providing adequate separation of detectors, signal cabling, power supplies, and actuation circuits for isolation and diversion valves to meet Institute of Electrical and Electronic Engineers (IEEE)-279 criteria.

F. Radioactivity levels are continuously indicated and recorded in the MCR, with the exception of radwaste effluent activity which is recorded in the radwaste control room.

G. MCR alarms annunciate high radioactivity levels and signal, circuit, or power failures.

H. For selected detectors listed in tables 11.4-1 and 11.4-2, alarms and recorders are provided in the radwaste control room or the MCR.

I. Access to alarm setpoints is under the administrative control of the plant manager (PM) or his authorized delegate.

J. Adequate lead (or equivalent) shielding is provided for detectors when the ability to sense low activity levels requires that background radiation has a minimum effect on the instruments.

K. Monitor components requiring maintenance and inspection are readily accessible or spare equipment is available in the plant.

L. Environmental design conditions for the components are listed in table 11.4-3. In addition, those safety-related components of the system are protected from the effects of extreme winds, floods, tornadoes, or missiles because they are housed in a structure designed to withstand the above environmental conditions as described in chapter 3.

M. Safety-related monitors are designed to seismic requirements consistent with the seismic design of the system being monitored.

N. All inline monitors have detector housings of the same piping class and seismic category as the system being monitored. Offline monitors have root valves designed to the same class and category as the system being monitored.

11.4.2.2 Basis for Detector Location Selection

Normal and potential paths for release of radioactive material during normal reactor operation, including AOOs and accidents, are monitored as follows:

- Process lines which may discharge radioactive fluids to the environs in order to indicate the radioactivity level and to alarm in the MCR when preestablished limits for the release of radioactive materials are reached or exceeded.

- Process lines that do not discharge directly to the environs in order to indicate possible process system malfunctions by detecting increases in radioactivity levels.

11.4.2.3 Radiation Levels

The radioactivity concentrations in the process and effluent streams are such that radiation levels at the site boundary are a small fraction of Offsite Dose Calculation Manual (ODCM) and Technical Specifications limits, and 10 CFR 20.1301(a)(2) limits, and are ALARA. The concentrations measured with each monitor are listed in tables 11.4-1 and 11.4-2.

11.4.2.4 Quantity Measured

The principal radionuclides monitored are indicated in tables 11.4-1 and 11.4-2. All channels measure gross radioactivity.

11.4.2.5 Detector Type, Sensitivity, and Range

The detectors are Geiger-Mueller (G-M) tubes, ionization chambers, or scintillation crystals which detect beta radiation or detect gamma radiation over an energy range of at least 0.02 MeV to 2.5 MeV. The sensitivity and range have been selected for most detectors so the alarm setpoint is at least an order of magnitude higher than the detector threshold and the instrument reads on scale during normal operation. If it does not read on scale, a small "bug" source is attached to the detector to clear the radiation alarm low (RAL) (failure). (This is not necessary for the main steam line and post-LOCA detectors.) Detector type, estimated sensitivity, and nominal ranges of each process and effluent monitor are indicated in tables 11.4-1 and 11.4-2.

11.4.2.6 Setpoints

Setpoints for effluent monitors are established to meet Technical Specifications limits which encompass ALARA guidelines. Setpoints for process monitors are established to provide a warning of increased system activity and to take corrective action where appropriate.

In all cases, the alarm and isolation setpoints are established to maintain offsite radiological effects within applicable regulations. Even if the particulate process stream in question resulted

in release rates identical with the monitor setpoint continuously, offsite exposures would be within regulations. Therefore, anything less would obviously be within regulations. However, such process streams do not contain sufficient activity to be near such setpoints during full-power plant operation.

Two independently adjustable radiation setpoints are provided for most monitors. The lower or RAH setpoint normally activates only an alarm, while the upper or RAHH setpoint activates an alarm and initiates corrective action where appropriate. The alarm and trip circuits are of the latching type and must be manually reset on the front of the PRMS panels located in the MCR. Most setpoints are at least twice the background level to reduce the number of spurious trips. Tentative RAHH setpoints and RAH setpoints, when used alone, are provided in tables 11.4-1 and 11.4-2. RAH setpoints when used in conjunction with RAHH setpoints are between background and the RAHH setpoints. The setpoints are under the administrative control of the PM or his authorized delegate and can be changed if needed as long as limits are not exceeded. Limits may be found in the Technical Specifications and ODCM.

11.4.2.7 Annunciators and Alarms

All gaseous process and effluent radiation monitors are annunciated in the MCR. A specific annunciator window alarms for each RAL (failure), RAH, or RAHH or low sample flow alarm, as shown in tables 11.4-1 and 11.4-2.

An operator can acknowledge the alarm and silence the audible alarm, but he cannot clear the annunciator window until the alarm has been cleared at the PRMS cabinets located in the MCR. Radiation alarms can be cleared only if the indication is less than the setpoint.

At the PRMS cabinets in the MCR, the channel which alarmed and the type of alarm are determined by the lights associated with three types of alarms. These alarms are as follows:

A. An RAH light illuminates when the radioactivity exceeds preset limits which have been selected to provide an early warning.

B. An RAHH light illuminates when radioactivity levels exceed a preset limit which is set at or below the Technical Specifications limits. This initiates prompt corrective action either automatically or through operation response.

C. An RAL (failure) light is activated when the meter reaches a downscale trip point which is indicative of a detector signal, circuit, or power failure. In certain cases, as discussed in paragraphs 11.4.2.8 and 11.4.2.9, this downscale trip also initiates action.

11.4.2.8 Continuous Monitoring Systems

11.4.2.8.1 Main Steam Line Radiation Monitor

This monitor measures the radioactive gases coming from the reactor through the main steam lines. These gases are activation gases which come mainly from activation of oxygen and fission gases which come from small fuel leaks and "Tramp" Uranium impurities.

The main steam line radiation monitor is a safety-related system and is described in detail in subsection 7.6.3. The P&ID is shown on drawing no. H-26011.

11.4.2.8.2 Refueling Floor Ventilation Exhaust Monitor System

This monitor subsystem measures the activity from the spent-fuel pool, reactor well, dryer separator pool areas, and the refueling floor area exhaust ducts before and after the air passes through the refueling floor ventilation filter, which is in the exhaust line to the reactor building vent plenum.

The fuel pool may contain gaseous activity due to mixing with the reactor coolant system during each refueling. Diffusion of this activity from the pool generates airborne activity which is swept into the spent-fuel pool area ventilation system. Gaseous activity released during a postulated fuel handling accident is also swept into this ventilation system.

Twelve monitors are mounted on exhaust ducts upstream of the refueling floor ventilation filters. These monitors have an automatic isolation function and are a designated safety system as shown on drawing no. H-26012. For a detailed description of the prefilter monitors which provide the isolation function, see subsection 7.6.3.

There are also two monitors mounted after the filter to monitor filter performance and activity discharge to the reactor building vent stack. These monitors are described in paragraph 11.4.2.8.8 and shown on drawing no. H-26013.

11.4.2.8.3 Reactor Building Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the radioactivity in the reactor building ventilation system exhaust duct prior to its discharge from the building and in doing so, complies with GDC 13, 23, and 64. During normal operation, including criticality tests, the monitors act as an engineered safety feature to detect a high activity level in the ductwork which could be due to fission gases from a leak. Because of the system's safety function, there are four radiation monitors with redundant two-channel trips mounted upstream of the reactor building ventilation exhaust filters. These monitors are described in detail in subsection 7.6.3. This system also includes a monitor between the filter's discharge and the reactor building vent stack. This monitor is not safety-related and is described in paragraph 11.4.2.8.8. These monitors are shown on drawing no. H-26013.

11.4.2.8.4 MCR Air Intake Radiation Monitors

This monitor subsystem measures the activity in the makeup air to the MCR. No measurable activity is present in the makeup air. However, in the event of a design basis accident (DBA), fission gases could escape from the plant structures and be drawn into the makeup air intake. These are four independent monitors. Two monitors are located at the intake filter and two are located at the discharges of the air coolers. Subsection 7.3.5 describes these monitors.

11.4.2.8.5 Off-Gas Radiation Monitoring System

The objectives of the off-gas radiation monitoring system are to indicate when limits for the release of radioactive material to the environs are approached and to effect appropriate control of the off-gas so that the limits are not exceeded.

The off-gas radiation monitoring system is designed to:

- Provide an alarm to operations personnel whenever the radioactivity level of the air ejector off-gas reaches limits specified in plant procedures.

- Provide a record of the radioactivity released via the air ejector off-gas line.

- Initiate appropriate action in time to prevent exceeding short-term limits on the release of radioactive material to the environs as a result of releasing the radioactivity contained in the air ejector off-gas.

The off-gas system is monitored by:

- Pretreatment monitor.

- Post-treatment monitor.

- Carbon vault monitor.

The off-gas radiation monitor system is shown on drawing no. H-26011 and specifications are given in table 11.4-1. The off-gas radiation monitors were selected with monitoring characteristics sufficient to provide plant operations personnel with accurate indication of radioactivity in the air ejector off-gas. The system thus provides the operator with enough information to control the activity release rate. Sufficient redundancy is provided to allow maintenance on one channel without losing the indications provided by the system.

<u>Pretreatment</u>

The monitoring system used prior to treatment is comprised of two instrument channels monitoring the gases passing through a vertical section of stainless steel pipe designed to minimize "plateout". A sample is drawn from the off-gas line through the sample chamber by the main condenser suction. The sample system is arranged to give at least a 2-min time delay

before the sample is monitored. This time delay allows nitrogen-16 and oxygen-19 activity decay. This reduces the background radiation that the detectors would otherwise measure. Each channel consists of a gamma-sensitive ion chamber, a logarithmic radiation monitor with digital display, a power supply, and one channel of a paperless recorder. The monitors and recorders are located in the MCR.

Each channel has two upscale trip circuits (high-high and high) and a downscale trip circuit (low). The upscale trips indicate high and high-high radiation, and the downscale trip indicates instrument trouble. The two monitors share a common set of annunciator alarms. One channel is aligned to the annunciator alarms, via a channel selector switch, while the other channel serves as backup instrumentation. Any one trip in the selected monitor channel gives an alarm in the MCR.

The high alarm is set at a level of release which is at or below the Technical Specifications release rate limit. The high-high alarm is set at a level equivalent to the instantaneous release rate limit.

Post-Treatment

The monitoring system used after the recombiner/carbon bed treatment is composed of two independent instrument channels monitoring gases passing through a sample chamber mounted on a sample rack along with pump, flow measuring and control equipment, check sources, purge equipment, scintillation detectors, and preamplifiers. Each channel is composed of a detector, a preamplifier, a log count rate monitor with digital display, a power supply, and one channel of a paperless recorder. The detectors monitoring the process after treatment are gamma-sensitive scintillation detectors. The monitors for these channels are 7-decade log count rate monitors located in the MCR with two adjustable upscale trip circuits, one downscale trip circuit, and an instrument inoperative trip. The lower level upscale trip (high) is used to close the bypass line, open the treatment line, and alarm; an intermediate upscale (high-high) alarm is activated by the recorder, and the upper level upscale trip (high-high-high) in conjunction with the downscale trip (low) is used to isolate the off-gas system outlet and drain valves and alarm. The lower alarm is set at a level of release which is at or below the Technical Specifications release rate limit. The upper alarm is to be set at a level equivalent to or below the instantaneous release limit. Functional control of these trips is described on drawing no. H-26011.

Carbon Vault Monitor

The carbon vault is monitored for gamma activity with a single-instrument channel. The channel includes a sensor and converter, an indicator and trip unit, and a locally mounted auxiliary unit. The indicator and trip unit is located in the MCR. The channel provides for sensing and readout, both local and remote, of gamma radiation over a range of six logarithmic decades (1 to 10^6 mr/h).

The indicator and trip unit has one adjustable upscale trip circuit for alarm and one downscale trip circuit for instrument trouble. The trip circuits are capable of convenient operational verification by means of test signals or through the use of portable gamma sources. Insofar as

practical, all components are self-monitoring to the extent that power failure to any component operates the trip circuits.

11.4.2.8.6 Main Stack (Off-Gas Vent Pipe) Radiation Monitor

The objectives of the off-gas vent pipe (main stack) radiation monitor are to indicate whenever limits on the actual release of radioactive material to the environs are reached or exceeded, and to indicate the rate of radioactive material released during planned operation.

The main stack (off-gas vent pipe) radiation monitor is designed to:

- Provide a clear indication to operations personnel whenever limits on the release of radioactive material to the environs are reached or exceeded.

- Indicate the rate of release of radioactive material from values above release rate limits down to the release rates normally encountered during high-power operation.

- Record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

The main stack (off-gas vent pipe) radiation monitor is shown on drawing no. H-16564 and specifications are given in table 11.4-1. The system has two ranges, normal and accident. The normal range consists of two individual channels; the accident range has one channel. Each normal-range channel consists of a gamma-sensitive scintillation detector, a log count rate monitor that includes a power supply, a meter, and one channel of a multichannel paperless recorder. The monitors and paperless recorder are located in the MCR.

Each normal-range monitor has two upscale setpoints and one downscale setpoint. Each setpoint initiates an alarm in the MCR. The upscale alarms indicate high and high-high radiation, and the downscale alarm indicates instrument trouble. The high-high alarm contact provides the start signal for the accident-range monitor and trips the normal-range monitor. The lower upscale alarm is set at a level ≤ 90% of the Technical Specifications limit. The higher upscale alarm is set at a level which will provide overlap with the accident-range monitor to assure the appropriate start signal.

To monitor the off-gas vent pipe stream, a gas sample is continuously drawn at a fixed rate of flow through an isokinetic-type probe which is located high enough in the vent pipe stream to assure representative sampling. The sample passes through two shielded chambers where the radiation level of the vent gas is measured by two scintillation detectors, one located in each shielded chamber.

Representative sampling is achieved by passing gaseous releases through high-efficiency particulate air (HEPA) filters before being sampled and discharged to the environment. Such treatment removes most large particulates > 5 microns in diameter. With the effluent stream

free of particulates with particle sizes > 5 microns in diameter, any remaining smaller size particulates behave in a manner much like a gas and are essentially independent of the effects of nonisokinetic sampling. Approval for nonisokinetic sampling in the reactor building and main stacks accident range monitors from the NRC is included in reference a below.

Two sampling systems are provided. Each has identical samplers, detectors, and controls as shown on drawing no. H-16564. Each system is powered from a separate division from an essential motor control center. The two sampling systems share the same sampling line, flow meter, rotameter, and isolation valves. There are two pumps in the sampling line. One pump is operating continuously while the other is in standby, isolated by manual valves. The sampling system is manually initiated and is provided with flow indication, thus assuring proper system operation.

The main stack isokinetic-type probe meets the guidelines on American National Standards Institute (ANSI)-N13.1-1969 with the exceptions of paragraph A3 in Appendix A. Only a single nozzle is provided for sampling the effluent. Due to the small diameter of the main stack at the location of the probe (33 in.) and since complete mixing has occurred, an adequate representative sample can be obtained using a single probe.

Design and administrative controls preclude the following specific events that are not indicated as abnormal operation:

A. Particulate and halogen filter holder(s) is removed or leaking.

B. Sampler monitor is removed from housing.

C. Sampler housing is open or leaking; valve is closed; and pump is running.

D. Monitor controls are in a position other than operate; e.g., test, check, or calibrate positions.

E. High- or low-flow indicator lights are burned out. Normal operation is between setpoints.

<u>Events A, B, and C</u>

Should any of these three events occur, the following design provisions alert the operator:

- A local flow-fault lamp for the reactor building vent stack.
- A flow-fault annunciator in the MCR for the reactor building vent stack.
- A high-/low-flow annunciator in the MCR for the main stack.
- An "inoperative" annunciator in the MCR for the main stack.

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a. ANSI N13.1-1969 and letter to J. T. Beckham (GPC) from J. F. Stolz (NRC) dated February 8, 1982.

Administrative controls for the main stack monitor are provided by an annunciator response procedure which governs operator response for the condition of main stack (off-gas) vent pipe sample high-/low-flow which would be caused by any of these three events.

Event D

When the monitor controls are in a position other than operate; e.g., test, check, or calibrate, an annunciator alarms in the MCR, indicating an inoperative condition. In addition, daily checks for proper operation of the main stack (off-gas) vent monitor and recorder are required by system operating procedures.

The main stack (off-gas) vent pipe condition of downscale or inoperative initiates an alarm in the MCR with both visual and audible annunciators.

Event E

The main stack high-/low-flow annunciators have audible alarms which alert the operator to an abnormal operating condition. Furthermore, the MCR annunciator lights are tested once per shift as part of normal operating practice.

As shown on drawing no. H-16564, the system also provides for monitoring iodine and particulates by the use of filters in the gas sample monitoring stream. The filters are routinely analyzed in a laboratory. The environmental and power supply design conditions are given in table 11.4-3.

HNP-1 and HNP-2 share the main stack and consequently the main stack radiation monitor.

The off-gas radiation monitors have been selected with monitoring characteristics sufficient to provide plant operations personnel with accurate indication of radioactivity being released to the environs via the main stack. The system thus enables the operator to control the activity release rate. Sufficient redundancy is provided to allow maintenance on one channel without losing the indication provided by the monitor.

The accident-range monitor is designed to comply with NUREG-0737, clarification item II.F.1, and Regulatory Guide 1.97, Revision 2, by providing a high-range, gaseous, effluent monitor for the main stack. (See drawing no. H-16564.)

11.4.2.8.7 Reactor Building Vent Stack Radiation Monitor

The system consists of a normal-range monitor with two redundant sampling channels and an accident-range monitor with one sampling channel. The monitoring system measures the activity in the reactor building vent stack prior to its discharge to the environment and, in doing so, complies with GDC 64. The activity this monitor is designed to detect is due to corrosion and fission products carried with the air from the reactor, turbine, control, and radwaste building ventilation systems.

For the normal-range monitor a continuous representative sample is extracted from the vent stack through an isokinetic probe, passed through a filter paper to collect particulates, and through an impregnated charcoal filter to collect iodine. The sample then travels through the redundant sample channels. Each redundant sampler consists of a gaseous monitor and indicator, a flow indicator which alarms locally on high or low flow, and a sample pump which returns the sample to the reactor building vent stack.

The design flowrate by the isokinetic probe in the reactor building vent stack is 143,000 ft^3/min. The flow rate through the probe is ~ 2 ft^3/min. The isokinetic probe is located in the stack in a position where complete mixing has occurred. Two redundant sampling systems are provided and both systems sample the activity being discharged through the stack. Each system has identical samplers, pumps, rotameters, controls, valves, detectors, and piping as shown on drawing no. H-26012. The sampling systems are manually initiated, and each system is provided with flow indication, thus assuring proper valving and sampling during releases.

Comparison of reactor building vent stack specification and performance to ANSI N13.10-1974 criteria is as follows:

The HNP-2 normal-range equipment follows the guidelines of the subject ANSI but deviates specifically as discussed below:

<u>Paragraph 5.3.1.3 - Range</u>

The reactor building vent stack meter monitors in counts/min. There are calibration curves to relate counts/min to $\mu C/cm^3$ instead of having to adjust the meter to read the count in $\mu C/cm^3$ directly for some individual isotope.

<u>Paragraph 5.3.2.1 - Temperature</u>

The temperature range for the HNP-2 equipment is 0-55°C (32-130°F). ANSI specifies 0-60°C.

<u>Paragraph 5.3.2.2 - Pressure</u>

ANSI requires that the pressure range be specified over the range 500-800 Torr (760 Torr = 1 atm). The HNP-2 equipment was specified to operate in a normal (atmospheric pressure) environment.

<u>Paragraph 5.3.2.4.2 - Power Variations</u>

ANSI specifies ±15% voltage and frequency. The HNP-2 equipment meets ± 10% voltage and ± 5 Hz (± 8%) frequency variations.

<u>Paragraph 5.3.2.7 - Background Radiation</u>

The HNP-2 requirement is 1 mr/h Co-60 gamma for background radiation. The ANSI guidelines specify:

- SR-90, Y-90 For beta background (0.8 MeV)
- Co-60 For gamma background (1.2 MeV)
- AmBe For neutron background (5 MeV)

Part C does not apply because the reactor building vent stack sampling system is not exposed to neutron background. Also, part A is not applicable because the instrument is shielded for gamma. Therefore, no beta should get through the shield.

Paragraph 5.4.1.1 - Detection in Gaseous Streams

When a mixture of radionuclides is present, ANSI requires that the minimum detectable concentration (MDC) be that of the nuclide with the smallest maximum dependable capacity as listed in table 1. The table requires sensor sensitivity noble gases be $2 \times 10^{-7} \mu C/cm^3$, whereas the HNP-2 sensor has the capability of measuring $5 \times 10^{-7} \mu C/cm^3$ of radioactivity concentration.

Paragraph 5.4.2 - Range

The range specified by ANSI is 4 decades. The HNP-2 unit has a 5-decade range.

Paragraph 5.4.7.1 - Temperature

The ANSI guideline suggests that there be < 5% change in calibration or response between 0 and 60°C. The HNP-2 general requirements were a 0 - 55°C temperature range with a 2% change allowed for meter accuracy.

Paragraph 5.4.7.3 - Humidity

The HNP-2 unit can operate in 10 to 95% humidity as recommended by ANSI.

Design and administrative controls that preclude specific events that would not be indicated as abnormal operation are discussed in paragraph 11.4.2.8.6.

The shielded gas monitor has a beta scintillation detector which consists of a beta-sensitive plastic crystal optically connected to a photomultiplier tube. The detector and a preamplifier are mounted in a protective housing which is inserted into a stainless steel chamber. Table 11.4-1 lists the location and range of the detector. The shielded gas monitor can be disassembled for cleaning or part replacement if the chamber should become contaminated.

The input from the preamplifier in the shielded gas monitor is fed to the log-rate meter indicator located on panel 2D11-P002. The ratemeter has three alarms which are annunciated in the MCR and are locally indicated by lights. These alarms are RAH, which warns of radioactivity levels at 90% of Technical Specifications limits; RAHH, which is set at a level to provide overlap with the accident-range monitor to assure the appropriate start signal; and a circuit failure

(downscale trip) alarm. The RAHH contact provides the start signal for the accident-range monitor and trips the normal-range monitor.

A two-pen 6-decade strip recorder is provided in the MCR. The recorder plots input from both reactor building vent stack gaseous monitors. The rate meter activates a RAH in the MCR. The setpoint for this alarm is given in table 11.4-1.

The particulate and iodine activity is usually accumulated on filters for a week to accumulate sufficient activity to be detectable. These filters are counted in the counting room to determine the specific radionuclides released and their quantities. The results, together with the gaseous activity strip chart recorder, provide a permanent record of the activity released to the environment.

The system provides no control function but is a diagnostic tool which enables the MCR operator to take appropriate action. Power is supplied from an essential motor control center. Arrangement details are shown on drawing no. H-26012.

The accident-range monitor is designed to comply with NUREG-0737, clarification item II.F.1, and Regulatory Guide 1.97, Revision 2, by providing a high-range, gaseous, effluent monitor for the reactor building vent plenum. (See drawing no. H-26012.) The Unit 2 accident range monitor has nonisokinetic sampling. The discussion on nonisokinetic sampling and reference a in paragraph 11.4.2.8.6 applies to the Unit 2 accident range sampling system.

11.4.2.8.8 Filter Performance Monitors

A number of radiation monitors are provided on filtered ventilation systems to detect a release which would be indicative of filter element decreased performance or failure. These elements monitor the ventilation ducts before the ducts enter the reactor building vent stack. Therefore, they are also useful in determining and isolating a problem area if the vent stack radiation alarms are actuated.

These monitors are used in the following systems:

- Reactor building ventilation.
- Refueling floor ventilation.
- Radwaste building ventilation.
- Turbine building ventilation.

The effluent radiation level from the reactor building exhaust filters is measured by a single radiation monitor mounted on the common discharge line of the two fans between the fans and the last isolation valves before the system discharges to the reactor building vent stack.

The effluent from the refueling floor ventilation exhaust filters is monitored by two detectors, one mounted on each filter discharge line between the filter and its associated fan.

The radwaste building and turbine building ventilation exhausts are monitored before and after the filters. In both systems, the air upstream of the filter is monitored by a single radiation monitor mounted on the respective common inlet duct to the system's exhaust filters. Both systems also have two monitors on the filter effluent ducts. The radwaste building exhaust filter effluent monitors are mounted one on each line between the filters and fans. The turbine building exhaust filter effluent monitors are mounted one each on each fan discharge. These mounting arrangements ensure that the influent and effluent of each exhaust filter is monitored regardless of which fan or filter is on line.

Each of the filter performance monitors has identical channels. G-M tubes are utilized for gamma detection. The detector has an integral preamplifier which produces pulse conditioning to match the input requirements of the indicator and trip unit mounted in the MCR.

The indicator and trip unit provides an input to alarms and a recorder in the MCR. The effluent monitors of each system have individual recorders. The turbine building ventilation exhaust filter influent radiation monitor shares a recorder with the off-gas carbon bed vault monitor and the drywell purge monitor. The other filter influent monitors each have their own recorder.

Each indicator and trip unit has a RAH and a RAL annunciated in the MCR. The RAH setpoint is provided in table 11.4-1. The RAL is set less than background and is indicative of a system equipment failure.

The indicating channels are powered from the 120-V-ac vital bus. The recorders are powered from the 120-V-ac instrument bus.

Filter performance monitors perform no control functions, but provide information to the MCR operators. These monitors and their locations are depicted on the figures showing the ventilation systems described in section 9.4.

11.4.2.8.9 SGTS Radiation Monitor

This monitor measures the activity in the exhaust vent lines from the SGTS prior to its discharge to the main stack vent pipe and the environment and in doing so, complies with GDC 64. There is a monitor on each SGTS system train. The activity these monitors are designed to detect is fission products from the reactor building which have been treated by the SGTS. If the monitor alarms on one SGTS, the MCR operator can shut down the operating train and use the standby train to clean up the air being discharged. The gaseous activity in the exhaust is normally below detectable levels.

Each channel consists of a local GM tube detector and preamplifier, an indicator and trip unit in the MCR, and one channel of a paperless recorder located in the MCR. Two alarms receive input from the indicator and trip unit, a RAH and a RAL. The setpoints for these alarms are provided in table 11.4-1. The RAL is set below background and is indicative of equipment failure.

The indicator and trip units are powered from the 120-V-ac uninterruptible ac cabinet bus; the recorder is powered from the 120-V-ac instrument bus.

11.4.2.8.10 Primary Containment Purge Radiation Monitor

This monitor measures the activity from the drywell and suppression chamber and in doing so, complies with GDC 30. It is designed:

- To help determine the effectiveness of the SGTS which is used to mitigate the effects of an incident by measuring the inlet activity. (The outlet activity is measured by the SGTS monitor.)

- To assist in determining the airborne activity when work is to be performed in these vessels during shutdown.

The detector is mounted on the exhaust line of the drywell and suppression pool purge system upstream of the SGTS suction line connection. The monitoring channel is identical to the channel described in paragraph 11.4.2.8.9 with the exception that the monitor shares a two-pen recorder with the turbine building ventilation filter intake radiation monitor. Setpoints for the alarms are provided in table 11.4-1.

11.4.2.8.11 Fission Product Radiation Monitor (HNP-1 and HNP-2)

The fission product monitor system is shown schematically for HNP-1 on drawing nos. H-16173 and H-16274 and for HNP-2 on drawing nos. H-26016 and H-26017. This monitor measures airborne activity in the drywell and suppression chamber as a means of detection of leakage from the reactor coolant pressure boundary.

A sample of the atmosphere from the drywell or the suppression chamber is pumped into two panels in parallel. The gas flows through a moving filter paper on the first panel and then is returned to the area from which it was taken. The moving filter paper is continuously monitored by a gamma-sensitive sodium-iodide scintillation detector. At the same time, the gas from either the drywell or suppression chamber also flows through an iodine filter and then through a shielded sample chamber in the second panel and then is returned. The iodine filter is also continuously monitored by a gamma-sensitive sodium-iodide scintillation detector. Beta-gamma sensitive GM tubes are located within the shielded sample chamber for monitoring noble gases. Each of the three detectors has a local preamplifier which sends a signal to the MCR where the levels are read out on a log-count rate meter and recorded.

High-level and downscale alarms from each channel are annunciated in the MCR.

The monitor performs no control actions.

Sampling provisions are incorporated into this subsystem whereby a sample bottle can be filled with the sample gases and taken to the lab for analysis.

11.4.2.8.12 Primary Containment Normal and Post-Accident Radiation Monitors (HNP-1 and HNP-2)

These monitors measure gross gamma radiation in the drywell and suppression chamber and consist of two subsystems. These subsystems are the narrow range radiation monitors and the post-accident (wide range) radiation monitors. Refer to drawing no. H-16274 for these systems.

The narrow range primary containment radiation monitors are used during normal plant operations to provide redundant indication, recording, and alarm functions in the MCR. This subsystem provides no safety-related functions.

The post-accident (wide range) primary containment radiation monitors are used before, during, and after a design basis event and are fully qualified for service in accordance with IEEE-323 (1974) and IEEE-344 (1975). These monitors provide redundant drywell gross gamma radiation level indication, recording, and alarm functions in the MCR. In addition, contacts from each channel of the wide range monitors are used as inputs to the control logic for containment purge and vent valves, and as inputs to the primary containment isolation system (PCIS). This subsystem is safety related for the primary containment isolation function only.

11.4.2.9 Description of Liquid Monitors

Each channel of the system contains a completely integrated modular assembly as described below. Specific details of each monitor are described in paragraphs 11.4.2.9.2.1 through 11.4.2.9.2.3.

11.4.2.9.1 General Liquid Monitor Details

11.4.2.9.1.1 Detector-Preamplifier Unit. Each detector is a NaI gamma-sensitive scintillation detector. A preamplifier is mounted on top of the detector. The detectors are designed to remain fully operational over a wide range of temperatures, as shown in table 11.4-3. If they are exposed to high radiation transients exceeding the channel range, the channel maintains full-scale deflection and returns to normal functioning when the transient has subsided. Since gamma detectors are used, comparison of monitor readout with the results of grab samples is easily made. Each inline monitor has a polished stainless steel well bolted to a flange on the line being monitored.

11.4.2.9.1.2 Radiation Analyzer. The radiation analyzers are located in the MCR and are composed of an amplifier, a count rate meter, a trip unit, and a power supply as described below:

A. The amplifier accepts pulses from the detector or preamplifier, performs a log integration, and amplifies the output.

B. The meter displays the output in counts/s on a 7-decade log scale.

C. The trip unit provides adjustable trips which can be set for alarm or control functions over the entire range of the unit. One low (failure) and one high trip are provided for all monitors. A high-high trip is provided on the radwaste effluent monitor.

D. The power supply unit provides the necessary ac and dc voltages for the radiation analyzer and the detector-preamplifier unit. Power for this unit and other auxiliary equipment is supplied from the uninterruptible bus (120 V ac) or from the 24/48-V-dc cabinets 2A and 2B.

11.4.2.9.1.3 **Recorder**. A recorder is provided in the MCR or radwaste control room to record the output from each channel.

11.4.2.9.2 Specific Liquid Monitor Details

11.4.2.9.2.1 **Radwaste Effluent Radiation Monitor**. This monitor measures the activity in the radwaste effluent discharge line to comply with GDCs 23 and 64. The radwaste effluent line discharges into the PSW dilution line where an average flow of 28.4 ft^3/s dilutes the waste prior to its discharge to the Altamaha River. This monitor detects the activity in the radwaste effluent discharge line to prevent the concentration in the discharge to the Altamaha River from exceeding the Technical Specifications limits. Waste liquid is normally discharged from the floor drain sample tank, the waste sample tank, or chemical waste sample tank. Prior to discharge, the liquid in the appropriate tank is sampled and analyzed in the laboratory for radioactivity. Based upon this analysis, the release and dilution rates are determined.

The shielded detector is located in a well in the common radwaste discharge line through which all radioactive liquid discharged to the environment must pass. Table 11.4-2 lists the location, sensitivity, and range of this detector. The piping arrangement is designed so that the section of pipe in which the well is located can be flushed to remove crud to lower the background radiation levels or to remove a slug of highly radioactive liquid to clear the high alarm. The flanged stainless-steel well, which protrudes into the liquid flow path, is bolted to the blowdown pipe. If the well becomes highly contaminated, it can be removed for decontamination after draining the line.

The channel consists of the local detector and preamplifier, a radiation analyzer in the MCR, and one pen on a recorder in the radwaste control room. The recorder is a single-pen, 7-decade strip chart recorder located in the radwaste control room. The radwaste monitor has a remote indicator with two adjustable setpoint controls located in the radwaste control room. The low trip alarm initiates valve closure because the trip circuit has been designed to fail safe in the event of loss of power. The high trip alarm alarms in the MCR and initiates valve closure. Power is supplied from 24/48-V-dc cabinet 2B for the channel components and from the 120-V-ac instrument bus for the recorder. Since the radwaste release is based on batch analysis, the basis for the alarm setpoint on the monitor is that an alarm should be given on a gross release

in the range of 10^{-6} to 10^{-2} μCi/cc as a cross check against significant operator error. The alarm setpoint may vary from one batch to the other depending upon the activity concentration of the batch and the available cooling tower discharge flow which is used to dilute the liquid effluent prior to leaving the site boundary. This system provides automatic isolation of the radwaste discharge. This monitor is depicted on drawing no. H-26012.

The purpose of measurement of the radwaste system effluent by the liquid radiation monitor, as expressed on table 11.4-2, is to automatically terminate discharge by closing the valves on the effluent control manifold.

Alarm/Trip Setpoint Controller	Location
Upscale radiation alarm	Radwaste control room
Upscale radiation alarm	Radwaste control room
Downscale radiation/inoperable alarm	Radwaste control room
Radiation monitor (setpoint control)	Radwaste control room

An automatic flow controller is provided on the dilution water system as described in paragraph 11.2.3.4.4. The controller low flow setpoint is set at the minimum dilution water rate. A signal from this controller automatically terminates discharges.

The radwaste effluent flow is measured prior to injection into the PSW dilution line.

The radwaste effluent flow measuring device is as follows:

No.	Type	Range (gal/min)	Minimum (gal/min)
1G11-R345	Vortex Flowmeter	0-100	8
2G11-N355	Vortex Flowmeter	0-100	8

The dual (3-in. and 3/4-in.) discharge flow control manifold on the radwaste system serves only to allow a greater rangeability of control on the discharge flowrate. Only one line serves the radiation monitor downstream where the 3/4-in. and 3-in. loops combine and enter the effluent line. The effluent monitor provides shutdown capability when the trip setpoint is reached. This would prevent discharges in excess of 10 CFR 20 limitations. The floor drain sample tank discharge line is shown on drawing no. H-26030.

The radioactive waste effluent monitoring system complies with the fail-safe requirements on GDC 23 by closing both discharge flow valves on the radwaste system on upscale movement above the high setpoint, and by doing the same on downscale failure due to internal component failure or failure of utility inputs, such as air or electrical power. The system complies with GDC 64 to monitor the release in that it reads the only liquid effluent line from the radwaste system. No bypass of this monitor is possible for liquid release. GDC 60 requirements are met for suitable control in that all flowrates from the radwaste system are allowed which result in concentrations below the Technical Specifications limits, provided the preset dilution water limits are also met. Radiation measurements reaching the high setpoint result in automatic shutoff of the radwaste discharge.

11.4.2.9.2.2 PSW Effluent Radiation Monitor. This monitor measures the activity in the general service water line to comply with GDC 64. The PSW line discharges into the main condenser circulating flume after usage in the plant and directly into the Altamaha River when used for additional dilution. No activity attributable to reactor operation is present in this line. To have activity in this line, a leak would have to develop simultaneously in equipment cooled by the RBCCW system and in the RBCCW heat exchanger or in the residual heat removal (RHR) pump seal cooler while the RHR system is operating. Samples of the RBCCW system are checked periodically for activity which would warn if a leak has developed in a component. In addition, there is an inline radiation monitor on the RBCCW system (paragraph 11.4.2.9.2.3) that would warn of any gross leak from a component cooled by that system between analyses.

The PSW monitor provides a backup for the above detection methods and detects gross leaks of radioactive liquid into the service water.

The shielded detector is located in a well in the service water discharge line. Table 11.4-2 lists the location, sensitivity, and range for this detector. The flanged stainless-steel well, which protrudes into the liquid flow path, is bolted to the service water pipe. If the well should become contaminated, it can be removed for decontamination after draining the line.

The channel consists of the local detector and preamplifier, a radiation analyzer in the control room, and one channel of a multichannel paperless recorder in the MCR. The recorder is shared with the RBCCW monitor.

The radiation analyzer provides input to two alarms which are annunciated in the MCR. One is a RAH alarm, the other is a RAL. The alarm setpoint is based on detecting leakage into the service water with the setpoint set sufficiently above background to preclude spurious alarms. Setpoints for these alarms are provided in table 11.4-2.

The system provides no control function, but is a diagnostic tool which enables the MCR operator to take appropriate action. Power is supplied from the 24/48-V-dc cabinet 2B for the channel and from the 120-V-ac instrument bus for the recorder.

11.4.2.9.2.3 RBCCW Radiation Monitor. This monitor subsystem measures the activity in the RBCCW system and, in doing so, complies with GDC 64. The RBCCW system cools components which contain radioactive liquids but does not normally have any activity unless one of these components develops a leak. Samples of the RBCCW system are checked periodically for activity to determine if a leak is starting in a component. A laboratory analysis has much greater sensitivity than a radiation monitor and, therefore, can detect smaller leaks. Since leaks usually start small and develop gradually, the radiological analyses performed in the laboratory normally detect the leak prior to the monitor. If a leak should increase dramatically between samples or if a gross failure should occur, the monitor would detect it.

The shielded detector is located in a well in the 16-in. inlet header of the RBCCW heat exchangers. Table 11.4-2 lists location, sensitivity, and range for this detector. The flange stainless steel well, which protrudes into the liquid flow path, is bolted to the cooling water pipe. If the well should become contaminated, it can be removed for decontamination after draining the line.

The channel consists of the local detector and preamplifier, a radiation analyzer in the MCR, and one channel of a multichannel paperless recorder in the MCR. The recorder is located on panel H11-P600. The recorder is shared with the general service water effluent monitor. The channel has two alarms, a RAH and a RAL for equipment failure. The RAH setpoint is based on detecting heat exchanger leakages, and the setpoint is set sufficiently above background to preclude spurious alarms. The detector for this monitor is an NaI scintillation detector. The RBCCW system provides no control function but is a diagnostic tool which enables the MCR operator to take appropriate action. Power is supplied from the ± 24-V-dc cabinet 2B for the channel and from the 120-V-ac instrument bus for the recorder. Arrangement details are shown on drawing no. H-26012.

11.4.3 SAMPLING

As required by Technical Specification 5.5.4, Radioactive Effluent Controls Program, the following paragraphs present a detailed description of the radiological sampling procedures, frequencies, and objectives for all plant process and effluent sampling.

11.4.3.1 Process Sampling

Subsection 9.3.2 presents a detailed description of the design of sampling facilities provided for general sampling. Aspects of sampling associated with the gaseous effluents from the main stack and the reactor building vent stack are discussed for the respective monitoring systems in paragraphs 11.4.2.8.6 and 11.4.2.8.7 above. The sample frequency, type of analyses, analytical sensitivity, and the purpose of the sample are summarized in table 11.4-4 for each liquid process sample location and in table 11.4-5 for each gas process sample location. The analytical procedures used in sample analysis are presented in paragraph 11.4.3.3. These samples monitor activity levels within various plant systems.

11.4.3.2 Effluent Sampling

Effluent sampling of all potentially radioactive liquid and gaseous effluent paths is conducted on a regular basis in order to verify the adequacy of effluent processing to meet the discharge limits to unrestricted areas. This effluent sampling program is of such a comprehensive nature as to provide the information for the effluent measuring and reporting programs required by 10 CFR 50.36a in annual reports to the Nuclear Regulatory Commission (NRC). The frequency of the periodic sampling and analysis described herein is normal and is increased if effluent levels approach the limits specified in the ODCM. Tables 11.4-6 and 11.4-7 summarize the sample and analysis schedules presented in the following paragraphs. These schedules correspond to Regulatory Guide 1.21 requirements.

Liquid Effluents

The following sample schedule applies to all radioactive liquid effluents released from the radwaste effluent line through the discharge structure to the Altamaha River:

A. Measurements are made on a representative sample of each batch of effluent released and kept as a record together with the volume of the batch, the average dilution water flow used during discharge, and the time and date of release.

B. Each batch released is analyzed for principal gamma emitters. The sensitivity of this analysis is such that concentrations of 5×10^{-7} µCi/ml are measurable.

C. At least monthly, a batch that is typical of average releases of radioactivity is analyzed for dissolved fission and activation gases. The sensitivity of this analysis is such that concentrations of 10^{-5} µCi/ml are measurable.

D. Proportional composite samples are made up of all tanks discharged. These are samples in which the quantity of liquid added to the composite from each batch released is proportional to the quantity of liquid in that batch. Such composite samples are made up and analyzed monthly or quarterly. The composite samples taken from each batch released during the month are analyzed for tritium and gross alpha radioactivity. Fe-55, Sr-89, and Sr-90 are analyzed quarterly. The sensitivity of these analyses is such that there is the capability of measuring concentrations of 10^{-5} µCi/ml of tritium, 2×10^{-6} µCi/ml of Fe-55, 5×10^{-8} µCi/ml of each of Sr-89 and Sr-90, and 10^{-7} µCi/ml of gross alpha radioactivity.

Gaseous Effluents

The following sample schedule applies to the off-gas release from the main stack and to the potentially radioactive gaseous releases continuously discharged from the reactor building ventilation exhaust system.

A. Meteorological measurements of wind speed, wind direction, and atmospheric stability are continuously recorded in the MCR.

B. Radionuclide-specific noble gas activity releases are quantitatively determined with the sample analyses results and flowrates in each of the effluent streams. The quarterly releases are reported annually.

C. Within 1 month of initial criticality, at least monthly thereafter, and following each refueling, process change, or other occurrence that could alter the mixture of radionuclides, an isotopic analysis is made of the gaseous activity being released from the off-gas system.

D. A continuous sample is drawn through an iodine sampling device to determine the quantity of radioiodine isotopes released. The device is analyzed at least weekly for I-131. A sample is analyzed at least monthly for I-133 and I-135. The sensitivity of the analyses is such that at least 1×10^{-10} µCi/ml is measurable for I-133, I-135, and 10^{-12} for I-131.

E. A continuous sample is drawn through a particulate filter device and analyzed weekly for the principal gamma emitting nuclides with (at least for Ba-La-140 and

I-131) analyses sensitive to $10^{-11}\mu Ci/ml$. A quarterly analysis for Sr-89 and Sr-90 is made on a composite of a quarter's duration of filters from individual effluent paths with analyses sensitive to $10^{-11}\mu Ci/ml$. An analysis for gross alpha radioactivity is made on a sample of a week's duration from the individual effluent paths at least monthly with analyses sensitive to at least $10^{-11}\mu Ci/ml$.

F. A representative sample from each effluent path is analyzed monthly for tritium. The sensitivity of analysis is $10^{-6}\mu Ci/ml$.

11.4.3.3 Analytical Procedures

Samples of process and effluent gases and liquids are analyzed in the laboratory by the following techniques:

- Gross beta counting.
- Gross alpha counting.
- Gamma spectrometry.
- Liquid scintillation counting (contract laboratory).
- Radiochemical separations (contract laboratory).

Instrumentation which is available in the laboratory for the measurement of radioactivity includes:

- End-window G-M counter.
- Thin-window gas flow proportional counter.
- NaI well counters.
- Gamma spectrometer.
    - High purity germanium (HPGe) detector.
    - Multichannel analyzer with interfaced computer.

Alpha analyses of air particulate samples and liquid effluent samples are performed by counting of the samples with a gas flow proportional counter. These analyses may be performed by a contract laboratory.

Gamma spectrometry is used extensively for isotopic analyses of gaseous, air particulate, and liquid samples. Three high-resolution HPGe detectors are available for this purpose. All three detectors are calibrated against National Institute of Standards (NIST)/National Bureau of

Standards (NBS) traceable gamma standards for a variety of sample detector geometries. The detectors are employed to meet required detection limits for certain noble gas, gaseous radioiodine, and air particulate effluent samples.

Gaseous tritium samples are collected by condensation or absorption (silica gel). Liquid samples for tritium analysis are purified prior to analysis by either passing the samples through mixed-bed ion-exchange columns or by distilling the samples, or both. A liquid scintillation counter is used to count the samples.

Radiochemical separations are used for the routine analysis of Fe-55, Sr-89, and Sr-90.

Liquid samples are collected in polyethylene bottles to minimize adsorption of nuclides onto container walls. Samples which are not analyzed immediately are acidified prior to storage. In most cases, liquid samples are analyzed without prior filtration.

Depending on initial experience, either activated coconut charcoal or impregnated charcoal is employed as the adsorption media in gaseous radioiodine sampling devices.

11.4.4 INSPECTION, CALIBRATION, AND MAINTENANCE

11.4.4.1 <u>Inspections and Tests</u>

During reactor operation, daily checks of system operability are made by observing channel behavior. At periodic intervals during reactor operation, the detector response (of each monitor provided with a remotely positioned check source) is recorded together with the instrument background count rate to ensure proper functioning on the monitors. Any detector whose response cannot be verified by observation during normal operation or by using the remotely positioned check source has its response checked with a portable check source. A record is maintained showing the background radiation level and the detector response.

The system has electronic testing and calibrating equipment which permits channel testing without relocating or dismounting channel components. An internal trip test circuit, adjustable over the full range of the readout meter, is used for testing. Each channel is tested at least semiannually prior to performing a calibration check. Verification of valve operation, ventilation diversion, or other trip function is done at this time if it can be done without jeopardizing the plant safety. The tests are documented.

11.4.4.1.1 Detailed Inspections and Tests

A. Main steam line radiation monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

B. Refueling floor ventilation exhaust radiation monitor system - All alarm trip circuits are tested by using test signals or portable gamma sources.

C. Reactor building ventilation exhaust radiation monitor system - All alarm trip circuits are tested by using test signals or portable gamma sources.

D. Control room intake air radiation monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

E. Off-gas radiation monitor system

   1. Pretreatment - All alarm trip circuits are tested by using test signals or portable gamma sources.

   2. Post-treatment - Each individual channel includes a built-in check source and a purge line to purge the vent gas from the sampling chamber. Both the purge valve and the check source are operated from the MCR.

F. Off-gas vent pipe radiation monitor system - Each individual channel includes a built-in check source and a purge line to purge the vent gas from the sampling chamber. Both the purge valve and the check source are operated from the MCR.

G. Reactor building vent stack radiation monitor (normal range) - Two operational checks are built into each gas monitoring channel. An electric pulse generator that simulates an indication of ~ 6 x 10^4 counts/min provides a check for the input of the rate meter. There is also a radioactive check source which is operated from the front panel of the locally mounted rate meter.

H. Radwaste building radiation monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

I. Turbine building ventilation radiation monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

J. SGTS radiation monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

K. Drywell purge radiation monitor - All alarm trip circuits are tested by using test signals or portable gamma sources.

L. Fission products radiation monitors - Each individual channel includes a built-in check source and a purge line to purge the vent gas from the sampling chamber. Both the purge valve and the check source are operated from the MCR.

M. Post-LOCA radiation monitors - Two operational checks are built into each wide-range containment monitor. An electronic check source (ECS) test triggers an electric pulse generator that simulates an indication of ~ 1 x 10^3 R/h to provide a system check for the input of the rate meter. There is also a channel test which verifies that the amplifier, meter and alarm circuitry is operative.

N. Liquid monitors - All alarm trip circuits are tested by using test signals or portable gamma sources.

11.4.4.2 Calibration

The continuous radiation monitor's calibration is traceable to certified National Institute of Standards and Technology or commercial radionuclide standards and is accurate to at least ± 15%. The source-detector geometry during primary efficiency calibration is identical to the sample-detector geometry in actual use. Secondary standards which were counted in reproducible geometry during the primary efficiency calibration are used in correlation with the primary efficiency calibration. The check sources are used as a qualitative assessment of equipment operability. Each continuous monitor is calibrated on a frequency corresponding to the refueling frequency, using the secondary radionuclide standard. A calibration can also be performed by using liquid or gaseous radionuclide standards or by analyzing particulate, iodine, or gaseous grab samples with laboratory instruments.

Specific calibration criteria are as follows:

A. Off-Gas Radiation Monitor and Sampler (Pretreatment)

   Criterion for calibration: The monitor shall respond to a gross gamma signal with the calibration factor to convert mr/h to μCi/s being derived from periodic analysis of a grab sample of the pretreated off-gas. The detector for this monitor is a gamma-sensitive ion chamber.

B. Off-Gas Radiation Monitors and Sampler (Post-Treatment)

   Criterion for calibration: The monitors shall respond to a gross gamma signal with the calibration factor to convert counts/s to μCi/s being derived from the primary efficiency calibration. The detector of these monitors is a scintillation detector.

C. Main Stack (Off-Gas Vent Pipe) Radiation Monitors

   Criterion for calibration: This channel is calibrated to respond to a gross gamma signal with a calibration factor to convert counts/s to μCi/s based on the primary efficiency calibration. The detector for these monitors is a scintillation detector.

D. Main Steam Line Radiation Monitors

   Criterion for calibration: The monitors shall read gross gamma dose rate in the steam tunnel. The detector for these monitors is a gamma sensitive ion chamber.

E. Refueling Floor Ventilation Exhaust Radiation Monitors

Criterion for calibration: These channels are calibrated to respond to gross gamma dose rate in the refueling floor ventilation duct. The detector for these monitors is a GM tube.

F. Reactor Building Ventilation Exhaust Radiation Monitors

Criterion for calibration: Same as refueling floor monitors, item E above. The detector for these monitors is a GM tube.

G. Liquid Radwaste Monitor

Criterion for calibration: The monitor is calibrated to respond to a gross gamma signal with a required least detectable concentration of 1 x $10^{-6}\mu$Ci/cc for Cs-137 with a process signal equal to 3 times the variance in the count rate from 0.1 mr/h 1 MeV gamma background.

H. PSW Effluent Monitor

Criterion for calibration: Same as liquid radwaste monitor, item G.

I. RBCCW Monitor

Criterion for calibration: Same as liquid radwaste monitor, item G.

11.4.4.3 <u>Maintenance</u>

The channel detectors and electronics which could impose a Limiting Condition for Operation are functionally tested and calibrated per the requirements of the Technical Specifications, Technical Requirements Manual, and ODCM, as applicable, to ensure reliable operation. All other channel detectors, electronics, and recorders are serviced and maintained on a regular basis. Such maintenance includes cleaning, lubrication, and assurance of free movement of the recorder in addition to the replacement or adjustment of any components required after performing a test or calibration check. If any work is performed which could affect the calibration, a recalibration is performed at the completion of the work.

11.4.4.5 <u>Audits and Verifications</u>

Independent audits and verifications of test, calibration, and maintenance records and procedures are conducted as described in the SNC Quality Assurance Topical Report (QATR).

TABLE 11.4-1 (SHEET 1 OF 4)

GASEOUS AND AIRBORNE RADIATION MONITORS

Monitored Process	No. of Channels	Purpose of Measurement	Detector Type	Detector Location	Range	Setpoints		Principal Radionuclides Measured
						Alarm	Trip	
Reactor bldg vent stack								
Normal range	2	Audit discharge to environs	Scintillation	Sample line from reactor bldg vent stack	10^{1} - 10^{6} cpm	(H) 90% of TS release rate limit; (HH) level which exceeds TS releases rate limit and which overlaps accident-range monitor to assure appropriate start.	NA	Kr-85m, 87, 88 Xe-135
Accident Range	1	Audit discharge to environs	Solid-state	Sample line from reactor bldg vent stack	1.0×10^{-3} to 1.0×10^{5} μCi/cc			
Main stack or off-gas vent discharge								
Normal range	2	Audit discharge to environs	Scintillation	Sample line from main stack	10^{-1} to 10^{6} counts/s	(H) 90% of TS release rate limit; (HH); level which exceeds TS release rate limit and which overlaps accident-range monitor to assure appropriate start.	NA (d)	Ar-41 Xe-133
Accident range	1	Audit discharge to environs	Solid-state	Sample line from main stack	1.0×10^{-3} to 1.0×10^{5} μCi/cc			

TABLE 11.4-1 (SHEET 2 OF 4)

Monitored Process	No. of Channels	Purpose of Measurement	Detector Type	Detector Location	Range	Setpoints Alarm	Setpoints Trip	Principal Radionuclides Measured
Off-gas post treatment	2	Monitor and control process after treatment	Scintillation	Sample line in waste gas treatment bldg	10^{-1} to 10^{6} counts/s	(H) Conservatively set well below TS release rate limit; (HH) 90% of TS release rate limit; (HHH) two times the TS release rate limit.	(HHH) Short-term maximum release rate	Kr-85 Xe-133
Pretreatment	2	Monitor process before treatment	Gamma sensitive ionization chamber	Sample line	$1\text{-}10^{6}$ mr/h	(H) 1.5 times nominal steady-state release rate; (HH) TS limit for maximum release rate without treatment.	NA	Kr-85m, 87, 88 Xe-133m,135
Carbon bed vault	1	Monitor process	GM tube vault	Carbon bed	$1\text{-}10^{6}$ mr/h	(a)	NA	Xe-135,135m Kr-87, 88
Main steam line	4	Limit fission product carryover to turbine plant	Gamma sensitive ionization chamber	Immediately downstream of last MSIV	$1\text{-}10^{6}$ mr/h	(a)	(a)	N-16, O-19 Xe-133 Xe-135
Reactor bldg ventilation exhaust	4	Isolate bldg and initiate SGTS	GM tube	Exhaust duct upstream of exhaust ventilation isolation valve	0.01 mr/h to 100 mr/h	NA	(a)	Xe-135 Kr-85m, 87, 88
Refueling floor zone ventilation exhaust	12	Isolate bldg and initiate SGTS	GM tube	Exhaust duct upstream of exhaust ventilation isolation valve	0.01 mr/h to 100 mr/h	NA	(a)	Xe-135 Kr-85m, 87, 88 I-131

TABLE 11.4-1 (SHEET 3 OF 4)

Monitored Process	No. of Channels	Purpose of Measurement	Detector Type	Detector Location	Range	Setpoints Alarm	Setpoints Trip	Principal Radionuclides Measured
SGTS exhaust	2	Monitor process duct	GM tube	Exhaust duct after SGTS filters	1.0 to 10^6 mr/h	(a)	NA	Xe-133 Ar-41
Primary containment purge	1	Monitor exhaust	GM tube	Exhaust duct	0.01 mr/h to 100 mr/h	(a)	NA[c]	Xe-133 Kr-85
Reactor bldg vent filter discharge	2	Monitor filter exhaust	GM tube	Exhaust duct	0.01 mr/h to 100 mr/h	(a)	NA	Xe-135 Kr-85m, 87, 88
Refuel floor vent filter	2	Monitor filter exhaust	GM tube	Exhaust duct	0.01 mr/h to 100 mr/h	(a)	NA	Xe-135 Kr-85, 85m, 87, 88
Turbine bldg vent filter discharge	2	Monitor filter exhaust	GM tube	Exhaust duct	0.01 to 100 mr/h	(a)	NA	Xe-135 Kr-85m, 87, 88
Turbine bldg vent filter intake	1	Monitor filter intake	GM tube	Exhaust duct	0.01 to 100 mr/h	(a)	NA	Xe-135 Kr-85m, 87, 88
Radwaste bldg filter intake	1	Monitor filter intake	GM tube	Exhaust duct	0.01 to 100 mr/h	(a)	NA	Xe-133, I-131 CS-137, Co-60
Radwaste bldg filter discharge	2	Monitor filter exhaust	GM tube	Exhaust duct	0.01 to 100 mr/h	(a)	NA	Xe-133 Kr-85
Fission products		Aid leak detection system						
Particulates Halogens Noble gases	1 1 1		NaI scint. NaI scint. β sensitive GM tube	Sample line from primary containment	10 to 10^6 counts/min	(a)	NA	CS-137, Co-60 I-131 Xe-133, KR-85

TABLE 11.4-1 (SHEET 4 OF 4)

Monitored Process	No. of Channels	Purpose of Measurement	Detector Type	Detector Location	Range	Setpoints Alarm	Setpoints Trip	Principal Radionuclides Measured
Low-range post-accident monitor	4	Monitor torus and drywell	γ sensitive ionization	Outside of torus and dry-well	1 to 10^6 R/h	(a)	NA	Cs-137 C0-60
High-range post-accident monitor	2	Monitor drywell	γ sensitive ionization	Inside drywell	1 to 10^7 R/h	NA	$\leq$ 138 R/h	Gross gamma

LEGEND
TS - Technical Specifications

a. Setpoint is determined relative to or as a function of background radiation level.
b. Selection of nuclides based upon half life, initial activity, and type and energy of emitted radiation.
c. The purge system is directly connected to the SGTS and will not be operated more than 1% of the time during which primary containment impurity is required.
d. The high-high alarm trips the normal-range monitor and starts the accident-range monitor.

TABLE 11.4-2

LIQUID RADIATION MONITORS

Monitored Process	No. of Channels	Purpose of Measurement	Detector Type	Detector Location	Normal Range	Channel Range	Setpoints Alarm	Setpoints Isolation	Principal Radionuclides Measured
Radioactive waste system effluent	1	Aid in checking waste discharge concentrations	Scintillation	Effluent pipe prior to discharge into other systems		$3x10^{-8}$ to .3 μCi/cc (a)	10^{-6} to 10^{-2} μCi/cc (b)	10^{-1} μCi/cc or downscale	Cs-137 Co-60
Service water discharge	1	Detect leaks into service water	Scintillation	Effluent pipe prior to discharge into other systems	$5x10^{-9}$ μCi/cc river water	$9x10^{-8}$ to .9 μCi/cc (a)	Above backgound level	NA	Cs-137 Co-60
RBCCW discharge	1	Detect heat exchanger leak	Scintillation	Suction header to closed cooling water pumps		10^{-7} to 1 μCi/cc (a)	Above background level	NA	Cs-137 Co-60

a. Readout is dependent on the discriminator setting.
b. Alarm setpoint is dependent on the flowrate and release limits in Technical Specifications.

TABLE 11.4-3

PROCESS RADIATION MONITORS ENVIRONMENTAL DESIGN PARAMETERS

Radiation/Monitor	Pressure (psig)	Temperature (°F)	Relative Humidity (%)
Main steam line detectors	0 to 250	392 (max)	---
Off-gas sample system			
Pretreatment	0 to 250	392 (max)	---
Post-treatment	0 to 5	-22 to +140	0 to 100
Reactor building vent stack monitor and sampler	Atmospheric	120 (max)	0 to 90
Main stack (off-gas) monitor and sampler normal	0 to 5	-22 to +140	0 to 100
Main stack (off-gas) monitor and sampler accident	Atmospheric	120 (max)	15 to 90
Fission products monitor			
Particulate	0 to 15	-22 to +140	0 to 95
Iodine and gaseous	0 to 5	-22 to +140	0 to 100
Post-accident gamma monitors	0 to 250	-22 to +392	0 to 100
All other radiation monitors	0 to 5	-22 to +140	0 to 100

TABLE 11.4-4

RADIOLOGICAL ANALYSIS SUMMARY OF LIQUID PROCESS SAMPLES

Sample Description	Grab Sample Frequency	Analysis	Sensitivity (μCi/ml)	Purpose
Reactor coolant	Once per 7 days	Gamma isotopic for D.E. I-131	10^{-6}	Evaluate fuel cadding integrity

TABLE 11.4-5

RADIOLOGICAL ANALYSIS SUMMARY OF GASEOUS PROCESS SAMPLES

Sample Description	Sample Frequency	Analysis	Sensitivity (μCi/ml)	Purpose
Containment atmosphere (drywell and torus)	As required	Principal gamma emitters	1×10^{-11} 1×10^{-6}	Determine potential release to environment
Off-gas monitor sample (pretreatment)[a]	Monthly	Gamma isotopic	1×10^{-10}	Determine off-gas sum of six (Σ6) activity
Post treatment sample	Monthly	Gamma isotopic	1×10^{-4}	Evaluate off-gas mixture

a. Evaluation of the following nuclides for release rates: Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, Kr-88.

TABLE 11.4-6

RADIOLOGICAL ANALYSIS SUMMARY OF LIQUID EFFLUENT SAMPLES

Sample Description	Sample Frequency	Analysis	Sensitivity (μCi/ml)	Purpose
Floor drain sample tank	Batch[a]	Principal gamma emitters & I-131 dissolved gases	5×10^{-7} 1×10^{-6}	Effluent discharge record
Waste sample tanks (2)	Batch[a]	Principal gamma emitters & I-131 dissolved gases	5×10^{-7} 1×10^{-6}	Effluent discharge record
Composites	Monthly[b]	Tritium gross alpha	1×10^{-5} 1×10^{-7}	Effluent discharge record
	Quarterly[b]	Sr-89/90 Fe-55	5×10^{-8} 2×10^{-6}	Effluent discharge record

a. If tank is to be discharged, analyses will be performed on each batch. Dissolved gases normally performed on each batch but must be performed on at least one batch per month.
b. Proportional composites of all releases for the period.

TABLE 11.4-7

RADIOLOGICAL ANALYSIS SUMMARY OF GASEOUS EFFLUENT SAMPLES

Sample Description	Sample Frequency	Analysis	Sensitivity (μCi/ml)	Purpose
Reactor bldg vent stack and off-gas vent (stack)	Weekly	Principal gamma emitters for at least: I-131 I-133	 1×10^{-12}(a) 1×10^{-10}(a)	Effluent release record
		Principal gamma emitters for I-131 and others	1×10^{-11}(a)	
	Monthly	Principal gamma emitters H-3 (Tritium)	1×10^{-4}(c) 1×10^{-6}	Effluent release record
Composites(d)	Quarterly	Sr-89, 90	1×10^{-11}	Effluent release record
	Monthly	Gross alpha	1×10^{-11}	

a. On charcoal cartridge.
b. On particulate filter.
c. Gas samples.
d. On composite of weekly particulate filters for each vent.

11.5 SOLID RADWASTE SYSTEM

The solid radwaste system collects, monitors, processes, packages, and provides temporary storage facilities for radioactive solid wastes for offsite shipment and permanent disposal. The Edwin I. Hatch Nuclear Plant Solid Radioactive Waste Process Control Program (PCP) describes this objective. The PCP is implemented by procedures which contain formulas, sampling, analyses, tests, and determinations to be made to ensure the processing and packaging of solid radioactive wastes, based on demonstrated processing of actual or simulated wet solid wastes, are accomplished to assure compliance with Title 10 Code of Federal Regulations (CFR) Parts 20, 61, and 71, as well as State regulations and burial ground requirements governing the disposal of solid radioactive waste.

11.5.1 DESIGN OBJECTIVES

The design objectives of the solid radwaste system are to:

- Provide collection, processing, packaging, and storage of solid wastes resulting from normal plant operations without limiting the operation or availability of the plant.

- Provide a reliable means for handling solid wastes and to allow system operation with as low as reasonably achievable (ALARA) radiation exposure of plant personnel.

- Package radioactive solid wastes for offsite shipment and burial in accordance with applicable regulations including 49 CFR 170-178.

- Prevent the release of significant quantities of radioactive materials to the environment so as to keep the overall exposure to the public well within 10 CFR 20.1001-20.2402 limits.

- Compact and bale low radiation level solid radwaste materials such as air filters, paper, contaminated clothing, rags, cloth smears, and shoe covers.

Subsection 3.8.7 provides evaluation of the radwaste facilities buildings.

11.5.2 SYSTEM INPUTS

The volumes and activities of solid wastes shipped offsite and the radiation levels of the shipping containers are given in tables 11.5-1, 11.5-2, and 11.5-3, respectively.

The activities of the solid wastes entering this system are dependent on the liquid activities in the various liquid systems such as the condensate, reactor water cleanup, fuel pool cleanup, equipment drain, and floor drain systems, whose activities are in turn a function of the reactor coolant activity. The design activity of the reactor coolant is discussed in section 11.1.

Table 11.5-4 provides a breakdown of the percent isotopic composition of the solid radwaste at maximum activity.

The quantities of solid wastes generated are dependent upon the plant operating factor, extent of equipment leakage, plant maintenance and housecleaning, and decontamination requirements.

Input to the solid radwaste system consists of powdered resins from various plant filters, as well as temporary filters.

Tables 11.5-1 and 11.5-2 provide the quantities and gross specific activities of the concentrated and dewatered/dried wastes. Figure 11.5-1 shows the process flow diagram for the solid waste-handling system.

11.5.2.1 Wet Solid Waste Inputs

The wet solid radwaste system is a continuous part of the liquid radwaste system. Wet wastes, consisting primarily of spent demineralizer resins and powdered filter resins, are accumulated in phase separators and waste sludge tanks. These tanks serve as storage and batching tanks for the wet solid radwaste system. A description of the liquid radwaste processing equipment is provided in subsection 11.2.2.

11.5.2.2 Dry Solid Waste Inputs

Dry waste consists of air filters, miscellaneous paper, rags, etc., from contaminated areas; contaminated clothing, tools, equipment parts that cannot be effectively decontaminated, and solid laboratory waste. The activity of much of this waste is low enough to permit handling by contact. This waste is collected in containers located in appropriate zones around the plant, as dictated by the volume of waste generated during operation and maintenance. The filled containers are moved to a controlled-access area for temporary storage. Compressible waste is compacted when needed to reduce their volume when needed. Ventilation is provided to control contaminated particles while this packaging equipment is being operated. Noncompressible waste is packaged manually. Because of its low activity, this waste is stored until enough is accumulated to permit economical transportation to an offsite burial ground or offsite processor for further processing and final disposal.

11.5.2.3 Irradiated Reactor Component Inputs

Because of the high activation and contamination levels, used reactor equipment is stored in the spent-fuel storage pool for sufficient radioactive decay before removal to inplant or offsite storage and final disposal in shielded containers or casks.

11.5.2.4 Waste Oil Inputs

Waste oil is handled independently from other waste collection and waste disposal systems. Waste oil is collected from various plant applications and sampled, to determine if it is clean or contaminated. Waste oil determined to be clean is released as clean material. Contaminated waste oil is either processed onsite or shipped offsite to a vendor capable of processing and/or disposing of the material.

11.5.3 EQUIPMENT DESCRIPTION

The solid radwaste system receives wet waste input from the sludge collector subsystem described in paragraph 11.2.2.1.4.

The solid radwaste system is nonseismic. The exterior filling station is equipped with locked-shut discharge valves (when not in use) to prevent an inadvertent discharge. The solid radwaste system was built, to the extent practicable, to American Society of Mechanical Engineers (ASME) Code, Section III, Class 3 standards. Certain items are standard commercial units built to ASME Code, Section VIII standards. In general, where equipment could not be supplied, ASME Code, Section III, Class 3 parallel documentation was provided to ensure quality control commensurate with the importance of the system. Replacement components to the solid radwaste system may be procured in accordance with Table 1 of Regulatory Guide 1.26, September 1974[(1)] and Table 1 of Regulatory Guide 1.143, October 1979.[(2)]

Radiation exposure to operating personnel is limited to a level ALARA by providing remote, shielded filling stations processing pads for resin processing. The equipment is also provided with flush water service to prevent the accumulation of radioactive material.

Administrative procedures are employed to minimize operator exposure. In addition, good housekeeping procedures are followed to minimize the quantities of dry radwaste generated during plant operation.

11.5.3.1 Resin Processing Equipment

The resin processing system provides the means for pumping the resin and filter sludge slurries from their storage tanks to a filling station at the exterior of the radwaste building where they are dewatered in an appropriate resin container. Dewatered resin containers may be stored temporarily in large shielded containers located within the owner-controlled area while awaiting processing and/or transportation for disposal. Other material may be stored within these large shielded containers as deemed necessary.

The resin filling station or resin process pad is designed to accommodate burial containers up to 202.1 ft^3. The curie content for two typical sizes of containers, 132.4 ft^3 and 202.1 ft^3, for wastes which can be processed by the filling station, is provided in table 11.5-5. The curie content is based upon the containers net waste weight (filled container weight minus tare weight of container).

The exterior fill system is nonsafety related. Table 1 of Regulatory Guide 1.143 specifies applicable codes for equipment purchased or leased for radwaste service. The system, which consists of pump and control skids, disposable liners, reusable liners, and flexible interconnecting piping, is constructed of standard industrial components.

A. Tanks - Table 1 of Regulatory Guide 1.143 specifies American Petroleum Institute (API) No. 620 or ASME Code, Section III, Class 3 construction with materials to ASME Code, Section II.

 Atmospheric Tanks - Table 1 of Regulatory Guide 1.143 specifies American Petroleum Institute (API) No. 650 or ASME Code, Section III, Class 3 construction with materials to ASME Code, Section II.

 The disposable liners are either fabricated of carbon steel using ordinary shop welding processes or constructed of high-density, cross-linked polyethylene plastic. The carbon steel vessels are hydrostatically tested to 3 psig for 15 min with no leakage allowed. The polyethylene high-integrity containers are designed for a minimum of 12 psig and a 300-year design life. The polyethylene containers are also designed in accordance with Department of Transportation (DOT) Specification 7A.

 The reusable liners are fabricated of stainless steel and are designed as an atmospheric tank with a passive vent system built in to avoid pressurization. All welding on the reusable liner is done in accordance with ASME Code, Section IX and materials used are in accordance with ASME Code, Section II. Inspection and testing on the reusable liner are done in accordance with ASME Code, Section V. A pressure drop test of 3 psig for 10 minutes with soap bubble detection is also performed.

 Since the disposal vessels are disposal containers rather than tanks, the methods of fabrication described above and the methods for testing for this type of container are acceptable.

B. Pumps - Table 1 of Regulatory Guide 1.143 specifies manufacturer's standards for fabrication with materials to ASME Code, Section II. The air-driven pumps are constructed of manufacturer's standard materials. As the pumps are air and water tested prior to use, they are acceptable for this service.

C. Piping and Valves - Table 1 of Regulatory Guide 1.143 specifies American National Standards Institute (ANSI) B31.1 design and fabrication with ASME Code, Section II materials.

 ANSI B31.1 does not apply to flexible hose, which constitutes a portion of the piping system. As the system is operated at 150 lb (maximum pressure), the pressure integrity of the Table 1 requirements is not warranted. The piping system is hydrostatically tested in accordance with plant procedures prior to placing the system back into service.

The low-pressure application and plant hydro test assure the system is fully qualified for the service.

11.5.3.1.1 Safety Evaluation

The system vendor has a quality assurance program. The requirements of this program are met for component procurement, system design, and component and system testing.

The system is connected in the field by Southern Nuclear Operating Company (SNC). The quality assurance requirements of SNC apply to field assembly and testing.

A. Offsite Gaseous Releases - The solidification system is vented to the radwaste area ventilation system. The airborne releases from the system consist primarily of noble gases.

   There is no additional exposure to members of the public to airborne releases from the system.

B. Offsite Liquid Releases - The volume of liquid releases is not increased by the use of the portable solidification system.

C. Evaluation of Effect of Resin Dewatering/Drying System Shipping Volume - Resins are dewatered in the liner. These resins are compacted slightly in the dewatering process. There is no overall volume increase.

D. Estimate of Operator Exposure - The dewatering operations are accomplished in a disposable liner inside a shield within the resin processing pad. The only significant operator exposure occurs when the fill bead and the fully dried resin liner are closed (lid secured) and removed from the process pad, or when the filled liner is lifted into another cask for shipment or when the filled liner is lifted from the process pad to one of the large concrete storage shield locations around the pad. This handling operation results in less operator exposure than the past practices of handling filled 55-gal drums. Therefore, operator exposure is reduced significantly.

E. Estimate of Effect Upon Public Exposure From Shipments - The shipment of waste in liners results in more efficient utilization of the shipping cask volume. For instance, a 300-ft^3 liner can be shipped in the same cask that accommodates twenty-one 55-gal drums. In this case, the number of required shipments is reduced by a factor of ~ 2.5. As the dose rate at the perimeter of the truck bed is approximately the same for all shipments, the dose to the public is reduced.

11.5.3.1.2 Review Per Regulatory Guide 1.143, Section C

Seismic Requirements

Dewatering and drying operations are performed on a seismic pad, with a seismic dike sufficient to contain the liner contents in the event of a liner failure. The liner and the resin processing system are not seismic. Because the diked pad is capable of containing all radioactive materials in the event of failure, the requirements of Regulatory Guide 1.143 are met.

11.5.3.2 Hydraulic Press

The hydraulic press is provided so soft compressible wastes such as paper, rags, and clothing can be reduced in volume. The press is designed to compress these wastes in appropriate containers by a vertical moving piston under high compression.

An integral part of the hydraulic press is the ventilation system which controls airborne particulate matter during the compressing operation. The ventilation system for the hydraulic press enclosure consists of an induced-draft fan and a filtering unit containing a prefilter and high-efficiency particulate air filter. Air openings located on the side of the container increase the draft effect. The air induced through the hydraulic press enclosure is discharged, after filtration, into the area housing the unit.

11.5.4 VOLUMES

Approximately 8000 ft^3 of spent resin and dry active waste (DAW) radwaste are generated each year. A qualitative breakdown of spent resin waste is given in table 11.5-1, and a curie content breakdown is given in table 11.5-2. The isotopic composition of these wastes is discussed in subsection 11.5.2.

Approximately 2500 ft^3 of spent resin waste are disposed of annually. Approximately 25 resin liners, each ~ 202 ft^3, are required each year to ship the waste to the burial site or to processors.

Table 11.5-3 provides a breakdown of the surface dose rates from resin liners containing dewatered/dried waste, based on dewatering/drying all waste and as a function of the resin drying process agent.

11.5.5 PACKAGING

Solid radwaste is packaged and shipped in steel containers (B25 LSA containers, Sea-Land, etc.) or resin liners which meet Nuclear Regulatory Commission and DOT requirements.

Wet solid waste is packaged by one of the appropriate methods below:

- In high-integrity containers without further processing if the packaged content has < 1% free water.

- In stainless steel reusable containers which are gross dewatered for shipment to the resin processor.

- In steel resin liners if the packaged content has ≤ 0.5% free water and < 1 μCi/cc with a half-life ≤ 5 years.

Filling of resin containers at the exterior filling station (resin process pad) is done from a remotely operated control panel to minimize operator exposure.

Dry compressible solid radwaste is compacted on site in steel containers by a hydraulic press when determined cost justifiable and within the concepts of ALARA.

11.5.6 STORAGE FACILITIES

The waste separation and temporary storage facility (WSTSF) consists of a precast concrete building (figure 1.2-4). The facility is designed to allow temporary storage staging of compacted dry radioactive trash, low specific activity boxes of radioactive trash, and radioactive reusable tools. The principal item stored/staged is dry radioactive trash. The maximum storage capacity is 65,000 ft^3.

The WSTSF is designed for protection against tornadoes and floods. Heating, ventilation, air-conditioning, and fire protection systems are provided. In addition, shielding and fencing are provided to limit doses in unprotected areas and at the site boundary to within the limits of applicable regulations. Items may be staged/stored outside the actual building but within the building fenced-in area, if they meet the necessary requirements for adverse weather conditions.

The Sealand Storage Facility (SSF) is a slab on grade structure with access ramps installed on the south and east sides. The structure is designed with a metal “A” frame roof supported by metal I-beams and poles. The SSF is 100 ft wide by 200 ft long, containing a 10-in. concrete slab with two horizontal reinforcing mats and a metal pitched roof. The SSF is located outside of the protected area (PA) and within the owner-controlled area (figures 1.2-1 and 1.2-4). The SSF will be used to store containerized reusable radioactively contaminated materials, equipment, and tools primarily used during refueling outages. The primary means of storing this material will be with the use of Sealand containers and/or other suitable metal containers. Containers should generally comply with 10 CFR 71 and 49 CFR criteria.

The SSF is not designed to protect the material being stored from adverse weather conditions. The location of the facility is on a higher elevation than the power block. This limits the possibility of flooding resulting in a breach of the containers being stored. The actual containers themselves provide the only protection against the elements to the materials being stored. The facility provides no heat, air monitoring, fire protection, or shielding. A fence surrounding the facility restricts access to the material being stored in the facility. The Health Physics

department will control access to the facility by controlling the locks to the two facility access gates. Therefore, departmental procedures, policies, and practices must be utilized to control the use and operations of this facility.

The low-level radwaste (LLRW) storage facility is a slab-on-grade structure designed for the storage of LLRW due to the unavailability of an offsite disposal facility for radwaste. The location of this storage facility is north of the WSTSF. The storage facility is enclosed by a fence with locked gates and area lighting. Location and design of the concrete pad is shown on drawing H-46598. The LLRW will be packaged in high-integrity containers (HICs) or other suitable long-term storage containers and then placed in secure environmental containers (SECs) or other appropriate shields to provide radiation dose reduction and normal environmental protection. The fence for the storage facility is established such that the dose rate at the fence is limited to no more than 0.25 mrem/h. The maximum activity limit for the LLRW storage facility is 750,000 Ci. However, prior to placing this amount of radioactive material on the pad, the boundary (fence) dose rate would exceed 0.25 mrem/h and additional shielding would be needed.

11.5.7 SHIPMENT

Solid waste is regularly shipped from the site to the burial ground by trucks operated by a licensed shipper. The waste packages are shipped unshielded or in shielded shipping casks as required to fully comply with 49 CFR 170 - 199, namely:

A. The dose rate is $<$ 2 mrem/h in the cab, 10 mrem/h at 2 meters from the vehicle surface, and 200 mrem/h at any point on the surface of the vehicle. When the vehicle does not conform, the containers are rearranged and/or shielding is placed appropriately inside the vehicle to meet these levels.

B. The vehicle smears are < 2200 dpm[a]/100cm^2 beta-gamma and/or 200 dpm/100cm^2 alpha.

C. Containers are labeled with the applicable shipping labels. All shipments are accompanied by paperwork stating the isotopes contained and the curie content.

D. Shipping of large filled liners requires lifting the liner with a crane. Failure of the rigging or failure of one or more of the lifting eyes on the liner results in a liner drop accident. Crane lifts are not conducted during periods of high winds or inclement weather, to minimize the potential for handling accidents.

   A hypothetical liner drop accident represents nothing more than a radioactive spill outside the confines of the radwaste building. A liner drop has no impact on the integrity of the building structure.

a. dpm = disintegrations per minute.

The consequences of a filled-liner handling accident have been evaluated. As the contents of the liner are dewatered, they remain in place if a liner bursts when dropped. Since lifts are not made during or succeeding heavy rain where runoff would spread contamination, spills can be cleaned up without offsite release of radioactivity.

All containers used for offsite shipment and burial of radwastes are DOT approved, meeting the requirements established in 49 CFR.

When used for shipping radwaste from the site, the trucks are used on an exclusive basis and are placarded per the previously mentioned code.

The drummed radwaste is not normally stored in any area other than the storage area discussed in subsection 11.5.6. Should the occasion arise, a full or partially loaded truck can be stored on the site in a restricted area. The truck would be barricaded and "Radiation Area" or "High Radiation Area" signs conspicuously posted as required.

TABLE 11.5-1

SOLID RADWASTE VOLUMES

Source	Approximate Volume (ft^3/year)
Powdex Resins	
Cleanup phase separators 1	90
Condensate phase separators 2	6042
Bead Resins	
Waste demineralizer 4	608
Floor drain demineralizer 5	80

NOTE:

Numbers in circles correspond to process lines on figure 11.5-1. All values are approximate and can change at any time based upon plant operation.

TABLE 11.5-2

SOLID RADWASTE ACTIVITIES

Source	Specific Activity (µCi/cc) Normal	Specific Activity (µCi/cc) Maximum
Powdex Resins		
Cleanup phase separators 1	8.0×10^{1}	2.5×10^{2}
Condensate phase separators 2	5.0×10^{-1}	1.5×10^{1}
Bead Resins		
Waste demineralizer 4	5×10^{-2}	1×10^{-1}
Floor drain demineralizer 5	5×10^{-2}	1×10^{-1}

NOTE:

Numbers in circles correspond to process lines on figure 11.5-1.

TABLE 11.5-3

SURFACE DOSE RATES FROM RADWASTE SHIPPING CONTAINERS[a]

(No. of Containers vs. Dose Rate)

Source	Dose Rate (R/h) < 0.2	0.2 to 1.0	1.0 to 5.0	> 5.0
Powdex resins				
Cleanup phase separators				2
Condensate phase separators		2	20	8
Bead resins				
Waste demineralizer		3		
Floor drain demineralizer		1		

NOTES:

1. Cleanup phase separator container volume = 132.4.
2. Condenser phase separator container volume = 202.1.
3. Waste demineralizer and floor drain demineralizer container volume = 202.1.
4. All container numbers are approximate and can change at any time based on needs.

a. Numbers in the table reflect the number of disposal containers of various sizes.

TABLE 11.5-4

PERCENT OF ISOTOPIC COMPOSITION OF SOLID RADWASTE AT MAXIMUM ACTIVITY[(a)(b)]

	Cleanup Resin	Condensate Resin	Waste Resins
Mn-54	2.55	4.8	3.57
Fe-55	10.6	6.5	0.09
Ni-62	0.17	1.9	0.39
H-3	0.01	2.2	0.030
Cr-51	0.73	2.4	--
Fe-59	--	0.6	--
Co-58	1.34	1.3	3.16
Zn-65	66.83	30.2	47.23
Co-60	15.8	42.3	17.46
Sr-89	17.13	2.6	19.17
Sr-90	0.06	0.1	0.35
Nb-95	--	0.2	--
Ru-103	--	--	--
Te-129m	--	--	--
Cs-134	5.13	0.2	0.33
Cs-137	0.17	1.6	7.46
Ba-140	--	1.1	--
Ce-141	0.09	0.4	0.05
Ce-144	0.03	0.2	0.06
Np-239	--	--	--
I-131	--	1.3	--
I-133	--	--	--
I-135	--	--	--
	100.0	100.0	100.0

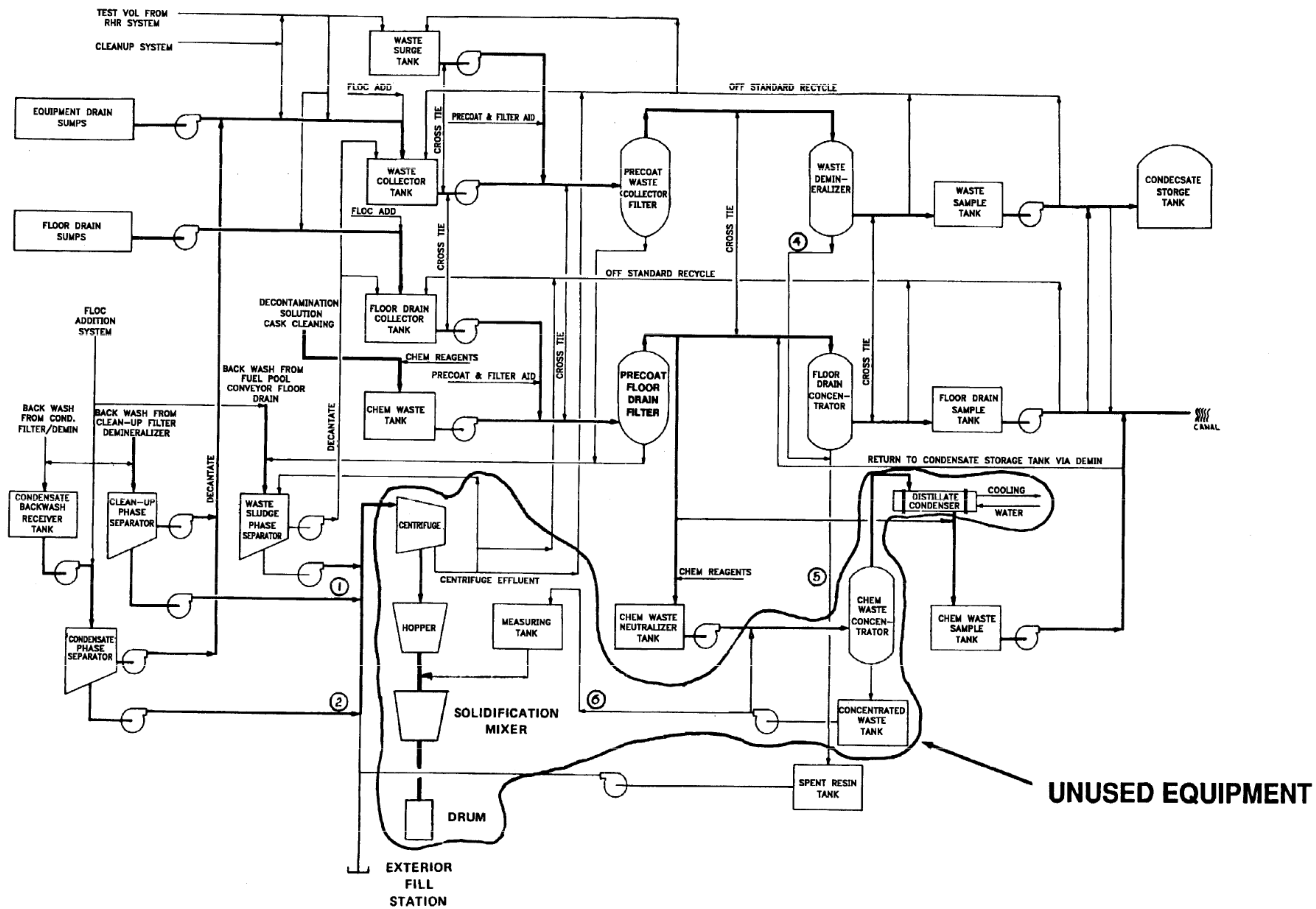
a. Values shown will vary depending upon plant performance.
b. All percentages are appropriate values and could change based upon plant operations.

TABLE 11.5-5

CURIE CONTENT OF SHIPPING CONTAINERS[a]

	Curies/Containers			
	132.4 ft^3		202.1 ft^3	
Source	Normal	Maximum	Normal	Maximum
Condensate phase separator (5% solids by weight)	0.42	1.19	3.00	75.00
Cleanup phase separator (5% solids by weight)	75.00	1000.00	N/A	N/A
Demineralizer resins (5% solids by weight)	--	--	0.5	10.00

a. All numbers are appropriate values and could change without notice based on plant conditions.



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RADWASTE SYSTEM PROCESS FLOW DIAGRAM

FIGURE 11.5-1

11.6 OFFSITE RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

The current offsite radiological environmental monitoring program is described in the Offsite Dose Calculation Manual.

12.0 RADIATION PROTECTION

This chapter provides information on methods for radiation protection and estimated occupational radiation exposures to operating personnel during normal operation and anticipated operational occurrences. It provides information on facility and equipment design employed in meeting the Title 10 Code of Federal Regulations (CFR) Part 20.1 - 20.601 (found in 10 CFR published before January 1994) requirements for protection against radiation and the guidance given in applicable regulatory guides. This chapter further provides information on planning and procedures and the programs, techniques, and practices employed in meeting 10 CFR 20.1001 - 20.2401 requirements for protection against radiation and the guidance given in applicable regulatory guides. The plant was designed and received a construction permit long before the series 8 regulatory guides were issued. Therefore, guidance given in this series of regulatory guides is not followed in presentation of this chapter. However, the plant was designed on the basis of sound engineering judgment and evaluation of operating practices; thus, the criteria for reducing occupational radiation exposures to as low as reasonably achievable (ALARA) are satisfied.

12.1 ASSURING OCCUPATIONAL RADIATION EXPOSURES ARE AS LOW AS REASONABLY ACHIEVABLE

12.1.1 POLICY CONSIDERATIONS

It is the policy of Southern Nuclear Operating Company (SNC) to keep all occupational radiation exposures ALARA.

The plant manager (PM) is responsible for the radiological safety of all plant personnel. In turn, all employees share this responsibility and are required to follow the rules and procedures for radiation protection established by plant procedures.

Responsibility for the implementation of the health physics program is delegated to the plant Health Physics Department which is under the supervision of the health physics superintendent/manager who is responsible to the plant manager.

The health physics staff performs, for plant management, the following activities:

A. Incorporates, as per plant procedures, the Nuclear Regulatory Commission (NRC) limits and standards for radiation protection, including permissible dose levels, contamination levels, and limits for the release of radioactive material to the environment.

B. Recommends measures and procedures for dealing with actual and potential radiation hazards, and evaluates and reports on the effectiveness of the health physics program.

C. Determines the origin of exposures received in the plant, and provides an analysis of any trends that may develop with reasons for the trends and appropriate recommendations.

D. Provides consultation and other assistance as required for the proper administration of the health physics program.

E. Performs effective monitoring and maintains adequate records of radiation exposure and contamination levels. (Records the exposure received by individual workers.)

F. Recommends any individual's radiation exposure to cease when known or estimated exposure is approaching allowable limits as set forth in 10 CFR 20.1001 - 20.2401.

G. Recommends curtailment of any or all operations when judged necessary to avoid exposure beyond allowable limits as set forth in 10 CFR 20.1001 - 20.2401.

H. Provides, calibrates, and maintains health physics detection and measurement instruments, equipment, and supplies.

I. Determines whether modifications to plant procedures and equipment should be made to reduce exposures and makes appropriate recommendations.

J. Directs and participates in the investigation of circumstances of unusual exposures.

The responsibilities and qualifications of the health physics superintendent/manager are described in subsections 13.1.1 and 12.5.1, respectively.

Site personnel qualifications meet the requirements of Regulatory Guide 1.8 (Revision 1, September 1975) and are discussed in subsection 13.1.3. Figure 13.1-3 shows the organizational relationships of these individuals. Other operational considerations and the health physics programs are discussed in subsection 12.1.3 and section 12.5, respectively.

Plant supervisors assist the health physics staff in ensuring occupational radiation exposures are maintained ALARA. Plant supervisors are responsible to:

A. Ensure the individuals under their direction are properly instructed in radiation problems associated with their duties and compliance with all rules and regulations governing radiation safety are met.

B. Ensure the individuals under their direction are aware of SNC's commitment to keep all exposures ALARA and are able to explain the meaning of "ALARA exposure to radiation."

C. Ensure all equipment and facilities are operated and maintained so personnel exposures are ALARA.

D. Know the location and extent of radiation hazards in the areas under their jurisdiction, and ensure all such areas are properly identified and controlled to limit exposure and the spread of radioactive material.

E. Ensure each individual under their supervision is aware of his/her exposure status which is available through information provided by the health physics staff.

F. Consult with the health physics staff on radiation protection matters.

Additionally, it is the responsibility of each individual to obey all radiation protection procedures and report to his/her supervisor any circumstances where there are any doubts as to correct procedures or to the safety of operation. Each individual on the operating plant staff is required to attend annually a radiation protection training course or pass an exemption test demonstrating knowledge of radiation protection techniques. SNC employees and visitors on the site for short periods of time and at infrequent intervals are not required to receive radiation protection training; however, such individuals must be escorted by an individual who has received radiation protection training.

The design considerations involved in the layout of the radwaste facilities are based, insofar as practicable, on remote system operation. The operation of the liquid radwaste system, including alignment of flow paths; preparation, use, and replacement of filters and resin beds; and emptying or processing sumps and tanks can be performed remotely, in large part, from the radwaste control room or locations that are shielded or distant from major radiation sources.

Maintenance of the radwaste system is facilitated by the design considerations involved in equipment layout described in paragraph 12.1.2.A.4. As described in paragraphs 12.1.3.1 and 12.1.3.2, most maintenance activities conducted in radiation areas are controlled administratively through issuance of radiation work permits (RWPs). The health physics staff surveys the work area and evaluates the pertinent radiological considerations prior to maintenance activities involving the radwaste system.

Maintenance activities on the gaseous radwaste systems are controlled as described in paragraphs 12.1.3.1, 12.1.3.2, and 12.5.3.6 by RWPs which prescribe the protection provisions required as determined by surveys of the work area. Appropriate measures are employed to remove or control airborne and surface contamination prior to the maintenance activity. The design of the ventilation systems described in paragraphs 12.3.1.2.E and F provides access and maintenance features to facilitate maintenance of the systems.

The reactor pressure vessel (RPV) insulation from the support skirt elevation to the refueling bellows is designed to be standoff insulation spaced a minimum of 8 in. from the RPV outside diameter. In addition, quick disconnect panels to permit rapid removal and replacement were incorporated at each nozzle location and over the circumferential and longitudinal welds above the reactor shieldwall. This combination of standoff insulation and quick disconnect panels provides access for remotely operated ultrasonic equipment methods of examination. In addition, snap-on-type insulation to permit rapid removal and replacement was installed on piping systems requiring insulation to the extent practicable.

Methods such as provision of removable insulation, adequate clearances, and use of automated transversing equipment to facilitate access for inservice inspection (subsection 5.2.8) reduce the time requirement for inspection personnel.

Equipment and methods utilized in opening the RPV; performing activities associated with the reactor fuel and internals; and maintaining the control rod drive (CRD) systems are based on design and operational methods that have evolved from GPC, SNC, General Electric (GE), and Bechtel experience at Hatch Nuclear Plant-Unit 1 (HNP-1) and other similar boiling water reactor (BWR) plants.

Maintenance procedures pertaining to preventive, normal routine, and repair maintenance require where applicable RWPs and use of protective measures as dictated by the permit. The procedures caution personnel concerning the possible presence of contamination in and near the work area and the possibility of changing circumstances in the work environment. Improved methods for reducing exposures during maintenance activities may be readily instituted as dictated by the health physics staff as a requirement of the RWP.

12.1.2 DESIGN CONSIDERATIONS

Limiting radiation exposure to both the general public and plant personnel is the primary objective of radiation protection design. The physical layout and the process equipment design are fundamental means of minimizing radiation exposures. By continuously reviewing operating plant experiences and their design parameters, a basic understanding of the problems was developed. Experiences and data from operating plants were evaluated to decide if and how equipment or facility designs could be improved to reduce overall plant personnel exposures. During plant design, operating reports were reviewed to determine which plant operations or procedures were significant in causing personnel exposures, and methods to mitigate such exposures were incorporated wherever practicable.

Some of the many considerations incorporated into the design for limiting radiation exposures to ALARA are described below:

A. Extensive guidance was given to individual engineers to design the plant so as to minimize the radiation exposures inside and outside of the plant to ALARA. Such guidance included, but was not limited to:

   1. Shielding

      Design of shielding around pipes, components, and valves containing or likely to contain radioactive material.

2. Piping

   a. Routing of pipes carrying radioactive materials through areas properly categorized for the level of activity in the pipes.

   b. Analysis of each piping run to determine the potential radioactivity level and surface dose rate.

   c. Provisions for shielding pipeways when routing through corridors or other low radiation areas.

   d. Utilization, when practicable, of equipment compartments as pipeways only for those pipes associated with equipment in that compartment.

   e. Separation, when practicable, of radioactive and nonradioactive piping.

   f. Provision for isolation and drainage of radioactive piping and associated equipment when maintenance is required.

   g. Design of piping to minimize low points and dead legs, including placement of drains on low points and dead legs.

   h. Placement of thermal expansion loops as raised rather than dropped, where possible.

   i. Placement of branch lines (having little or no flow during normal operation) above the horizontal midplane of the main pipe.

3. Penetrations

   a. Location of as many penetrations as practicable with an offset between the source and the accessible areas.

   b. Location, when offsets are not practicable, of penetrations as far as possible above the floor elevation.

   c. Use of alternate means, such as baffle shield walls or grouting the area around the penetration, where necessary.

4. Equipment Layout

   a. Separation of pumps, valves, and instruments from the process component in those systems where process equipment is a major radiation source (such as fuel pool cleanup, radwaste, condensate demineralizer, etc.).

   b. Placement of major components (such as tanks, demineralizers, and filters) in individual shielded compartments as practicable.

c. Provision for removal of some major plant components to lower radiation areas for maintenance.

5. Field-Run Piping

Limitation of field-run piping to 2 in. and smaller to minimize radiation exposure to plant personnel.

6. Clean Systems

Placement, whenever practicable, of clean systems and equipment, such as compressed air piping, clean water piping, ventilation ducts, and cable trays, in nonradioactive pipeways.

B. Review

1. To ensure ALARA exposure to operating personnel from piping and components containing radioactive material, specific design and review criteria for the original plant construction were established. These criteria included a review of equipment and piping arrangement drawings by engineers with nuclear and shielding experience or training to ensure that the equipment was adequately shielded from surrounding equipment and operating spaces, and the appropriate radiation area was assigned.

To minimize exposure from piping containing radioactive material, all such piping larger than 2 in. in diameter was designed and routed by the architect-engineer. Engineers reviewed these drawings to ensure the routing was consistent with the radiation areas through which they passed. Design techniques, such as grouping pipes containing radioactive materials and use of shielded pipe chases, were also employed to minimize exposure.

Process piping 2 in. and smaller that carries radioactive material was shown schematically on the architect-engineer's piping drawings to define the desired routing of the piping. These drawings received the same review as the review described for larger piping.

In the field, isometric drawings were developed to establish the actual routing of the small piping. The applicable GPC system engineer reviewed these drawings to ensure the actual routing was consistent with the recommended routing given on the architect-engineer's drawings.

For permanent system modifications, a checklist is completed to determine if an ALARA review is required. If required, the ALARA review is performed to ensure that radiation exposure is maintained ALARA.

2. Frequent review of piping layout and instrumentation by nuclear specialists ensures the nuclear properties of the materials used were considered. Any incompatibility of materials in the system and the nuclear fluids transmitted was reviewed, and proper changes were made when necessary.

C. Shielding Arrangement

1. The physical layout of structural walls and shield walls is designed to limit exposure throughout the plant. Exposure is limited by the construction of labyrinths as passageways to high and very high radiation areas. These labyrinths provide significant reduction of radiation between areas.

2. The consolidation of a large number of system valves into one location confines leakage to a small area of the system layout. Reach rods are provided for manually operated valves located in these areas. This was found to be a satisfactory design practice in all operating plants.

3. Concrete shield block walls are used, where necessary, to conveniently remove a wall for access to a room or chamber for maintenance.

D. Crud Buildup

1. Attention was and is given to the design of equipment, piping, and valves to minimize the buildup of radioactive material.

2. All highly contaminated systems, including cleaning and flushing apparatus, minimize crud buildup when used periodically. Use of cleaning and flushing prior to maintenance or testing reduces radiation levels caused by crud buildup.

E. The systems were designed and constructed and the components purchased to stringent quality assurance standards. This ensures a high degree of reliability and trouble-free operation that reduces the need for maintenance, consequently reducing radiation exposure.

F. Maintenance

1. The plant health physics staff reviews all proposed maintenance activities in radiation control areas through an RWP procedure. Dose rate, contamination, and airborne radioactivity surveys are made to determine habitability of the area(s) involved, clothing requirements, stay time, hazards, additional shielding required, monitoring, and special dosimetry requirements, exposure limitations, and whether dry runs should be performed prior to starting the maintenance activity.

   Maintenance and operational activities are conducted with as few personnel in a particular radiation area as practical at any one time consistent with safe performance of the particular activity.

The HNP radiation protection procedures establish annual administrative dose limits for dose categories defined in 10 CFR 20.1003 at levels well below the limits established by 10 CFR 20.1201 - 20.1208. These administrative dose limits may not be exceeded without prior approval by the health physics staff. In keeping with the ALARA policy, HNP endeavors to keep doses within annual limits.

The estimation of total mrems to be expended on large jobs is determined whenever necessary. The health physics staff evaluates the need for such determinations by considering the intensity of the radiation field anticipated and the complexity of the operation to be performed in an effort to achieve the ALARA radiation field anticipated and the complexity of the operation to be performed in an effort to achieve the ALARA commitment. Mrem goals are established on a case-by-case basis with consideration to maintaining the goals ALARA in light of prudent operation decisions and judgment.

The criteria for deciding when dry runs are necessary prior to maintenance work in radiation areas involve consideration of the following:

- Dose rates and airborne activity in the area.
- Estimated time to perform the job.
- Clothing requirements for the job.
- Criticality of the job as it related to plant operation.
- Necessity for performing the job at this time.
- Previous dose to workers.
- Use of additional workers on the job on a short-term basis.
- Training and skill of the workers.
- Can the work be moved to a lower radiation area.
- Experience gained from previous work on same equipment.

All practical means are taken in advance of operations involving significant radiation exposure levels to minimize such exposures through the consideration of all of the above criteria, the SNC ALARA policy as described in subsection 12.1.1, the RWP procedures, computerized personnel exposure programs, administrative exposure limits, radiation and contamination survey procedures, and, in general, the radiation protection procedures for the plant as described in subsection 12.1.3.

2. Wherever possible, discomfort to workers is minimized so their efficiency is increased and less time is spent in radiation areas.

G. Other

1. A continuous review of reports from both the NRC and operating plants is conducted to determine whether any design changes would be practical in reducing radiation exposures.

2. Manufacturers of nuclear power plant equipment supply information based upon pertinent research, development, and operating experience with their equipment.

3. More emphasis is currently being placed upon maintenance procedures and design for maintenance and testing accessibility to reduce exposures.

12.1.3 OPERATIONAL CONSIDERATIONS

12.1.3.1 Operating Procedures

Radiation protection procedures (subsection 13.5.10) are maintained at the plant and provide the basis for minimizing radiation exposure of plant personnel and visitors during all phases of plant operation and maintenance. These procedures are based upon the approved procedures currently in effect in the operation of HNP-1.

Most work performed in radiation areas must be authorized by RWPs issued by health physics personnel and approved by a health physics foreman or higher authority to ensure all work is performed in a manner that keeps radiation exposures ALARA. The permits require a description of the location and type of work to be performed to allow an evaluation of dose rates and contamination levels to be encountered. The RWP prescribes the use of temporary shielding, protective clothing, occupancy times, and monitoring requirements that may be necessary to minimize exposure.

During the startup test program, radiation surveys are made to ensure:

- The shielding contains no defects or inadequacies that might affect personnel exposures during normal operation and maintenance of the plant.

- Areas of the plant are correctly posted and barricaded as a radiation area, high radiation area, contaminated area, airborne radioactivity area, and/or radioactive materials in accordance with the requirements of 10 CFR 20.1001 - 20.2401 (table 12.1-1).

Routine radiation surveys of all normally traversed areas of the plant are made to ensure integrity of the shielding. The maximum time allowable in any one of the radiation areas

depends on the dose rate and the previous exposure of each individual. In all cases, exposures are kept ALARA. Individuals who in the course of employment are likely to receive in a year an occupational dose in excess of 100 mrem are trained in accordance with the requirements of 10 CFR 19, Section 19.12.

Radiation protection procedures are reviewed by the health physics superintendent/manager in an effort to identify situations in which exposures can be reduced. For proposed procedures/procedure revisions, a checklist is completed to determine if an ALARA review is required. If required, the ALARA review is performed to ensure that radiation exposure is maintained ALARA.

Access restrictions are enforced by removable concrete shielding blocks, controlled doors (controlled access barrier), and administrative control. Security doors permit rapid egress from an area if an emergency or high radiation level should develop.

Plant areas susceptible to airborne radioactivity are monitored and air samples collected when conditions warrant. Whenever entry must be made into an area where airborne contamination may exist, the concentration of airborne radioactivity is determined by either sampling and analytical procedures or with portable instrumentation. If airborne radioactivity is found to exist in the area, appropriate measures are taken to reduce this airborne radioactivity, if practical, prior to personnel entry. These measures include draining and flushing of radioactive materials contained in equipment located in the area and removal of surface contamination from equipment and area surfaces. Filtered ventilation is used to reduce airborne radioactive materials. Appropriate respiratory protection is provided as required when the above mentioned procedures are inadequate.

The use of proper training (dry runs) and appropriate tools and equipment (special handling equipment or jigs) reduces the possibility of mistakes and also decreases the exposure time. Permanent service lines (electrical power, service air, etc.) are provided, when practical, to frequently utilized areas; i.e., decontamination facility. Where practical, equipment is moved to a lower radiation area for maintenance.

Proper supervision, monitoring, and issuance of personnel dosimetry permit the progress of work and exposure to be noted and appropriate action taken, as required. Health physics personnel identify radiation levels in occupied areas and ensure all radiation monitoring instruments are properly calibrated and adequate exposure records are maintained.

Radiation protection procedures, fire protection procedures, and emergency procedures are maintained at the plant and provide the basis for minimizing radiation exposure by coordinated expeditious action in case of fires, spills, equipment failure, and other accidents. Operating personnel become familiar with such procedures during the performance of regular work activities and training exercises.

These operational considerations and plant radiation protection procedures were formulated from various successful programs in use at other power reactor and radioactive materials handling facilities. Experience gained through the operation and maintenance of HNP-1 aids in the refinement of operating procedures to ensure radiation exposures are kept ALARA. The health physics program for HNP-2 is the same as the program approved for HNP-1.

Review of the conduct of operations to identify areas where individual exposures (as well as total mrems) could be reduced is a primary function of the radiation protection program (subsection 12.1.1). The working guidelines applied at the plant result in radiation exposures below 10 CFR 20.1001 - 20.2401 criteria and as such provide for a conservative approach toward radiation exposure.

12.1.3.2 Radiation and Contamination Control

The plant Health Physics Department personnel perform surveys necessary for the designation of radiation areas as defined in 10 CFR 20.1001 - 20.2401. Personnel, material, and equipment unconditionally released from radiation control areas are free of significant radioactive contamination. Each individual is responsible for monitoring himself/herself before leaving a radiation control area. If contamination is detected, the individual immediately contacts health physics personnel. A personnel contamination report is completed on all individuals found to be contaminated at levels greater than the administrative limit. Followup measures are initiated as appropriate. Plant procedures establish a basic technique for the decontamination of personnel, equipment, and floors that may have become contaminated.

Special radiation and contamination surveys, in addition to routine surveys, are made for the following:

- Installation or removal of incore fission chambers.
- Installation or removal of core startup sources.
- Installation or removal of reactor components after initial criticality.
- The loading and unloading of fuel bundles.
- The opening of the primary coolant system.
- The removal of any material that has been in contact with the primary coolant.
- Prior to and following any decontamination activity.
- When radioactive spills are reported.

Prior to performing maintenance on systems that contain, collect, store, or transport radioactive liquids, gases, and solids (i.e., turbine system; nuclear steam supply system; residual heat removal system; spent-fuel transfer, storage, and cleanup systems; and the radioactive-waste treatment, handling, and storage systems), the health physics staff is notified to perform surveys. In addition, following the survey, the health physics staff may specify various procedures and techniques to ensure radiation exposures are kept ALARA. The health physics staff has the authority to enforce safe plant operations in matters relating to radiation protection. The health physics superintendent/manager, who oversees the health physics staff, has the capacity to prevent unsafe practices by communicating directly and promptly with the appropriate plant supervisor to halt an activity deemed unsafe.

TABLE 12.1-1 (SHEET 1 OF 2)

RADIATION CONTROL AREA CLASSIFICATIONS[a]

Unrestricted Area

An unrestricted area is an area to which access is not limited or controlled by the licensee, or any area within the site boundary used for residential quarters or for industrial, commercial, institutional, and/or recreational purposes.

Restricted Area

A restricted area is an area to which access is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. A restricted area does not include areas used as residential quarters; however, separate rooms in a residential building may be set apart as a restricted area.

Radiation Control Area

A radiation control area is any area accessible to personnel in which radioactive materials or radiation is present in quantities or levels sufficient to require protection measures. Each radiation control area is classified as a radiation area, high radiation area, very high radiation area, contaminated area, airborne radioactivity area, and/or radioactive materials.

Radiation Area

A radiation area is an area, accessible to individuals, in which radiation levels could result in an individual receiving a dose equivalent in excess of 0.005 rem within 1 h at 30 cm from the radiation source or from any surface that the radiation penetrates.

High Radiation Area

A high radiation area is an area, accessible to individuals, in which radiation levels from radiation sources external to the body, could result in an individual receiving a dose equivalent in excess of 0.1 rem within 1 h at 30 cm from the radiation source or from any surface that the radiation penetrates.

Very High Radiation Area

A very high radiation area is an area, accessible to individuals, in which radiation levels from radiation sources external to the body could result in an individual receiving an absorbed dose in excess of 500 rad[b] within 1 h at 1 m from a radiation source or from any surface that the radiation penetrates.

TABLE 12.1-1 (SHEET 2 OF 2)

Contaminated Area

A contaminated area is a radiation control area whose surface contamination level exceeds one of the following limits:

- Smearable/loose surface radioactive contamination

  Beta-gamma 1000 dpm/100 cm^2

  Alpha 50 dpm/100 cm^2

- Fixed surface radioactive contamination

  Beta-gamma 100 cpm/GM probe area

  Alpha 50 dpm/detector area

Airborne Radioactivity Area

An airborne radioactivity area is a room, enclosure, or area in which airborne radioactive material, composed wholly or partly of licensed material, exists in concentrations:

- In excess of the derived air concentrations (DACs) specified in 10 CFR 20.1001 - 20.2401, Appendix B, or

- To such a degree that an individual present in the area without respiratory protective equipment could exceed, during the hours an individual is present in a week, an intake of 0.6% of the annual limit on intake (ALI) or 12 DAC-hours.

Radioactive Material

An area designated for radioactive material is a radiation control area in which licensed material is used or stored, and contains any radioactive material in an amount exceeding 10 times the limits given in 10 CFR 20.1001 - 20.2401, Appendix C.

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a. Radiation control areas are conspicuously posted with a sign or signs bearing the radiation caution symbol and the type of radiation control area in accordance with the guidelines of 10 CFR 20.1001 - 20.2401.
b. At very high doses received at high dose rates, units of absorbed dose (e.g., rads) are appropriate, rather than units of dose equivalent (e.g., rems).

12.2 RADIATION SOURCES

12.2.1 CONTAINED SOURCES

Byproduct, source, and special nuclear material are required for reactor operation in the form of reactor fuel, sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and fission detectors.

12.2.1.1 General

The three types of radiation sources that occur in the plant are primary radiation from the reactor core, secondary radiation resulting from nuclear reactions between the primary radiation and the reactor environment, and release of radioactive material from the reactor core to the coolant. During normal plant operation, secondary sources and released radioactive material are transported in either the reactor coolant or main steam to process equipment in the plant.

The source intensity in equipment and pipelines handling radioactive fluids was determined from that in the reactor water or reactor steam by considering the processes that the reactor water or steam have undergone (dilution, filtering, demineralization, delay, or change of phase) prior to entering the equipment or pipe. In all cases, the process or combination of processes leading to the highest activity was considered.

The shield design of Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) during normal operation and anticipated operational occurrences is based on design radiation sources, which provide a rational basis for design. The source data assume plant operation is at maximum design power with a noble gas release rate of at least 0.1 Ci/s after 30-min decay. Halogen concentrations in the reactor water are based on a fission product equilibrium halogen concentration as defined in section 11.1. Concentrations of other fission and activation products are based on information also defined in section 11.1. The activities of these sources are considered to be maximum values, although it is not anticipated that the plant will normally operate at these high levels.

For shielding, it is conservative to design for fission product sources at peak values rather than annual average values, even though experience supports a lower annual average than the design average. It should be noted that activation products, principally N-16, control shielding calculations in most of the primary system. In areas where fission products are significant, conservative allowance is made for transit decay, while at the same time providing for transient increase of the noble gas source, daughter product formation, and energy level of emission. Areas where fission products are significant relative to N-16 include the off-gas system downstream of the off-gas condenser, the liquid or solid radwaste equipment, and portions of the feedwater system downstream of the hot well including the condensate treatment equipment.

12.2.1.2 Radiation for Reactor Core

During full-power operation, radiation from the reactor core proper consists of neutrons and gamma radiation resulting from the fission process itself, gamma radiation resulting from capture or inelastic scattering of neutrons within the core, and gamma radiation resulting from fission product decay. In addition, neutron interactions with the core shroud and reactor pressure vessel (RPV) result in capture or inelastically scattered gamma rays.

Table 11.1-9 presents neutron and multigroup gamma ray fluxes at the outside of the RPV. The gamma ray fluxes include the core-fission gamma source, as well as the secondary gamma sources, which result from neutron capture in the core, water shroud, and vessel.

12.2.1.3 Activity in Steam and Condensate

Piping and equipment that contain reactor water, steam, or condensate are principal sources of radiation. The predominant activity requiring shielding in these systems is the N-16 carried in the steam and water from the reactor. Usually, activity sources in the steam other than N-16 can be neglected since their magnitude is so much smaller. The radiation source strength at any of the various pieces of equipment containing steam or reactor water is simply the RPV appropriate outlet nozzle activity of N-16 decayed by the transit time from the reactor outlet to the equipment. The N-16 sources used in the shield design are given in subsection 11.1.6 and table 11.1-4.

12.2.1.4 Activity in Reactor Water Cleanup (RWC) and Condensate Demineralizer Systems

The radiation source in these systems is due to the radioisotopes originating in the reactor water and steam. In the RWC system, radioisotopes (including corrosion products) present in the water are the source of activity. In the condensate demineralizer system, the sources are the nongaseous activity carried over in the primary steam and daughters resulting from radioactive gas decay in the condensate demineralizer system itself. In the RWC system, N-16 and similar short-lived activity were taken into account. However, this source was not considered in the condensate demineralizer systems, where transit times from the reactor are long, and the N-16 has essentially decayed. The inventories of radioactivity in these systems are discussed further in subsection 11.1.6.

In the reactor water, the corrosion product activity is present in both soluble and insoluble forms. The latter is primarily removed by filtration and the former by ion exchange. When considering fission product accumulation, the predominant fission products were assumed to be essentially soluble. Activity levels in such equipment build up during plant operation until equilibrium is achieved or until the activity is removed (or diminished) by backwashing or by discard, regeneration, or resins.

12.2.1.5 Shutdown Sources

The largest radiation source after reactor shutdown is the decaying fission products in the fuel. For shield design purposes, the strength of the fission product source has been based either upon data from other operating plants or upon a reactor which has operated long enough to establish equilibrium conditions for the buildup of all major fission products.

A secondary source is the structural material activation of the RPV, its internals, and the piping and equipment located between the RPV and the biological shield.

The third source is the activated corrosion products accumulated or deposited on the internals of the RPV, the primary coolant system piping, and other process system piping.

12.2.1.6 Spent-Fuel Sources

The radiation source for spent fuel is discussed in paragraph 11.1.6.4. Sources in terms of MeV/s/MWt are given in table 11.1-8.

12.2.1.7 Condensate Storage Tank

The condensate storage tank contains small amounts of radioisotopes, the total concentration of which is not expected to exceed 5×10^{-3} μCi/cm^3 as discussed in subsection 11.1.6.

12.2.1.8 Miscellaneous Sources

There is no source or special nuclear material to be used for sample analysis or instrument calibration that exceeds 600 mg. Byproduct material in excess of 100 mCi to be used for sample analysis or instrument calibration includes a 130-mCi Cs-137 source and a dual 400-Ci and 130-mCi Cs-137 source. Six curies of sealed Am-241 is to be used for equipment checkout. Ten sealed sources of Sb-124 totaling < 9000 Ci are used as startup neutron sources inside the reactor core.

12.2.2 AIRBORNE RADIOACTIVE MATERIAL SOURCES

This section contains the models, parameters, and sources use in calculating peak airborne concentrations in the turbine building, radwaste building, and reactor building below the refueling floor. The refueling floor is discussed in subsection 12.2.3. A listing by isotope of peak airborne concentrations in each region is given in table 12.2-2 and is discussed below.

The peak airborne concentrations in the various regions were calculated using the following equation:

$$K_i\,(t) = \frac{(LR)\ x\ A_i\ x\ (PF)_i}{V\lambda_{Ti}}\left(1 - e^{-\lambda_{Ti}\,t}\right)$$

where:

LR = leak rate of the radioactive source (gm/s).

A_i = activity concentration of the i^{th} leaking radioisotope (µCi/gm).

$(PF)_i$ = partition factor the i^{th} radioisotope.

V = volume of the region (cm^3).

λ_{Ti} = total removal rate constant for the i^{th} radioisotope (s^{-1}) equal to decay removal constant (λ_{decay}) plus exhaust removal constant ($\lambda_{exhaust}$).

t = time interval between start of leak and calculation of concentration (s).

$K_i(t)$ = airborne concentration at time t (µCi/m^3).

From the above equation, it is evident the equilibrium concentration of the i^{th} isotope is given by the following expression:

$$K_i(\text{equilibrium}) = \frac{(LR)\times A_i \times (PF)_i}{V\lambda_{Ti}}$$

With high exhaust rates, this peak concentration is reached within a few hours.

The parameters used for calculating the peak airborne concentrations are given in table 12.2-1. The radioisotope sources used for calculating the peak airborne concentrations are the sources given in section 11.1 with the following modifications:

A. Short Half-Life Isotopes

Isotopes with half-lives < 40 s were neglected.

B. Noble Radiogases

Release rates at t = 0, as given in table 11.1-1, are divided by 4 to account for lower average values experienced in operating boiling water reactors. This would result in a total noble gas release rate of 25,000 µCi/s after 30-min decay.

C. Radiohalogens

Concentrations of these isotopes in the primary coolant are in the same proportion as presented in table 11.1-2 with the assumption that the I-131 concentration in the primary coolant is 5 x 10^{-3} μCi/gm, independent of power level.

D. Other Reactor Water Fission Products

Concentrations of these isotopes, as given in table 11.1-3, are also divided by 4 on the same basis as item B above.

12.2.3 RADIATION SOURCES IN WET SPENT-FUEL STORAGE AREA

An estimate of the dose rate in the wet spent-fuel storage area, along with calculational methods and assumptions, is presented below.

The peak dose rates in the wet spent-fuel pool storage area contributed by airborne fission products are 1.64 mrem/h thyroid dose, 4.55 x 10^{-3} mrem/h skin dose, 4.60 x 10^{-4} mrem/h whole-body gamma, and 0.532 mrem/h to the lungs. The dose rate at the surface of the pool, due to radionuclides in the water, is 2.4 mrem/h.

Airborne dose rates were evaluated assuming that an iodine spike, which peaked coolant activity 150 times the normal activity level, occurred immediately after shutdown. Approximately 76 h are required for removal of the RPV head. During this time, the radionuclides present in the reactor coolant decayed and were reduced in concentration by the RWC system. The decontamination factor of the RWC demineralizer was assumed to be 10 in accordance with Draft Regulatory Guide 1.CC. After 76 h, the reactor coolant was assumed to mix instantaneously with the water inventory of the reactor well, fuel transfer canal, spent-fuel pool, and dryer-separator pool.

Airborne concentrations were then determined by utilizing the normal evaporation rate of the spent-fuel pool into the refueling floor air volume, using no partition factors. No decay or cleanup of the spent-fuel pool water by the spent-fuel pool cooling and cleanup (SFPCC) system was assumed. Therefore, the only cleanup mechanism assumed for the airborne activity was normal refueling floor ventilation. All noble gases were vented before opening the reactor vessel head. Contributions to airborne or spent-fuel pool water concentrations from fuel assemblies were considered negligible because leak rates from a fuel assembly decrease as the temperature of the assembly is lowered. Also, the SFPCC system and decay of radionuclides would lower the activity of the spent-fuel pool water, and the activity would significantly decrease from initial levels.

A major portion of any airborne radioactivity released due to evaporation from the reactor cavity, spent-fuel pool, and the dryer-separator pool would be entrained in an airsweep and would consequently not pose any major radiological problem for an operator on the refueling floor.

Source terms were derived from expected reactor coolant chemistry and decayed over 76 h using a combined decay constant that was dependent upon cleanup effects and radioactive decay.

The dose rate at the surface of the pool was calculated by considering the pool to be a cylinder with the same surface area as the actual geometry. The source volume was represented by a number of point isotopic sources and a computation of the line of sight distance from each of these source points to the detector point. The cylindrical pool was a reasonable approximation because the pool is effectively an infinite plane source.

The contribution of the spent fuel in the pool to the surface dose rate was assumed to be negligible because the water level in the pool is a minimum of 21 ft above the elements. Assuming a 2.8 MeV gamma, an approximate 8.5-ft water height above the fuel represents a dose reduction factor of 1.8×10^4. Also, the RWC system was assumed to have cleaned the reactor coolant for 76 h with no credit taken for further cleanup by the SFPCC system.

TABLE 12.2-1

PARAMETERS FOR CALCULATING AIRBORNE RADIOACTIVITY CONCENTRATIONS

Leak Rates (lb/h)			
Leak into accessible region of reactor building below refueling floor (primary coolant)			34
Leak into inaccessible region of reactor building below refueling floor			466
Leak into radwaste building accessible region (0.01 of primary coolant concentration)			348[a]
Steam leak into turbine building			1700
Partition Factors[b]	Halogens	Particulates	
Reactor building	10^{-3}	10^{-5}	
Radwaste building	10^{-3}	10^{-5}	
Turbine building[c]	10^{-2}	10^{-3}	
Ventilation Rates (ft^3/m)			
Exhaust rate from reactor building[d]			6500
Exhaust rate from accessible region of radwaste building			24,000
Exhaust rate from turbine building			25,000
Volumes of the Regions (ft^3)			
Accessible regions of reactor building below refueling floor			8.7×10^5
Accessible regions of radwaste building			1.86×10^5
Turbine building			3.75×10^6
Main Steam Flowrate			1.05×10^7 lb/h
I-131 Concentration in Reactor Coolant			5×10^{-3} µCi/g

a. This corresponds to 1000 gal/day at density = 1 g/cc.
b. Ratio of airborne activity to liquid activity.
c. RPV internal partition factor is the ratio of reactor steam activity to reactor water activity.
d. Accessible region below the refueling floor.

TABLE 12.2-2 (SHEET 1 OF 2)

PEAK AIRBORNE CONCENTRATIONS IN DIFFERENT REGIONS OF PLANT

Isotope	Accessible Region Below Refueling Floor Concentration (μCi/cc)	Radwaste Bldg Accessible Region (μCi/cc)	Turbine Bldg Concentration (μCi/cc)	MPC Air 40 h/week[b] Critical Organ (μCi/cc)
N-13	--	--	1(-8)	1(-6)
F-18	--	--	4(-8)	3(-6)
Na-24	3(-14)[a]	8(-16)	3(-11)	1(-7)
P-32	3(-16)	8(-18)	4(-13)	7(-8)
Cr-51	7(-15)	2(-16)	9(-12)	2(-6)
Mn-54	6(-16)	2(-17)	7(-13)	4(-8)
Mn-56	4(-13)	2(-14)	5(-10)	5(-7)
Fe-59	1(-15)	3(-17)	1(-12)	5(-8)
Co-58	7(-14)	2(-15)	9(-11)	5(-8)
Co-60	7(-15)	2(-16)	9(-12)	9(-9)
Ni-65	3(-15)	1(-16)	3(-12)	5(-7)
Zn-65	3(-17)	8(-19)	4(-14)	6(-8)
Zn-69m	4(-16)	1(-17)	5(-13)	3(-7)
Br-83	5(-12)	2(-13)	6(-10)	3(-9)
Br-84	3(-12)	3(-13)	4(-10)	1(-6)
Br-85	3(-13)	8(-14)	3(-11)	1(-6)
Kr-83m	--	--	6(-9)	1(-6)
Kr-85m	--	--	2(-8)	6(-6)
Kr-85	--	--	7(-11)	1(-5)
Kr-87	--	--	3(-8)	1(-6)
Kr-88	--	--	4(-8)	1(-6)
Kr-89	--	--	1(-8)	1(-6)
Sr-89	1(-14)	4(-16)	2(-11)	3(-8)
Sr-90	1(-15)	3(-17)	1(-12)	1(-9)
Sr-91	3(-13)	9(-15)	4(-10)	3(-7)
Sr-92	3(-13)	1(-14)	4(-10)	3(-7)
Zr-95	2(-16)	5(-18)	2(-13)	3(-8)
Zr-97	1(-16)	4(-18)	2(-13)	9(-8)
Nb-95	2(-16)	5(-18)	3(-13)	1(-7)
Mo-99	1(-12)	4(-14)	2(-9)	2(-7)
Tc-101	8(-14)	1(-14)	9(-11)	1(-6)
Ru-103	9(-17)	3(-18)	1(-13)	8(-8)

TABLE 12.2-2 (SHEET 2 OF 2)

Isotope	Accessible Region Below Refueling Floor Concentration (μCi/cc)	Radwaste Bldg Accessible Region (μCi/cc)	Turbine Bldg Concentration (μCi/cc)	MPC Air 40 h/week[b] Critical Organ (μCi/cc)
Ru-106	1(-17)	3(-19)	2(-14)	6(-9)
Te-129m	2(-16)	5(-18)	2(-13)	3(-8)
Te-132	2(-13)	6(-15)	3(-10)	1(-7)
I-131	7(-12)	2(-13)	9(-10)	9(-9)
I-132	4(-11)	2(-12)	5(-9)	2(-7)
I-133	4(-11)	1(-12)	6(-9)	3(-8)
I-134	4(-11)	3(-12)	5(-9)	5(-7)
I-135	5(-11)	2(-12)	7(-9)	1(-7)
Xe-131m	--	--	5(-11)	2(-5)
Xe-133m	--	--	1(-9)	1(-5)
Xe-133	--	--	3(-8)	1(-5)
Xe-135m	--	--	1(-8)	1(-6)
Xe-135	--	--	6(-8)	4(-6)
Xe-137	--	--	2(-8)	1(-6)
Xe-138	--	--	4(-8)	1(-6)
Cs-134	1(-16)	2(-17)	1(-12)	1(-8)
Cs-136	5(-16)	1(-7)	6(-13)	2(-7)
Cs-137	1(-15)	3(-17)	1(-12)	1(-8)
Cs-138	2(-13)	2(-14)	3(-10)	1(-6)
Ba-139	3(-13)	2(-14)	4(-10)	1(-6)
Ba-140	4(-14)	1(-15)	5(-11)	4(-8)
Ba-141	1(-13)	2(-14)	1(-10)	1(-6)
Ba-142	8(-14)	1(-14)	9(-11)	1(-6)
Ce-141	2(-16)	5(-18)	2(-13)	2(-7)
Ce-143	2(-16)	4(-18)	2(-13)	2(-7)
Ce-144	2(-16)	5(-18)	2(-13)	6(-9)
Pr-143	2(-16)	5(-18)	2(-13)	2(-7)
Nd-147	7(-17)	2(-18)	9(-14)	2(-7)
W-187	4(-14)	1(-15)	5(-11)	3(-7)
Nb-239	1(-12)	3(-14)	1(-9)	7(-7)

a. 3(-14) = 3×10^{-14}.
b. From 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), Appendix B, table I, column 1.

12.3 RADIATION PROTECTION DESIGN FEATURES

12.3.1 FACILITY DESIGN FEATURES

The Edwin I. Hatch Nuclear Plant design was based upon sound engineering judgment and practice with reviews and evaluations of past experiences on operating power reactors. The following discussion of the design features, plant layout, and general arrangement figures illustrates how the facility is designed to maintain occupational radiation exposures as low as reasonably achievable (ALARA).

12.3.1.1 Plant Layout and Arrangement

Equipment decontamination areas, wall thicknesses, and controlled access areas (control access barriers and airtight doors) are shown in figure 12.3-7 and drawing nos. H-15874, H-15903, and H-25993 through H-25999.

The various radioactive waste systems are discussed in chapter 11; the control panel locations are shown on general arrangement drawings (drawing nos. H-26097 through H-26100 and H-26106). The radiochemistry laboratory, health physics office, and counting room are shown in figure 12.3-2.

The general arrangement of the reactor building is shown on drawing nos. H-26096, H-26098, and H-26100 through H-26105.

The general arrangement of the turbine building is shown on drawing nos. H-21001 through H-21004, H-21006, and H-21007.

The above referenced figures, drawings and text illustrate how the facility arrangements are designed to maintain occupational radiation exposures ALARA.

12.3.1.2 Design

During design, an effort was made to provide shielding, separation of contaminated equipment, and other protective measures to minimize personnel exposures. Experience has shown that most exposure occurs during maintenance, refueling, and other nonroutine operations. The following are specific examples of design measures which were taken to minimize personnel exposures:

A. Quality valves are used to minimize leakage of radioactive materials. In the off-gas system, specially designed Kerotest valves are used. These valves maintain a positive pressure on the valve stems (supplied from instrument air) so that any leakage around the valve stem is into the off-gas system.

B. ARMs with remote readout are located in accessible areas where it is desirable to monitor the radiation levels continuously. These monitors are listed in table 12.3-1.

C. Shielding is provided, where practicable, between radiation sources and areas to which personnel have access. The 5-ft-thick concrete slab covering the main steam pipe chase is an example of this; it separates a high-radiation area from the working floor. This area is shown on drawing no. H-25996 (T13, TB to T14, TG). Other examples on the same figure are feedpump turbines (TB, T19, TB, T17), turbine-to-generator 8-in. steel plate shield (T19, TF), and reactor vessel biological shield (R18, RF).

D. Special movable shielding, which is neither temporary nor portable, is specifically designed for Plant Hatch in the inservice inspection doors in the sacrificial shield to allow access for inservice inspection of nozzle welds required by the American Society of Mechanical Engineers (ASME) Code, Section XI. These doors have a unique triple hinge, shown on drawing no. H-29000, which allows for ease of movement.

Removable block wall shielding is used in those areas where personnel access is required in the vicinity of potentially radioactive components, and where maintenance space normally provided is required to be used so infrequently as to make the use of removable walls economical, as opposed to permanent walls enclosing a much larger volume. Removable shielding walls are used for removal of large pieces of equipment. Removable walls are also more feasible than permanent walls for heat exchanger tube pull areas. The removable walls around the reactor water cleanup (RWC) heat exchanger room (R23, RF) are examples.

E. The ventilation system is designed to ensure control of airborne contaminants.

All of the normal exhaust filter trains are isolated by dampers for filter maintenance periods. A 50% flowrate by use of one of two normally operating filter trains is possible for the refueling floor, the turbine building, and the radwaste building systems to enable significant filter maintenance while allowing operation of the system. The ventilation system maintains airflow direction from areas of lesser airborne radioactive contamination potential to areas of greater airborne radioactive contamination potential and continues the filtering of the exhaust air even during filter maintenance periods (drawing nos. H-26072, H-26086, and H-26090).

F. The ventilation systems are designed with access galleries for prefilter and high-efficiency particulate air (HEPA) filter inspection, maintenance, testing, and change out. The access galleries are reached by access doors in the side of the filter train. Figure 12.3-5 illustrates a typical filter train being used. Except for the control room and technical support center tray-type filters, the charcoal is the deep-bed design which allows for change-out through use of an external connection through a portable blower. Access aisle space is provided as shown on drawing no. H-26102.

G. Equipment requiring maintenance is separated from other sources of radiation. As an example, the centrifugal pumps in the radwaste system (drawing no. H-25993;

B2, BD) are separated from the storage tanks they service by shield walls. The pumps and motors are removed easily in the event a major overhaul is required. Additionally, heating, ventilation, and air-conditioning (HVAC) components are located in rooms separated from major radiation sources (drawing no. H-25996; R15, RB, R24, and RA).

H. The major radiation sources in the liquid radwaste system are the various storage and processing tanks (drawing no. H-25993; B2, BD). Most tanks are located in separate shielded enclosures to minimize exposure in the operating areas.

I. Components that can become contaminated, such as the radwaste centrifuges and hoppers (drawing no. H-25996; B4, BD) and resin transfer pumps (drawing no. H-25996; B8, BD), are provided with connections from the condensate system for flushing purposes.

J. The radwaste system is shielded such that normally occupied areas and operating stations expose personnel to ALARA radiation levels. The radwaste control room (drawing no. H-25996; B1, BC to B3, BA) is shielded to restrict exposures to $<$ 0.5 mrem/h.

K. Remote handling equipment is provided where practicable.

12.3.1.3 <u>Radiation Zones and Access Control</u> (HNP-1 and HNP-2)

12.3.1.3.1 Radiation Zones

Radiation zones were used during the initial design of the plant to support access control planning and radiation shielding design. The current radiation control area classifications and current radiation access control practices are described in paragraph 12.3.1.3.2.

For initial design purposes, areas were zoned according to their expected occupancy by plant personnel relative to the radiation dose rate during normal operation, hot standby, refueling, component maintenance, and system testing. The areas inside the plant structures, as well as the general yard areas, were identified by one or more of the radiation zones defined in table 12.3-2.

12.3.1.3.2 Radiation Access Control

Table 12.1-1 provides detailed information relative to current radiation control area classifications.

Access to restricted areas is permitted after the areas are surveyed to establish the area dose rates. To maintain exposure ALARA, some surveys may be performed while providing health physics job coverage. The maximum time allowed in one of these areas depends upon the area dose rates and the available dose exposure of the individuals to be working in a particular area. Whenever practical, the measured area dose rates reflecting the most recent dose rate survey of the area will be provide by health physics personnel.

Access restrictions are enforced by removable concrete shielding blocks, controlled doors (controlled access barriers), and administrative control. Access into high and very high radiation areas requires a radiation work permit (RWP) issued by the health physics staff. Access into contaminated area normally requires an RWP. All personnel entering contaminated areas wear radiation protection clothing in accordance with the work to be performed and the area to be entered. All locked doors are provided with bars or knobs to permit rapid egress of an area if an emergency develops.

12.3.2 SHIELDING

12.3.2.1 <u>Design Objective</u> (HNP-1 and HNP-2

The primary objective of the shielding design and access control is to protect operating personnel and the general public from potential radiation sources in the reactor, the radwaste system, and other auxiliary systems, including associated equipment and piping. The shielding is designed to:

A. Ensure that during normal operation, including anticipated operational occurrences (AOOs), the radiation dose to plant personnel and authorized site visitors is ALARA and within the limits set forth in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

B. Provide the necessary protection for plant operating personnel following a reactor accident to maintain habitability of the control room as specified in 10 CFR 50, Appendix A, Criterion 19.

C. Limit offsite exposures to the general public and to meet the dose requirements of 10 CFR 50.67 or 10 CFR 100, as applicable, for all postulated accident conditions.

D. Protect certain components from excessive radiation damage or activation.

The basis of radiation shielding design for normal operation, hot standby, refueling, component maintenance, and system testing is the requirements set forth in 10 CFR 20 and 50. The maximum allowable design dose rates for all plant areas, when coupled with the access control program, limits personnel exposures to an integrated whole-body dose of 5 rem/12-month period. For all areas outside the site property boundary, the design maximum dose rate does not exceed a maximum integrated whole-body dose of 0.5 rem in any 12-month period. The average doses are well below these values. This can be attributed, in part, to the planned

operational procedures and the conservative approach used in calculating the shielding requirements.

12.3.2.2 Design Description

12.3.2.2.1 General Shielding Description (HNP-1 and HNP-2)

The shielding design considers the following plant operating conditions:

A. Normal operation at full power and hot standby.

B. Shutdown, refueling, system testing, and component maintenance. These conditions deal mainly with the radioactivity from a subcritical core, spent-fuel elements, waterborne fission products, crud deposits, and neutron-activated materials.

C. Design basis accidents (DBAs) have been investigated where the release of radioactivity to the environment may occur.

The material most commonly employed for shielding is concrete with a bulk density of 2.35 g/cm^3. Where space is limited, steel or lead is substituted for ordinary concrete in equivalent thicknesses. Whenever cast-in-place concrete is replaced by concrete block (removable or fixed), the design ensures protection on an equivalent shielding basis.

At full-power operation, the N-16 activity leaving the reactor vessel is shown in table 11.1-4. The off-gas system shielding is conservatively based upon a noble release rate (350,000 μCi/s after 30-min holdup) which is 3.5 times the off-gas system design basis release rate (100,000 μCi/s after 30-min holdup). Source terms are provided in section 11.1.

The shutdown case assumes that the reactor core has been operating at full power for 1000 h. At 1000 h, the fission product inventory closely approximates the infinite operation case.

The different areas of radiation protection are described in subsequent subsections and listed by specific location or building for convenience.

The shielding thicknesses provided to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions. The thickness of each shield wall was determined by approximating the actual geometry and physical condition of the source.

The geometric model assumed for shielding evaluation of tanks, heat exchangers, filters, demineralizers, and evaporators is a finite, cylindrical volume source. For shielding evaluation of piping, the geometric model is a finite shielded cylinder.

ANISN and QAD-P5 computer codes, as well as standard hand calculation techniques, were used in the shielding design.

The shielding thicknesses were selected to reduce the aggregate computed radiation level from all contributing sources below the upper limit of the radiation zone specified for each plant area. Shielding requirements were evaluated at the point of maximum radiation dose through any wall. The actual radiation levels in the greater region of each plant area are less than the maximum dose and, therefore, are less than the applicable radiation zone upper limit.

To minimize radiation streaming through penetrations, as many penetrations as practicable are located with an offset between the source and the accessible areas. If offsets are not practicable, penetrations are located as far as possible over the floor elevation to reduce the exposure to personnel. If these two methods are not adequate, alternative additional means, such as baffle shield walls or grouting the area around the penetration, are employed.

12.3.2.2.2 Reactor Building (HNP-1 and HNP-2)

The design dose rate in most areas outside the drywell and torus chamber is a maximum 2.5 mrem/h. To achieve this dose rate, a reactor (sacrificial) shield inside the drywell and the drywell (biological) shield outside the drywell are provided.

The reactor shield also serves to protect certain major portions of the drywell space from excessive nuclear radiation exposures during operation. After shutdown, it provides shielding from reactor vessel radiation for personnel engaged in inspection, maintenance, and repair of drywell equipment and components.

Numerous shielded rooms surround the drywell structure. These rooms enclose the reactor water cleanup (RWC) system, fuel pool cooling and cleanup (FPCC) system, traversing incore probe (TIP) system, residual heat removal (RHR) system, and engineered safety feature (ESF) systems. Enclosing these secondary sources of radiation in shielded rooms minimizes the necessity of limiting access time to adjacent areas. In addition to the above, five heavily shielded rooms below grade level house the major components of the various ESF systems.

The personnel and equipment access locks leading into drywell at grade level are shielded to equal the unbreached biological shield wall adjacent to the access lock. All penetrations of the biological shield wall that could create a personnel hazard are shielded.

The main steam line pipe chase, with 4-ft-thick concrete walls, is the connecting shield structure between the reactor and turbine buildings. The chase shielding protects against the penetrating N-16 gamma radiation which is radiated from the passing steam.

The spent-fuel pool contains the highly radioactive spent-fuel assemblies, control rods, and instrumentation. A 5-ft 6-in.-thick concrete shield is used for radiation protection at the sides and bottom of the storage pool. A minimum cover of ~ 21.0 ft of water above the active fuel is maintained for shielding of plant personnel during fuel transfer operations from the reactor vessel.

12.3.2.2.3 Turbine Building (HNP-1 and HNP-2)

Radioactive steam enters the turbine building from the reactor. In addition to N-16, fission product gases and some other radioisotopes are carried over from the reactor water. Some of the N-16 activity is retained in the condensate. The remaining N-16 activity is removed by the steam jet air ejector (SJAE).

The 2-min water retention in the condenser Unit 2 hotwell effectively eliminates the condensate N-16 activity. The radioisotopes (fission and corrosion products) carried over are treated by the condensate demineralizers. The noncondensibles are removed from the condenser by the SJAE to the off-gas system for treatment prior to release to the environment.

Radiation shielding is provided around the following areas:

- Main steam lines.
- Primary and extraction steam piping.
- High- and low-pressure turbines.
- Moisture separator reheaters.
- Reactor feedwater system heaters and heater drains.
- Main condenser and hotwell.
- Air ejectors, steam packing exhausts, and mechanical vacuum pump.
- Condensate demineralizer.
- Condensate demineralizer backwash system.
- Turbine-driven reactor feed pumps.
- Off-gas lines.

12.3.2.2.4 Waste Gas Treatment Building (HNP-1 and HNP-2)

The waste gas treatment building houses the process equipment and charcoal beds for the off-gas system. All areas for control and operation of the off-gas system are separated and shielded from the process equipment. These working floors are continuously monitored for gamma radiation. The shielding layout for the waste gas treatment building is depicted on drawing no. H-15903.

12.3.2.2.5 Main Stack (HNP-1 and HNP-2)

The shielding design for the main stack provides for controlled access to maintain the filters and instrumentation. The shielding layout is depicted on drawing no. H-15874.

12.3.2.2.6 Condensate Storage Tank (CST)

The CST has a 500,000-gal capacity and is surrounded by a 2-ft 6-in.-thick concrete Seismic Category I containing wall. This wall acts as both a shielding and containment structure in the case of a tank rupture. The contents of this tank are described in paragraph 12.2.1.7.

12.3.2.2.7 Radwaste Building (HNP-1 and HNP-2)

All areas for preparing, handling, storing, and shipping the radwaste are shielded to permit controlled access as required for operation of the radwaste system.

The individual radwaste subsystems are separated from each other and shielded as much as practical to minimize personnel exposure during maintenance and repair of any of the equipment.

The radwaste building control room and chemical treatment room are shielded and are controlled access areas. A radiation monitoring station, decontamination shower, and lockable doors separate the control room and chemical treatment room from the remainder of the radwaste building.

12.3.2.2.8 Main Control Room (HNP-1 and HNP-2)

The DBAs define the protection required for the MCR. The accident conditions and their resultant effects on MCR habitability are described in chapter 15. For continued MCR occupancy during the DBA, shielding design is based on a whole-body integrated dose of < 0.5 rem in any 8-h period from any direct radiation due to any possible airborne radioactivity external to the MCR following an accident. The MCR is shielded on all sides with 2-ft-thick concrete walls and on the roof with 2-ft 6-in.-thick concrete. The shielding on the floors below the MCR is a minimum of 2-ft-thick concrete prior to reaching any external area that may contain radioactive material. The minimum interposing concrete thickness between the MCR and the secondary containment is 4 ft, ignoring angularities.

12.3.2.2.9 Service Building (HNP-1 and HNP-2)

All areas of the service building are fully accessible at all times. Turbine building shielding prevents excessive N-16 shine onto the service building.

12.3.2.2.10 General Plant Yard Areas (HNP-1 and HNP-2)

Plant yard areas frequently occupied by plant personnel receive a radiation field of < 0.5 mrem/h. These areas are surrounded by a security barrier and closed off from areas accessible to the general public for reasons of general safety.

12.3.2.2.11 Technical Support Center (HNP-1 and HNP-2)

The DBAs define the protection required for the technical support center (TSC). The accident conditions and their resultant effects on TSC habitability are described in chapter 15. For TSC occupancy following the DBA, shielding design is based on a whole-body integrated dose of < 5 rem for the duration of the accident due to any possible airborne radioactivity external to the TSC following an accident. The TSC is shielded on all sides by the equivalent of 6-in.-thick concrete.

12.3.2.2.12 Independent Spent Fuel Storage Installation (ISFSI) (HNP-1 and HNP-2)

The ISFSI provides additional storage capacity for spent-fuel in dry casks which provide shielding and missile protection. The ISFSI is located in a radiation control area (RCA) south of the main plant protected area within its own protected area. The RCA fence for the ISFSI is established such that the doses at the fence do not exceed 2 mrem/h, thereby providing assurance that members of the public allowed onsite do not exceed the limits of 10 CFR 20.1301(b).

12.3.2.2.13 Low-Level Radioactive Waste (LLRW) Storage Facility (HNP-1 and HNP-2)

LLRW is defined as Class A, Class B, Class C, and Greater than Class C (GTCC) radwaste. Due to the unavailability of a disposal facility for Class B, Class C, and GTCC radwaste, a LLRW storage facility is provided onsite. The location of this storage facility is north of the WSTSF. Location and design of the concrete pad is shown on drawing H-46598. The LLRW will be packaged in high-integrity containers (HICs) or other suitable long-term storage containers and then placed in secure environmental containers (SECs) or other appropriate shielded containers to provide radiation dose reduction and normal environmental protection. Sufficient shielding is maintained for all packages stored on the storage facility to keep radiation levels at the storage facility fence below the Zone 1 levels. This area is surrounded by a chain link fence and provided with locked gates and area lighting. Access to the area is under control by the Health Physics Department as a radioactive material storage area and is monitored by OCA security patrols or surveillance equipment in accordance with the Southern Nuclear Operating Company Security Plan. The fence for the storage facility is established such that the dose rate at the fence is limited to no more than 0.25 mrem/h. The maximum activity limit for the LLRW storage facility is 750,000 Ci. However, prior to placing this amount of radioactive material on the pad, the boundary (fence) dose rate would exceed 0.25 mrem/h and additional shielding would be needed.

12.3.2.3 Plans and Procedures

Aside from the physical layout, shielding, and piping routing, ALARA criteria are ensured with planning and procedures reviewed by the health physics ALARA staff. Details of these plans and procedures are described in section 12.5.

12.3.2.4 Inspection and Performance Analysis

The normal construction quality control program ensures there are no major defects in the shielding. After startup, the adequacy of the shielding and the efficiency of the access control are checked by radiation and contamination surveys performed at various reactor power levels. General surveys are made prior to, or concurrent with, personnel entry into maintenance work areas designated as restricted.

12.3.3 VENTILATION

12.3.3.1 Design Objectives

The plant ventilation system is designed to accomplish the following:

A. Maintain the required ambient air temperature to prevent extreme thermal environmental conditions for operating personnel and equipment.

B. Protect the operating personnel against possible airborne radioactive contamination in areas where this may occur.

C. Ensure the maximum airborne radioactivity levels for normal operation and AOOs are within the limits of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), Appendix B, table I, column 1, for areas within the plant structures and restricted areas on the plant site.

D. Provide a suitable environment for continuous personnel occupancy in the MCR under normal and post-accident conditions in accordance with 10 CFR 50, Appendix A, Criterion 19.

E. Ensure the maximum radiological exposures to the general public following a DBA are within the limits of the guidelines of 10 CFR 50.67.

F. Provide a suitable environment for personnel occupancy in the TSC under post-accident conditions.

12.3.3.2 Design Description

To meet the intended design objectives for the plant ventilation system, the following design guidelines are applied:

A. Air movement patterns are provided from areas of lesser radioactive contamination to areas of progressively greater radioactive contamination prior to final exhaust.

B. Negative pressures are maintained, where applicable, to prevent uncontrolled exfiltration of contamination. The MCR is maintained at slightly positive pressure to prevent infiltration of potential contaminants.

C. Valves and equipment are as leaktight, as practical, to prevent leakage of radioactive fluids and subsequent airborne contamination.

D. Individual air supplies are provided for each building to keep potentially contaminated airflows separate from noncontaminated air.

E. To reduce onsite and offsite radiation levels, potentially radioactive air is exhausted through a filter train consisting of roughing, charcoal, and HEPA filters. Filters and monitored exhausts are provided in all of the buildings that potentially contain radioactive airborne contamination with the exception of the waste gas treatment building. The waste gas treatment building air is discharged through the main stack and monitored by the main stack radiation monitor. An example of an air cleaning system layout is shown in figure 12.3-5.

F. Roughing, charcoal, and HEPA filters are used for filtration of the recirculated air of the MCR during accident and abnormal conditions.

G. Roughing, charcoal, and HEPA filters are used for filtration of the recirculated and makeup air of the TSC during accident conditions.

The standby gas treatment system (SGTS) and MCR recirculation air cleaning system which operate during the plant's accident modes following DBAs adhere to the intent and philosophy of Regulatory Guide 1.52, and redundancy is provided in such safety-related ventilation systems. The standby gas filter train is shown in figure 12.3-6.

The TSC air cleaning system adheres to the intent and philosophy of Regulatory Guide 1.140. Redundancy is not provided for this nonsafety-related ventilation system.

12.3.4 AREA RADIATION AND AIRBORNE RADIOACTIVITY MONITORING INSTRUMENTATION

12.3.4.1 Area Radiation Monitoring

The objective of an ARM system is to provide plant personnel with a system such that they can move about and work in restricted areas with reasonable assurance the radiation levels are below those requiring special monitoring precaution. Thus, the objective of the ARM system is to indicate, alarm, and record abnormal gamma radiation levels in areas where radioactive material may be present, stored, handled, or inadvertently introduced.

The ARM system is designed to:

A. Indicate, in the MCR, radiation levels at selected locations within the plant where personnel are either working or passing through or where monitoring can assist in maintaining exposure levels ALARA.

B. Locally alarm where it is necessary to warn personnel of substantial immediate change in radiation levels up to or exceeding the selected setpoints for that area.

C. Warn operating personnel when an instrument is not operational.

D. Have sufficient range and sensitivity to monitor normal operation and AOOs.

For a discussion of criticality monitoring, reference paragraph 9.1.1.1.

The area gamma monitors are primarily used to provide dose rate measurements in mrem/h for the protection of plant personnel. The location, range, and instrument designation are listed in table 12.3-1.

The ARM system is shown as a functional block diagram on drawing no. H-26010. Each channel consists of a combined sensor and converter unit, a combined indicator, an audible alarm and trip unit, and a shared power supply. All 40 channels provide input to the safety parameter display system, and channels 1 through 30 are recorded on a multipoint recorder.

Each monitor has an upscale trip that indicates high radiation and a downscale trip that indicates instrument trouble. These trips sound alarms but cause no control action. The system is powered from the 120-V-ac instrument bus. The trip circuits are designed so that loss of power causes an alarm. The environmental and power supply design conditions are given below.

Parameter	Design Center	Monitor Environment Range	Detector Preamplifier Environment Range
Temperature (°C)	25	5-50	0-60
Relative humidity (%)	50	20-90	20-100

The overall accuracy within the design range of temperature, humidity, line voltage, and line frequency variation is such that the actual reading relative to the true reading, including susceptibility and energy dependence (100 keV to 3 MeV), is within 9.5% of equivalent liner full-scale recorder output for any decade. The power supply is compatible with the instrument ac supply. All instruments function without effective change in performance with the ac supply voltage changes over a range of nominal value ± 10%, frequency nominal ± 5%. All instruments that contain trip circuits for use in annunciation or alarm are arranged so interruption or failure of the ac power supply or component failure that causes the loss of signal results in actuation of the trip circuit in a direction to cause alarm.

When the ARM system is connected and in operation, noise from any source in the operating environment does not cause a meter indication of > ± 2% of equivalent linear full scale.
The detector-indicator and trip units are responsive to gamma radiation over an energy range of 80 keV to 7 MeV. The energy dependence does not exceed ± 20% of the reading for a dose rate of ~ 50 mrem/h from 100 keV to 3 MeV and has a response from 80 keV to 7 MeV.

An internal trip test circuit, adjustable over the full range of the trip circuit, is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a real trip. All trip circuits are of the latching type and must be manually reset at the front panel. A portable calibration unit is also provided. This is a test unit designed for use in the adjustment procedure for the ARM sensor and converter unit. A cavity in the calibration unit is designed to receive the sensor and converter unit. Located on the back of the cylindrical lower half of the cavity is a window through which radiation from the source emanates. A chart on each unit indicates the radiation levels available from the unit for the various control settings. The unit is calibrated at least every 24 months. Calibration procedures are discussed in chapter 13.

The recorder panel is located in the MCR. Table 12.3-1 lists the ranges of the detectors.

Friskers are strategically located throughout the plant for personnel contamination control. Typical locations of friskers are noted on figures 12.3-1, 12.3-2, and 12.3-4 and drawing nos. H-15874, H-15903, and H-25993 through H-25999. Friskers may be moved, as necessary, at the discretion of the superintendent health physics.

12.3.4.2 Airborne Radioactivity Monitoring

Portable airborne radioactivity monitoring systems monitor the air within or exhausted from an enclosed area. Each monitoring system, which is self-contained and mounted on a mobile cart, consists of an air collection and filtration unit and a detection unit.

Two examples of airborne radioactivity monitoring systems are:

- Type I systems which continuously monitor and record airborne particulate radioactivity by collecting the particulates on a stationary filter and detecting and recording the activity on a graphic recorder. The buildup of activity on the filter is detected by a beta-gamma-sensitive Geiger-Mueller counter.

- Type II systems which perform the same monitoring function as Type I systems and, in addition, monitor the filtered air for iodine collected by a fixed, activated charcoal cartridge. The buildup of I-131 on the cartridge is detected by a scintillation detector.

Local audio and visual alarms contained in each portable monitoring system alert personnel in the particular area in the event airborne activity is at or above administrative limits for either particulate or iodine radioactivity. These monitoring and alarm functions ensure personnel are not subjected to airborne radioactivity concentrations in excess of the limits of 10 CFR 20.1001 - 20.2401, Appendix B, table I, column 3. These records also assist operating personnel in maintaining airborne concentrations at the lowest practical levels.

The airborne radioactivity monitoring systems are in areas where occupational factors and the possibility of airborne contamination are most predominant. Monitoring systems are typically located at the following locations:

- Refueling floor.
- Turbine floor.
- Reactor building - el 130, 158, and 185 ft.

These airborne radioactivity monitoring systems may be relocated at the discretion of health physics supervision. Type II monitoring systems are located in the above areas in situations in which the plant operating staff judges the possibility of higher airborne iodine concentrations exist. These systems are mobile and, based on the particular circumstance of personnel occupancy within a particular region of the above areas, the plant operating staff determines whether the monitoring system should be relocated to the immediate work area.

The airborne radioactivity monitoring systems do not perform an initiation function for essential HVAC systems. As described in paragraphs 9.4.2.2.1 and 9.4.2.2.2, radiation monitors in the exhaust ventilation system ducts in the reactor zone, and the refueling zone ventilation systems shut down the normal supply and exhaust systems and initiate SGTS operation upon detection of a high radiation level.

Prior to entry of plant personnel into plant areas susceptible to airborne radioactivity, the concentration of airborne radioactivity is determined by the health physics staff as discussed in paragraph 12.1.3.1. As part of this determination and evaluation of the necessity of protective measures for personnel occupancy, the health physics staff considers the shielding and dilution effects from the location of the portable airborne particulate monitor to the actual work area.

TABLE 12.3-1 (SHEET 1 OF 2)

LOCATION AND RANGE OF AREA MONITORS

Channel No.	Range (mr/h)	Description	Location	Auxiliary Unit	Sensor and Convertor	Indicator and Trip Unit
1	$1.0\text{-}10^4$	Reactor head laydown area	Reactor bldg	K002A	N002A	K601A
2	$1.0\text{-}10^4$	158-ft level area SE	Reactor bldg		N002B	K601B
3	$1.0\text{-}10^4$	158-ft level area NE	Reactor bldg		N002C	K601C
4	$1.0\text{-}10^4$	158-level area NW	Reactor bldg		N002D	K601D
5	$1.0\text{-}10^4$	Dryer/separator pool	Reactor bldg	K002B	N002E	K601E
6	$1.0\text{-}10^4$	Transient incore probe area	Reactor bldg	K002V	N002F	K601F
7	$1.0\text{-}10^4$	130-ft NE work area	Reactor bldg		N002G	K601G
8	$1.0\text{-}10^4$	130-ft SW work area	Reactor bldg		N002H	K601H
9	$1.0\text{-}10^4$	Decant pump and equipment room	Reactor bldg	K002C	N002L	K601L
10	$1.0\text{-}10^4$	Spent-fuel/fuel pool areas	Reactor bldg	K002D	N002M	K601M
11	$1.0\text{-}10^4$	South control rod drive (CRD) hydraulic units	Reactor bldg	K002E	N002N	K601N
12	$1.0\text{-}10^4$	Spent-fuel pool passageway	Reactor bldg	K002F	N002P	K601P
13	$1.0\text{-}10^4$	185-ft level operating floor	Reactor bldg		N002R	K601R
14	$1.0\text{-}10^4$	185-ft level sample panel area	Reactor bldg		N002S	K601S
15	$1.0\text{-}10^4$	CRD repair area	Reactor bldg		N002T	K601T
16	$1.0\text{-}10^4$	185-ft level RWC control panel	Reactor bldg		N002U	K601U
17	$1.0\text{-}10^4$	Reactor core isolation cooling equipment area	Reactor bldg		N002V	K601V
18	$1.0\text{-}10^4$	CRD pump room SW	Reactor bldg		N002W	K601W
19	$1.0\text{-}10^4$	RHR and core spray room NE	Reactor bldg		N002X	K601X

TABLE 12.3-1 (SHEET 2 OF 2)

Channel No.	Range (mr/h)	Description	Location	Auxiliary Unit	Sensor and Convertor	Indicator and Trip Unit
20	$1.0\text{-}10^4$	RHR and core spray room SE	Reactor bldg		N002Y	K601Y
21	$1.0\text{-}10^4$	Reactor vessel refueling el 228 ft	Reactor bldg	K002T	N012K	---
22	$1.0\text{-}10^4$	Reactor vessel refueling el 228 ft	Reactor bldg	K002U	N012L	--
23	0.01-100	HVAC room west el 203 ft	Reactor bldg	K001B	N001D	K600D
24	0.01-100	Waste gas treatment glycol el 106 ft	Waste gas treatment bldg	K001C	N001E	K600E
25	0.01-100	16-ft level uncontrolled access area	Turbine bldg	K001A	N001A	K600A
26	0.01-100	130-ft level uncontrolled access area	Turbine bldg		N001B	K600B
27	0.01-100	Recombiner access passage el 122 ft	Turbine bldg		N001C	K600C
28	0.01-100	Condensate booster pump area el 112 ft	Turbine bldg		N001F	K600F
29	0.01-100	North turbine room working floor el 164 ft	Turbine bldg	K001D	N001G	K600G
30	0.01-100	Stator cooling unit el 130 ft	Turbine bldg		N001H	K600H
31	0.01-100	Low-pressure heater area el 130 ft	Turbine bldg		N001K	K600K
32	$1.0\text{-}10^4$	Condensate demineralizer/112-ft stairwell area SE	Turbine bldg	K002G	N002Z	K601Z
33	$1.0\text{-}10^4$	Radwaste operating floor	Radwaste bldg	K002H	N012A	K611A
34	$1.0\text{-}10^4$	Radwaste conveyor operating aisle	Radwaste bldg	K002K	N012B	K611B
35	$1.0\text{-}10^4$	Radwaste basement pump room	Radwaste bldg	K002L	N012C	K611C
36	$1.0\text{-}10^4$	132-ft 4-in. level monorail area	Radwaste bldg	K002M	N012D	K611D
37	$1.0\text{-}10^4$	148-ft level hopper area	Radwaste bldg	K002N	N012E	K611E
38	$1.0\text{-}10^4$	148-ft level stairway area	Radwaste bldg	K002P	N012F	K611F
39	$1.0\text{-}10^4$	164-ft level centrifuge area	Radwaste bldg	K002R	N012G	K611G
40	$1.0\text{-}10^4$	164-ft level working area	Radwaste bldg	K002S	N012H	K611H

TABLE 12.3-2

SHIELDING
DESIGN BASES LIMITATIONS[a]
(HNP-1 AND HNP-2)

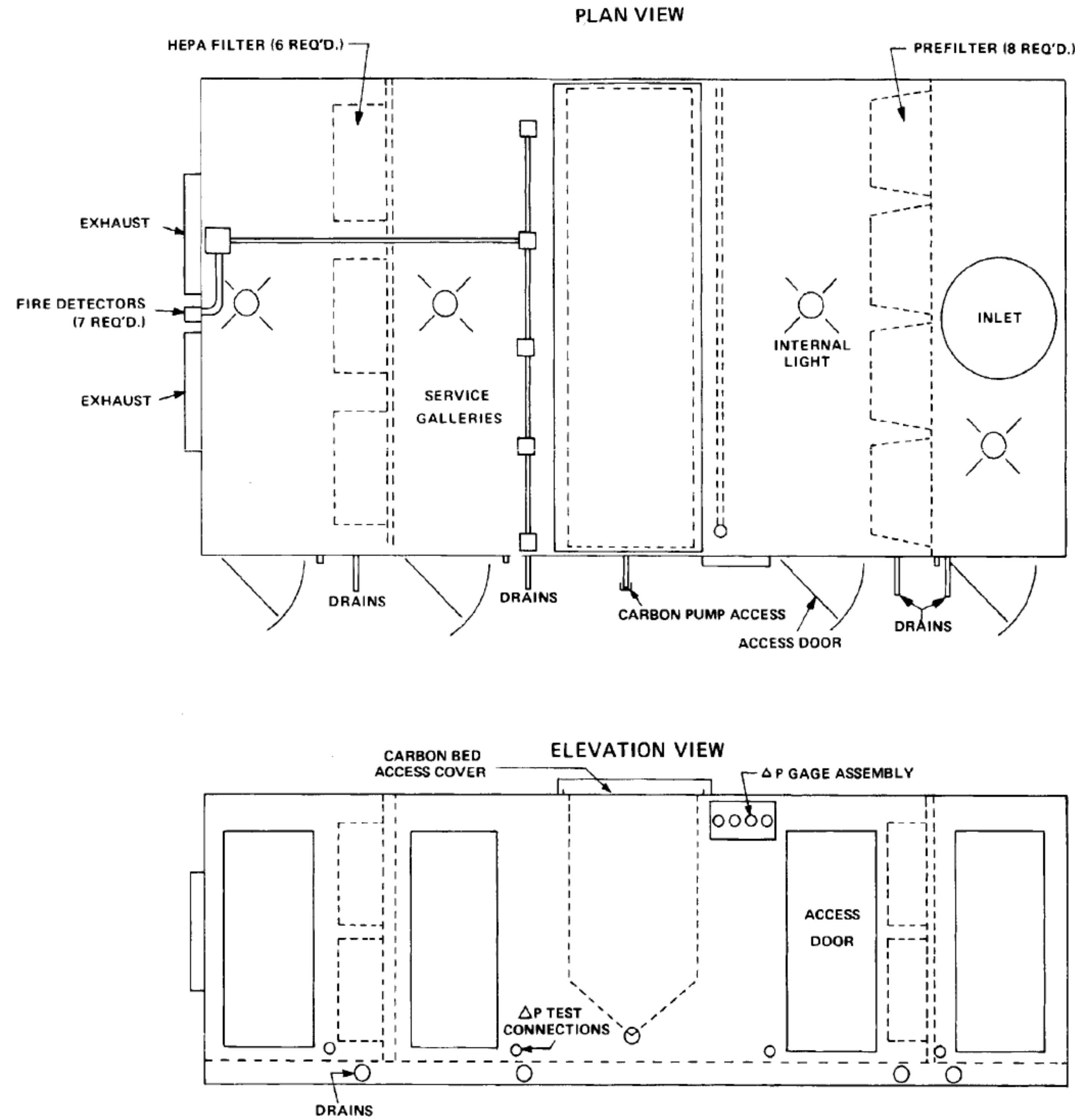
Uncontrolled Access Zone

Zone I	-	Unlimited Access:	0 - 0.5 mrem/h

Controlled Access Zones

Zone II	-	Normal Access:	0.5 - 2.5 mrem/h, 40 h/week at 2.5 mrem/h
Zone III	-	Short Time Access:	2.5 - 15 mrem/h, 6 h/week at 15 mrem/h
Zone IV	-	Limited Access:	15 - 100 mrem/h, 1 h/week at 100 mrem/h
Zone V	-	Restricted Access:	Over 100 mrem/h

a. Radiation zones were used during the initial design of the plant to support access control planning and radiation shielding design. The current radiation control area classifications and current radiation access control practices are described in paragraph 12.3.1.3.2.



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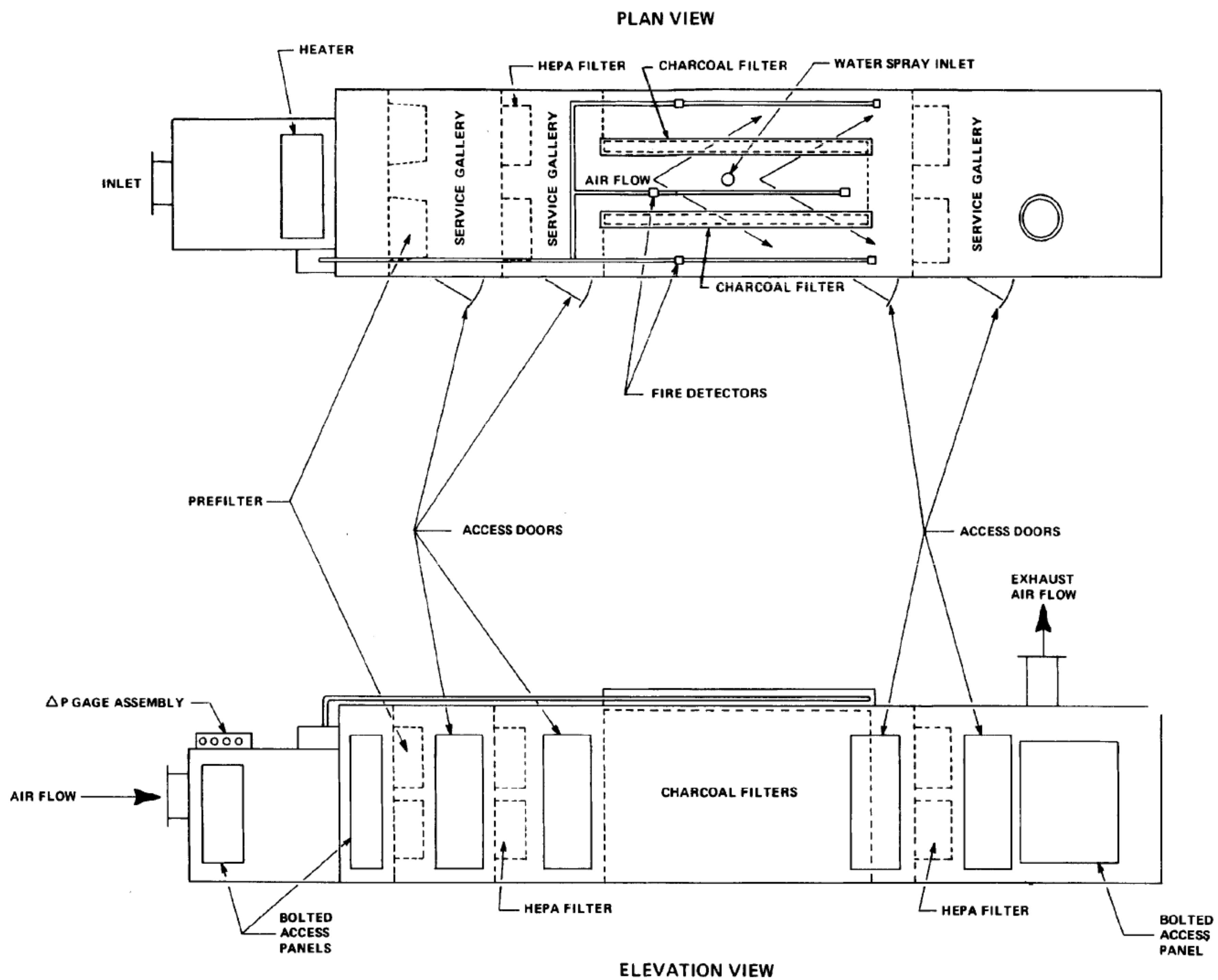
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

REACTOR BUILDING
EXHAUST FILTER TRAIN

FIGURE 12.3-5



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STANDBY GAS TREATMENT FILTER TRAIN

FIGURE 12.3-6

12.4 DOSE ASSESSMENT

This section describes the expected exposure to personnel during operation of HNP-2. Actual exposure records are maintained at the plant site and are reported in the annual report to the Nuclear Regulatory Commission (NRC).

The plant design criteria regarding occupancy of the different control areas are detailed in subsection 12.3.1. The ventilation system, as discussed in subsection 12.3.3, is also designed so normally occupied areas are not contaminated by potential radioactivity from inaccessible areas. Because of the inaccessibility of the high-radiation areas and the planned personnel protection procedures, no excessive radiation exposure to plant personnel is expected.

12.4.1 ESTIMATES OF DIRECT EXPOSURE

A detailed assessment of estimated direct annual exposures to plant personnel is provided in table 12.4-1. Estimates of annual exposures to plant personnel were made by first gauging the annual occupancy time in manhours by plant personnel in each area defined in paragraph 12.3.1.3 and are broken down by various types of work performed. The total annual occupancy time estimates for radiation workers in manhours for various areas were then multiplied by the respective expected average dose rate in mrem/year. The occupational classification, working time, and area distribution bases for table 12.4-1 are provided in table 12.4-2.

Contractor employees were excluded from table 12.4-1. At the time of initial operation of HNP-2, construction work was essentially complete, particularly in the radiation areas. Security personnel, in most instances, are located outside radiation control areas. Clerical and other workers who enter only the service building do not enter any radiation control areas.
Tables 12.4-1 and 12.4-2 were established based on SNC's estimate of occupancy times and dose rate considered to be representative of values which would not be expected to be exceeded during normal operation and maintenance of two boiling water reactors (BWRs) the size of the HNP units.

12.4.2 ESTIMATES OF EXPOSURE DUE TO INHALATION

The annual inhalation doses to occupational workers from airborne concentrations of radioisotopes depends upon their exposure time to specified concentrations in the various regions. Since all accessible regions have airborne concentrations well below 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) limits, annual doses are well within the permissible limits for occupational workers, as specified by 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994). (See subsection 12.2.2.) Expected lung and thyroid rates, expected annual occupancy in manhours with appropriate explanations, and annual mrems for various plant operations in various regions are presented in table 12.4-3.

12.4.3 SITE BOUNDARY AND PLANT AREA DOSE RATES

An evaluation was made of the radiation exposures to individuals from skyshine N-16 activity in the turbine and noble gas activity in the off-gas effluent.

12.4.3.1 Skyshine

The SKYSHINE computer code was used to calculate N-16 radiation exposure at locations at and within the site boundary. The SKYSHINE code permitted modeling the multiple N-16 sources of the turbine. The source strengths of the high-pressure turbine, low-pressure turbine, reheaters, and control intercept valves were calculated from the coolant activity and the source geometry. One energy, 6.2 MeV, was assumed. The walls of the individual sources were modeled as box shields. The turbine and its associated components are considered to be the only significant contributors to direct external exposure. The calculated exposure rates at the visitor center and the closest approach of U.S. Highway No. 1 to the turbine buildings are 8 µR/h and 0.5 µR/h, respectively. These figures represent exposure rates for combined operation of both units at 100% plant capacity.

12.4.3.2 Off-Gas

The off-gas exposure rates were calculated using an off-gas release equivalent to 100,000 µCi/s at 30-min holdup [prior to recombiner charcoal (RECHAR) treatment system]. This results in a release rate of 6900 µCi/s of noble gases to the environment. Estimated release rates are discussed in section 11.3. The calculated exposure rate (at both the visitor center and U.S. Highway No. 1) is ~ 0.16 µR/h. For both iodine and noble gas releases, the calculated thyroid exposure is $< 10^{-3}$ µR/h for either location. Exposures due to off-gas to individuals in the vicinity of the power block are considered negligible.

12.4.3.3 Yearly Doses

The predominant exposure on the site is due to N-16 activity in the turbines. At the site boundary, the off-gas and skyshine contributions to the exposure rate are approximately equal. Beyond the site boundary, the off-gas contribution predominates. A tourist staying at the visitors center for 8 h/year will receive a total dose of < 32 µrem. A camper at the boy scout camp staying once a month for 2 1/2 days (30 days/year) will receive < 372 µrem. Surveys of the radiation levels onsite and offsite, at the maximum hydrogen injection rate, have confirmed that the expected annual exposure is within the limit of 10 CFR 20.1301.

12.4.4 TOTAL ANNUAL EXPOSURE

From tables 12.4-1, 12.4-2, and 12.4-3, the total annual whole-body exposure to plant personnel is estimated to be ~ 469 man-rem/year due to the operation of HNP-1 and HNP-2. Actual data are available from the annual reports to the NRC.

REFERENCES

1. "Occupational Radiation Exposure at Light-Water-Cooled Power Reactors 1969-1974," Radiation Protection Section, Radiological Assessment Branch, Office of Nuclear Reactor Regulation, USNRC, June 1975.

TABLE 12.4-1

ESTIMATED ANNUAL GAMMA DOSE TO PLANT PERSONNEL[a] AND EXPECTED NUMBER OF MANHOURS OF OCCUPANCY PER YEAR

Radiation Zone[d]	Expected Average Dose Rate in Zone (man-rem/h)[b]	Operation	Maintenance	Radwaste Handling	Refueling	Inservice Inspection	Security	Total Annual Manhours	Estimated Annual Exposure (man-rem)[c]
I	0.2	128,400	119,025	13,200	-	22,800	2000	285,425	57
II	1	25,500	43,100	4,600	-	14,700	-	87,900	88
III	6	2,500	7,800	460	600	3,000	-	14,400	86
IV	40	470	1,700	46	200	740	-	3,200	128
V	100	90	700	46	80	200	-	1,100	110
	TOTALS	157,000	172,325	18,400	880	41,400	2000	392,025	469

a Based on 173 plant operating personnel only for two-unit operation (contractors not included).
b. BWR operating experience was used as the basis of dose estimation. D. G. Bridenbaugh, "Operating Maintenance and Inservice Inspection Experience at General Electric BWR Plants," presented at Southeast Electric Exchange Annual Conference Engineering and Operation Division.
c. Startup experience is used. Each individual has about 300-h/year overtime added to a high and conservative total estimated man-rem.
d. Radiation zones shown were those used in initial plant design for access control planning and radiation shielding. Table 12.1-1 provides detailed information relative to current radiation control area classifications. Although a one-to-one correlation does not exist, ALARA considerations are not compromised.

TABLE 12.4-2

PLANT STAFF CLASSIFICATION - WORKING TIME AND ZONE DISTRIBUTION

Classification of Personnel			No.	Category[a]	Working h/year	Percentage of Time Spent in Zone[b] I	II	III	IV	V
A.	Operation									
	1.	Plant staff	12	0	2300	100	-	-	-	-
		Clerk	11	0	2000	100	-	-	-	-
	2.	Reactor operation supervisor	8	0	2100	72	25	2.6	0.35	0.05
		Plant operator	6	0	2100	72	25	2.6	0.35	0.05
		Assistant operator	20	0	2250	72	25	2.6	0.35	0.05
		Equipment operator	10	0	2250	72	25	2.6	0.35	0.05
B.	Health Physics/Chemistry									
	1.	Health physics	6	1	2300	55	37.5	5.0	2.0	0.5
	2.	Chemistry								
		Operation	4	0	2200	80	14	4.0	1.0	0.5
		Inspection	4	I	2300	55	37.5	5.0	2.0	0.5
C.	Maintenance		60	M	2300	69	25	4.5	1.0	0.5
D.	Test Shop									
	1.	Inspection supervisor	2	I	2300	55	33	10.0	1.5	0.5
		Inspection technician	6	I	2300	55	33	10.0	1.5	0.5
	2.	Maintenance supervisor	3	M	2300	69	25	4.5	1.0	0.5
		Maintenance technician	12	M	2300	69	25	4.5	1.0	0.5
E.	Radwaste Handling									
		Assistant operator	8	RH	2300	72	25	2.5	0.25	0.25
F.	Security									
		Security officer	1	S	2000	100	-	-	-	-
G.	Refueling = assume 880 h spent									

a. 0 = operation; M = maintenance; I = inservice; RH = radwaste handling; S = security.

b. Radiation zones shown were those used in initial plant design for access control planning and radiation shielding. Table 12.1-1 provides detailed information relative to current radiation control area classifications. Although a one-to-one correlation does not exist, ALARA considerations are not compromised.

TABLE 12.4-3

ESTIMATED ANNUAL INHALATION DOSES TO PLANT PERSONNEL DUE TO AIRBORNE RADIOACTIVITY

Region	Maximum Lung Dose Rate (rem/h)	Thyroid Dose Rate (rem/h)	Expected No. of Manhours of Occupancy per Year: Operation	Maintenance	Radwaste Handling	Inservice Inspection	Total Annual (manhours)	Annual Exposures: Lung Dose (man-rem)	Thyroid Dose (man-rem)
Reactor bldg (accessible region below refueling floor)	8×10^{-7}	5×10^{-5}	17,000	69,000	--	14,300	100,000	0.08	5.0
Radwaste bldg	2×10^{-8}	1×10^{-6}	1,000	9,000	18,000	3,000	31,000	0.0006	0.03
Turbine bldg	2×10^{-4}	6×10^{-3}	90,000	47,000	--	21,000	158,000	30.0	950.0

12.5 HEALTH PHYSICS/CHEMISTRY PROGRAM

12.5.1 ORGANIZATION

The basic objective of the plant health physics program is to protect individuals from exposure to radiation and radioactive material. Specifically, the health physics program consists of rules, practices, and procedures (described in subsections 12.1.3 and 13.5.10) which keep doses to individuals in restricted areas of the plant to levels that are as low as reasonably achievable (ALARA) and within the limits set forth in Title 10 Code of Federal Regulations (CFR) Part 20.1001 - 20.2401.

Responsibility for the operation of the health physics program at the plant is delegated to the plant Health Physics Department. This does not preclude the overall radiological safety responsibility of the plant manager. Responsibilities of the health physics staff and plant supervisors relative to radiation protection are given in subsection 12.1.1. The Plant Hatch Health Physics Department consists of the health physics superintendent/manager, health physics support supervisor, health physics foremen, plant health physicist, nuclear specialists, and health physics technicians.

The health physics superintendent/manager has functional control of, and is responsible for, establishing the health physics program. He has the responsibility for ensuring the ALARA policy is implemented. The health physics support supervisor has at least 5 years responsible professional experience in health physics or nuclear engineering and a baccalaureate degree in science or engineering or its equivalent.

In all cases, radiation monitoring and control practices are such that resultant radiation exposures and releases to unrestricted areas are maintained ALARA. Records of surveys, radiation monitoring, and disposal are maintained in accordance with the requirements of 10 CFR 20.2101 - 20.2110. The American National Standards Institute (ANSI) Standard N13.2-1969, Guide for Administrative Practices in Radiation Monitoring, was used in general guidance toward establishing adequate radiation monitoring programs.

Plant management is committed to the concept of and stresses maintaining exposures ALARA.

The chemistry manager has functional control of, and is responsible for establishing, the chemistry program. The Plant Hatch Chemistry Department consists of the chemistry manager, chemistry support supervisor, chemistry foremen, plant chemist, nuclear specialists, and chemistry technicians.

12.5.2 EQUIPMENT, INSTRUMENTATION, AND FACILITIES

12.5.2.1 Facilities

The health physics/chemistry facilities include the offices of the health physics superintendent/manager, the chemistry manager, and the health physics/chemistry support

supervisors, and the health physics office/technician area and ALARA office located in the service building; the health physics satellite/chemistry offices and laboratory located in the control building at el 130 ft (drawing no. H-15852); and the calibration room located between the HNP-1 turbine and radwaste buildings (figure 12.5-1). A counting room, cold chemistry, and radiochemistry laboratory all form the chemical radiation laboratory. The calibration room contains facilities for storing radioactive calibration sources and instruments undergoing calibration or repair and an area for maintenance of radiation instruments. The major calibration sources, which are housed in the Shepard Calibrator, are two Cs-137 sources of 400 Ci and 130 mCi, respectively. This calibrator is located in the health physics instrument office. Calibration sources are secured from unauthorized use by a lock on the source container. Small check sources and calibration sources used in counting room instrument calibration are secured inside locked cabinets or boxes in the radiochemistry laboratory and health physics office. The health physics office, located in the Unit 1 service building 130-ft elevation near the entrance to the RCA, houses the health physics foremen work area and the technician's assembly area. The health physics satellite office is located between the control, reactor, and turbine buildings so that health physics services, respiratory equipment, and personnel decontamination may be conveniently provided for those who enter and leave this area. The personnel decontamination sink and hot shower are conveniently located adjacent to the health physics satellite office. This facility is used primarily during periods of extensive in-plant work activities, refueling outages, and plant emergency situations.

In addition to the facilities above, there are frisking stations located throughout the operating buildings for contamination control. The health physics policy is to contain radioactive contamination and prevent its spread. Therefore, where entry into contaminated areas is required, stepoff pad zones are established at the entrance to each affected area. (See paragraph 12.5.3.5.) Stepoff pad areas are located between the contaminated area and the clean area. At the stepoff pad, drums or bag racks are provided for depositing contaminated or potentially contaminated clothing after removal, using the stepoff pad undressing procedure. When full, the drums or bag racks are sealed shut, removed, surveyed, and stored in the laundry storage area prior to being shipped to an offsite vendor for cleaning.

Normal access to the reactor, turbine, radwaste, and control buildings is through a corridor from the service building into the control building at el 130 ft (figure 12.3-2). Access is limited to authorized personnel only by the use of the locked door or security guard at the doorway to the control building. Access through any exterior doors of these buildings is controlled by locked doors and security precautions.

Access into radiation control areas; i.e., high/very high radiation areas as designated by 10 CFR 20.1001 - 20.2401 requirements, requires clearance through the health physics office.

Prior to entering a radiation control area (high/very high radiation), a worker must secure a radiation work permit (RWP) approved by a health physics foreman or higher authority. The normal procedure a worker adheres to when entering areas involving potential contamination is as follows:

A. An RWP is issued as described in paragraph 12.5.3.3.

B. Upon accessing the computer system, the worker must read the RWP and acknowledge that he/she has read and understands the requirements set forth by the RWP. If the computer system is down, this process may be done manually.

C. The worker proceeds to the dressout area where protective clothing is obtained.

Additional dosimeters and/or respirators, if required by the RWP, are normally obtained at the health physics office. However, during outage conditions, required dosimetry and respirators are also obtained at the field dressout area.

A worker returning to the clean area removes all potentially contaminated clothing prior to crossing the contaminated area boundary onto the clean area stepoff pad.

If the individual is found contaminated upon performing a whole-body frisk, health physics is notified, and the worker is decontaminated in the health physics area of the control building where decon shower and sink are provided. Alternate decontamination stations may be authorized, particularly during outage periods. After the personal survey is complete, the worker may don his/her personal clothing.

By use of the above procedure for ingress and egress from contaminated areas, the spread of contamination is minimized, since workers wearing uncontained contaminated clothing or carrying uncontained contaminated equipment are not allowed in clean areas of the plant. (See paragraph 12.1.3.2.)

All personnel entering areas of potential contamination are required to follow the above process. These workers include construction and contract workers, SNC employees, and visitors. Personnel who have not received health physics orientation must be escorted by a trained individual who understands the process for entering these areas.

Personnel exiting the operating buildings are required to monitor themselves for radioactive contamination using contamination monitoring instrumentation provided at that location.

In addition to the monitors provided above, there are frisking stations at locations throughout the plant area, requiring personnel use, to minimize the spread of contamination and personnel exposure.

12.5.2.2 Respiratory Equipment

Respiratory equipment is required in areas in which airborne radioactive material exceeds those concentrations given in 10 CFR 20.1001 - 20.2401, Appendix B, table I, column 3, if the use of such equipment is consistent with maintaining total effective dose equivalent ALARA. The following respiratory devices are available at the plant:

- Full-face and half-face masks with high-efficiency particulate filters.

- Full-face masks with air line respirator.

- Hoods and suits with air line respirator.
- Full-face masks with self-contained breathing apparatus with 30- and 45-min air bottles.

A description of the respiratory protection program is presented in paragraph 12.5.3.6.

12.5.2.3 Protective Clothing

Protective clothing is required in contaminated areas or in areas in which the potential for radioactive material contamination exists. Examples of protective clothing available at the plant are listed below:

- Coveralls.
- Laboratory coats.
- Plastic suits.
- Cloth or plastic hoods.
- Plastic or rubber shoe covers.
- Rubber boots.
- Plastic, rubber, and cotton gloves.

12.5.2.4 Portable Instrumentation

The majority of the inservice portable health physics instrumentation is located in the control building in the health physics office. For purposes of emergency monitoring, instruments are kept in emergency operating facilities. A list/description of the portable health physics instruments is given in table 12.5-1.

The plant Health Physics Department is responsible for writing and implementing calibration and maintenance procedures for this equipment. Detailed records on the maintenance and calibration of this instrumentation are maintained at the plant. Calibration is performed using sources of known strength purchased from the National Institute of Standards and Technology (NIST) or other reputable vendors and/or using reference instruments calibrated traceable to the NIST. Health physics technicians calibrate and perform maintenance on portable health physics instrumentation when required. Calibration is also performed after a piece of equipment has undergone repair work that would alter the calibration.

12.5.2.5 Laboratory Equipment

Fixed laboratory counting instrumentation is located in the health physics office and chemistry counting room. A list of this equipment, including location and description, is given in table 12.5-2.

The plant health physics staff is responsible for writing and implementing calibration and maintenance procedures for this equipment. Detailed records on the maintenance and calibration of this instrumentation are maintained at the plant. Calibration is performed using sources of known strength purchased from the NIST or other reputable vendors and/or using reference instruments calibrated traceable to the NIST. Health physics technicians calibrate and perform monthly preventive maintenance on fixed laboratory instrumentation or as required. Calibration is also performed after a piece of equipment has undergone repair work. Although the equipment and instrumentation listed in tables 12.5-1 and 12.5-2 have been purchased, should more suitable material become available, it will be purchased in lieu of that listed. Location of the calibration room is shown on drawing no. H-15852.

12.5.2.6 Personnel Radiation Monitoring Instrumentation

Personnel radiation monitoring instrumentation includes:

- Thermoluminescent dosimeter with a range of 0.010 to 1000 rem.
- Digital alarming dosimeters.

12.5.2.7 Emergency Instrumentation

Portable instruments are kept in the control room, health physics office, and in emergency kits for access in the event of an emergency. The following instruments are rotated with plant instruments to ensure their proper functioning:

- A wide-range ionization chamber detector capable of measuring radiation fields from 2 to 50 rem/h.
- A portable Geiger-Mueller-type instrument to detect low-level contamination.
- A battery-operated air sampler.
- Self-reading dosimeters with ranges of 0 to 1678 rem.

12.5.3 PROCEDURES

Strict adherence to the Units 1 and 2 radiation protection procedures ensures personnel radiation exposures are both ALARA and within the limits of 10 CFR 20.1001 - 20.2401. The

specific procedures implemented for minimizing personnel exposures are detailed in subsection 13.5.10. Policy and operational considerations for radiation protection are set forth in subsections 12.1.1 and 12.1.3. A general discussion of radiation protection practices is given in this section.

12.5.3.1 Radiation Surveys

Health physics personnel (health physics technicians) perform routine radiation surveys of all accessible areas of the plant. Radiation surveys are performed on a frequency varying from weekly to annually, depending on the area of the plant in question. These surveys consist of wipe tests, air samples, and external radiation measurements as appropriate for the specific area. Additionally, specific surveys may be performed before, during, and after operational and maintenance functions, involving potential exposure of personnel to radiation or radioactive materials.

Any area found contaminated is roped off or otherwise delineated with a physical barrier, posted with appropriate signs, and decontaminated as soon as practical. Temporary shielding is provided where necessary to reduce external personnel exposures during operational and maintenance activities in radiation, high radiation, and very high radiation areas. Each activity in these areas requires a specific evaluation of dose rates, job complexity (number of people and overall time required), available space, and time required to place and remove temporary shielding. For these reasons, the use of temporary shielding is determined by the health physics superintendent/manager or designee on a case-by-case basis rather than at a specific dose rate action level.

12.5.3.2 Personnel Dosimetry

Plant employees, visitors, and support personnel are required to wear a self-reading dosimeter and thermoluminescent dosimeter (TLD) badge while in a restricted area. (Some visitors may be exempted from this requirement.) Plant personnel normally obtain electronic dosimetry at radiation control area entry/exit locations. Visitors and support personnel normally obtain personal dosimetry at the dosimetry office located in the service building. Only individuals who have completed training in radiation protection and emergency procedures are authorized to enter restricted areas unescorted. When entering the protected area, visitors and other persons who have not completed training obtain an escort trained in these procedures prior to entering a restricted area. TLDs are processed by the GPC Central Laboratory on a frequency determined by SNC. Personnel dosimeters are read daily for each individual who entered a restricted area. During outages, refueling, or when an individual's exposure is in doubt, some TLD badges may be read more frequently than others. TLD badge readings are recorded by plant personnel or via electronic file transfer.

A computerized exposure control program is utilized for controlling and reducing exposure. The daily personnel dosimeter readings are entered into a computer, updating each worker's exposure computer file. Access control software identifies workers who are approaching a marginal limit and restricts their access. In the absence of access control software, a report identifying individuals nearing limits can be generated. Health Physics uses this report to

restrict workers, where practical, from exceeding the allowed limit. The daily computer report lists information as on Form Nuclear Regulatory Commission (NRC)-5. Health Physics uses the report to plan future maintenance and operating work for minimizing exposure.

Each member of the normal plant operating organization who may be exposed to airborne radioactivity typically receives a baseline whole-body count prior to entering a restricted area for the first time. Additional whole-body counts and/or bioassays are performed on an individual basis as necessary. These special individual measurements are initiated when the results of monitoring in the workplace indicate significant intakes may have occurred or when workers have been associated with known accidents possibly involving significant intakes of radioactivity. Air monitoring and surface contamination tests in the workplace, and tests of skin contamination, nose blows, and nasal smears are used for determining whether special measurements are required. An investigation level of 4 derived air concentration hours/week is established for providing additional bioassay and/or whole-body counting.

Exposure data of all personnel are collected and recorded on Form NRC-5, Current Occupational External Radiation Exposure, or the equivalent. Every reasonable effort is made to obtain occupational exposures incurred by individuals prior to working at the Edwin I. Hatch Nuclear Plant (HNP). When provided, this exposure history is summarized on Form NRC-4, Occupational External Radiation Exposure History, or the equivalent. These records are maintained at the plant and preserved indefinitely or until the NRC authorizes their disposal pursuant to 10 CFR 20.2106. Reports of overexposure to radiation workers are made to the NRC pursuant to 10 CFR 20.2202 - 20.2203.

12.5.3.3 Radiation Work Permits

As stated in paragraph 12.1.3.1, RWPs are issued by the health physics staff prior to allowing most work to be performed in radiation control areas. The health physics superintendent/manager has direct management responsibility for the issuance of RWPs. No RWPs are issued without proper health physics approval which includes a review by an ALARA representative and a health physics foreman (or designated alternate), or higher authority. RWPs state protective clothing requirements, monitoring requirements, and any special instructions or cautions pertinent to radiation hazards. These permits ensure all work is performed in a radiologically safe manner. Violations of permits are reported to management. Repeated, willful violations are cause for disciplinary action.

12.5.3.4 Radiation Protection Training

Each member of the permanent operating organization whose duties entail entering restricted areas or directing the activities of others who enter restricted areas is instructed in the fundamentals of health physics.

Training in radiation procedures associated with general employees is conducted following employment or transfer to Plant Hatch. Employee comprehension is evaluated by written test. Employees assigned a “Protected Area Only” badge may attend radiation protection lectures but are not required to take a test on radiation protection training.

Personnel whose duties do not entail entering restricted areas are made aware of the reasons for not entering these areas. The training program includes instruction in applicable provisions of the NRC's regulations for the protection of personnel from exposures to radiation or radioactive material. These instructions are provided pursuant to 10 CFR 19.12. Radiation exposure data for an individual and the results of any measurements, analyses, and calculations of radioactive material deposited or retained in the body of an individual are reported to the individual as specified in 10 CFR 19.13.

12.5.3.5 Contamination Control

Contamination of plant noncontaminated areas by movement of personnel between contaminated and noncontaminated areas is controlled by using the stepoff pad technique. Bags or other approved wrapping material are normally used to carry contaminated tools and equipment from an area. Portal monitors and Geiger-Mueller count-rate meters (friskers) are located at major dress/undress areas so personnel can survey themselves to determine whether they are contaminated. Additional portal monitors and friskers are located at the exits of controlled areas of the plant.

The plant ventilation systems (section 9.4 and subsection 12.3.3) provide a means of purging areas of the reactor and control buildings to minimize the accumulation of airborne radioactive materials. Airflow is always directed from normally occupied or routinely accessed areas of low potential contamination to areas of higher potential contamination. Airborne contamination is minimized by keeping loose contamination levels low and reducing sources of leakage as much as is practical. The ventilation airflow prevents the buildup of air contamination concentrations.

Special coatings applied to the floors and walls of areas containing radioactive fluids, together with a system of floor drains and hose washdown stations, permit effective area decontamination. In addition, equipment vents and drains are piped directly to collection devices to prevent radioactive fluids from flowing across the floor to drains.

Contamination of personnel entering contaminated areas is minimized by the use of protective clothing, such as lab coats, coveralls, gloves, plastic suits, shoe covers, and hoods. In most cases where protective clothing is worn, a stepoff pad is used.

Normally, most of the plant is accessible to personnel in street clothes. Friskers are used to verify absence of personnel contamination.

Available respiratory equipment is identified in subsection 12.5.2.

12.5.3.6 Respiratory Protection

If personnel entry is required into areas where the source of airborne radioactivity cannot be removed or controlled to levels below the limits of 10 CFR 20.1001 - 20.2401, Appendix B, table I, column 3, either occupancy is restricted and/or respiratory protection equipment is provided as necessary to maintain total effective dose equivalent ALARA and within the limits of 10 CFR 20.1201 - 20.1208. Also, certain operations or maintenance work may require

respiratory protection as a precautionary measure. Such operations as welding, cutting and grinding on contaminated parts, repacking of valves used in radioactive water and steam lines, opening contaminated equipment lines and parts, and performing maintenance in highly contaminated areas suggest use of respiratory equipment for protection. When airborne radioactivity is detected in excess of the levels that define an airborne radioactivity area in 10 CFR 20.1003, the area is posted as an airborne radioactivity area, and access is controlled. Entry into these areas requires the issuance of an RWP. The use of an RWP (paragraph 12.5.3.3) provides radiation exposure control by controlling and recording conditions under which work in airborne radiation areas is performed. Air sampling techniques are used to ensure appropriate respiratory protective equipment is specified on the RWP. Selection of the appropriate type of respiratory equipment is then determined. The respiratory protection program is organized to conform to the applicable portions of ANSI Standard Z88.2-1969 in an effort to ensure the effectiveness of respiratory equipment. Whole-body counting, bioassay analysis, nasal smears, or facepiece interior smears may be performed to evaluate the protection afforded.

Respiratory equipment may be obtained in the health physics office on the ground floor (el 130 ft) of the control building. Respirators may also be issued at major dressout areas during controlled situations. Supplementary emergency respiratory equipment is available in the control room and some emergency locations. Available respiratory equipment includes full-face masks and self-contained breathing equipment.

To ensure an adequate program for respiratory protection, the following controls are incorporated into the program:

A. Each respirator user is advised that he/she may leave a high airborne radioactivity area for psychological or physical relief from respirator use. Each user must leave the area in the case of respirator malfunction or any other condition that might cause reduction in the protection afforded the user.

B. Sufficient air samples and surveys are made to identify the various forms and types of nuclides present and to estimate the individual exposures so that selection of appropriate respiratory equipment can be made.

C. Training procedures are established to ensure correct fittings, use, maintenance, and cleaning of the various types of respiratory equipment. Each employee is individually fitted prior to each required use.

   The fitting procedure consists of the following steps:

   1. Don the mask.

   2. Adjust straps for tight, comfortable fit.

   3. Block intake opening.

   4. Inhale gently to form a vacuum-pressure seal around face.

5. Hold breath and maintain seal for 10 s.

6. If seal is lost, readjust straps and repeat until seal is maintained for a minimum of 10 s.

D. Cleaning and sanitizing of masks are performed as described in ANSI Standard Z88.2-1969, using a cleaner sanitizer solution. Each respirator is inspected routinely before and after each use. Respirators stored for emergency use are inspected each month. Inspections conform to ANSI Standard Z88.2-1969. Replacement of components or repairs are done only by experienced persons with parts designed for the respirator. No attempt is made to replace components or make adjustments or repairs beyond the manufacturer's recommendations.

E. Each member of the normal plant operating organization who may have been exposed to airborne radioactivity normally receives a bioassay measurement as appropriate. Additional whole-body counts and/or bioassays are performed on an individual basis as necessary.

12.5.3.7 Radioactive Material Safety Program (HNP-1 and HNP-2)

Equipment and fluids in certain plant systems become radioactive during normal plant operation. These radioactively contaminated material and fluids, together with radioactive material contained in new fuel, spent fuel, neutron startup sources, and instrument calibration devices can result in the radiation exposure to plant personnel. Procedures, facilities, and equipment for remote handling and processing of radioactive liquid, gaseous, and solid wastes are described in HNP-1-FSAR chapter 9 and section 12.7, and in HNP-2-FSAR chapters 11 and 12. Procedures, facilities, and equipment for the safe handling and storage of new-fuel assemblies and spent-fuel assemblies are described in section 9.1.

Various types and quantities of radioactive sources (subsection 12.2.1) are employed to calibrate the process and effluent radiation monitors described in HNP-1-FSAR section 7.12, and in HNP-2-FSAR section 11.4, the area radiation monitors described in HNP-1-FSAR section 7.13, and in HNP-2-FSAR subsection 12.3.4, and the portable and laboratory radiation detectors described in subsection 12.5.2. Check sources that are integral to the area, process, and effluent monitors may consist of exempt quantities of byproduct material isotopes and do not require special handling, storage, or use procedures for radiation protection purposes if the sources are exempt quantities. The same consideration applies to solid and liquid radionuclide sources of exempt quantities used to calibrate or check the portable and laboratory radiation measurement instruments.

Recognized methods for the safe handling of radioactive material, such as those recommended by the National Council of Radiation Protection and Measurements, are implemented to maintain potential external and internal doses at levels that are ALARA. External doses are minimized by a combination of time, distance, and shielding considerations. Internal doses are minimized by the measurement and control of loose contamination. The handling of licensed material is addressed in the plant radiation protection procedures.

Sealed radionuclide sources having activities greater than the quantities of radionuclides defined in Appendix C to 10 CFR 20.1001 - 20.2401 and Schedule B of 10 CFR 30 are subject to material controls for radiological protection. The controls include:

- Monitoring of all packages containing radioactive material for external dose rate and removable contamination is required upon receipt at the plant and prior to shipment away from the plant. If incoming packages are found to have removable surface contamination, the transport vehicle is monitored.

- Monitoring of each source for removable surface contamination (leakage testing) at 6-month intervals. Excluded are sealed sources of ≤ 100 mCi of beta and/or gamma emitting material and ≤ 10 mCi of alpha emitting materials.

- Labeling of each source with the radiation symbol, stating the activity, isotope, and source identification number.

- Storing each source that is not installed in an instrument or other piece of equipment in a locked area.

- Inventorying of all sources every 6 months.

- Maintaining records on the results of inventories, leakage tests, use, location, condition, principal user, and the receipt and final disposition dates for all sources.

Additional details of the materials safety program are provided in the plant radiation protection procedures.

The laboratory facilities and equipment contained therein for handling radioactive material are described in detail in subsection 12.5.2. Equipment and facilities for the sampling of radioactive liquids and gases are described in HNP-1-FSAR section 10.14, and in HNP-2-FSAR subsection 9.3.2. The area radiation monitoring and the process and effluent monitoring systems are detailed in HNP-1-FSAR section 7.12, and HNP-2-FSAR section 11.4; and in HNP-1-FSAR section 7.13, and HNP-2-FSAR subsection 12.3.4, respectively. Health physics radiation protection instrumentation is described in subsection 12.5.2.

Radioactive sources subject to the material controls described herein are used or handled only by or under the direction of plant health physics personnel. Each individual using these sources is familiar with the radiological restrictions and limitations placed on their use. These limitations protect both the user and the source. RWPs, described in paragraph 12.5.3.3, provide detailed instructions for all work in radiation, high radiation, very high radiation, and airborne radioactivity areas. The experience, qualifications, and training programs for personnel responsible for handling and monitoring radioactive material are described in paragraph 12.5.3.4, and sections 13.1 and 13.2.

Considerable time and effort are devoted to ensure employees understand radiation and radiation protection as it applies to their work. Supervisors are responsible for ensuring their employees follow proper radiation protection procedures. The amount and type of training

depends on the kind of work they perform and the area in which the work is performed. Orientation lectures on radiation and radiation protection are given to all new employees entering controlled access areas of the plant. Training continues with detailed discussions of the specific radiological hazards associated with work assignments. In the course of their work, employees receive additional training in radiation protection practices from supervisors, senior coworkers, and health physics personnel.

A listing of isotopes, quantities, forms, and uses for byproduct, source, and special nuclear materials is provided in subsection 12.2.1.

REFERENCES

1. "Final Environmental Statement Concerning Proposed Rule Making Action: Numerical Guides for Design Objective and Limiting Conditions for Operation to Meet the Criterion 'As Low As Practicable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," Vol 2, Analytical Models and Calculations, WASH-1258, USAEC, July 1973.

2. Smith, James M., "Noble Gas Experience in Boiling Water Reactors," Paper No. A-54 presented at Noble Gases Symposium, Las Vegas, Nevada, September 24, 1974.

TABLE 12.5-1 (SHEET 1 OF 3)

PORTABLE HEALTH PHYSICS INSTRUMENTS[a]

Instrument	Radiation Detected	Accuracy	Range	Remarks
GM[b] survey meter	Beta-Gamma	± 10% of full scale	0.1 mrem/h to 1000 R/h	Probe extendable to 13 ft and retractable to 20 in.; dose rate instrument
GM survey meter (frisker)	Beta-Gamma	± 10% of full scale	0 to 50,000 cpm	Count rate instrument with alarm; personnel survey instrument
Alpha survey meter	Alpha	± 10% of full scale	0 to 500,000 cpm	Gas flow proportional
Neutron survey meter	Neutrons	See remarks.	0 to 5,000 mrem/h	Provides dose rate in mrem/h for neutrons with energies between 0.025 MeV and 10 MeV; directional response ± 10%, energy response ± 15%; scale linearity ± 10%
Personnel dosimeters	Gamma	± 20% of reading	0 to 1678 rem	Integrates direct reading; capable of displaying accumulated dose and dose rate
Continuous air monitors	Beta-Gamma	± 10% of reading	0 to 100,000 cpm	Alarms on high airborne count rate; continuous recording of airborne activity
Gas flow proportional survey meter (frisker)	Beta-Gamma	± 10% of full scale	0 to 500,000 cpm	Count rate instrument with alarm; personal survey instrument with 100-cm^2 probe
Ion chamber survey meter	Beta-Gamma	± 20% of reading	0 to 50 rem/h	Air-filled chamber dose rate instrument
Ion chamber survey meter	Beta-Gamma	± 20% of reading	0 to 199 rem/h	Air-filled chamber dose rate instrument

a. These instruments were purchased initially for startup. Other types or numbers of instruments may now be in use.
b. GM - Geiger-Mueller.

TABLE 12.5-1 (SHEET 2 OF 3)

Instrument	Radiation Detected	Accuracy	Range	Remarks
Ion chamber underwater	Gamma	± 20% of reading (5% correction stainless shielding)	Up to 1.99 rem/h; 199 rem/h; 19 krem/h	Three detectors; low, mid, and high; stainless-steel shielding, and cable (60 ft)
Continuous air monitor	Beta-Gamma	± 20% of reading	Count rate converted to µci/cc	Monitors airborne activity in µci/cc. Reports particulate, iodine, and noble gas activity
Digital meter underwater	Gamma	± 10% of reading	0 to 300 rem/h	Digital readout above water; dosimeter encased underwater
Scintillation dose rate meter	Gamma	± 20% of reading	0 to 3 mrem/h	Na I detector; low dose rate application
Lapel air sampler	NA	Flowrate ± 20%	Sample flowrate; ~ 4000 cc/min	Breathing zone air sampler
Portable air sampler	NA	Calibrated to 3 ft^3/min	Sample flowrate; ~ 85 liters/min	Higher volume air sampler
Air analyzer	NA	O_2 = (16.2% - 26%) combined gas = (21.3% - 44%)	NA	Oxygen and combustible gas meter with alarms
Regulated air sampler	NA	Calibrated with merriam flow meter; correction factor used	Up to 60 lpm depending on condition of motor	Pulls sample for 24-h high-volume representation
Personnel contamination monitor	Beta-Gamma	Capable of monitoring from 3100 to 5000 dpm	NA	Gas flow proportional detector; micro-processor based unit
Portal contamination monitor	Beta-Gamma	Capable of monitoring from 5000 to 7500 dpm	NA	Gas flow proportional detector; micro-processor based unit

TABLE 12.5-1 (SHEET 3 OF 3)

Instrument	Radiation Detected	Accuracy	Range	Remarks
Article monitor	Gamma	Capable of monitoring down to 5000 dpm	NA	Plastic scintillation detector; microprocessor based unit
Continuous air monitor	Beta-Gamma	± 20% of reading	Count rate converted to μci/cc	Gas-sealed proportional detector
Area radiation monitor	Gamma	± 20% of reading	0.1 mrem/h to 10,000 mrem/h	GM detector
Automated materials frisker	Beta-Gamma	Capable of monitoring down to 5000 dpm	NA	Gas flow proportional detector; microprocessor based unit
High-pressure ion chamber	Gamma	Capable of monitoring to environmental levels	0 – 100 mrem/h	Chamber pressurized to 25 atm.

TABLE 12.5-2

FIXED LABORATORY INSTRUMENTS[a]

Instrument	Radiation Detected	Accuracy	Range	Remarks
GM counter	Beta-Gamma	12 - 14% Beta[b] ~ 1% Gamma[b]	NA	Automatic changer counting system or single sample scaler counter
Well counter	Gamma	7 - 10%[b]	NA	Gross counter; sodium iodide detector
Gamma spectrometer	Gamma	One = 40%[b] Two = 15%[b] Three = 20%[b]	0 – 2 MeV	Six GE (Li) detectors each connected to a gamma spectrometer. The six spectrometers are interfaced to a computer system for isotopic identification and data calculations.

a. Instruments may be added or deleted based upon plant need.
b. Approximate figure.

13.0 CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE (HNP-1 AND HNP-2)

13.1.1 CORPORATE ORGANIZATION

This section provides information concerning corporate organization, functions, responsibilities, and participation in the facility design, design review, design approval, construction management, testing, and operation of the plant. Southern Nuclear Operating Company (SNC) is responsible for directing activities at Hatch Nuclear Plant (HNP). The corporate organization functions in a support role to the HNP.

13.1.1.1 Corporate Functions, Responsibilities, and Authorities

The major corporations engaged by SNC for support services in the design, construction, quality assurance (QA), testing, and operation of HNP are:

- Southern Company Services, Inc. (SCS), Birmingham, Alabama.
- Bechtel Power Corporation (BPC), Frederick, Maryland.
- General Electric (GE), San Jose, California.

The functions and responsibilities of each organization are described in chapter 1. SNC technical qualifications are described in paragraph 13.1.1.2.

13.1.1.2 Corporate Management and Technical Support

The nuclear operations organization (figure 13.1-1), under the management of the president and CEO, has direct responsibility for the operation and maintenance of the SNC nuclear plants. The president and CEO reports to the SNC Board of Directors.

Both HNP units are in the operations phase and have been for several years. SNC is responsible for assuring the availability of and providing or securing technical support for HNP. Support capability has been available through the joint efforts of the SNC nuclear support (Hatch) general office staff and Southern Company Services (SCS) architect-engineering and service company. As a result of the consolidation of SCS and SNC nuclear expertise, and in addition to being the licensee, SNC also serves as its own architect/engineer and performs the functions previously performed by SCS. BPC and GE are also subcontracted for engineering work, as required, to maintain proper technical support to SNC. Support activities normally include the following:

A. Services required for the design engineering of plant modifications, including maintenance-related design changes, plant improvement-related design changes, and design changes or major plant additions as a result of new regulatory requirements and commitments. These services include both conceptual and detail design, issuance and maintenance of design drawings and specifications, review/approval of design change requests, incorporation of as-built notices, related quality assurance functions, etc.

B. Design-related evaluation and analysis.

C. Evaluation and analysis which are not directly related to design, for example, with respect to operational requirements, Technical Specifications changes.

D. Inservice inspection and testing.

E. Nuclear fuel procurement.

F. Nuclear fuel core analysis.

G. Evaluations on licensing issues.

H. Plant chemistry support.

I. Maintenance support.

GPC organizations provide limited support to HNP, as requested, in the areas of motor repair and environmental affairs.

Environmental radiological and nonradiological technical support are provided under the direction of the vice president and general counsel (paragraph 13.1.1.4.6).

13.1.1.3 Interrelationships with Contractors and Suppliers

13.1.1.3.1 Design Stage

General Electric and BPC were delegated the responsibility for design of the nuclear steam supply system (NSSS) and the balance of the plant, respectively, with GPC providing oversight. For preparation of the Final Safety Analysis Report (FSAR), all parties (GPC, SCS, BPC, and GE) were involved in the preparation and review of design bases and philosophies of both systems and structures. The intent of this review was to contribute as much expertise as possible to the plant design.

13.1.1.3.2 Procurement Stage

A. GE Scope of Supply

All items within the GE scope of supply were the sole responsibility of GE. However, GPC was responsible, with appropriate inputs from GE, BPC, and SCS, for ensuring all items contributed to a licensable plant.

B. BPC Scope of Supply

For the equipment under the BPC scope of supply, procurement procedures were established to require GPC, BPC, and SCS participation. BPC prepared the inquiries and transmitted them to GPC and SCS for approval, allowing for review to ascertain whether sufficient information was contained to inform the bidders of all requirements for the supplied equipment including, but not limited to, material, documentation, and shipping requirements. From this point, BPC had the responsibility of sending the inquiry out for bids in accordance with a bidders list supplied by GPC. After review of the bids, requisition preparation by BPC, and approval by GPC, the purchase order was prepared by GPC.

13.1.1.3.3 Construction Stage

All construction activities at the site were under the supervision of GPC. Independent testing agencies were contracted as necessary to perform special testing and provided expertise in the interpretation of results.

13.1.1.3.4 Operating Stage

Georgia Power Company initially had the responsibility for the operation of HNP. Effective March 22, 1997, SNC is the exclusive operating licensee of HNP.

13.1.1.4 Nuclear Operations Organization

The nuclear operations organization, under the supervision of the president and CEO, has direct responsibility for the operation and maintenance of Southern Company's nuclear plants. The nuclear operations organization consists of the plant operating staff and corporate management, planning and performance, and quality assurance. Engineering support is provided primarily by the corporate and site engineering organizations as described herein.

As shown on figures 13.1-1 and 13.1-2, the president and CEO, executive vice president/chief nuclear officer (CNO), and vice president-Hatch provide line management direction for the operation of the plant.

The structure of the nuclear operations organization is described in the following paragraphs. Portions of the SNC Fleet Operations Support, Engineering, General Counsel and External Affairs, and Human Resources organizations are also described in the following paragraphs.

13.1.1.4.1 President and Chief Executive Officer (CEO)

The president and CEO is responsible for all aspects of operation of Southern Company's nuclear plants, including employment decisions. The president/CEO is also responsible for all technical and administrative support activities provided by SNC and nonaffiliated contractors. The president and CEO directs the executive vice president/CNO and the vice president and general counsel in fulfillment of their responsibilities. The president/CEO reports to the Board of Directors with respect to all matters.

13.1.1.4.2 Chief Nuclear Officer (CNO)

The executive vice president/CNO reports to the president/CEO. This individual is responsible for the safe, reliable, and efficient operation of HNP, the Joseph M. Farley Nuclear Plant (FNP), and the Vogtle Electric Generating Plant (VEGP). The executive vice president/CNO directs the efforts of the vice president-Hatch, the vice president-Vogtle, the vice president-Farley, the vice president-engineering, the vice president-nuclear oversight, and the vice president-fleet operations support.

13.1.1.4.2.1 **<u>Vice President-Nuclear Oversight</u>.** The vice president-nuclear oversight reports to the executive vice president/CNO. This individual is responsible for SNC nuclear oversight activities using staffs located at corporate headquarters and at each of the operating plants. Activities include performance of independent assessments and verification of QA program implementation in accordance with regulatory commitments. The vice president-nuclear oversight directs the nuclear oversight manager.

13.1.1.4.2.1 **<u>Nuclear Oversight Manager</u>**. The nuclear oversight manager is the senior manager responsible for quality assurance described in the SNC Quality Assurance Topical Report (QATR). The nuclear oversight manager reports to the vice president-nuclear oversight. The nuclear oversight manager is responsible for implementation of the QA program for design, testing, operation, and maintenance in accordance with the requirements of the QATR. In addition, the nuclear oversight manager is responsible for managing independent assessments. The nuclear oversight organization is composed of a staff at the corporate headquarters and a staff at each SNC-operated plant.

The nuclear oversight organization does not provide technical support (as defined in subsection 13.1.1 of Regulatory Guide 1.70) for the operation of HNP. The activities of the nuclear oversight organization are fully described in the QATR.

13.1.1.4.2.2 Vice President-Fleet Operations Support. The vice president-fleet operations support reports to the executive vice president/CNO and is responsible for identifying and resolving fleet issues and utilizing trends, operating experience, and industry best practices to improve fleet performance. The vice president-fleet operations support directs the fleet operations manager, the fleet maintenance manager, the fleet work management director, the fleet training manager, the fleet support manager, and the environmental affairs, chemistry and radiological services manager. In addition, the vice president-fleet operations support provides direction to the information technology manager.

13.1.1.4.2.2.1 Fleet Operations Manager. The fleet operations manger is responsible for overall governance, oversight, and support of nuclear plant operations and related functions. The fleet operations manager establishes policy level guidance, provides strategic direction to plant operations departments regarding operating practices and standards, evaluates programs for conformance to industry best practices, and drives performance improvements where needed.

13.1.1.4.2.2.2 Fleet Maintenance. The fleet maintenance manager is responsible for overall governance, oversight, and support of nuclear plant maintenance and related functions. The fleet maintenance manager establishes policy level guidance, provides direction to plant maintenance departments regarding maintenance practices, and drives performance improvements where needed.

13.1.1.4.2.2.3 Fleet Work Management Director. The fleet work management director is responsible for overall governance, oversight, and support of refueling outage planning and execution and the online work control process. The fleet work management director establishes policy level guidance, provides direction to plant staffs regarding online work control and outage practices and standards, evaluates programs for conformance to industry best practices, and drives performance improvements where needed.

13.1.1.4.2.2.4 Fleet Training Manager. The fleet training manager is responsible for overall governance, oversight, and support of training and qualification related functions. The fleet training manager establishes policy level guidance, provides direction to nuclear plant training departments regarding practices and standards, evaluates programs for conformance to industry best practices, and drives improvements where needed.

13.1.1.4.2.2.5 Fleet Support Manager. The fleet support manager reports to the vice president-fleet operations support and is responsible for the overall coordination of fleet security activities and programs. The fleet support manager is also responsible for overall governance, oversight, and support for fleet performance improvement activities, procedures, and records management. The fleet support manager establishes policy level guidance, provides direction to nuclear plant performance improvement staffs regarding practices and standards, evaluates programs for conformance to industry best practices, and drives performance improvements

where needed. Accordingly, the fleet support manager is responsible for administration of the corrective action program in the corporate headquarters. The fleet support manager is responsible for the overall coordination of the corporate emergency preparedness programs (including the common Emergency Operations Facility) and the Emergency Plans. The fleet support manager also has responsibility for site emergency response communication. The fleet support manager is also responsible for Enterprise Solutions.

13.1.1.4.2.2.6 Environmental Affairs, Chemistry and Radiological Services Manager. The environmental affairs, chemistry and radiological services manager reports to the vice president-fleet operations support. The environmental affairs, chemistry and radiological services manager is responsible for providing technical support in matters related to environmental issues. Some specific responsibilities of the environmental affairs, chemistry and radiological services manager include managing environmental issues such as radiological environmental, nonradiological environmental, dose and shielding calculations, and low-level radioactive waste. The environmental affairs, chemistry and radiological services manager is responsible for overall governance, oversight, and support of plant chemistry, radiation protection, and related functions. The environmental affairs, chemistry and radiological services manager provides direction to plant chemistry and health physics departments regarding operating practices and standards, evaluates programs, for conformance to industry best practices, and drives performance improvements where needed.

13.1.1.4.3 Vice President-Hatch

The vice president-Hatch reports to the executive vice president/CNO regarding operation issues and support matters. As vice president-Hatch, he/she is responsible for operation and maintenance of HNP. He/she directs the plant manager (PM), the site support manager (SSM), the engineering director, the site training manager, and the human resources supervisor.

13.1.1.4.4 Vice President-Engineering

The vice president-engineering reports directly to the executive vice president/CNO. This organization includes both project-specific and generic engineering support organizations. Additionally, the vice president-engineering is responsible for nuclear fuel and risk-informed engineering activities and provides direction to supply chain for nuclear-related procurement activities.

The vice president-engineering directs the risk-informed director, the nuclear fuel director, the fleet design director, the fleet engineering services director, the major projects manager, and the supply chain director. Some specific responsibilities include:

A. Design support including creation, revision, and retention of calculations, domestic documents, vendor drawings, and other design basis material.

B. Inservice inspection and testing.

C. Nuclear fuel procurement, nuclear fuel and core design, nuclear fuel reload licensing, nuclear fuel performance, dry storage fuel selection, and nuclear fuel procurement vendor oversight.

D. Engineering support on licensing issues.

E. Maintenance of the plant design basis (e.g., calculations, design criteria, and functional system descriptions) for each site.

F. Maintenance of probabilistic risk models.

G. Major project management.

H. Procurement activities.

13.1.1.4.4.1 **Nuclear Fuel Director.** The nuclear fuel director reports to the vice president-engineering and directs the core analysis manager, the project engineer for fuel performance, and the nuclear fuel services manager. The nuclear fuel director is responsible for nuclear fuel procurement, fuel and core design, reload licensing, nuclear fuel performance, dry cask storage fuel selection, and vendor oversight for SNC sites.

13.1.1.4.4.2 **Fleet Design Director.** The fleet design director reports to the vice president-engineering and is the chief engineer and design authority for SNC plants. The individual manages the design support organization which consists of three departments associated with discipline oriented design support and configuration management. These departments are responsible for creation, revision, and retention of calculations, domestic documents, vendor drawings, and other design basis material. The fleet design director is responsible for standardization, long-term resource planning, and promoting best practices.

13.1.1.4.4.3 **Fleet Engineering Services Director.** The fleet engineering services director reports to the vice president-engineering. This individual is responsible for providing corporate support to SNC plants in matters related to engineering systems, engineering programs, and engineering support. Specific responsibilities of engineering services include:

A. Provide expertise to address equipment operability and reliability issues.

B. Provide expertise in the areas of seismic and stress analysis, fire protection, dry spent fuel storage, security, and environmental qualification.

C. Inservice inspection and testing programs.

13.1.1.4.4.4 **Major Projects Manager**. The major projects manager reports to the vice president-engineering and directs the Farley, Hatch, and Vogtle project controls, performance

improvement, and strategic supervisors. The major projects manager is responsible for providing long range planning and project management services for SNC plants.

13.1.1.4.4.5 Risk-Informed Engineering (RIE) Director. The RIE director reports to the vice president-engineering and directs the RIE staff. The RIE director is responsible for all RIE activities and risk-informed initiatives affecting plant sites and the corporate office.

13.1.1.4.4.6 Supply Chain Director. The supply chain director is responsible for procurement, procurement document control, development of sources of supply including the selection of suppliers to be awarded purchase orders or contracts, and materials management activities.

13.1.1.4.5 Vice President and General Counsel

The vice president and general counsel reports to the president/CEO. This individual is responsible for the legal, compliance, and external affairs associated with operation of SNC plants. This individual is also responsible for external affairs activities which include governmental affairs and corporate communications. The vice president and general counsel is also the corporate secretary and directs the managing attorney/compliance manager and the public affairs manager.

13.1.1.4.6 Vice President Regulatory Affairs

The vice president-regulatory affairs reports to the president/CEO. This individual is responsible for licensing and interface activities with the Nuclear Regulatory Commission (NRC). The vice president-regulatory affairs directs the nuclear licensing director.

13.1.1.4.6.1 Nuclear Licensing Director. The nuclear licensing director reports to the vice president-regulatory affairs and directs the regulatory response manager, the licensing manager, and their staffs. The regulatory response manager and the licensing manager provide matrixed accountability to the vice presidents-plant for each site and are responsible for providing corporate support in matters related to nuclear licensing.

Nuclear licensing performs both plant-specific and generic nuclear licensing activities. Responsibilities include:

A. Act as the primary interface with the NRC. Evaluate regulatory information and interpret NRC requirements.

B. Maintain the Final Safety Analysis Report (FSAR), Technical Specifications, Emergency Plan, Security Plan, and other licensing documents for each plant.

13.1.1.4.7 Human Resources Director

The human resources (HR) director reports to the president/CEO. This individual is responsible for the delivery of HR services to the nuclear operating company. This includes HR consulting, organizational effectiveness, succession planning, workforce development, wellness, medical services, fitness for duty, case management, fleet access, and nonunion employee relations. The HR director directs the medical and fitness-for-duty manager.

13.1.1.4.7.1 Medical and Fitness-for-Duty (FFD) Manager. The medical and FFD manager is responsible for coordinating the overall FFD program among SNC management, managing medical services, disability responsibilities, access authorization, the corporate safety and health staff, and the safety and health staff at each of the SNC nuclear plants.

13.1.1.5 Qualifications

Georgia Power Company operates electric generating plants with an aggregate capacity in excess of 14,000 MWe. GPC has experience in the design, construction, startup testing, operating, and staffing of modern generating facilities, including HNP, a nuclear power plant with two boiling water reactors. Effective March 22, 1997, SNC is the exclusive operating licensee of HNP and assumes the technical qualifications of GPC in all aspects.

The corporate organization, which provides the line responsibility for the operation of the HNP, is shown in figure 13.1-2. The ultimate responsibility for design, procurement, construction, testing, quality assurance, and operation of the HNP rests with the president and CEO.

Members of the staff available for the technical support of the Hatch project possess education, experience, and skills commensurate with their levels of responsibility. The qualification level of the support staff provides reasonable assurance that decisions and actions during the operation of the HNP units will not constitute a hazard to the health and safety of the public.

The operating organization for the HNP is described in subsection 13.1.2. The company technical support organizations for operation, modification, and maintenance are described in paragraph 13.1.1.4 and shown in figures 13.1-1 and 13.1-2. The organization described herein provides assurance of safe operation of HNP-1 and HNP-2 and for meeting regulatory requirements.

13.1.2 OPERATING ORGANIZATION

Plant Hatch consists of two nearly identical nuclear generating units. The plant organization is shown in figure 13.1-3. The plant staff, excluding the Security Department, consists of ~ 800 full-time employees functioning in the areas of operation, maintenance, administration, and technical support. Additional personnel are added as required.

Onsite executive responsibility for all aspects of HNP operation rests with the vice president-Hatch. This position reports directly to the executive vice president/CNO. The plant manager (PM), the site support manager (SSM), the engineering director (ED), and the human resources supervisor report directly to the vice president-Hatch.

The PM maintains overall and direct responsibility for operation of the units. The PM functional responsibilities focus strictly on those activities related to the safety and effectiveness of day-to-day operation of the plant (operations, maintenance, health physics, chemistry, and work management). The SSM oversees support-type functions (performance improvement, security, supply chain superintendent, the procedure writing group including Document Control, and emergency preparedness). The ED is responsible for design, implementation of modifications, and engineering support necessary for operations of the plant. The human resources supervisor reports to the vice president-Hatch and is responsible for human resources support activities.

The PM is responsible for verifying that personnel providing technical support for Plant Hatch operations possess adequate qualifications to perform the tasks to which they are assigned. Personnel providing offsite technical support are usually assigned to specific Hatch operations problems on the basis of educational background and experience they possess. This includes personnel providing support in the areas of maintenance; plant modification; chemical, mechanical, electrical, and nuclear engineering; refueling; outage planning; and other areas.

The PM is responsible for all onsite activities in connection with the operation and maintenance of the plant. The company support organizations for operation, modification, and maintenance are shown in figures 13.1-1 and 13.1-2.

13.1.2.1 Plant Organization

Reporting to the operations manager are the operations superintendent-outage, operations superintendent-support, and operations superintendent-daily. Operation of the plant is directed by the operations manager, who is responsible to the PM. Normal shift operation is under direct control of the shift manager, who is responsible to the operations superintendent-daily. A shift manager is onsite at all times when at least one unit is loaded with fuel. A normal operating shift for each unit consists of the shift supervisor, shift support supervisor, two plant operators, a radwaste operator, and four system operators. The shift supervisor, as a minimum, will be qualified as a senior reactor operator.

Figure 13.1-4 is a shift manning chart for unit operation for both units and provides exceptions to the above when a unit is in the cold shutdown condition.

Normal plant maintenance is accomplished by plant personnel under the direction of the maintenance manager, who is responsible to the PM. Other employees and contract maintenance crews may be used to supplement the plant Maintenance Department, as necessary.

Plant QA is monitored by the Hatch nuclear oversight manager and nuclear oversight site staff. The Hatch nuclear oversight manager's primary line of communication is with the nuclear oversight vice president with liaison to the vice president-Hatch.

Quality control is the responsibility of an engineering supervisor, who is responsible to the ED, with assistance from designated inspection personnel. The vice president-Hatch has the site responsibility for implementation of the plant's QA program to ensure compliance with codes, standards, regulatory requirements, operating license, and company policies and rules for the operation, maintenance, and modification of the plant.

Technical support in the areas of reactor physics and onsite engineering support is under the direction of the engineering systems manager, who is responsible to the ED. Technical support in the area of design and plant modifications is under the direction of the design manager who is responsible to the EM. Technical support in the areas of chemistry and radiochemistry is under the direction of the chemistry manager, and radiation protection is under the direction of the health physics superintendent/manager, who are both responsible to the PM.

The security organization, described in section 13.7, is responsible to the SSM for its day-to-day operation. The plant training manager is responsible to the vice president-Hatch for administering the operator training and retraining program as described in section 13.2. The performance improvement supervisor is responsible to the SSM to identify and close key performance gaps.

In addition, administrative assistants and other personnel are retained to assist in the various plant departments.

13.1.2.2 Personnel Functions, Responsibilities, and Authorities

NOTE: The following descriptions apply to figure 13.1-3. Not all of the positions described are shown on the figure and vice versa.

The personnel functions, responsibilities, and authorities of the plant operating organization are:

A. Vice President-Hatch

The vice president-Hatch maintains onsite executive responsibility for all aspects of the plant. This position reports directly to the executive vice president/CNO. He/she designates the chairman and the members of the plant review board (PRB). He/she is responsible for the safety of the plant staff and the general public.

B. Plant Manager

The PM reports directly to the vice president-Hatch (figure 13.1-3). He/she has line responsibility over operations, maintenance, health physics, chemistry, and work management. Furthermore, he/she is responsible for operating the plant within the

Technical Specifications and for complying with the provisions of the operating licenses for HNP-1 and HNP-2.

The succession to responsibility for overall operation of the plant in the event of absences, incapacitation of personnel, or other emergencies is as follows:

- Plant manager.
- Operations manager.
- Shift manager.
- Shift supervisor.

C. Site Support Manager

The SSM reports directly to the vice president-Hatch (figure 13.1-3). The SSM oversees plant support functions. He/she maintains line responsibility for security, performance improvement, supply chain superintendent, the procedures writing group including Document Control, and emergency preparedness.

D. Engineering Director

The ED reports directly to the vice president-Hatch (figure 13.1-3). He/she manages the plant's technical activities in the areas of reactor physics, surveillance and efficiency testing, and preparation and implementation of design change requests.

E. Operations Manager

The operations manager directs day-to-day operation of the plant in a safe and efficient manner in compliance with the established plant procedures and assumes responsibility for overall operation of the plant in accordance with the succession specified in paragraph 13.1.2.2.B.

F. Operations Superintendent and Operations Support Superintendent

Both the operations superintendent and the operations support superintendent report directly to the operations manager and aid the operations manager in his duties. The operations support superintendent has responsibility for operations support personnel including engineers, nuclear specialists, plant operators, system operators, and shift technical advisors.

G. Shift Manager

The shift manager reports to the operations superintendent-daily and is cognizant of all activities and operational conditions which might affect the safety of the plant. The shift manager has the ultimate command authority in the control room and is

responsible for taking control of all activities in the control room during an accident or emergency situation to ensure the proper coordination of all activities. He/she assumes responsibility for overall operation of the plant in accordance with the succession specified in paragraph 13.1.2.2.B.

H. Shift Supervisor

The shift supervisor directs and is responsible for the actual operation of the unit on his assigned shift. He/she supervises the operators on his shift and is aware of all maintenance and testing being performed during his shift. He/she has the responsibility and authority to shut down the reactor unit if, in his judgment, conditions warrant this action. The shift supervisor is responsible for the actual unit operation during his assigned shift, as indicated in paragraph 13.1.2.3.

In the event the shift supervisor is incapacitated, the plant operator assumes shift supervisor responsibilities and authorities until a licensed senior reactor operator is available. He/she assumes responsibility for overall operation of the plant in accordance with the succession specified in paragraph 13.1.2.2.B.

I. Plant Operator

The plant operator works under the direction of the shift supervisor. He/she controls and directs the operation of one of the reactors and turbine-generator units, including auxiliaries and electrical transmission equipment. He/she has the responsibility and authority to shut down the reactor unit under his control if, in his judgment, conditions warrant this action.

J. System Operator

The system operator works under the direction of the shift supervisor. He/she inspects, operates, and services turbine-generator and reactor components, mechanical and electrical auxiliaries, and other plant equipment.

K. Performance Improvement Supervisor

The performance improvement supervisor is directly responsible to the SSM. He/she supervises the plant operating experience program, reviews plant events for reportability, and acts as the site interface for NRC, Institute of Nuclear Power Operations (INPO), insurers, and other regulatory bodies. The performance improvement supervisor is also responsible for the corrective action program.

L. Training Manager

The training manager is responsible for the training department, including operator qualification and requalification. He/she reports directly to the vice president-Hatch.

M. Maintenance Manager

The maintenance manager reports to the PM. With the assistance of the other departments, he/she directs and plans the plant maintenance activities, including the instrumentation and control (I&C) systems maintenance. He/she is also responsible for buildings and grounds support and maintenance support contractors.

N. Health Physics Manager and Chemistry Manager

The health physics manager and the chemistry manager both report to the PM, and direct chemical, radiochemical, and health physics activities (sections 12.1 and 12.5). The health physics manager supervises personnel monitoring and coordinates maintenance in radiation control areas. He/she is also responsible for area radiation monitoring systems and their proper calibration.

O. Shift Technical Advisor(s)

The shift technical advisor(s) report to the operations support superintendent. Responsibilities of this position are to aid plant management in carrying out safe, reliable, and efficient fuel loading, operation, and maintenance, and to ensure compliance with requirements of the operating license and other regulations. During assigned shifts, the shift technical advisor is cognizant of plant and equipment status and is available to provide appropriate assistance to the normal shift complement. He/she maintains independence from normal plant operations as necessary to make objective evaluations of plant operations, and to advise or assist plant supervision in correcting conditions adverse to safe operation.

P. Engineering Systems Manager

The engineering systems manager is responsible to the ED. He/she manages the plant's technical activities in the areas of reactor physics, surveillance and efficiency testing, and equipment reliability.

Q. Design Manager

The design manager is responsible to the ED. He/she manages the preparation of design changes, implementation of plant modifications, and post-modification testing of plant modifications.

R. Security (Site) Manager

The security (site) manager is responsible for onsite nuclear security. He/she reports to the SSM.

S. Work Management Director

The work management director reports to the PM and is responsible for outage planning, scheduling, and management. The work management director is the senior manager responsible for work controls described in section 1.2.2.1.5 of the QATR.

T. Emergency Preparedness Supervisor

The emergency preparedness supervisor is responsible for all onsite emergency preparedness activities. The emergency preparedness supervisor reports directly to the SSM.

U. Engineering Programs Manager

The engineering programs manager reports to the ED and ensures that plant technical activities in the area of program management and emergent engineering issue resolution are addressed.

V. Manager of Site Projects

The manager of site projects is responsible for providing oversight of major project activities by ensuring outage activities are integrated and supported, budgets are maintained, and schedules and objectives are met.

13.1.2.3 <u>Shift Crew Composition</u>

The main control room (MCR) is manned by a minimum of one licensed reactor operator per unit who remains in full view of the front of the main control panels. A licensed reactor operator or senior reactor operator is present at the controls at all times during operation of the facility. Figure 13.1-4 indicates minimum shift manning for all operational conditions and reflects the requirements of NUREG 0737.

13.1.3 QUALIFICATION REQUIREMENTS FOR NUCLEAR PLANT PERSONNEL

The following qualification requirements are met or exceeded by the minimum plant operating staff. There may be instances where additional servicemen or technicians are used to supplement the normal staff and do not meet these qualifications. The minimum operating staff is required to obtain and maintain qualification standards equal to, or better than, those specified in ANSI N18.1-1971, Standard for Selection and Training of Personnel for Nuclear Power Plants. The personnel selection and training program ensures fulfillment of these qualification requirements and also satisfies the NRC's Regulatory Guide 1.8 (March 1971), Personnel Selection and Training. Specific minimum qualifications for all those employees identified in subsection 13.1.2 are given below. The minimum number of licensed operators is given in figure 13.1-4. Minimum qualification requirements need be met only by the number indicated.

13.1.3.1 Minimum Qualification Requirements

The qualifications with regard to educational and experience backgrounds of the key supervisory or professional personnel of the operating staff at the time of initial core loading or appointment to the active position are as follows:

13.1.3.1.1 Plant Manager

The PM is required to have 10 years of responsible power plant experience of which a minimum of 3 years is to be nuclear power plant experience. A maximum of 4 of the remaining 7 years of experience may be fulfilled by academic training on a one-for-one basis. This academic training is required to be in an engineering or scientific field generally associated with power production. The PM is required to have acquired the experience and training normally required for examination by the NRC for a senior reactor operator's license whether or not the examination was taken.

The PM is required to have a recognized baccalaureate or higher degree in an engineering or scientific field generally associated with power production.

13.1.3.1.2 Site Support Manager

The SSM is required to have a minimum of 8 years of responsible power plant experience of which a minimum of 3 years is required to be nuclear plant experience. A maximum of 4 of the remaining 5 years of the power experience may be fulfilled by satisfactorily completing academic or related technical training on a one-for-one time basis. A degree in science or engineering is desirable.

If the PM has the required 3 years of nuclear experience, the requirements of the SSM may be reduced so that only 1 of his 8 years of experience needs to be nuclear plant experience.

13.1.3.1.3 Operations Manager and Operations Superintendent

The operations manager or at least one operations superintendent shall hold an SRO license.

13.1.3.1.4 Operations Support Superintendent

The operations support superintendent is required to meet the qualification requirements of section 4.3.1 of ANSI N18.1-1971.

13.1.3.1.5 Shift Manager

The shift manager is required to have a minimum of a high school diploma or equivalent and 4 years of responsible power plant experience, of which a minimum of 1 year is to be nuclear power plant experience. A maximum of 2 of the remaining 3 years of power plant experience may be fulfilled by academic or related technical training on a one-for-one time basis. He/she is required to hold a senior reactor operator's license.

13.1.3.1.6 Plant Operator

The plant operator is required to hold a reactor operator's license. He/she is required to have a minimum of 2 years of power plant experience, of which a minimum of 1 year is to be nuclear power plant experience, and he/she is required to have a high school diploma or equivalent.

13.1.3.1.7 System Operator

The system operator is required to have a high school diploma or equivalent. He/she should have a high degree of manual dexterity and mature judgment.

13.1.3.1.8 Engineering Support Manager

The engineering support manager is required to have a minimum of 8 years of responsible power plant experience, of which a minimum of 1 year is nuclear power plant experience. A maximum of 4 of the remaining 7 years of experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis.

13.1.3.1.9 Plant Training Manager

The plant training manager is required to have a minimum of 2 years of experience in operation or maintenance of a power plant.

13.1.3.1.10 Maintenance Manager

The maintenance manager is required to have a minimum of 7 years of responsible power plant or applicable industrial experience, of which a minimum of 1 year is nuclear power plant experience.

A maximum of 2 of the remaining 6 years of power plant or industrial experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. He/she is required to have nondestructive testing familiarity, craft knowledge, and an understanding of electrical, pressure vessel, and piping codes.

13.1.3.1.11 Chemistry Manager

The chemistry manager is required to meet the qualification requirements of section 4.4.3 of ANSI N18.1-1971.

13.1.3.1.12 Shift Technical Advisors

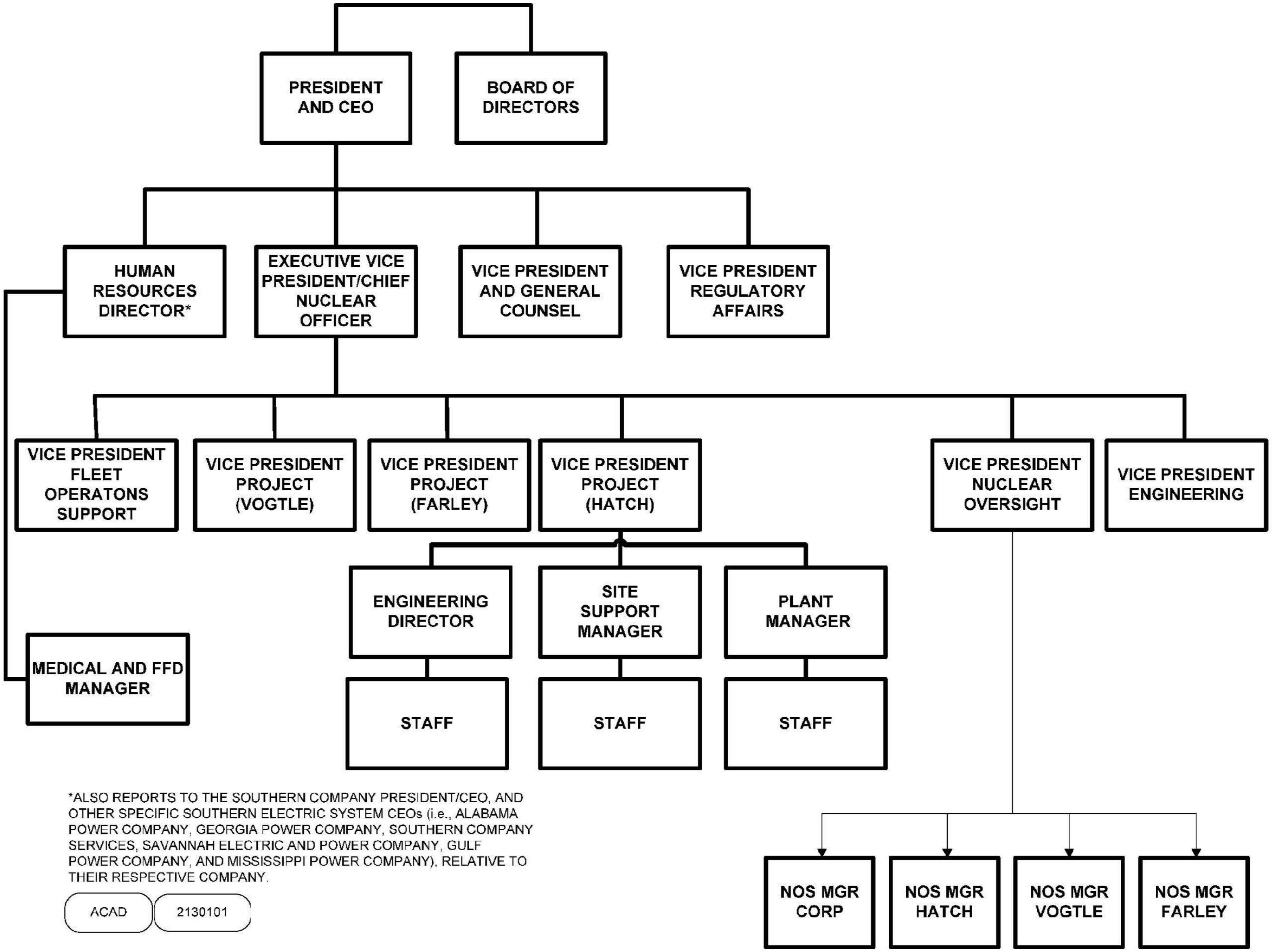
Each shift technical advisor is required to have a bachelor's degree or equivalent in a scientific or engineering discipline. Also, each shift technical advisor is required to complete a shift technical advisor training program as described in plant procedures.

13.1.3.1.13 Engineering Director

The ED is required to have a baccalaureate degree in engineering or the physical sciences and a minimum of 4 years of responsible experience in power plant design or operation, of which a minimum of 1 year is nuclear power plant experience.

13.1.3.1.14 Design Manager

The design manager is required to have a minimum of 8 years of responsible power plant experience, of which a minimum of 1 year is nuclear power plant experience. A maximum of 4 of the remaining 7 years of experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis.



*ALSO REPORTS TO THE SOUTHERN COMPANY PRESIDENT/CEO, AND OTHER SPECIFIC SOUTHERN ELECTRIC SYSTEM CEOs (i.e., ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, SOUTHERN COMPANY SERVICES, SAVANNAH ELECTRIC AND POWER COMPANY, GULF POWER COMPANY, AND MISSISSIPPI POWER COMPANY), RELATIVE TO THEIR RESPECTIVE COMPANY.

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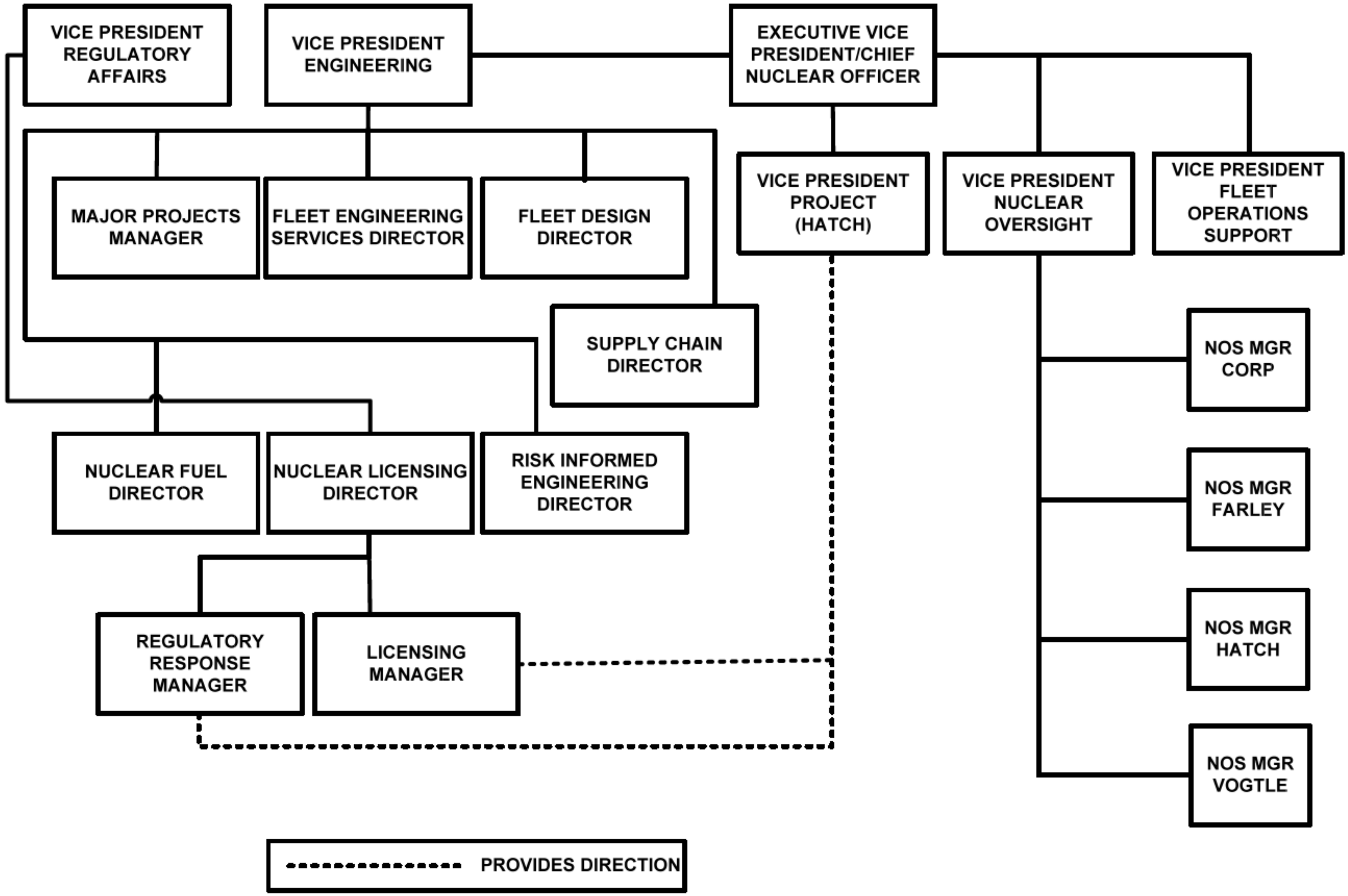
EDWIN I. HATCH NUCLEAR PLANT
UNITS 1 & 2

QUALITY ASSURANCE ORGANIZATION

FIGURE 13.1-1



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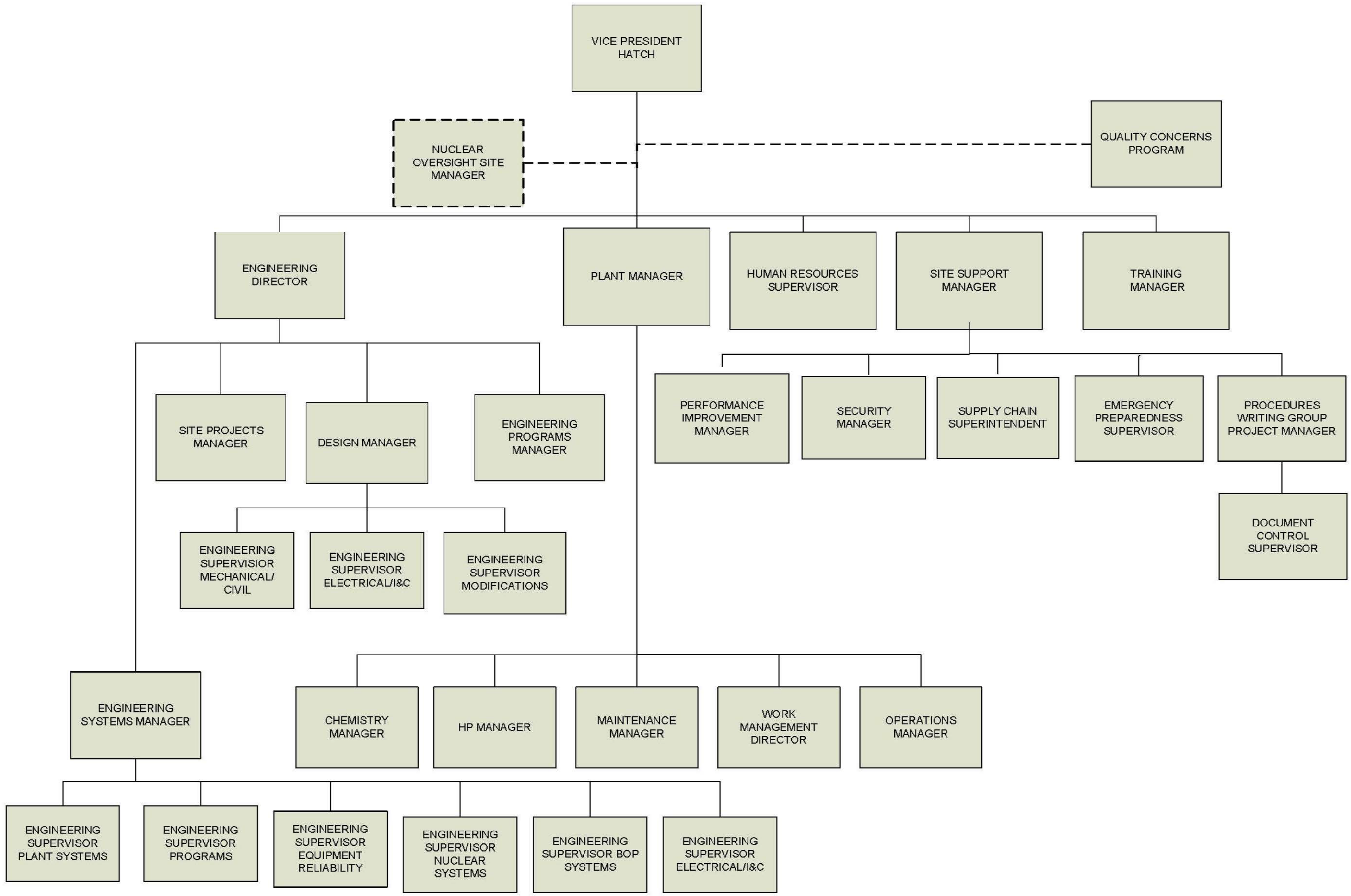
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

QUALITY ASSURANCE ORGANIZATION

FIGURE 13.1-2



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EDWIN I. HATCH NUCLEAR PLANT
UNITS 1 & 2

ORGANIZATION FOR HATCH NUCLEAR PLANT

FIGURE 13.1-3

UNIT 2 ↓ / UNIT 1 →	POWER OPER. HOT STANDBY HOT SHUTDOWN	COLD SHUTDOWN REFUEL	FUEL REMOVED
POWER OPERATION HOT STANDBY HOT SHUTDOWN	SRO 2 RO 3 NL 3 STA 1	SRO 2 RO 3 NL 3 STA 1	SRO 2 RO 3 NL 3 STA 1
COLD SHUTDOWN REFUEL	SRO 2 RO 3 NL 3 STA 1	SRO 1 RO 2 NL 3 STA 0	SRO 1 RO 2 NL 3 STA 0
FUEL REMOVED	SRO 2 RO 3 NL 3 STA 1	SRO 1 RO 2 NL 3 STA 0	

SRO - SENIOR REACTOR OPERATOR
RO - REACTOR OPERATOR
NL - NONLICENSED
STA - SHIFT TECHNICAL ADVISOR

(1) CONTROL ROOM MANNING IS DEPENDENT ON OPERATION CONDITIONAL CONDITION OF BOTH UNITS.

(2) ASSUMES EACH LICENSED INDIVIDUAL IS LICENSED ON BOTH UNITS.

ACAD 2130104

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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

MINIMUM CONTROL ROOM MANNING

FIGURE 13.1-4

13.2 TRAINING PROGRAM (HNP-1 AND HNP-2)

13.2.1 PROGRAM DESCRIPTION

The main objective of the training program is to train the operating, maintenance, and technical plant personnel in order to ensure the safe and efficient operation and maintenance of the plant.

13.2.1.1 Program Content

Individual training needs are established by carefully examining the individual's experience and previous training and comparing these with the job requirements. The following paragraphs describe the nominal training for plant employee classifications.

13.2.1.2 Licensed Plant Personnel Training and Retraining

The purpose of the training program is to develop license personnel to be responsible for the operation of the Hatch Nuclear Plant facilities. A continuing program is provided for training of replacement personnel and for retraining of licensed personnel to ensure that they remain proficient in their particular job. Exceptions are permitted to the following training programs for initial training for personnel who have extensive prior nuclear experience. The Nuclear Regulatory Commission (NRC) is notified on a case-by-case basis when the individual's application for license is submitted.

13.2.1.2.1 Initial Training

13.2.1.2.1.1 Basic Training for Reactor Operator License. Basic training for personnel requiring a license is provided in a program consisting of topics as follows:

- Fundamentals.
- Reactor systems.
- Balance-of-plant system.
- Simulator.
- On-the-job training.
- Walk-thru training and evaluation.

Three months (12 weeks) training on shift as an extra operator is included as part of the on-the-job training.

A. Evaluation

Exams are given at intervals during the basic training program to verify knowledge of subjects covered in the program.

B. License

The basic training program covers those subjects necessary for an employee to become sufficiently familiar with the plant and the nuclear field to qualify for the NRC licensing exam.

13.2.1.2.1.2 **Training for Senior Operating License.** Training for personnel requiring a senior operating license is provided in a school consisting of the following programs:

- Fundamentals.
- Systems.
- Simulator.
- On-shift, on-the-job training.
- Final preparation and audits.

The academic refresher program is only required for those personnel who need more basic training on theory, thermodynamics, and fluid flow as determined by a review of previous training.

The on-shift portion consists of 3 months (12 weeks) on-the-job training. The training for a senior operating license is applicable to both instant and upgrade candidates. Upgrade candidates with a current reactor operator license may not be required to attend fundamentals or systems courses. Instant senior reactor operator (SRO) candidates are required to perform five reactivity manipulations in the plant. This program replaces the initial Plant Hatch cold license program.

A. Evaluation

Exams are given at intervals during the training to verify knowledge of subjects covered in the program.

B. Senior License

The training program includes those topics necessary for an employee to become sufficiently familiar with the plant and administrative duties to qualify for the NRC senior licensing exam.

13.2.1.2.1.3 **Documentation**. Records of training, qualifications, and experience of both licensed and unlicensed personnel are maintained to document participation in the program. Copies of completed exams administered are also maintained in each individual's file.

13.2.1.2.2 License Requalification Program

13.2.1.2.2.1 **Applicability**. The program applies to all NRC-licensed reactor operators, senior reactor operators, senior reactor operator certified personnel, and certified shift technical advisors. Waivers for specific areas within the training program may be granted in cases where an individual has been extensively involved in that area. Personnel not attending the program, but otherwise meeting the conditions of their license for an extended period of time, may be readmitted to the program after demonstrating a satisfactory knowledge level for the license or certification they hold.

13.2.1.2.2.2 **Schedule**. The License Requalification training program will be conducted for a continuous period not to exceed 2 years, and upon conclusion will be promptly followed, pursuant to a continuous schedule, by successive requalification programs.

13.2.1.2.2.3 **Lectures.** The lectures presented during the 2-year cycle will be selected based on a systematic approach to training and will include topics identified by:

- The license requalification program system master plan.
- Plant feedback.
- Management input.
- Training feedback.
- Plant commitments and regulatory requirements.

13.2.1.2.2.4 **On-The-Job Training.** Students will participate in structured on-the-job training consisting of simulator training and in-plant training. The magnitude of each type of on-the-job training may vary from one segment to another depending on student needs.

13.2.1.2.2.5 Evaluations. Students will be required to successfully complete written examinations, segment simulator evaluations, annual simulator evaluations, and annual job performance evaluations to demonstrate that an acceptable level of skills and knowledge is maintained to the degree required by their license or certification. In cases where students fail to demonstrate an acceptable level of skills and knowledge, remedial training and reexamination will be required.

13.2.1.2.2.6 Individual Responsibilities. All individuals holding a reactor operator or senior reactor operator license are required to meet the conditions of their license as specified in 10 CFR 55.53. Any individual who fails to attend all the required license requalification program courses in a timely manner, to successfully complete an evaluation, or to fulfill any other requirement for active status will be removed from active license status until the deficiency has been corrected.

13.2.1.2.2.7 Plant Notification. Notifications to the NRC concerning license personnel status will be initiated by the plant and made by the corporate office in accordance with 10 CFR 50 and 10 CFR 55.

13.2.1.3 Nonlicensed Departmental Training

The purpose of this program is to provide the training program for nonlicensed personnel in each of the nuclear operations departments at Plant Hatch. The nonlicensed personnel included for this purpose are nonlicensed operators, mechanical and electrical personnel, instrument personnel, engineering services personnel, quality control personnel, health physics, and chemistry personnel.

Training for Plant Hatch engineering and technical personnel is the responsibility of nonlicensed departmental managers and supervisors.

The required training that is common to all the departments, i.e., radiation control, security, emergency and disaster, etc., is completed as part of the general employee training program which is described in paragraph 13.2.1.4.

Training programs for nonlicensed operators, mechanical personnel, electrical personnel, instrument personnel, engineering and technical staff, health physics, and chemistry personnel are based on a job and task analysis or job survey.

13.2.1.4 General Employee Training

The purpose of this program is to provide general training for all personnel regularly employed at Plant Hatch.

The general training for personnel permanently employed at Plant Hatch is provided as outlined in the following paragraphs for each of the required subjects.

13.2.1.4.1 Procedures

A. Emergency and Disaster Procedures

These procedures include those that are necessary for an individual to know in order to properly respond to a plant emergency. They are reviewed with personnel following employment at Plant Hatch. Employee comprehension and retention of this material are evaluated by a written test.

B. Procedures for Individual Duties

Training and review of procedures required for performance of individual duties are the responsibility of the individual departments. Review of these procedures is determined and administered by the immediate supervisor or other qualified individual.

13.2.1.4.2 Radiological Safety

A. Radiation Training

Training in radiation procedures associated with general employees is conducted following employment or transfer to Plant Hatch. Employee comprehension is evaluated by written test. Employees assigned a PROTECTED AREA ONLY badge may attend radiation protection lectures but are not required to take a test on radiation protection training.

B. Respiratory Training

Training in respiratory protection is required for all individuals subject to the wearing of respiratory equipment. This training consists of a lecture followed by individual fitting. Evaluation is by written test and a qualitative test for proper fitting.

13.2.1.4.3 Security Orientation

Security orientation for the general employee is conducted following employment or transfer to Plant Hatch. Employee understanding and retention are evaluated by written test.

13.2.1.4.4 QA Orientation

QA training is accomplished during initial employee orientation. It is also conducted, as necessary, for both general employee and individual department training.

13.2.1.4.5 Permanent Personnel - Retraining

Retraining in procedures, radiation training, and security as outlined above is required on a periodic basis of once each 3 years. During the interim, personnel are required to demonstrate adequate familiarization with these topics through an annual test administered to all personnel who have unescorted access to the plant.

Those employees assigned a PROTECTED AREA ONLY badge are tested only on the security and emergency disaster portions of the training. Those employees assigned a PROTECTED AREA ONLY badge may attend the radiation protection training lecture once each 3 years, but are exempt from testing on the radiation protection training.

Retraining in industrial safety and QA is conducted on a periodic basis as determined by responsible individuals of those departments.

Administration of the evaluation tests is performed by a member of the Plant Hatch training department, and satisfactory performance is required for unescorted access to Plant Hatch. Personnel failing to meet the minimum grade on any lecture test are allowed, upon application to the training department, to take a second test after attending an additional training session. Escorted access is required for these individuals until testing requirements have been satisfied.

Temporary personnel for Plant Hatch are trained in the above areas to the extent necessary to assure safe execution of their duties.

The performance analysis supervisor has the responsibility for maintaining all records for documentation of the preceding program.

13.2.2 RESPONSIBLE INDIVIDUAL

The training manager has the responsibility for establishing and supervising the above programs. The performance analysis supervisor is responsible for maintaining training records.

13.3 EMERGENCY PLANNING (HNP-1 AND HNP-2)

The original emergency plan for the Edwin I. Hatch Nuclear Plant (HNP) was submitted as a separate document and detailed those matters required in Appendix E to 10 CFR 50 at that time. The HNP Emergency Plan (applicable to both HNP-1 and HNP-2) was reviewed by the Nuclear Regulatory Commission in support of the HNP-1 application for an operating license (Docket No. 50-321). The current Emergency Plan reflects changes which have occurred in the regulatory posture as well as other changes made since the original was submitted.

In summarization of the program, SNC has established an organization for coping with emergencies. The plan includes written agreements, liaison, and communications with appropriate local, State of Georgia, and Federal agencies that have responsibilities for coping with emergencies. Categories of incidents are defined, including criteria for determining when protective measures should be considered and for the notification of offsite support groups. Arrangements have been made by SNC to provide for medical support in the event of a radiological incident or other emergencies. Provisions for periodic training for both plant personnel and offsite emergency organizations are included in the Emergency Plan. For further information, consult the current Emergency Plan.

13.4 <u>REVIEW AND AUDIT</u> (HNP-1 AND HNP-2)

During construction of Hatch Nuclear Plant (HNP), Georgia Power Company's (GPC's) quality assurance (QA) program complied with the requirements of Title 10 Code of Federal Regulations (CFR) Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." The type of review and audit function performed by GPC during construction is briefly addressed in subsection 13.4.1.

In addition to the QA organization described in the SNC Quality Assurance Topical Report (QATR), SNC utilizes a formal committee method for review and audit. This review and audit function is at two levels:

- Plant operation level - plant review board (PRB).

- Corporate level - nuclear safety review board (NSRB).

These organizational units for the review and audit of plant operations are constituted and have the responsibilities and authorities outlined in the QATR.

The NSRB functions during HNP operational phase and is independent of direct responsibility for plant operations. The PRB reviews plant operations and plans for future activities. Proposed procedures/procedure revisions and tests are reviewed by the PRB. Guidance in development of the essential elements in SNC's review and audit program for tests and operations (which is discussed more fully in subsection 13.4.2) was derived from American National Standards Institute (ANSI) N18.7-1976, "Administrative Controls for Nuclear Power Plants." The charters for the PRB and NSRB are presented in the QATR.

Review and audit of the independent spent-fuel storage installation (ISFSI) is performed as described in subsection 13.4.3.

13.4.1 REVIEW AND AUDIT - CONSTRUCTION

Review and audit during construction of HNP was part of the QA program. This program utilized an organization unit responsible through the GPC manager of QA to provide formal review and audit. A second element of the QA program during construction was the QA committee.

In addition, the GPC administrative and technical staff reviewed design documentation such as specifications, drawings, and design changes for compliance with applicable codes, standards, engineering practice, and overall design intent. The QA field representatives also systematically audited activities at the plant site to assure that the required standards of quality were attained in all construction and installation work.

13.4.2 REVIEW AND AUDIT - TEST AND OPERATION

A continuing review of operations is performed by the plant operating staff. The PRB, composed of plant employees, also reviews operations and serves in an advisory capacity to the vice president-Hatch. PRB responsibilities are outlined in the SNC QATR. Independent audits are made under the cognizance of the SRB, as specified in the QATR, on a periodic basis as required. The QA organization implements the operations phase of the program as set forth in the QATR.

13.4.2.1 Deleted

13.4.2.2 Administration of Plant Review Board

The PRB was established and functional 6 months prior to initial fuel loading. Prior to the 6-month period before initial fuel loading, a temporary PRB primarily reviewed and approved procedures required to bring HNP from the construction phase through the preoperational testing phase. The PRB chairman had the authority to approve or disapprove PRB proposals. The plant manager assumed PRB chairmanship at least 6 months prior to initial fuel loading. Up to that time, the temporary board was chaired by the superintendent of operations.

The PRB meets the requirements of ANSI N18.7-1976 as described in the QATR. Membership, meeting frequency, quorum, responsibilities, authority, meeting minutes, and administrative procedures for PRB operations are discussed in the QATR.

The PRB chairman is currently designated by the vice president-Hatch. The PRB charter described in the QATR defines the responsibilities and method of operation of the PRB.

13.4.2.3 Administration of Nuclear Safety Review Board

Activities of the NSRB are addressed in the QATR.

13.4.3 REVIEW AND AUDIT - ISFSI

Review of ISFSI operations is performed by the PRB and NSRB through review of 10 CFR 72.48 evaluations.

Review and audits of ISFSI activities are also conducted by the QA organization as described in the QATR.

13.4A EDWIN I. HATCH PLANT REVIEW BOARD CHARTER (HNP-1 AND HNP-2)

The plant review board (PRB) charter is provided in the SNC Quality Assurance Topical Report (QATR).

13.4B EDWIN I. HATCH SAFETY REVIEW BOARD (HNP-1 AND HNP-2)

The nuclear safety review board (NSRB) charter is provided in the SNC Quality Assurance Topical Report (QATR).

13.5 PLANT PROCEDURES (HNP-1 AND HNP-2)

13.5.1 SYSTEM OR PLANT PROCEDURES

All safety-related operations are conducted in accordance with detailed written plant procedures.

The procedures manual, which includes all plant procedures, is prepared by the plant operating organization with the technical assistance of General Electric Company (GE), Bechtel Power Corporation (BPC), and other technical support organizations as needed. The plant procedures follow the guidance of standard American National Standards Institute (ANSI) N18.7-1976, "Administrative Controls for Nuclear Power Plants." Prior to initial use and if required, proposed procedures/procedure revisions are reviewed by the Plant Review Board as described in the SNC Quality Assurance Topical Report (QATR), and recommended for approval to the appropriate member of plant management designated by the vice president-Hatch, the site support manager (SSM), or the plant manager (PM). The emergency implementing procedures are reviewed on an annual basis to determine adequacy, accuracy, and need. All other safety-related procedures are reviewed as described in the QATR. An updated set of plant procedures is always available in the main control room (MCR). A provision is made to ensure that emergency operating procedures and abnormal operating procedures are reviewed at least every 2 years by a knowledgeable individual to determine whether changes are necessary or desirable.

As part of the overall quality assurance (QA) program, the QA group performs various audits described in the QATR to assure that the procedural process is working and that procedures are being properly maintained.

Day-to-day operations are carried out by the various plant departments. Each department is assigned an area of responsibility and operates with some degree of independence and freedom from close supervision; yet their actions are closely coordinated to best achieve the common purpose.

The vice president-Hatch, the PM, or the SSM issues procedures governing employee actions and established standards for plant operation. These procedures contain administrative restrictions and plant requirements established to ensure safe operation of the plant within the limitations set by plant licenses, the Technical Specifications, and the Technical Requirements Manual (TRM).[a] They assure plant activities are conducted in a manner to protect the general public, plant personnel, and equipment.

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a. When the Technical Specifications were revised to be consistent with NUREG-1433, "Standard Technical Specifications," some previous Technical Specifications requirements were relocated to other documents. Some requirements were relocated to the TRM. Any changes to the relocated requirements contained in the TRM are reviewed pursuant to 10 CFR 50.59.

A formalized system of written procedures conforming to the requirements of the operating QA program QATR is employed in support of the standard practices.

Systems and components described in the FSAR are maintained with the aid of written procedures. These maintenance procedures consider vendor or manufacturer's technical manuals and recommendations, as well as engineering inputs and regulatory requirements.

Administrative procedures prescribe the methods whereby plant procedures can be temporarily revised without undue delay when the need arises. Temporary procedure revisions that do not change the intent of the approved procedure may be made with the consurrence of two individuals, one of whom holds a senior reactor operator's license on the affected unit. Such revisions are documented and if required, reviewed by the Plant Review Board (as described in the QATR), and approved by the appropriate member of plant management (see QATR) within 14 days of implementation. In cases of emergency, personnel are authorized to depart from approved procedures when necessary to prevent injury to personnel or damage to the plant. Such departures are logged describing the prevailing conditions and the reasons for the action taken.

- Administrative procedures.
- Normal operating procedures.
- Annunciator response procedures.
- Surveillance procedures.
- Emergency procedures.
- Instrument calibration procedures.
- Maintenance procedures.
- Chemical control procedures.
- Radiation protection procedures.
- Core calculations and fuel handling procedures.
- Miscellaneous procedures.

Procedures are revised or added as experience dictates. Administrative controls require maintenance of an index that provides a current list of all plant procedures.

13.5.2 ADMINISTRATIVE PROCEDURES

Administrative procedures are the means by which plant operations are subject to management control. Measures specified in these procedures provide for rules, orders, instructions, policies, practices, review and audit mechanisms, reporting requirements, document controls, personnel conduct and control, materials control, and assignment of responsibilities and authorities, to ensure that plant operation and maintenance are carried out in a safe and dependable manner.

Administrative procedures for both units include requirements to comply with 10 CFR 50.54 (i), (j), (k), (l), and (m).

13.5.3 NORMAL OPERATING PROCEDURES

Normal operating procedures provide instructions for operation of plant equipment processes or systems. They are written in a manner to ensure that the operation of such equipment, processes, or systems is carried out in a safe and dependable manner.

13.5.4 ANNUNCIATOR RESPONSE PROCEDURES

Annunciator response procedures specify operator actions taken in response to alarms which might indicate off-normal operating conditions. These procedures are written in a simple direct format so that a trained operator has enough information to bring a process or parameter back to within normal operating limits. These are not emergency procedures but were written to aid the operator in determining if a true emergency exists.

13.5.5 SURVEILLANCE PROCEDURES

Surveillance procedures provide instructions for performing periodic tests in order to verify and document that safety-related systems, structures, instrumentation, or components continue to function properly or remain in a state of readiness to perform their intended safety functions.

13.5.6 EMERGENCY PROCEDURES

Emergency procedures provide a guide to operators and other personnel for action during potential emergencies. They are written in a simple and direct method so that a trained operator or other personnel know in advance the expected course of events that identify an emergency and the action they should take.

13.5.7 INSTRUMENT CALIBRATION PROCEDURES

Instrument calibration procedures provide a means of testing and calibrating various plant instrumentation for surveillance and required or preventative maintenance.

13.5.8 MAINTENANCE PROCEDURES

Maintenance procedures are written to provide instructions for performing maintenance on plant safety-related equipment or systems. Instrument maintenance is covered under instrument calibration procedures.

13.5.9 CHEMICAL CONTROL PROCEDURES

Chemical control procedures used for water quality analysis include:

- Chemical determination procedures such as for zirconium or sodium pentaborate.
- Radiochemical determination procedures such as for cesium or nickel.
- Instrument operation and calibration procedures such as for a spectrophotometer or conductivity bridge.

13.5.10 RADIATION PROTECTION PROCEDURES

Radiation protection procedures provide guidelines and rules for effective radiation protection for plant personnel, visitors, and the general public. These procedures include:

- Radiation protection procedures such as for personnel dosimetry or radiation work permits.
- Health physics instrument operation and calibration procedures such as for the neutron counter or the beta-gamma survey meter.

13.5.11 CORE CALCULATIONS AND FUEL-HANDLING PROCEDURES

Core calculations and fuel-handling procedures give instructions for such subjects as:

- Performing core calculations.
- Fuel-handling receipt.
- Refueling.
- Reactor engineering tests.
- Computer outputs.
- Special nuclear material inventory and transfer control.

13.5.12 MISCELLANEOUS PROCEDURES

Miscellaneous procedures are those that are considered as one-time use procedures, or procedures that have limited applicability over the lifetime of the plant. These procedures are written as they are required.

13.6 PLANT RECORDS (HNP-1 AND HNP-2)

13.6.1 PLANT HISTORY

A history of Hatch Nuclear Plant (HNP) is recorded and maintained in accordance with 10 CFR 50, Appendix B, Section XVII, "Quality Assurance Records." Southern Nuclear Operating Company (SNC) complies with Federal Energy Regulatory Commission regulations concerning the preservation and disposal of records for public utilities and licensees insofar as these regulations apply to SNC records relating to the generation, transmission, and sale of electric energy. Records documenting the operation and maintenance of, or modification to, HNP are maintained at the plant site for durations as specified in subsection 13.6.5. Plant records are maintained in accordance with the SNC Quality Assurance Topical Report.

The document control supervisor (site) has responsibility for general supervision and coordination of the plant master file under the direction of the performance analysis supervisor.

13.6.2 OPERATING RECORDS

Records reflecting plant or equipment performance and records of tests and inspections which support compliance with the plant licenses, including records of radioactivity release to the environs, are routed to the document control supervisor (site) for retention. These records are originated by all plant departments.

Operations maintains an operating log which is a chronological record of significant plant events and conditions. The normal method of log keeping is by computerized log, with sub-logs for the applicable shift members including, but not limited to, the shift manager, shift supervisor, shift support supervisor, and control board operators. If the computerized log becomes unavailable, logs are recorded manually in accordance with plant procedures.

The content of operating logs and sub-logs is prescribed by plant procedures. When applicable, these logs are supported by information available from installed recording and data logging instrumentation.

To ensure the appropriate operating history is maintained, operating logs are printed, reviewed, and sent to the plant master file for retention. Supporting information may accompany the operating logs.

Records on all safety-related electrical and mechanical equipment maintenance are retained in the plant master file. Also, similar records for safety-related instrumentation systems (including instrument check, functional test, and calibration as required in the Technical Specifications) are retained in the plant master file. These records contain complete information on all repairs, modifications, tests, derangements, and other data as considered necessary to provide a comprehensive material history of the item concerned. Records of reportable occurrences, as defined in 10 CFR 50.72 and 50.73, including the results of subsequent investigations and corrective actions, if any, are maintained in the Plant Hatch master file (see subsection 13.6.5).

Specific operating records and their retention periods are specified in subsection 13.6.5.

13.6.3 EVENT RECORDS

Records of personnel radiation exposures and plant and environs radiation levels are retained by the plant health physics department.

Records of results of all environmental surveillance requirements are retained in the plant master file. Records of radioactive effluent discharges and quantities of radioactive wastes shipped for offsite disposal are also retained in the plant master file.

Specific event records and their retention periods are specified in subsection 13.6.5.

13.6.4 STARTUP REPORT

A summary report of plant startup and power escalation testing shall be submitted following:

- Receipt of an operating license.
- Amendment to the license involving a planned increase in power level.
- Installation of fuel that has a different design or has been manufactured by a different fuel supplier.
- Modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant.

The startup report shall address each of the tests identified in the Final Safety Analysis Report (FSAR) and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

Startup reports shall be submitted within:

- 90 days following completion of the startup test program, or
- 90 days following resumption or commencement of commercial power operation, or
- 12 months following initial criticality, whichever is earliest.

If the startup report does not cover all three events (i.e., initial criticality, completion of the startup test program, and resumption or commencement of commercial operation),

supplementary reports shall be submitted at least every 3 months until all three events have been completed.

13.6.5 RECORD RETENTION

In addition to the applicable record retention requirements of 10 CFR, the following records are retained for at least the minimum period indicated.

A. Records retained for at least 5 years include:

- Records and logs of unit operation covering time interval at each power level.
- Records and logs of principal maintenance activities, inspections, and repair and replacement of principal items of equipment related to nuclear safety.
- All reportable events submitted to the Nuclear Regulatory Commission.
- Records of surveillance activities, inspections, and calibrations required by the Technical Specifications.
- Records of changes made to the procedures required by Technical Specification 5.4.1.
- Records of radioactive shipments.
- Records of sealed source and fission detector leak tests and results.
- Records of annual physical inventory of all sealed-source material of record.

B. Records retained for the duration of the unit operating license include:

- Records and drawing changes reflecting unit design modifications made to systems and equipment described in the FSAR.
- Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories.
- Records of radiation exposure for all individuals entering radiation control areas.
- Records of gaseous and liquid radioactive material released to the environs.
- Records of transient or operational cycles for unit components covered in Technical Specification 5.5.5.
- Records of reactor tests and experiments.

- Records of training and qualification for current members of the unit staff.
- Records of inservice inspections performed pursuant to 10 CFR 50.55a.
- Records of quality assurance activities required by the QA Manual.
- Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.
- Records of plant review board and safety review board meetings.
- Records for Environmental Qualification which are covered under the provisions of 10 CFR 50.49.
- Records of analyses required by the Radiological Environmental Monitoring Program.
- Records of service lives of all safety-related hydraulic and mechanical snubbers, including the date at which service life commences, and associated installation and maintenance records.
- Records of reviews performed for changes made to the Offsite Dose Calculation Manual and the Process Control Program.

13.7 SECURITY (HNP-1 AND HNP-2)

This section describes, in general terms, the security measures in effect at Edwin I. Hatch Nuclear Plant (HNP) for protection against sabotage. A detailed security plan, not for public disclosure, for HNP-Units 1 and 2 discusses the specific measures for the physical protection of the plant. The Security Plan has been approved by the Nuclear Regulatory Commission (NRC).

13.7.1 PERSONNEL AND PLANT DESIGN

The overall responsibility for the plant security program rests with the site support manager (SSM). In his/her absence, the security (site) manager, as ordered in subsection 13.1.2, is responsible for the overall security of the plant and has the authority to implement any action to ensure the security of the plant. The security program is administered by the security (site) manager, who reports to the SSM (figure 13.7-1), and is conducted in accordance with the Security Plan described in subsection 13.7.2.

The plant site is in a remote location, and it is unlikely that a major civil disorder would occur at or near the plant area.

The plant was designed and is operated so as to minimize the potential for sabotage by the use of access control measures that prevent unauthorized persons and vehicles from entering the protected area to the extent that vital buildings and systems and components as defined in the Security Plan could be physically threatened. Should such persons succeed in entering the protected areas, special access control measures are available to prevent them from entering vital equipment areas.

The built-in features and other physical security measures that protect against or limit the effects of possible sabotage efforts include:

- A physical security barrier around the perimeter of the plant, with gates that are kept locked closed except during periods of authorized use.

- An additional physical security barrier system around the plant perimeter to prevent the malevolent use of vehicles, in accordance with Regulatory Guide (RG) 5.68 and NUREG/CR-6190, Rev. 1, Volumes 1 and 2.

- A public visitors information center located outside the controlled area and well away from the plant.

- Employee and visitor parking located outside the protected area.

- A perimeter patrol road inside the protected area.

- A well-lighted plant area to provide good observation of equipment areas.

- Television surveillance of the perimeter and intrusion devices on doors.

- A minimum of exterior doors; these doors are locked or secured when not in use to preclude entry from outside.

- A force of trained, uniformed, and armed security officers, used on a 24-h basis to patrol the property and provide access control.

- Firefighting and other emergency equipment located throughout the plant to minimize the consequences of fires or explosions (subsection 9.5.1).

- Redundant protective systems and engineered safety features that are provided to minimize the consequences of fires or explosions or to minimize the effects of postulated major equipment failures, natural disasters, operator errors, and the effects of sabotage.

13.7.1.1 Employee Selection

Before a person is assigned to a position in the security department at Plant Hatch, it is necessary for that individual to take a job-related test, to receive a formal interview, to pass a physical examination, and to complete a series of aptitude tests. For further discussion see subsection 13.1.3 and section 13.2.

Employees on the plant staff have been screened to eliminate potential security risks. This investigation includes a background examination to disclose adverse character traits that might bear on one's abilities or motivation to discharge his duties in a responsible manner. In addition, company personnel who have a need to be at the plant on a frequent basis, are subject to the same background check.

13.7.1.2 Employee Evaluation

Because of the general policy of promoting present employees rather than appointing candidates from outside SNC, most employees at Plant Hatch are known from their previous employment record with SNC.

Although employees are not given routine psychiatric examinations, other than the required preemployment psychological test, Minnesota Multi-phasic Personality Inventory (MMPI), they may be tested when an employee's on-the-job performance indicates that this is desirable.

Observation of employee behavior is made as a regular part of day-to-day supervision. When performing this function, supervisors are alert for any unusual behavioral patterns, such as may result from mental stress, alcohol, or other drug abuse.

In addition to this kind of review, the performance of employees in management and supervisory positions is reviewed formally and the results reported in order to:

- Further aid in maintaining a high level of employee performance and the maximum utilization of employee abilities.

- Provide recorded evidence of employee performance for use in making judgments concerning transfer, demotion, promotion, and terminations.

- Assure that employees are adequately and systematically informed of the effectiveness of their service.

- Further facilitate the maintenance of a high standard of supervision in SNC.

All employees' services are reviewed formally at the time of status changes and at such other times as may be required to achieve the above purposes. A service review precedes each recommendation for operator licensing or renewal of an operator's license.

13.7.1.3 Security Training

Each plant employee receives appropriate security orientation and training with particular emphasis on those matters for which he has responsibility.

Periodic security bulletins and/or meetings assure that the plant staff is kept up-to-date on security measures.

Security procedures are located in the plant entry and security building (PESB), the security supervisor's office, and other selected locations. These procedures cover actions to be taken in the event of fires, explosions, natural disasters, suspicious persons, illegal entry, bomb threats, civil disturbance, and sabotage threats. Plant employees receive training in each of these areas with emphasis on being alert to the presence of unauthorized persons and evidence of forced entry.

13.7.2 SECURITY PLAN

A detailed security plan approved by the NRC describes in greater detail the security measures used to minimize the potential for industrial sabotage including access control, surveillance of vital equipment, and plans for responding to security threats.

13.7.2.1 Access Control

A double perimeter protection system (owner-controlled area and protected area) was established to thwart attempts at industrial sabotage. This consists of an inner and outer perimeter protection concept. The double perimeter system provides protection for all vital equipment and structures, and access to vital areas is limited, by written authorization procedures, to those individuals required to work inside the area. Only authorized personnel and vehicles are allowed to enter. Employee and visitor parking areas are located outside the

inner security barrier. Vehicle access is limited to those vehicles required for delivery of material, operations, maintenance, emergencies, and security of the plant. Persons, packages, and vehicles are subject to search upon entering and leaving. In accordance with RG 5.68 and NUREG/CR-6190, an additional continuous barrier system comprised of active and passive barrier components was installed to prevent the unauthorized, forced entry of a design basis vehicle into the proximity of vital systems and components.

There is a minimum number of outside accesses to the plant buildings. These doors are kept locked or secured when not in use. Also, a number of interior doors are locked and controlled to prevent unauthorized access to certain vital areas.

Even persons who are authorized "unescorted access" have their movement limited by physical barriers, such as locked doors, to prevent them from entering areas containing vital equipment or areas of high radiation levels. Only those who need access to these areas are allowed to enter.

Only those persons who have completed training in radiation protection and emergency procedures are authorized to enter the restricted plant areas unescorted. When special visitors and other persons who have not completed this training enter the plant, they are escorted by an employee trained in these procedures. The escort is responsible for the people in his charge.

13.7.2.2 Control of Personnel by Categories

Each person who is authorized unescorted access to the protected area has the physical characteristics of one hand assigned to a unique cardkey picture badge in the security computer database. Hand readers provide verification of identity of each individual entering the protected area.

Visitors who require access to the protected area are logged in and badged by a security force officer. The officer calls the appropriate plant supervision and arranges for an escort, when needed. The escort is responsible for the safety and actions of these persons until he checks them out through the PESB.

13.7.2.3 Access Control During Emergencies

Upon hearing of an emergency, the security force officers on duty at the access points lock all gates on the protected area perimeter to ensure controlled entry and exit. Plant employees report to predesignated stations from which they are dispatched as needed to combat the emergency in accordance with established written procedures.

13.7.2.4 Surveillance of Vital Equipment

The reactor operator(s) continuously monitor the status of plant systems and equipment by means of annunciators, indicating lights, indicators, and recorders. Operating logs and computer printout data are periodically examined for changes in equipment performance.

Most equipment is continuous operation and any change is immediately detected by the operator. Standby and emergency equipment is periodically tested on a routine basis as required by the Technical Specifications. Shift supervisors, shift support supervisors, and other supervisory personnel knowledgeable in plant conditions make frequent unscheduled inspection tours through the plant. The combination of these efforts should provide reasonable assurance that unauthorized physical changes in the status of components or equipment do not go undetected for long periods of time.

Key operating log sheets and selected recorder tracings are reviewed on a regular basis. Abnormal changes observed are called to the attention of plant management and the appropriate supervisors for investigation and corrective action, if required. This operation audit serves to assure early detection of physical changes which would have a significant bearing on plant performance.

13.7.2.5 Potential Security Threats

Should an unauthorized person succeed in entering the protected area, the access control measures in use would not allow him access to vital equipment. Operating personnel trained to be alert for unauthorized persons would recognize him as an intruder and arrange for his apprehension by security force officers.

Plans have been prepared to cover actions in the event of civil disturbance, emergencies, and bomb threats. Detailed emergency procedures are provided to plant employees so that they may cope with these and other events in the optimum manner possible.

If there appears to be a real threat of civil disorder or another type of serious security threat to the plant or a radiological emergency, all off-duty security force officers are subject to being recalled, and additional assistance provided, as necessary. Local and State authorities are contacted for assistance, and unauthorized access to the plant is prevented to the extent possible. Arrangements with law enforcement agencies are discussed in the Plant Hatch Security Plan. In the plant, precautions are taken to protect vital areas from threat of fire or other damage.

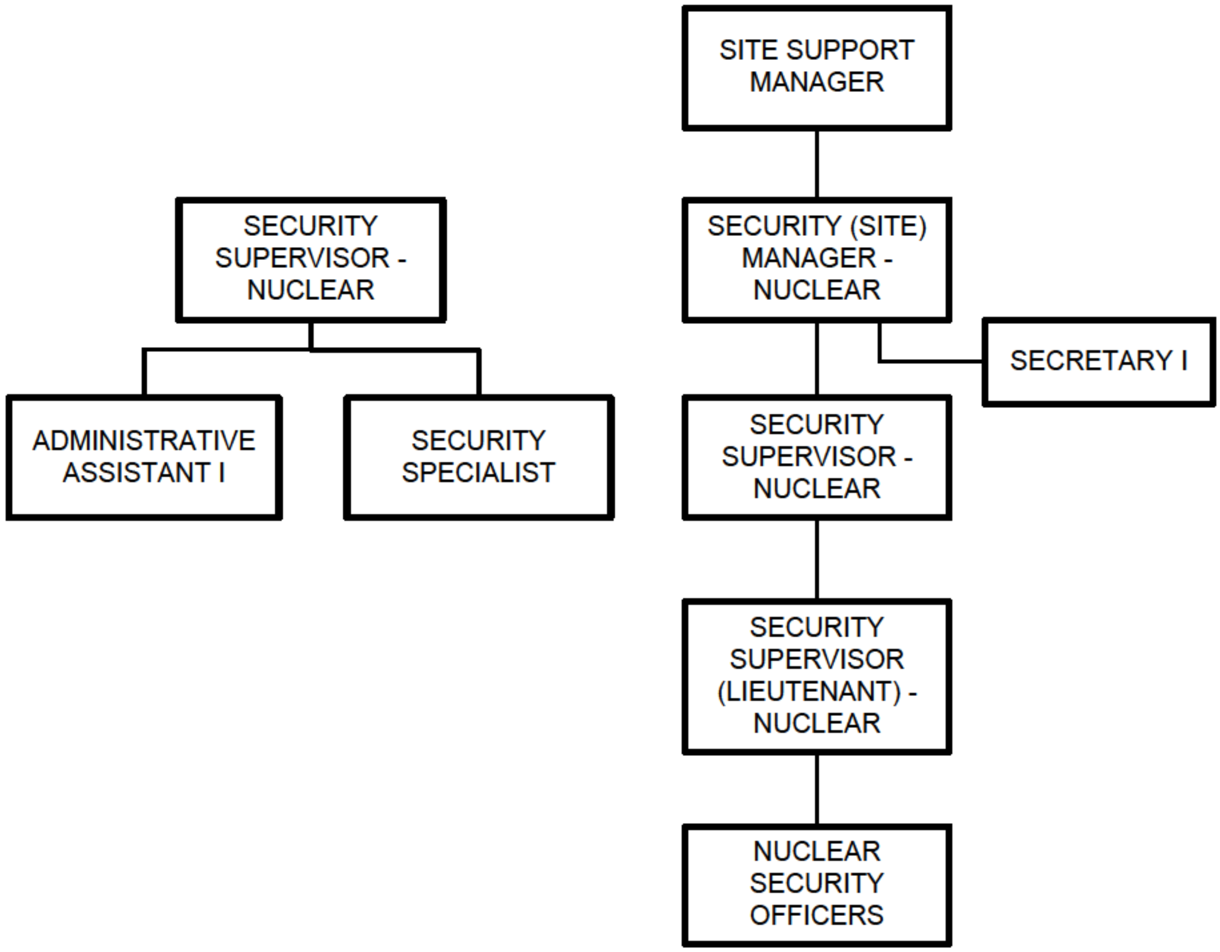
When appropriate, plant management makes a written report to the NRC. Bomb threats are anticipated to come by telephone. Employees who might receive such a call are trained to extract as much information as possible from the caller using a bomb threat checklist. Based on this and other information, action would be taken to search for the bomb, evacuate areas, shut down the reactor, or take any other actions deemed necessary to protect the plant and personnel.

13.7.2.6 Administrative Procedures

In the event of an incident of suspected sabotage or condition which threatens the security of the plant, the security force immediately notifies plant management (vice president-Hatch or SSM) and/or the shift supervisor and initiates a thorough investigation.

In such instances where initiation of the Emergency Plan may be required, plant management or the emergency duty officer gives direction to the security forces. A report is prepared which includes, as a minimum, the cause of the event, the extent of damage if any, and action taken to prevent recurrence of a similar event. Copies of the report are sent to plant management, the operations manager, and the chairman of the safety review board. When appropriate, plant management also reports the situation to the NRC.

Audits of the security program are conducted as specified in Chapter 12 of the Security Plan.



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SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

HNP SECURITY ORGANIZATION

FIGURE 13.7-1

14.0 INITIAL TESTS AND OPERATION

This chapter describes the initial testing and operating program that will be conducted at the HNP-2. This program, as defined in the Startup Manual, details the manner in which the testing and initial operation will be performed, controlled, and documented for the following three testing and initial operating phases.

A. Construction Acceptance Test Phase

Construction acceptance tests, including initial equipment energizing, flushing and cleaning operations, initial calibration of instrumentation, electrical wiring and equipment tests, valve testing, and initial equipment and system operation, take place. The construction acceptance test phase is the responsibility of the Georgia Power Company (GPC) production department.

B. Preoperational Test Phase

This phase is the time period during which approved preoperational tests are performed. The preoperational test phase is the responsibility of the GPC production department.

C. Startup Test Phase

This phase is the time period, beginning with fuel loading and extending through 100% power and warranty demonstrations, where GPC production department has overall control and responsibility for testing. This phase is subdivided into four parts:

- *Fuel loading and open-vessel tests.*
- *Initial heating to rated temperature and pressure.*
- *Power testing from rated temperature and pressure to 100% of rated output.*
- *Warranty demonstrations.*

The three testing phases also encompass cold functional testing and hot functional testing. Each phase is discussed in this chapter.

GPC will conduct the preoperational and startup test program in conformance with Regulatory Guide 1.68 (November 1973) with the following exceptions and qualifications noted as follows:

A.1.b Those items not applicable to boiling water reactors (BWRs) (pressurizer, steam, generator) will not be tested.

A.2.a Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.

A.2.f *HNP-2 will comply with this requirement through the functional testing of auxiliary startup instrumentation in the fuel loading startup test (STI-3) and startup procedure HNP-2-10203. This requirement is not covered in a preoperational test procedure.*

A.4.b *Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.*

A.4.c *Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.*

A.4.h *Will not be tested as part of the HNP-2 program; this system is shared with HNP-1.*

A.5.0 *Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.*

A.5.1 *Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.*

A.5.d *See section 14A.39.*

A.5.q *See sections 14A.2 and 14B.24.*

A.11 *See section 14A.28.*

A.12.b *Will not be tested as part of the HNP-2 program; this system is shared with HNP-1.*

A.12.c *Will not be tested as part of the HNP-2 program; this system is shared with HNP-1.*

B.1 *Will not be tested as part of the HNP-2 program; the section is not applicable to this plant.*

C.1 *Will not be tested as part of the HNP-2 program; the section is not applicable to this plant.*

C.2.f *See section 14A.29. The calibration program is not a part of preoperational or startup tests but rather is covered in plant operating procedures. No releases are planned for calibration of the effluent radiation monitors.*

D.1 *Will not be tested as part of the HNP-2 program the section is not applicable to this plant.*

D.2 *Will not be tested as part of the HNP-2 program; the system is not applicable to this plant.*

D.2.f *This test will be performed from ~ 50% power. Since the two-pump trip is not a limiting transient from the standpoint of the minimum critical power ratio (MCPR), there is no need for conducting the more extensive tests. The two-pump trip from test condition (TC) 3 will be sufficient to demonstrate plant response to simultaneous loss of both pumps.*

Testing is already planned at TC 4 (natural circulation), which is the point of minimum control stability referred to in the question. Arriving at this condition from 100% power by tripping both pumps offers no additional information.

More recent analytical information shows that the simultaneous trip of both recirculation pumps from very high initial power levels is no longer a significant fuel thermal transient. Previous calculations of minimum critical heat flux rates (MCHFR) showed this event to be important, but now the more accurate MCPR method shows wide fuel thermal margins, and hence this test has been deleted as unnecessary from our initial startup test programs since it causes a significant operational transient, power loss, and possible additional scram.

The reactor core power-void mode of dynamic response is known to be the least stable at a combination of low-core flowrate and higher power levels. This mode has behavior characteristics that are predictable from linear system analytical methods (NEDO-21506, Stability and Dynamic Performance of the GE-BWR, January 1977). Either small-, medium-, or large-disturbance inputs can be used to test for its characteristics such as decay ratio and frequency. The only requirement is to make the test disturbance of a size sufficient to make the response observable on the transient recorder. At TC 4, several different types of reactor transient tests are performed. In particular, the pressure-control backup regulator test and the control rod notch test are adequately sized to make the core power-void mode observable. Pressure setpoint steps and feedwater level setpoint step tests are also performed at TC 4 to show the reactor and its control systems to be acceptably stable.

The recirculation two-pump trip event, using the 100% control rod line, does yield a larger neutron flux transient, but most of that occurs while the reactor core flowrate is still high. By the time the core flow is nearing its minimum value, the relative rates of response have converged and stabilized to near steady state. They are smaller than some of those transient tests already initiated from TC 4 in each startup test program. Thus, the data to analyze for core stability have not been improved, but the plant has suffered a large power loss (100% power to 50% power). There is even a small possibility of a reactor scram and its attendant operational delay and power loss.

It is our judgment, with respect to observing reactor stability, and from the hydraulic consideration, that a recirculation pump trip (RPT) test on the 100% control rod line yields no added useful data, and it burdens the plant with an added large power loss. For this reason, we recommend that this test be performed from TC 3, where its flow coastdown data more efficiently fit in with other startup test objectives.

It may also be noted that when the Hench/Levy thermal hydraulic correlation was used as the analysis basis for BWRs, the large flow transients were the limiting transients of concern. With the change to the GEXL thermal hydraulic correlation, the flow transients are no longer limiting, as may be seen from the HNP-2 plant transient analysis. Consequently, the need to examine plant performance for wide flow reductions is no longer regarded as a startup test requirement. When the new RPT system is installed, there will be an added two-pump trip test scheduled for midpower levels. This will be

performed to verify proper RPT system performance prior to the plant's ascension to very high power levels.

D.2.j Plant response to changes in recirculation flow will be demonstrated at each major TC and along each major load line, i.e., midpower and rated load line. In addition, plant response to a larger load swing will be demonstrated along a midpower load line.

Plant load changes result from controlled maneuvers of the recirculation system. The optimized recirculation flow control system adjustments are determined after stability and response performance transients are performed. Stability testing is done first and yields faster load changes of from 2 to 7% of rated power. Core flow and power response transients follow with magnitudes of 18 to 35% of rated power along constant control rod pattern lines. In general, the size of midpower load maneuvers is about half of those performed along the rated power rod line. The load changes are accomplished by an increase in recirculation flow from about 65 to 100% over a period of ≤ 1 min.

D.2.o This rod sequence exchange demonstration will be included in the startup test program as STI-8.

D.2.s
D.2.t Both a turbine trip and a generator trip at and 100% power are not desired due to the extreme transients involved. It has been concluded that the reactor system's response to these two trips is essentially similar and need not be conducted twice.

Several years ago, both turbine and generator trip tests were performed from high power at General Electric Company (GE) direction to provide more data on variations from nominal conditions. For the last few years, the trip scram test matrix has been more efficient. For BWR plants with partial turbine bypass valve flow capacity, the transient experienced by the reactor in the turbine trip case is virtually identical to that in the generator trip case. The only important difference is the turbine valve closure times, which differ only by one-tenth of a second or less. After considering the great cost and transient impact of such trip scram events, when compared to the relatively small value of the data-gathering advantage, the need for both tests could not be justified.

At this time, GE requires choosing one or the other of a turbine or a generator trip at rated conditions in the startup program. Most plants decide in favor of the generator trip to simultaneously obtain main turbine speed and acceleration data while they are verifying the protective aspects of the fast control valve closure. They must have already performed a main turbine trip at between 60 and 80% where protective-related data can be obtained prior to the ascension to very high power levels. Thus, one of each kind of transient test is performed. This differs from Regulatory Guide 1.68 only in specified initial power levels.

Note also that another generator trip test is required of every plant early in its startup program at a power level just within the partial bypass valve flow capacity rating. With regard to the main turbine control and stop valves, the evidence to date indicates consistent operation in terms of characteristic and operating time. During a turbine trip, the turbine stop valves, turbine control valves, reheat stop valves, and intercept valves are all required to close from the initiating signal. For the load-rejection transient, only

the control valves and intercept valves are called upon to close. For this latter case, the turbine overspeed protection performs in such a manner that the turbine stop valves and reheat valves do not close. Thus, performance of the load-rejection test provides additional performance data. As stated above, the operating characteristics of all the valves involved are so well known that the performance of an additional turbine trip at 100% power is not justified on the basis of obtaining new information. There has been no evidence from previous tests of this type of turbine stop valves showing any sensitivity to flow with respect to an effect on closing time.

D.2.v Sampling of effluent monitoring system will be accomplished at major power levels in the implementation of chemical and radiochemical tests as part of the chemical and radiochemical startup test (STI-1) and startup test procedure HNP-2-10080.

D.2.aa Process computer checkout by means of completion of the dynamic system test case will be accomplished during the testing at TC 1, TC 2, and TC 3. This testing will be completed and all nuclear steam supply system (NSSS) software operational prior to power ascent above 50%.

Items identified above by A.4.h, A.12.b, and A.12.c will not be tested as part of the preoperational and startup testing programs. These functions are shared with, and are operational on, HNP-1, and thus functional capability has been proven adequately.

Acceptance criteria for the following tests will be based on predictions of the transients from actual conditions using expected core coefficients at beginning-of-life (BOL) as described below:

- *Main steam isolation valve (MSIV) full closure at 100% power.*
- *Turbine trip and generator load rejections at 100% power.*
- *Loss of turbine-generator and offsite power.*

The transient safety analysis will include parametric information for the prediction of performance criteria for a 75% power turbine trip, a full-power isolation, a full-power load rejection, and for a loss of feedwater heater transient. This new parametric information will be available before December 31, 1977.

A. The input for the test predictions is consistent with that used throughout this report. Briefly, the analysis basis can be expressed as follows:

1. Nuclear parameters are based on beginning-of-cycle core performance.

2. All plant hardware is assumed to operate properly, including bypass valves, relief valves, scram and trip functions, etc. (Should a significant hardware failure occur, such as bypass valve failure, the criteria may be violated and reanalysis might be required. This reanalysis could identify hardware or modeling errors or could use available sensitivity studies to correct discrepancies between actual plant conditions

and the conditions assumed in the original analysis.) The operation of this equipment is recorded during the test.

3. *Plant hardware is assumed to perform within the nominal expected limits required by technical specifications and design specifications. In some cases, performances will be assumed to be at a particular value in this range; measured values will be used with parametric studies to make appropriate corrections to the acceptance criteria. Sensitivity studies have been performed for many parameters, such as power level, relief valve setpoints, capacity and opening delay, bypass valve capacity and delay, reactivity insertion rate, and MSIV closure times. The studies demonstrate the relative sensitivity of the transient results to these parameters and permit adjustments to the analytical results for actual test conditions for these effects. Performance of this plant hardware is recorded during the test.*

B. *For the pressurization transients, i.e, the turbine trip, load rejection, and MSIV closure, there are two key predicted parameters.*

1. *The positive change in reactor pressure that occurs within the first 30 s following the initiation of the transient represents the highest pressure experienced by the system and will have the highest rate of increase; thus, it will provide the best measure of the plant performance compared to expectations in the area of overpressure protection. The pressure response of the reactor is recorded throughout the test.*

2. *The positive change in reactor-simulated heat flux that occurs within the first 30 s following the initiation of the transient provides information representative of the thermal output and performance of the system. In the case of these transients, a reactor scram is initiated and turns power before steam flow is significantly decreased; therefore, no increase in heat flux is expected. The reactor-simulated heat flux is also recorded during the test as well as steam flow.*

C. *The loss of turbine-generator and offsite power test is not amenable to the preceding approach because it is largely a test of balance-of-plant equipment and predicted performance would be of little value. It should also be noted that this test is not as good an indicator of reactor performance as the aforementioned tests. This test is used to verify that the diesels start and power their assigned loads. Parameters such as emergency core cooling system (ECCS) equipment and diesel generator automatic actuation are recorded as well as the reactor responses.*

14.1 TEST PROGRAM

A comprehensive testing program planned for HNP-2 is outlined in figure 14.1-1. This program ensures the following:

- *That the equipment and systems perform in accordance with design criteria.*
- *That the initial fuel loading is accomplished in a safe and efficient manner.*
- *That required verification of nuclear parameters is obtained.*
- *That the plant can be safely brought to rated capacity and safely shut down under all expected operational conditions.*

Systems and components are tested and evaluated by organizations outlined in the Startup Manual according to written and approved test procedures. An analysis of test results verifies that each system or component performs satisfactorily. The written procedures for the initial tests and operation include objectives and prerequisites of the tests, precautions, test methods, acceptance criteria, return-to-normal status, and appropriate references.

The HNP-2 administrative staff also receives various bulletins [Nuclear Regulatory Commission (NRC) circulars, GE Weekly Startup Reports, GE SILs, etc.] that are read and reviewed for applicability by the HNP-2 operations superintendent and responsible department heads as designated by the HNP-2 operations superintendent. Each HNP-1 design change request is reviewed for its applicability to HNP-2. Those items that are determined to be applicable are incorporated into the HNP-2 design. The initial testing and operation program is under the responsibility of GPC, including the performance and evaluation of tests. Technical assistance will be provided by Bechtel Corporation, GE, vendor technical representatives, and consultants as deemed necessary to prepare test procedures, perform tests, and evaluate test results.

The production and construction departments each have site organizations to accomplish all necessary activities for plant startup. The construction department is responsible for all construction activities and for final turnover of all plant equipment to the production department. Turnover of plant equipment is accomplished according to written procedures in the Startup Manual and occurs once the production department is satisfied that the equipment is functional and installed correctly.

The production department is responsible for the initial testing and startup program. This testing phase includes the construction acceptance testing, preoperational testing, and startup testing.

During the preoperational and startup test phase, the permanent plant operating procedures, as described in section 13.5, are used where possible to support the preoperational and startup tests, as specified by the test procedures, to provide step-by-step procedures for normal systems operations that are used in implementing the tests.

14.1.1 ADMINISTRATIVE PROCEDURES (TESTING)

The entire test program outlined in figure 14.1-1 is described in detail in the Startup Manual. This document is a controlled working document that establishes the tasks to be performed, describes responsibilities for performing the tasks, and provides means for ensuring that the approved program is followed by all organizations involved with the plant testing and initial operation.

14.1.1.1 Purpose of the Startup Manual

The Startup Manual clearly defines the manner in which the test and startup programs will be performed, controlled, and documented; describes the implementation of the three phases of testing; and defines interfaces among documents, programs, and organizations. The manual does not, however, provide details that of necessity must be included in and approved for specific procedures (such as preoperational test procedures).

Methods are described so that procedures are prepared, checked, approved, utilized, and documented for all initial tests and operation. Methods are also described that show how test results are evaluated, approved, and documented. The manual is itself controlled so that up-to-date and approved methods are utilized. This document fulfills requirements of Criterion XI, Test Control, of 10 CFR 50, Appendix B.

14.1.1.2 Responsibilities and Interfaces of Onsite Organizations

The responsibilities and interfaces of principal onsite organizations involved in the construction assurance testing, preoperational testing, and startup testing of HNP-2 are described below. Refer to figure 14.2-1 for organizational relationships. Section 13.1 describes the relationship of the production department to the various onsite organizations. These organizations are as follows:

A. *GPC Production Department*

   Once equipment and systems are turned over from the construction department, production is responsible for operating and maintaining the equipment and systems. The overall startup test program, from construction acceptance tests through the warranty demonstration run, is under the direction of the production department.

B. *Field Quality Assurance (QA) Organization (Engineering and Construction)*

   The site QA field representative is responsible for reviewing and auditing production activities during construction acceptance testing, preoperational testing, startup testing. As each system is turned over to the production department, the QA audit function becomes a part of the existing program of the QA representative for operations. (See section 17.2.)

C. General Electric Company

GE is the supplier of the NSSS and certain other plant systems such as radwaste. With respect to construction, testing, and startup activities, GE has the responsibility for providing advice, guidance, and counseling. The GE startup staff is responsible for providing technical direction during NSSS preoperational tests and fuel loading and startup tests, as required.

D. Bechtel Corporation

The Bechtel site representative is responsible for reviewing, commenting on, and approving preoperational test procedures and test results. The representative works closely with the GPC production department in resolving problems associated with preoperational tests.

14.1.1.3 Equipment and System Turnover Procedures

Turnover procedures facilitate equipment, subsystems, or systems release from GPC construction to GPC production department. For permanent equipment transfers, the construction supervisor and his staff ensure that all work on the system is complete and all required documentation is in the construction files. The construction supervisor, senior EMDFR, construction superintendent or assistant superintendent, and the contractor superintendent sign the transfer form indicating the system has been reviewed and approved for turnover. Acceptance is confirmed when the transfer form is signed by the production plant superintendent or assistant plant superintendent.

Detailed procedures to be followed in preparing the transfer form and in the handling of the followup on exception items are provided in the Startup Manual.

14.1.1.4 Construction Acceptance Test Phase Procedures

The purpose of this section is to describe the procedures and activities that take place during the construction acceptance test phase and to describe the responsibilities and interfaces of various organizations in performing these tasks:

A. Documentation for Construction Acceptance Test Activities

Required general procedures for all inspections, checks, and tests are described in the Startup Manual. Also outlined are the responsibilities for preparing and approving controlling test procedures and for maintaining documents.

B. Description of Construction Acceptance Test Activities

Each item considered to be a construction acceptance test activity is listed. The following lists some, but not necessarily all, of the construction acceptance test activities:

- *Wiring continuity checks.*

- *Megger and high potential tests.*
- *Initial adjustment and rotational checks of rotating equipment.*
- *Checking control and interlock functions of instruments.*
- *Calibrating instruments and checking or setting initial trip setpoints.*
- *Pneumatic testing of instrument and service air system and cleaning of lines.*
- *Equipment adjustments such as alignment, greasing, and tightening of bolts.*
- *Checking and adjusting designated relief and safety valves.*
- *Initial adjustment of motor-operated valves, including adjusting limit switches, checking interlocks and controls, and measuring motor current and operating speed.*
- *Initial adjustment of air-operated valves, including checking all interlocks and controls, adjusting limit switches, measuring operating speed, and initial setting and functional checks of controllers, pilot solenoids, etc.*

The construction acceptance test program consists of a procedure for electrical systems and a procedure for mechanical systems. Data sheets are provided to document tests described in the procedure. The construction acceptance test procedures and data sheets are developed by production department personnel and are reviewed by the construction and engineering departments. After this review, comments received are incorporated into the procedure.

14.1.1.5 Preoperational Test Procedures

Preoperational testing is coordinated with construction acceptance testing in order to permit fuel loading without compromising nuclear safety. Preoperational testing is completed prior to core fuel loading to the maximum extent practical. As construction acceptance testing is completed on individual systems, the initiation of preoperational testing is approved and tests are performed to verify, as closely as possible, the performance of the system under actual operating conditions. Where required, simulated signals or inputs are used to verify the full operating range of the system and to calibrate and align systems and instruments at those conditions. Systems that are used during normal operation are verified and calibrated under actual operating conditions. Systems that are not used during normal plant operations but must be in a state of readiness to perform safety functions are checked to the extent possible prior to fuel loading.

Abnormal conditions are simulated during testing, when required, and when such conditions do not endanger personnel, equipment, or the NSSS whose cleanliness has been established. To the extent feasible, abnormal operating procedures are checked during simulation of these conditions.

The GPC production department has primary responsibility during this phase of activity.

14.1.1.5.1 Preparation and Review of Preoperational Test Procedures

Preoperational test procedures will be prepared by GPC engineers or Bechtel engineers. A detailed format, which will be followed, is outlined in procedure HNP-2-11.

Each preoperational test procedure is reviewed and approved by the plant review board (PRB) and site representatives for GE and Bechtel. After the initial review by the PRB and design group representatives, comments are incorporated into the procedure. The procedure then goes through the review chain again for release-for-execution signatures. The release-for-execution signatures authorize performance of the preoperational test.

When a preoperational test procedure requires changes that alter the intent of that test, the test supervisor initiates the change by completing a change sheet with the pertinent information and forwarding the change sheet to the senior plant engineer or his designated alternate. After a review of the change, the technical supervisor submits it to the PRB. After PRB action, the change is submitted to the operations superintendent, the Bechtel site representative, and the GE operations manager for final disposition and issuance if appropriate.

Changes that do not change the intent of the preoperational test may be made by the test supervisor during performance of the test. The change is recorded as an outstanding exception pending approval of a change sheet. The performance of the test may continue, pending approval of the change sheet. The test supervisor clears the outstanding exception through the same procedure outlined above for changes that alter the intent of a test. When the change is approved, the exception can be signed off by the test supervisor. If recommendation of approval is not made by the PRB, the affected part of the test must be reperformed as specified by the PRB and site management.

14.1.1.5.2 Execution of Preoperational Tests

During preoperational testing, the responsible GPC engineer, as designated by the senior plant engineer, is assigned to a particular test. The responsible GPC engineer for the particular test will be the test supervisor for that test.

A tentative sequence of testing is shown in figures 14.1-2 through 14.2-11. This sequence is developed on the assumption that power ascension will be from TC to TC in numerical order of TCs, with the exception of testing at TC 7, which will be done during testing from TC 3. This sequence of testing at each plateau is only tentative and is subject to change on a day-to-day basis as it is reviewed by plant management and operation personnel during actual testing.

Test results will be reviewed at the completion of each test plateau by the following persons and group:

- *GPC senior plant engineer.*
- *GE lead startup test design and analysis engineer.*
- *GE site operations manager.*

- *GPC operations superintendent - Unit 2.*

- *PRB.*

The results review will be conducted to assure that testing has been completed, that criteria have been met, and that power ascension is justified by the test results.

Review and approval will constitute approval to proceed to the next TC for further testing and is certified by the signing of a checkoff list by the GPC HNP-2 operations supervisor and the operations superintendent. If test results are unacceptable, corrective action will be taken and additional testing performed prior to any increase in power.

Each test will be carefully performed in strict conformance with the test procedure and authorized changes. All test data will be recorded within the procedure or on specially prepared data sheets.

The tests, data sheets, forms, records, recorder traces, and photographs that are part of the preoperational and startup test program are the property of the GPC and will be retained in the plant files for the life of the plant.

When the test is complete, the test supervisor will review the test procedure and data against stated acceptance criteria. After successful completion of the test, the test supervisor forwards the test results for review and approval.

14.1.1.5.3 Review and Approval of Preoperational Test Results

The test results again pass through the review chain where GE, Bechtel, and the PRB review the results for compliance with the procedure and the acceptance criteria. Approval is indicated by the test completed signature.

14.1.1.6 Startup Test Program Procedures

The startup test program and relevant administrative procedures are described in subsection 14.1.4.

14.1.2 ADMINISTRATIVE PROCEDURES (MODIFICATIONS)

Deficiencies, which become apparent as a result of the test program, in a critical system's design or performance, the methods of test conductance, or in-station operating instructions are documented and submitted to the plant superintendent. Such documentation is controlled through use of deficiency reports, which are described in administrative procedure HNP-2-5.

If the deficiency is in either the test instruction or an operating instruction utilized during testing, the applicable sections of the instructions are revised and appropriately reviewed. All such revisions, which affect testing, are documented, reviewed by the PRB, and approved by the plant superintendent.

If the deficiency is in equipment performance because of improper installation or checkout and does not involve a change in design, the deficiency will be corrected and corrective action will be documented and testing resumed.

In the event that modifications to system hardware are necessary to meet the objectives or to improve system performance, a design change request or an as-built will be initiated. The request will be approved by the plant superintendent and forwarded to the cognizant design group. System modifications so requested are subject to the same requirements as those described in chapter 17. Any changes that are required to be made to a preoperational test will be routed through the review chain as described in paragraph 14.1.1.5.1.

14.1.3 TEST OBJECTIVES AND PROCEDURES

14.1.3.1 General Objectives of the Testing Phase

- *To confirm that construction is complete and acceptable.*
- *To adjust, calibrate, and align equipment, instruments, and systems to the extent possible in a cold plant.*
- *To ensure that design objectives and acceptance criteria are met.*
- *To provide documentation of the performance and safety of equipment and systems.*
- *To provide baseline test and operating data on equipment and systems for future reference.*
- *To run-in new equipment for a sufficient period so that design, manufacturing, or installation defects may be detected and corrected.*
- *To ensure, to the extent possible, that plant systems operate together on an integrated basis.*
- *To give maximum opportunity to the permanent plant operating staff to obtain practical experience in the operation and maintenance of equipment and systems.*
- *To establish, to the extent possible, safe and efficient normal, abnormal, and emergency operating procedures.*
- *To establish and evaluate surveillance testing procedures.*
- *To demonstrate that systems and safety equipment are operational and that it is allowable to proceed to fuel loading and to the startup phase.*

14.1.3.2 <u>Objectives of the Preoperational Testing Phase - Discussion of Preoperational Tests</u>

Preoperational tests are those tests to be conducted prior to fuel loading to demonstrate the capability of plant systems to meet safety-related performance requirements. As described in paragraph 14.1.1.5.1, the preoperational test procedures are prepared in detail with input from system design documents and from vendor technical documents. These procedures are then approved by the PRB.

The preoperational test synopses presented in supplement 14A define the scope of each test while leaving the detailed test methods to the test procedures themselves, which are reviewed and approved by the PRB.

Each of the test synopses indicates that GPC will prepare and execute a comprehensive preoperational test on each of the systems listed. Each test will require verification of operation and/or demonstration that the systems' components operate within their respective engineering design specifications and, additionally, that the systems' components operate together in a proper integrated fashion. Total systems' performance will similarly be demonstrated to be within their respective design parameters.

Tests on nonsafety-related systems are also performed. These tests are not required to be completed prior to performance of fuel loading or nuclear heatup and will be performed whenever the required conditions are available.

Further testing of systems after fuel loading are called startup tests and are described in subsection 14.1.4.

Preoperational tests, which are required to be completed prior to fuel loading, are identified in the Startup Manual.

14.1.4 FUEL LOAD AND INITIAL OPERATION - STARTUP PHASE

After a sufficient number of tests in the preoperational test phase described previously in this chapter have been completed, their results approved by the PRB, and access control established, the startup phase begins. The startup phase begins with fuel loading and extends to the completion of warranty demonstrations. This phase is subdivided into the following four parts:

- *Fuel loading and open vessel tests.*
- *Initial heatup to rated pressure and temperature.*
- *Power testing from rated pressure and temperature to 100 % of rated output.*
- *Warranty demonstration.*

The HNP-2 Startup Manual prescribes administrative procedures to be followed during the startup phase and describes responsibilities and authorities during the startup phase. Normal plant staff responsibilities, authorities, and qualifications are given in chapter 13.

The overall objectives of the startup phase are as follows:

- *To achieve an orderly and safe initial core loading.*
- *To accomplish all testing and measurements necessary to determine that the approach to initial criticality and subsequent power ascension is safe and orderly.*
- *To conduct low-power physics tests sufficient to ensure that physics design parameters have been met.*
- *To conduct initial heatup and operating functional checks so that integrated operation of systems is shown to meet power operation requirements as determined by experienced plant operations personnel.*
- *To conduct an orderly and safe power ascension program, with requisite physics and systems testing, to ensure that the plant operating at power meets design intent.*
- *To conduct a successful warranty demonstration program.*

Tests conducted during the startup phase consist of major plant transients (table 14.1-1), stability tests (table 14.1-2), and a remainder of tests that are directed toward demonstrating correct performance of the NSSS and numerous auxiliary plant systems while at power. Certain tests may be identified with more than one class of test. Table 14.1-3 shows a typical startup phase test program and should be considered in conjunction with figure 14.1-12, which shows graphically the various test points as a function of core thermal power and flow.

The exact program and specific acceptance criteria for each of the tests to be performed will be determined prior to initiation of the startup testing. The tests and acceptance criteria shown are typical and based on prior experience from other similar BWRs, including HNP-1.

14.1.4.1 Fuel Loading and Open Vessel Tests

Fuel loading begins when the preoperational testing program, described in subsection 14.1.3, has been essentially completed.

Prior to approving fuel loading, the plant superintendent must verify that the plant is ready to load fuel. This verification is accomplished by the following steps, which are performed at the completion of preoperational testing.

A. Loss-of-Power Demonstration - Standby Core Cooling Required

This test demonstrates the capability of each standby diesel generator to start automatically and assume its emergency core cooling loads in a loss of normal auxiliary power.

B. Cold Functional Testing

The cold functional testing defined here is an integrated system operation of various plant systems that can be operated as systems prior to fuel loading. The intent is to observe any unexpected operational problems from either an equipment or a procedural source and to provide an opportunity for operator familiarizations with the system operating procedures under operating conditions.

Some of the cold functional testing will be accomplished during the preoperational test program. For example, integrated and simultaneous operation of the following systems may take place during the flush of the total system: condensate system, condensate demineralizer system, low-pressure coolant injection (LPCI) system, core spray system, reactor water cleanup (RWC) system, plant service water system, reactor building closed cooling water system, and others. As required, additional integrated systems performance will be demonstrated prior to fuel loading.

C. Routine Surveillance Testing

Because the interval between completion of a preoperational test on a system and the requirement for that system to be operated may be of considerable length, a number of routine surveillance tests must be performed prior to fuel loading and must be repeated on a routine basis. The Technical Specifications detail the test frequency. In general, this surveillance test program (specified in the Technical Specifications) is instituted prior to fuel loading by the HNP-2 operating staff. Chemical and radiochemical tests are made in order to check the quality of the reactor water before fuel is loaded and to establish base and background levels, which will be required to facilitate later analysis and instrument calibrations. Plant and site radiation surveys are made at specific locations for later comparison with the values obtained at the subsequent operating power levels.

D. Master Startup Checklist

A detailed list of items that must be completed, including the preoperational tests and proper disposition of all exceptions noted during preoperational testing listed in supplement 14A, is rechecked to verify completion just prior to the final approvals for fuel loading.

After the above mentioned steps have been completed to the satisfaction of the plant superintendent, fuel loading may begin. Fuel loading requires the movement of the full core complement of assemblies from the fuel pool to the core, with each assembly identified by number before being placed in the correct coordinate position. The procedure controlling this movement is arranged so that shutdown margin and subcritical checks are made at predetermined intervals throughout the loading, thus ensuring safe loading increments. Specifically sensitive in-vessel neutron monitors serve to provide indication for the shutdown margin measurements and also to allow the monitoring of the core flux level as each assembly is added. A complete check is made of the fully loaded core to ascertain that all assemblies are properly installed, correctly oriented, and are occupying their designated positions.

Shutdown margin checks are repeated for the fully loaded core and criticality is achieved with each of the two prescribed rod sequences in turn, the data being recorded for each rod withdrawn.

Each rod drive is subjected to scram and performance testing. An initial setting is given to the intermediate range monitors (IRMs) by comparison with the source range monitors (SRMs). The process computer is checked to see that it is receiving correct values for those process variables that are available.

14.1.4.2 Initial Heatup to Rated Pressure and Temperature

Heatup follows the satisfactory completion of the fuel loading and open vessel tests (subsection 14.1.4) and further checks are made of coolant chemistry together with radiation surveys at the selected plant locations. All control rod drives (CRDs) are scram-timed at rated temperature and pressure with selected drives timed at two intermediate reactor pressures and at different accumulator pressures. Both control rod sequences are further investigated in order to obtain rod pattern versus coolant temperature relationships. The process computer checkout continues as more process variables become available for input. The reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems will undergo controlled starts at low reactor pressure and rated conditions and again in the quick-start mode at a selected power level. Correlations are obtained between process temperatures and the values of other process variables as heatup continues. The movements of NSSS piping in the drywell mainly as a function of expansion are recorded for comparison with design data. An IRM and average power range monitor (APRM) calibration is made using coolant temperature rise data during nuclear heatup.

14.1.4.3 Power Testing From Rated Temperature and Pressure to Licensed Output

The power test phase consists of several tests, many of which are repeated several times at the different test levels; consequently, reference should be made to table 14.1-3 for the probable order of execution for the full series. While a certain basic order of testing is maintained relative to power ascension, there is, nevertheless, considerable flexibility in the test sequence.

Coolant chemistry tests and radiation surveys are made at each principal test level in order to ensure a safe and efficient power increase. Selected CRDs are scram-timed at various power levels to provide correlation with the initial data. The effect of control rod movement on other parameters, e.g., electrical output, steam flow, and neutron flux level, is examined for different power conditions. Following the first reasonably accurate heat balance (25% power), the IRMs are reset.

At each major power level the low-power range monitors (LPRMs) are calibrated, whereas the APRMs are calibrated initially at each new power level and following LPRM calibration. Completion of the process computer checkout is made for all variables, and the various options are compared with calculations from the BUCLE code as soon as significant power levels are available. Further tests of the RCIC and the HPCI systems are made with and without injection into the reactor pressure vessel (RPV).

Collection of data from the system expansion tests is completed for those piping systems that had not previously reached full operating temperatures. The axial and radial power profiles are explored fully by means of the traversing incore probe (TIP) system at representative power levels during power ascension.

Core performance evaluations are made at all test points above the 10% power level and for selected flow transient conditions; the work involves the determination of core thermal power, maximum fuel rod surface heat flux, and the MCPR.

Overall plant stability in relation to minor perturbations is shown by the following group of tests:

- *Flux response to control rod movement.*
- *Pressure regulator setpoint change.*
- *Water level setpoint change.*
- *Bypass valve opening.*

For the first of these tests, a centrally located control rod is moved and the flux response is noted on a selected LPRM chamber. The next two tests require that the changes made approximate as closely as possible a step change in demand, while for the remaining test the bypass valve is opened as quickly as possible. For all of these tests, the plant performance is monitored by recording the transient behavior of numerous process variables, the one of principal interest being neutron flux. Other imposed transients are produced by step changing of demand core flow, isolating a feedwater heater, and failing the controlling pressure regulator to permit takeover by the backup regulator. Table 14.1-2 shows the TCs at which all these stability tests are performed.

The category of major plant transients includes full closure of all the main steam isolation valves (MSIVs), fast closure of turbine-generator control valves, fast closure of turbine-generator stop valves, loss of the main generator and offsite power, trip of a feedwater pump, and several trips of the recirculation pumps. The plant transient behavior is recorded for each test and the results are compared with the predicted design performance. Table 14.1-1 shows the operating TCs for all the proposed major transients.

The transient performance of the plant during each stability test and major plant transient described in the above paragraphs is recorded for all parameters of interest by temporary test equipment, which includes the startup test transient recorder. This test equipment will be removed at the conclusion of the initial startup testing phase and the circuits disconnected both at the recorder and at the signal source.

Signals from certain process variables are recorded on a tape recorder during startup testing. This tape recorder is referred to as the startup test transient recorder.

The transient recording system takes many signals, which come from sources mainly in the control and relay panels in the main control room. The majority of these signals are derived from indicating instruments, recorders, and indicating lights. In all cases a high-resistance connection is made between the signal source and the recorder. It is recognized that certain signals are derived from relay panels, which also contain safety grade circuits, and in all such cases signals developed from relays use only spare contacts and are thus isolated from the remainder of the system circuitry. The only signals taken from circuits that are required to perform a safety function are in the HPCI flow-control circuitry for the HPCI discharge flow, flow controller output, and ramp generator output. These circuits will be disconnected from the HPCI system[a] when the startup testing is completed (currently anticipated to be 12 months from the date of initial fuel loading). Since no connections are made to the startup test recorders from circuits required to perform other safety functions (including functions redundant to HPCI), any failure of the recording circuitry would affect only the HPCI system. Due to the above and the short duration of time during which the startup test recording circuitry will be installed, it is believed

that the isolation amplifiers provide adequate protection for the three safety-related circuits connected to the startup test recorder. This same criterion is used for signals that are derived from any control system that could in any way affect plant operation. The isolation amplifiers are located within the safety grade panels, thus removing the separation requirement for the secondary cables that run to the transient recording equipment. Nevertheless, separation is provided for HNP-2 as discussed below. In some earlier installations the isolation amplifiers were situated at the transient recorder, and it was then necessary to observe divisional separation for the connecting cables. As indicated above, this requirement does not apply to HNP-2, and no failure of transient recording equipment or connecting cables can interfere with any reactor safety systems.

Each cable has been assigned with the same division designation as the associated device to which it is connected and is routed in accordance with paragraph 8.3.1.4.1.2. When a raceway of the same division is not available, cables are installed in conduits.

The raceway system is installed in accordance with paragraph 8.3.1.4.1.

A test is made of the safety relief valves in which leaktightness and general operability are demonstrated. At all major power levels the jet pump flow instrumentation is calibrated. The as-built characteristics of the recirculation pump drives are investigated as soon as operating conditions permit full core flow. The local control loop performance, based on the drive motor, fluid coupler, generator, drive pump, jet pumps, and control equipment is checked. The vibration testing is conducted at several power conditions as the operating power level is raised.

14.1.4.4 <u>Warranty Demonstration</u>

The warranty test phase consists of a demonstration in which the steaming rate and steam quality are shown to comply with contractual obligations. This demonstration includes a 100-h full-power run.

14.1.4.5 <u>General Discussion of Startup Tests</u>

All those tests comprising the startup test phase are discussed in supplement 14B. For each test a description is provided for tests purpose, test description, and, where applicable, a statement of test acceptance criteria. The exact program and the specific acceptance criteria for each of the tests to be performed will be determined and reviewed with the NRC prior to initiation of the startup testing. The tests and acceptance criteria shown are typical of the HNP-2 startup test program and reflect prior GE experience.

In describing the objectives of a test, an attempt is made to identify those operating and safety-oriented characteristics that are being explored.

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a. The cabling for the startup test recording system will remain installed, but all connections to the loop will be lifted at the source of the signal tap at the completion of startup and warranty testing.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either level 1 or level 2. A level-1 criterion normally relates to the value of a process variable assigned in the design of the plant, component systems, or associated equipment. If a level-1 criterion is not satisfied, the plant will be placed in a suitable hold condition, and compatible testing may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the level-1 criterion are now satisfied.

A level-2 criterion is associated with expectations relating to the performance of systems. If a level-2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

For transients involving oscillatory response, the criteria are specified in terms of decay ratio (defined as the ratio of successive maximum amplitudes of the same polarity). The decay ratio must be less than unity to meet a level-1 criterion and less than 0.25 to meet level 2.

14.1.4.6 Startup Test Procedure Preparation, Approval, and Modifications

Startup test instructions will be developed by GE with approval remaining with GPC. The GE startup test instructions will be used for the preparation of detailed startup test procedures for implementing the startup test program. Approval of the startup test procedures is given by the PRB, the HNP-2 operations superintendent, and the GE operations manager.

Major modifications to the procedures are those that change the intent of the startup test or will change safety margins already approved. Such proposed modifications must undergo review and approval of the PRB.

If startup test specifications level-2 criteria are involved in the major change, the GE site operations manager may be required to obtain approval of the intended change from BWRSD engineering in San Jose.

After the above approvals, minor modifications to the procedures can be made if the modification does not change the intent of the test. Responsible GPC engineers and lead GE test design and analysis engineer will provide approval of the minor modifications. Minor changes required after starting a test are documented by completion of a test change notice and pen and ink changes to the official copy. The review and approval process of a test change notice is the same as that given any procedure revision except that it may be reviewed after the test has been completed. Any minor change items, which have been successfully resolved, are approved by the PRB when it approves the test results. Major changes to the procedures required after the start of testing necessitate stopping the test until the HNP-2 operations superintendent and GE site operations manager review and give approval to the proposed modifications.

14.1.4.7 Startup Test Execution

During startup testing, the responsible GPC engineer, as designated by the senior plant engineer, is assigned to follow the startup testing program on a shift basis with the technical direction of the GE test design and analysis shift engineer.

The HNP-2 senior plant engineer and the operations superintendent review and approve the responsible GPC engineers assigned to the above functions.

All startup tests will be performed according to approval startup test procedures.

Testing will be conducted on a TC and test plateau basis as outlined below. (See table 14.1-2.)

Plateau	*Test Condition*
I	*Fuel load and open vessel*
II	*Heatup*
III	*TC 1*
IV	*TC 2, TC 3, and TC 7*
V	*TC 4, TC 5, and TC 6*
VI	*Warranty*

14.1.4.8 Startup Test Results Approval and Approvals for Power Escalation

Test results will be reviewed at the completion of each test plateau by the following persons and group:

- *GPC senior plant engineer.*
- *GE lead startup test design and analysis engineer.*
- *GE site operations manager.*
- *GPC operations superintendent.*
- *PRB.*

At each test plateau (as indicated in paragraph 14.1.4.7), the persons and group listed above will review all tests performed at the indicated testing point and determine that these results are adequate and present no safety hazards either to personnel or equipment. They will give approval to escalate power to the next indicated testing point.

14.1.5 ADMINISTRATIVE PROCEDURES (SYSTEM OPERATION)

Normal and abnormal operating procedures will be reviewed throughout the preoperational test and startup test phases. Paragraph 14.1.1.5 describes how the responsible GPC production personnel will review, utilize, or modify normal and abnormal condition operating procedures during the

preoperational test phase. Similar methods will be employed during the startup test phase by the HNP-2 staff so that when commercial operation is attained, a correct, usable set of procedures will be available.

TABLE 14.1-1

MAJOR PLANT TRANSIENTS

	Test Condition					
Test Title	*1*	*2*	*3*	*4*	*5*	*6*
Feedwater pump trip (STI-23)						*X*
MSIVs (one valve) (STI-25)					*X*[(a)]	
MSIVs (all valves) (STI-25)						*X*[(a)]
Turbine-generator (TG) stop valve fast closure			*X*[(b)]			*X*[(c)]
TG control valve fast closure		*X*				*X*[(c)]
RPT (one) (STI-30)			*X*			*X*
RPT (two) (STI-30)			*X*			
Loss of TG and offsite power		*X*				

a. Between TC 5 and TC 6.
b. 60 to 80% power - may be done at TC 5.
c. Either TG stop valve fast closure or TG control valve fast closure will be performed.

TABLE 14.1-2

STABILITY TESTS

Test Title	*Test Condition* 1	2	3	4	5	6
Core-power-void mode test (STI-21)				X		
Pressure regulator setpoints-change (STI-22)	X	X	X	X	X	X
Pressure backup regulator change (STI-22)	X	X	X	X	X	X
Feedwater system water level setpoint change (STI-23)		X	X	X	X	X
Feedwater system heater loss (STI-23)					X[a]	
Turbine valve surveillance		X			X[a]	X
Flow control (STI-29)		X[b]			X[a]	

a. Between TC 5 and TC 6.
b. Between TC 2 and TC 3.

TABLE 14.1-3 (SHEET 1 OF 4)

STARTUP TEST PROGRAM

PLATEAU DESIGNATION		I	II	III	IV		V			VI
TEST PLATEAU PROCEDURE[a]		HNP-2-10200	HNP-2-10300	HNP-2-10400	HNP-2-10400		HNP-2-10900			HNP-2-10995
TEST CONDITION SERIES[b]		10200	10300	10400	10500	10600	10700	10800	10900	10995
				TEST CONDITIONS [c,d]						
ST1 NO.	TEST NAME	OPEN VESSEL OR COLD TEST	HEATUP	1	2	3	4	5	6	WARRANTY[e]
1	CHEMICAL AND RADIOCHEMICAL[f]	X	X	X		X		X	X	
2	RADIATION MEASUREMENT [g]	X	X		X	X			X	
3	FUEL LOADING	X								
4	FULL CORE SHUTDOWN MARGIN	X								
5	CRD	X	X	X	X	X			X	
6	SRM PERFORMANCE AND CONTROL ROD SEQUENCE	X	X	X	X					
8	ROD SEQUENCE EXCHANGE				X					
9	WATER LEVEL MEASUREMENTS		X	X	X	X	X	X	X	
10	IRM PERFORMANCE	X	X	X						
11	LPRM CALIBRATION		X[n]	X		X			X	
12	APRM CALIBRATION		X	X	X	X		X	X	X
13	PROCESS COMPUTER	X	X	X		X				
14	RCIC		X[f]		X[l]					
15	HPCI		X[fi]			X[l]				
16	SELECTED PROCESS TEMPERATURES		X	X		X	X		X	
17	SYSTEM EXPANSION	X[j]	X	X	X	X			X	
18	CORE POWER DISTRIBUTION			X		X			X	
19	CORE PERFORMANCE			X	X	X	X	X	X	X
20	STEAM PRODUCTION									X
21	CORE POWER VOID MODE TEST						X			

TABLE 14.1-3 (SHEET 2 OF 4)

PLATEAU DESIGNATION		I	II	III	IV		V			VI
TEST PLATEAU PROCEDURE[a]		HNP-2-10200	HNP-2-10300	HNP-2-10400	HNP-2-10400		HNP-2-10900			HNP-2-10995
TEST CONDITION SERIES[b]		10200	10300	10400	10500	10600	10700	10800	10900	10995
				TEST CONDITIONS [c,d]						
STI NO.	TEST NAME	OPEN VESSEL OR COLD TEST	HEATUP	1	2	3	4	5	6	WARRANTY[e]
22	PRESSURE: SETPOINT CHANGES			X, BP[l]	X[i]	X[a,k], BP	X	X	X, A	
	REGULATOR BACKUP REGULATOR			X, BP	X	X[a,k], BP	X	X	X, A	
23	FW SYSTEM: FW PUMP TRIP								M[i]	
	WATER LEVEL SETPOINT CHANGE	X[j]		X	X[l]	X	X	X	X, A	
	HEATER LOSS								X[l]	
24	TURBINE VALVE SURVEILLANCE				X[i,m]			X[e], SP	X[o,p]	
25	MSIVs: EACH VALVE	X[j]	X			X[i,q]				
	ONE VALVE								X[n,p], SP	
	FULL ISOLATION								X[g,i,r,s], SD	
26	RELIEF VALVES: FLOW DEMONSTRATION				X[l]					
	OPERATIONAL		X[i]		X					
27	TURBINE STOP VALVE TRIP &					X[j,r,t], SD				
	GENERATOR LOAD REJECTION				X[i], SP				X[l,r], SD	
28	SHUTDOWN FROM OUTSIDE CONTROL ROOM			X, SD						
29	FLOW CONTROL				L	M[m], A[m]		M, A	M, A	

TABLE 14.1-3 (SHEET 3 OF 4)

PLATEAU DESIGNATION		I	II	III	IV		V			VI
TEST PLATEAU PROCEDURE[a]		HNP-2-10200	HNP-2-10300	HNP-2-10400	HNP-2-10400		HNP-2-10900			HNP-2-10995
TEST CONDITION SERIES[b]		10200	10300	10400	10500	10600	10700	10800	10900	10995
		OPEN VESSEL OR COLD TEST	HEATUP	TEST CONDITIONS [c,d]						WARRANTY[e]
ST1 NO.	TEST NAME			1	2	3	4	5	6	
30	RECIRCULATION SYSTEM: TRIP ONE PUMP					X[l]			X[l]	
	TRIP BOTH PUMPS					X[i]				
	SYSTEM PERFORMANCE			X	X	X	X		X	
	NONCAVIT VERIFICATION					X[i]				
31	LOSS OF TG OFFSITE POWER									
33	DRYWELL PIPING VIBRATION		X	X	X	X			X	
35	RECIRCULATION SYSTEM FLOW CALIBRATION	X[j]			X[m]	X		X, X[n]	X	
42	RHR SERVICE WATER		X	X		X			X	
44	DRYWELL COOLING		X	X	X	X			X	
70	RWC SYSTEM		X		X					
71	RHR SYSTEM		X	X[l]						
74	OFFGAS SYSTEM		X	X		X			X	

TABLE 14.1-3 (SHEET 4 OF 4)

LEGEND:

X	*-*	*LOCAL OR MASTER MANUAL FLOW CONTROL MODE*
L	*-*	*LOCAL FLOW CONTROL MODE*
M	*-*	*MASTER MANUAL FLOW CONTROL MODE*
A	*-*	*AUTOMATIC FLOW CONTROL MODE*
SP	*-*	*SCRAM POSSIBILITY*
SD	*-*	*SCRAM DEFINITE*
BP	*-*	*BYPASS VALVE RESPONSE*

a. *SEE HNP-2-10001 FOR ADMINISTRATION OF STARTUP TEST PROCEDURES.*

b. *INDIVIDUAL PROCEDURES UNDER THE SAME TC WILL BE NUMBERED BY THE TC SERIES NUMBER WITH THE EXCEPTION OF THE LAST TWO DIGITS, WHICH WILL BE THE ST1 NUMBER.*

c. *SEE FIGURE 14.1-12 FOR TEST CONDITIONS REGION MAP.*

d. *PROCEDURES PERFORMED BETWEEN THE CONDITIONS WILL BE INCLUDED UNDER THE HIGHER TEST CONDITION SERIES.*

e. *WARRANTY WILL BE DEMONSTRATED UNDER SINGLE PROCEDURE HNP-2-10995.*

f. *SEE HNP-2-10080 FOR THE CHEMICAL AND RADIOCHEMICAL PROCEDURES.*

g. *SEE HNP-2-10090 FOR THE RADIATION MEASUREMENTS PROCEDURE.*

h. *FUNCTIONAL CHECK ONLY.*

i. *DO ST1 33 IN CONJUNCTION WITH THIS TEST.*

j. *SPECIAL INSTRUMENT CHECKOUT ONLY. NO TESTING.*

k. *NOT USED.*

l. *80 TO 90% POWER*

m. *BETWEEN TCs 2 AND 3.*

n. *BETWEEN TCs 5 AND 6.*

o. *FUTURE MAXIMUM POWER WITHOUT SCRAM.*

p. *DETERMINE MAXIMUM POWER WITHOUT SCRAM.*

q. *BETWEEN TCs 1 AND 3.*

r. *PERFORM TEST 5, TIMING OF FOUR SLOWEST CONTROL RODS IN C CONJUNCTION WITH THESE SCRAMS.*

s. *BEFORE 100% TURBINE TRIP.*

t. *60 TO 80% POWER.*

PROGRAM PHASE	RESPONSIBILITIES	MAJOR ACTIVITIES
CONSTRUCTION ACCEPTANCE TEST PHASE CONSTRUCTION ACCEPTANCE TEST PHASE COMPLETE	GEORGIA POWER COMPANY – PRIMARY RESPONSIBILITY AND PERFORMING AGENT BECHTEL, GE, CONSULTANTS, VENDORS AS NECESSARY FOR ASSISTANCE	1. INITIAL EQUIPMENT ENERGIZATION 2. FLUSHING AND CLEANING 3. INITIAL CALIBRATION OF INSTRUMENTATION 4. ELECTRICAL WIRING AND EQUIPMENT TESTS 5. VALUE AND MECHANICAL EQUIPMENT TESTS 6. INITIAL EQUIPMENT OPERATION 7. EQUIPMENT AND SYSTEM MAINTENANCE 8. REVIEW AND APPROVE TEST RESULTS
PRE-OPERATIONAL TEST PHASE EQUIPMENT CONTROL TRANSFER TO PRODUCTION DEPARTMENT	GEORGIA POWER COMPANY – PRIMARY RESPONSIBILITY AND PERFORMING AGENT GE, CONSULTANTS AS NECESSARY FOR ASSISTANCE	1. APPROVE PREREQUISITES FOR PREOP TESTING 2. PERFORM PREOP TESTS 3. RETURN SYSTEMS TO NORMAL STATUS 4. REVIEW AND APPROVE PREOP TESTS RESULTS
STARTUP TEST PHASE FUEL LOAD	GEORGIA POWER COMPANY – PRIMARY RESPONSIBILITY AND PERFORMING AGENT GE, CONSULTANTS AS NECESSARY FOR ASSISTANCE	1. APPROVE READINESS FOR FUEL LOADING 2. LOAD FUEL 3. PERFORM STARTUP TESTS FROM INITIAL CRITICALITY TO FULL POWER 4. REVIEW AND APPROVE STARTUP TESTS RESULTS
WARRANTY DEMONSTRATION PHASE COMMERCIAL OPERATION	GEORGIA POWER COMPANY – PRIMARY RESPONSIBILITY AND PERFORMING AGENT GE, VENDORS, CONSULTANTS AS NECESSARY FOR ASSISTANCE	1. APPROVE READINESS FOR WARRANTY TESTS 2. PERFORM WARRANTY TESTS 3. REVIEW AND APPROVE WARRANTY TEST RESULTS

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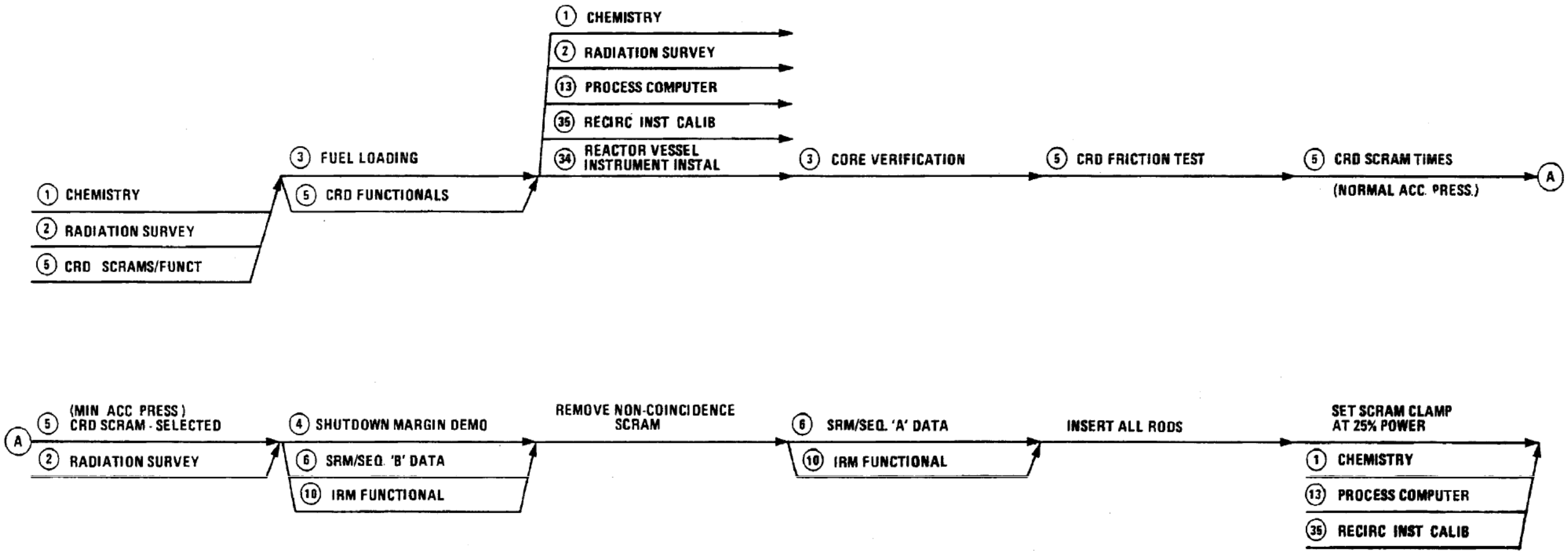
UNIT 2

TEST PROGRAM OUTLINE

FIGURE 14.1-1



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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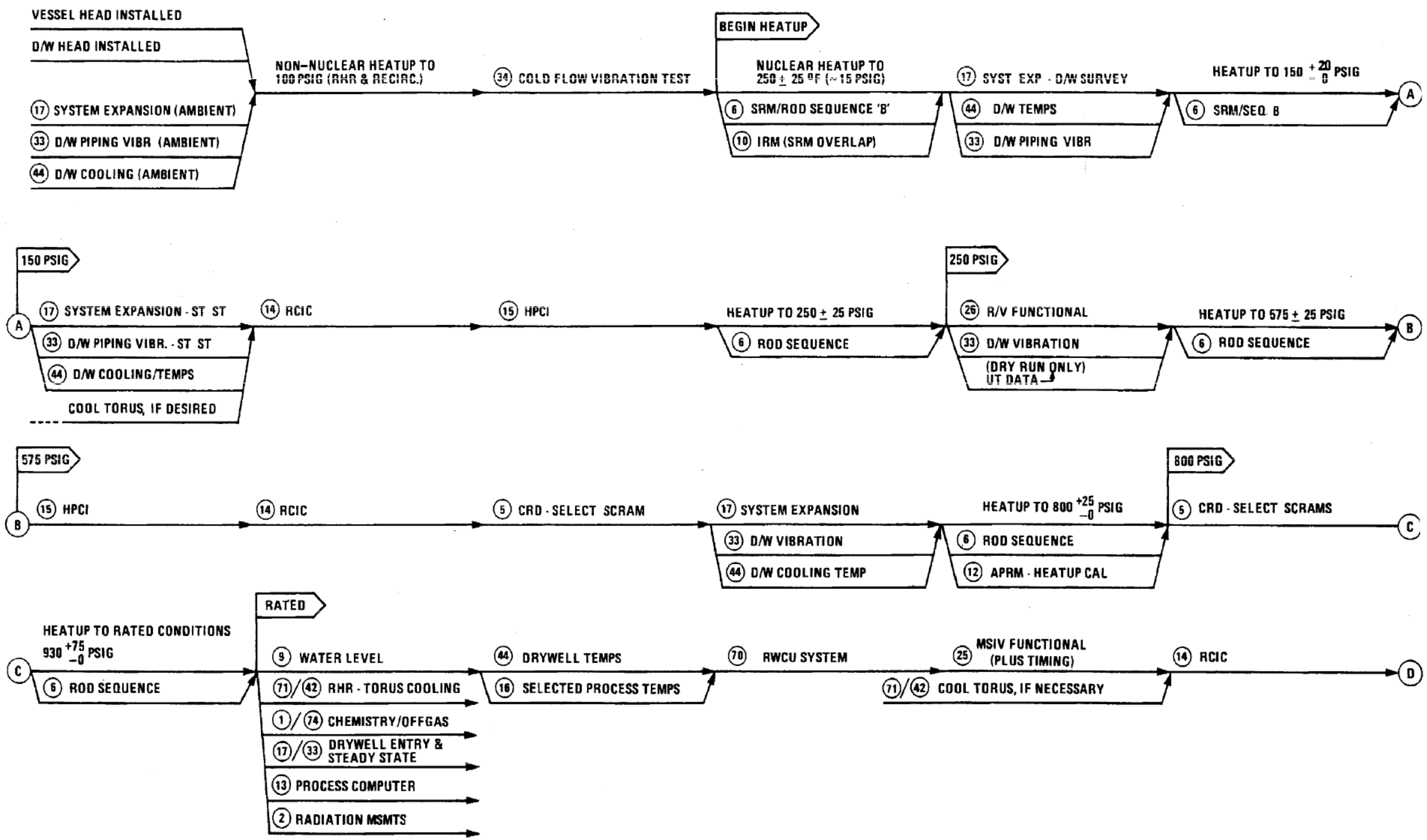
STARTUP TESTING – OPEN VESSEL

FIGURE 14.1-2



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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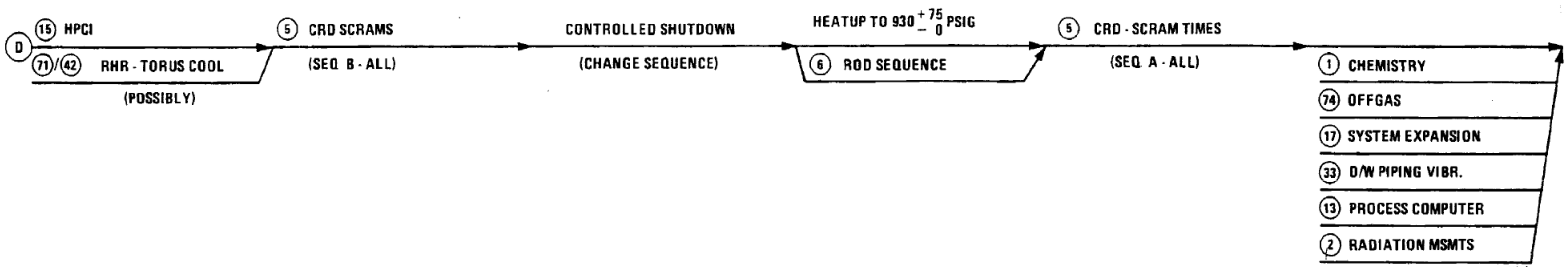
STARTUP TESTING
HEATUP – PART I

FIGURE 14.1-3



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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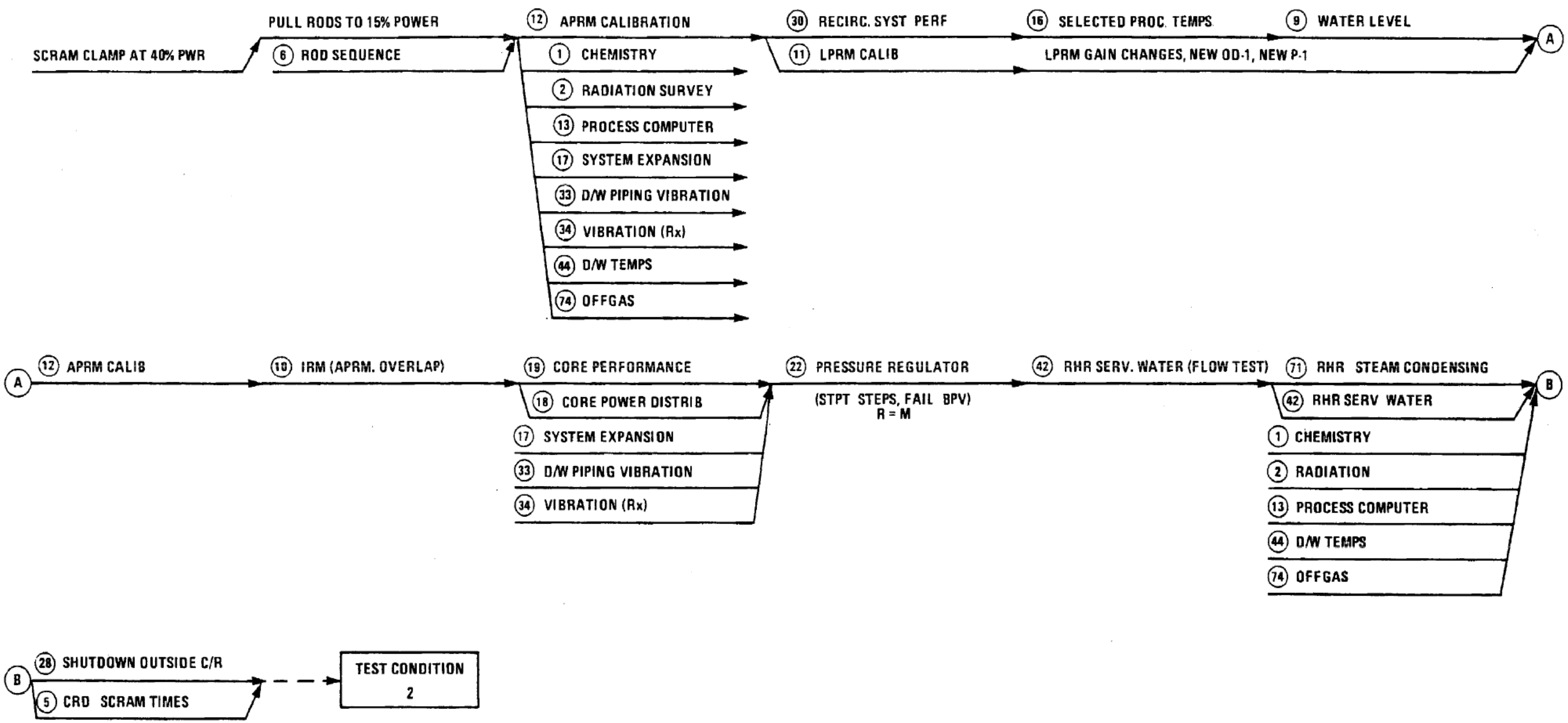
STARTUP TESTING
HEATUP – PART II

FIGURE 14.1-4



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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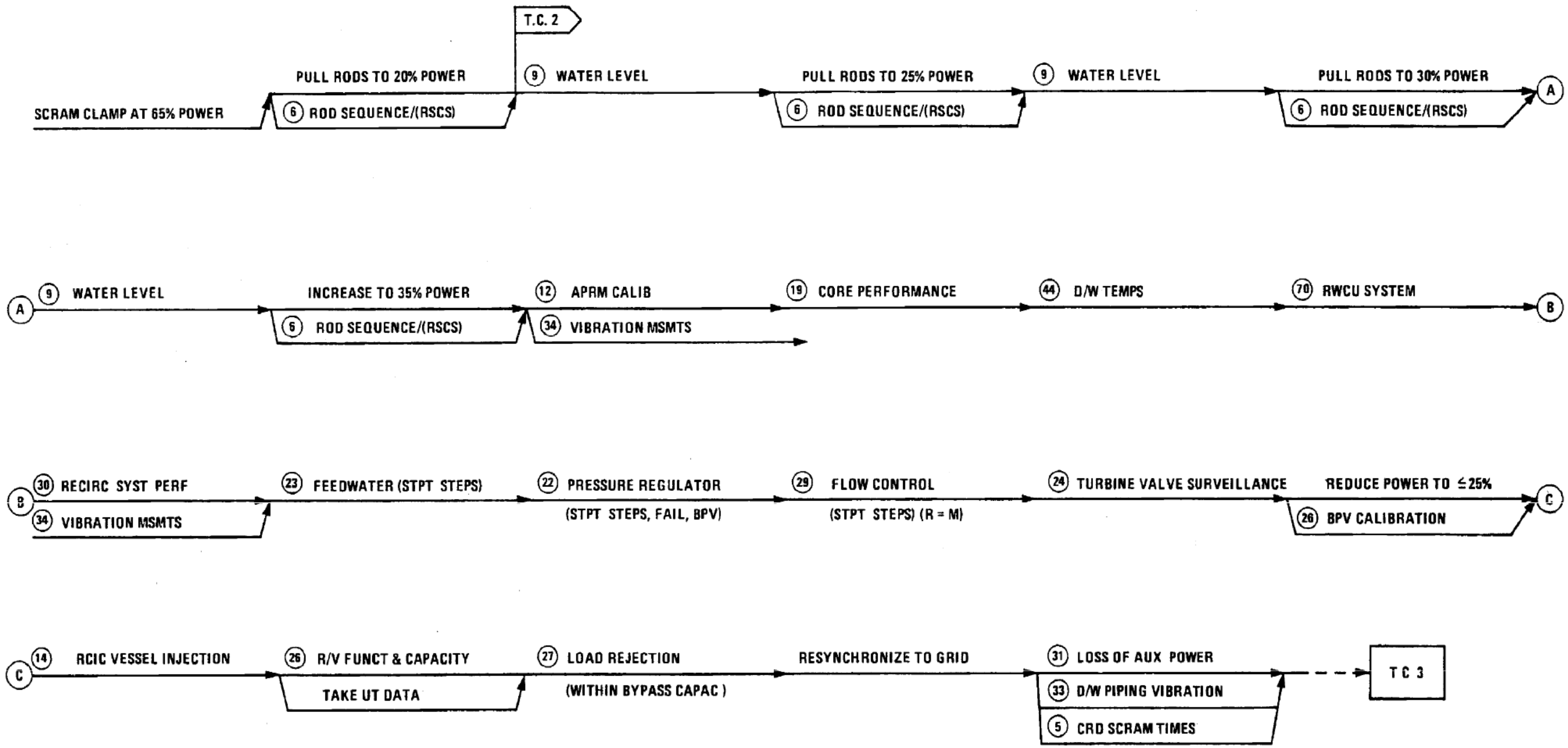
STARTUP TESTING
TEST CONDITION 1

FIGURE 14.1-5



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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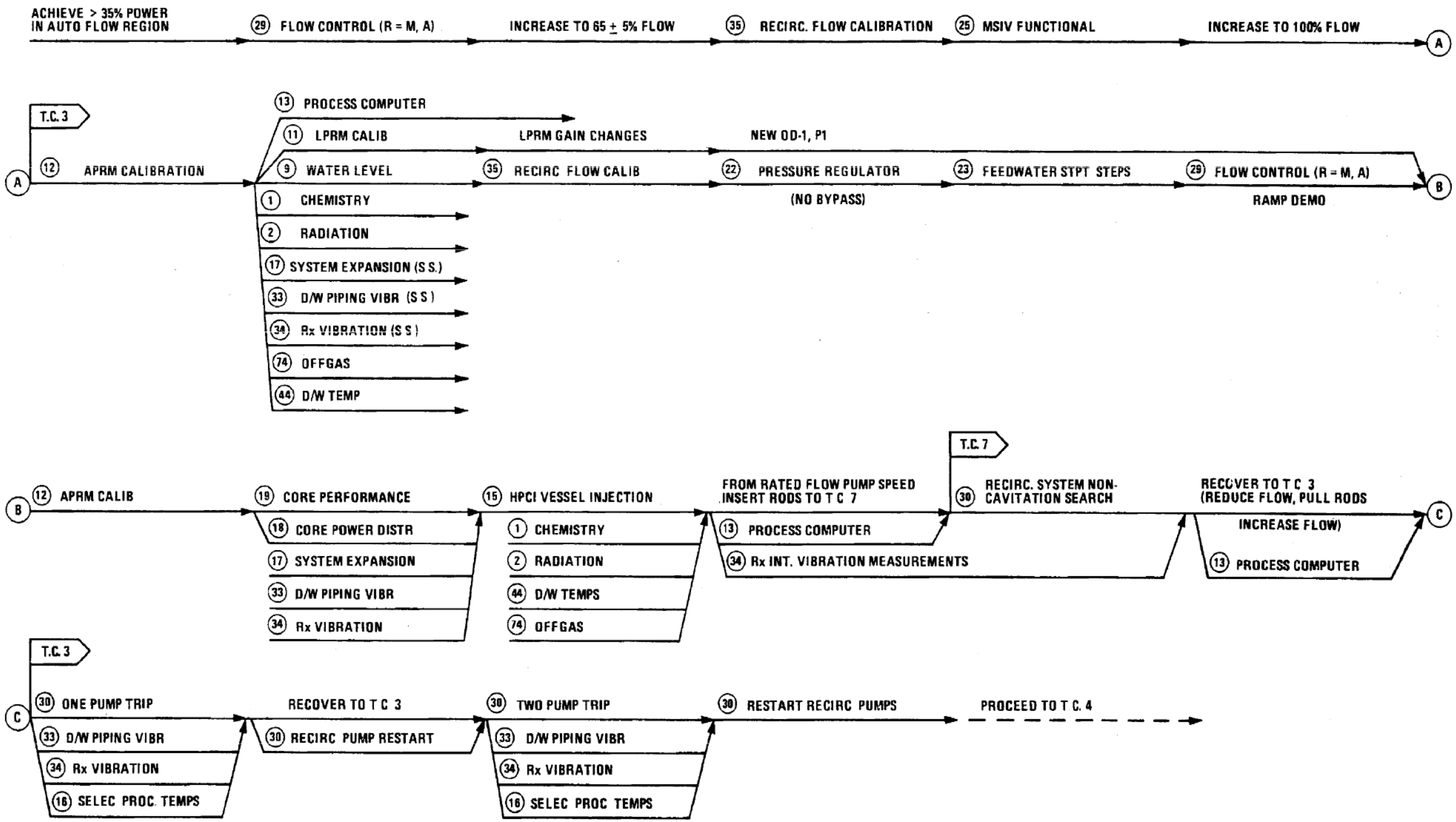
STARTUP TESTING
TEST CONDITION 2

FIGURE 14.1-6



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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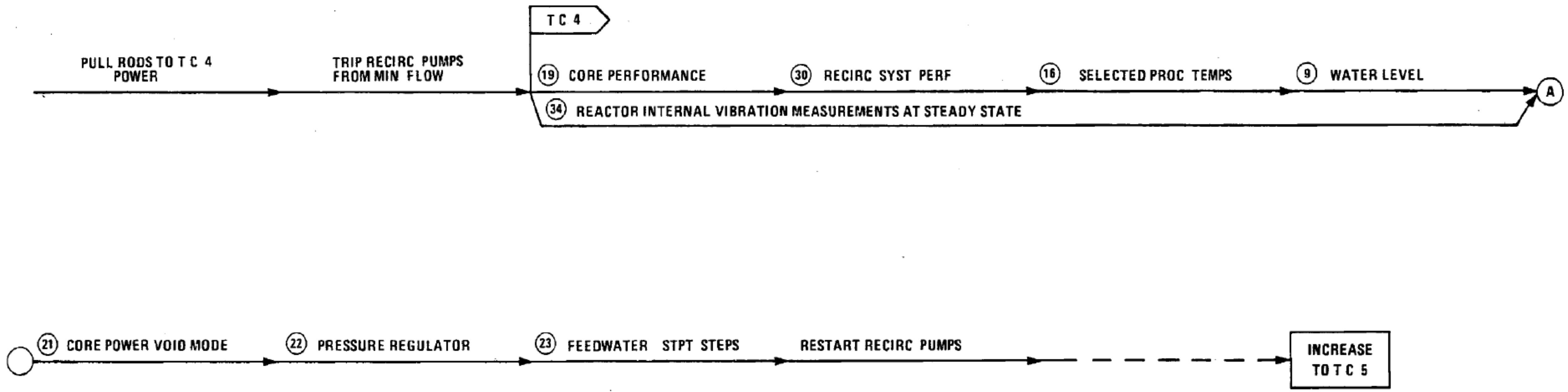
SOUTHERN COMPANY *Energy to Serve Your World®*	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	STARTUP TESTING TEST CONDITION 3
		FIGURE 14.1-7



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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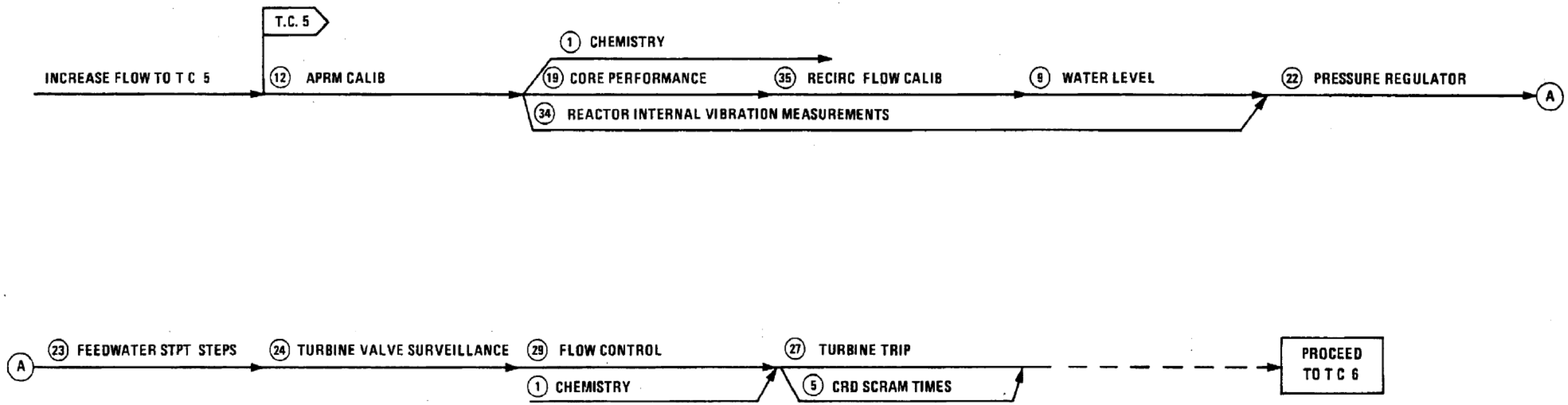
SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	STARTUP TESTING TEST CONDITION 4
	FIGURE 14.1-8



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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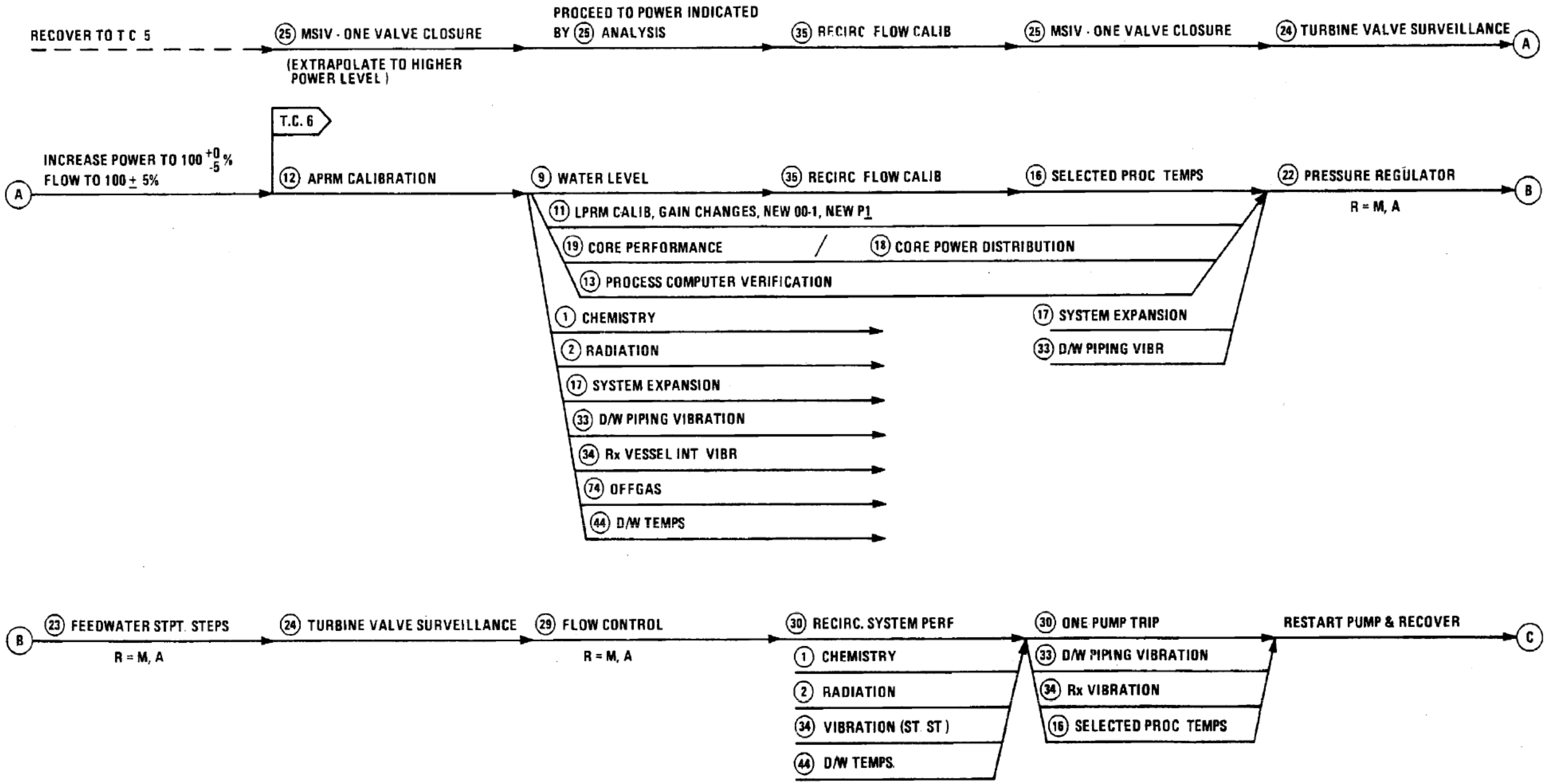
STARTUP TESTING
TEST CONDITION 5

FIGURE 14.1-9



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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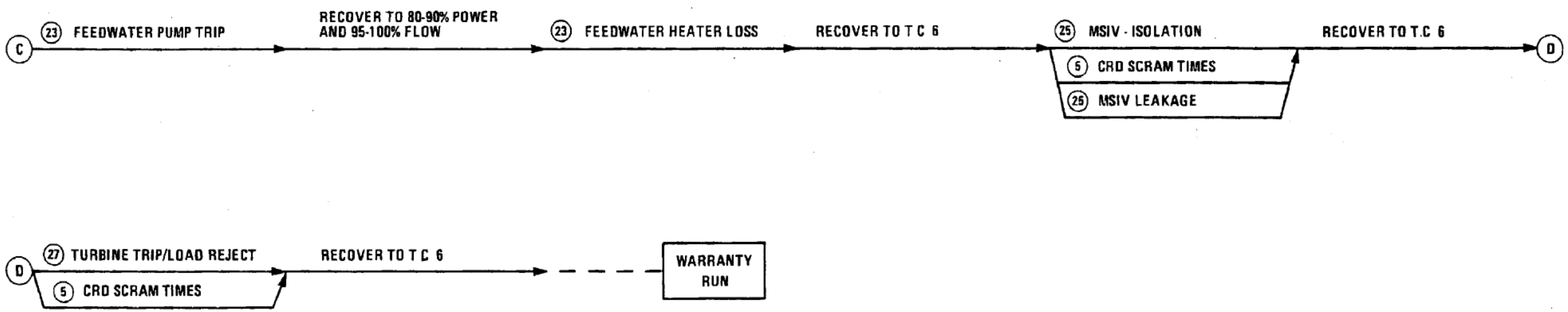
STARTUP TESTING
TEST CONDITION 6

FIGURE 14.1-10 (SHEET 1 OF 2)



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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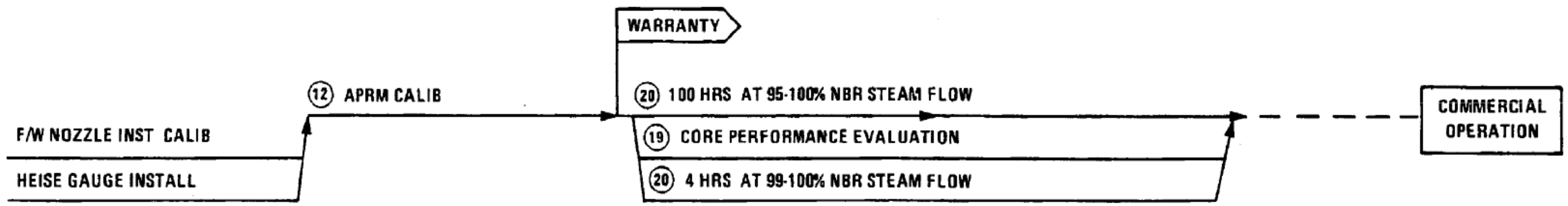
STARTUP TESTING
TEST CONDITION 6

FIGURE 14.1-10 (SHEET 2 OF 2)



NOTE: THIS FIGURE IS SUBJECT TO CHANGE.
NUMBERS IN CIRCLES INDICATE STARTUP TESTS LISTED IN FSAR SUPPLEMENT 14B.

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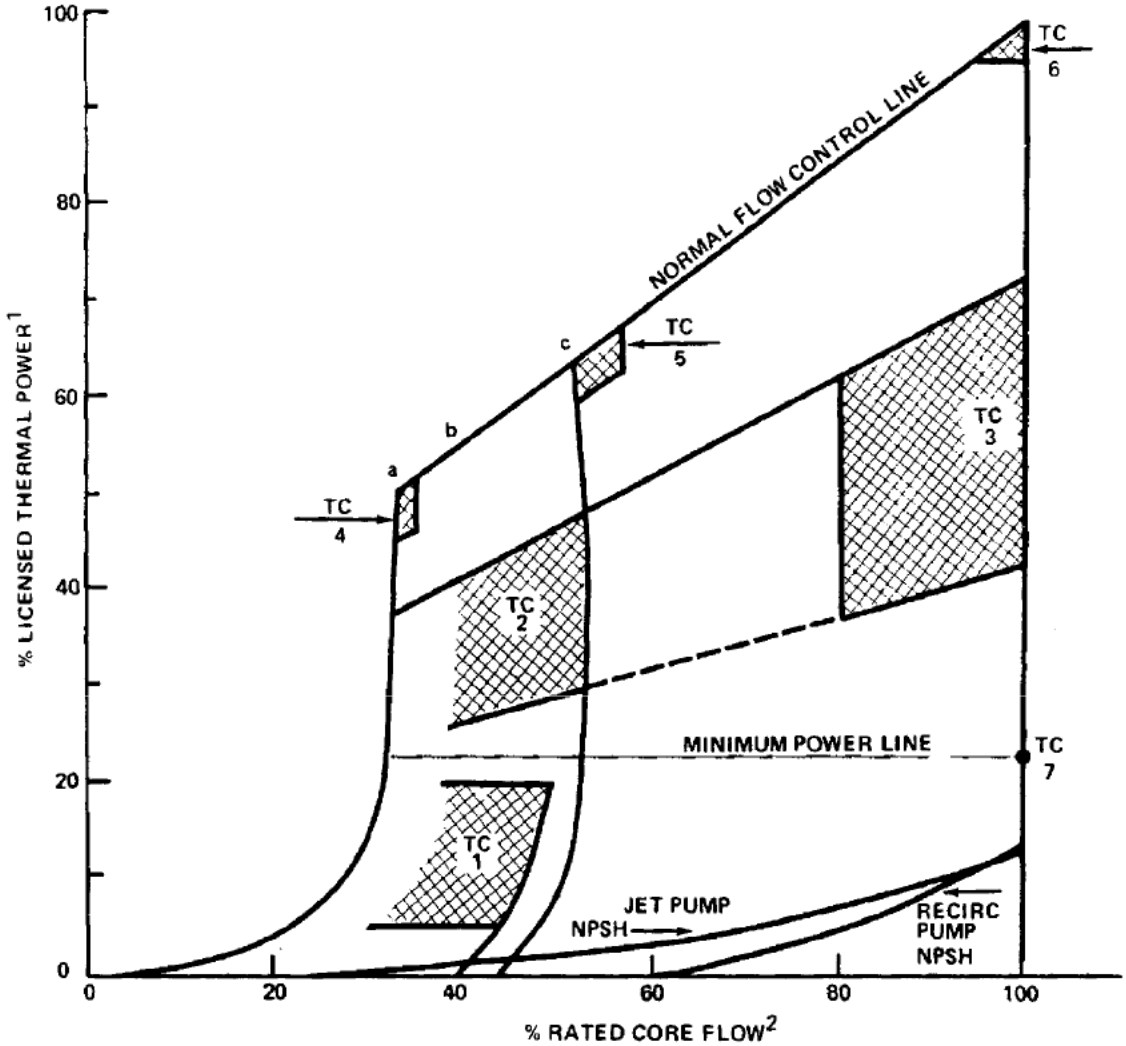
STARTUP TESTING
WARRANTY DEMONSTRATION

FIGURE 14.1-11



1. Power in percent of rated thermal power, 2436 MWt
2. Core flow in percent of rated core recirculation flow, 77.0 MLB/hr

CONSTANT PUMP SPEED LINES

a) Natural circulation
b) 20% Pump Speed
c) Contractual lower limit of master flow control

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UNIT 2

APPROXIMATE POWER FLOW MAP SHOWING STARTUP TEST CONDITIONS

FIGURE 14.1-12

14.2 NUCLEAR SYSTEM STARTUP ORGANIZATIONS AND RESPONSIBILITY

The Georgia Power Company (GPC) production department is responsible for all operations and for providing an adequate staff of qualified and licensed personnel. Preoperational tests, the initial fuel loading, and nuclear system startup and operational testing are performed by the applicant with technical assistance, where required, from General Electric (GE) and the Bechtel Power Corporation.

The procedures covering these activities will be written in detail and will include methods, data, and calculation aids. The startup procedures include test methods and describe the steps for performing tests and judging results. The test program is described in section 14.1.

14.2.1 ORGANIZATIONAL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

Within its contractual responsibilities, GE supplies various types of technical direction to GPC at the Edwin I. Hatch Nuclear Power Plant-Unit 2 (HNP-2) site. Basically, GE has the responsibility for providing technical direction, advice, and counsel based upon current engineering, installation, and testing practices to GPC.

The site installation technical direction staff consists of a resident site manager assisted by a field engineer or engineers, technical specialists, and a quality control (QC) representative.

The resident site manager has overall responsibility for the technical direction of installation of all equipment with the boiling water reactor (BWR) project department scope of supply. He is BWR project department's senior representative at the site on matters within the scope of the nuclear steam supply system (NSSS) contract as described above. He provides administrative direction to all GE personnel assigned to the site. When GE instrument and service engineering personnel are used as installation specialists in the discharge of technical direction obligations, the resident site manager has the same degree of control over their work activities as he does with the GE personnel.

The technical specialist personnel include both short-visit specialists from San Jose and longer-term resident specialists such as specialists on reactor pressure vessel (RPV) internals, mechanical and piping, nuclear instrumentation, process instrumentation, electrical, and control systems.

These specialists are consulted from time to time as deemed necessary by GE or as requested by GPC.

The GE startup staff consists of personnel from the startup and training subsection. The operations manager, operations superintendent, and lead startup test design and analysis engineer form a team, which is headed by the operations manager.

GE provides an operations superintendent and operations engineers for shift coverage throughout the startup testing phase.

The startup test design and analysis site personnel include the lead test design and analysis engineer and three other test design and analysis engineers to provide shift coverage during startup testing.

The operations manager has overall functional responsibility for all GE startup activities at the site. He assumes this responsibility from the resident site manager about 1 month prior to fuel loading and

normally arrives at the site about 6 months prior to fuel loading. In some cases, he assumes a portion or all of the responsibilities of the resident site manager, and in other cases the resident site manager may continue and function in both positions. The operations superintendent is specifically responsible for supervising the operations engineers and for coordinating the GE technical advice given to GPC on certain preoperational tests and during startup operations (commencing with fuel load). He is also available for review, with the operations engineers, of the GPC-prepared plant operating procedures for NSSSs. The operations engineers provide technical assistance during the startup test period. While on shift, the operations engineer is the responsible GE engineer. The operations engineers are assigned to rotating shift responsibility shortly before fuel loading to provide continuous GE technical direction of test operations for the full 168 h/week.

The lead test design and analysis engineer is specifically responsible for supervising the three test design and analysis engineers and for coordinating the technical direction of the startup test design and analysis group. He specifically reviews the results of each startup test, evaluates the safety and acceptability of the test results of each startup test, and evaluates the safety and acceptability of the test results together with the HNP-2 technical supervisor or designated alternate, in reference to expected performance of the plant.

The three test design and analysis engineers will have shift responsibility for technical support, interpretation of startup instructions, and data analysis and interpretation during the fuel loading and startup testing. They work closely with the operations shift engineer in the planning and in the conducting of the test operations, and they advise the operations engineers on the optimum test conduct. These test design and analysis engineers are assigned to shift in order to provide full coverage during startup testing.

All of the above listed support personnel will remain at the plant site until completion of the startup test program.

GPC engineering will provide technical assistance, where required, during initial fuel handling, storage, loading, startup, startup tests, and operation of the nuclear system prior to commercial operation. The objective of technical assistance is to ensure the inherent safety and reliability of the nuclear system and to ensure that operating procedures reflect a course of action based on current engineering and operating practices for the NSSS. Technical assistance is defined as engineering and technical guidance relating the work to be performed.

14.2.2 INTERRELATIONSHIPS AND INTERFACES

14.2.2.1 GPC Production Department

The GPC production department is responsible for coordinating the activities associated with construction assurance testing, development and/or approval of procedures for preoperational and startup tests, directing and conducting these tests, directing and conducting system flushes, and documentation of results. These functions for safety-related systems will all be performed by written procedures.

The GPC production department has overall control and responsibility for the initial testing and operating phases, including construction acceptance testing, preoperational testing, and startup testing. Involvement of the HNP-2 plant staff in these phases of the initial testing is as follows:

A. *Procedure Development, Review, and Approval*

Construction acceptance tests - Procedures and data sheets are developed by the GPC production department and are reviewed and approved by the HNP-2 operations superintendent as part of the Startup Manual.

Preoperational tests - Procedures are prepared by GPC engineers and Bechtel engineers in accordance with HNP-2-11 and are reviewed and approved by the plant review board (PRB) and the HNP-2 operations superintendent.

Startup tests - Specifications and instructions are prepared by the GE test, design, and analysis group and are reviewed and approved by the PRB and the HNP-2 operations superintendent.

B. *Conduct of Tests*

Construction acceptance tests - Production department test supervisors are assigned to each test and are responsible for verification that the appropriate tests are performed and documented. Members of the plant staff maintenance department, test department, laboratory staff, and operating staff perform the construction acceptance tests.

Preoperational tests - The performance of each test is under the supervision of a production department test supervisor who is responsible for reviewing the procedure and test data against defined acceptance criteria and verifying acceptable completion of the test. Members of the plant staff maintenance department, test department, laboratory staff, and operating staff perform the preoperational tests.

Startup tests - GE and HNP-2 technical personnel will provide assistance for performance of the tests. HNP-2 plant staff shift engineers will be assigned to follow the tests on a shift basis. HNP-2 operating staff personnel will perform the tests with respect to operation of plant equipment.

C. *Review of Test Results*

Construction acceptance tests - The results of the tests are reviewed and approved by the assigned test supervisor.

Preoperational tests and startup tests - The results of the tests are reviewed and approved by the PRB and the HNP-2 operations superintendent.

There are currently no plans to augment the plant technical staff with additional personnel from the GPC general office staff or from other organizations other than that personnel currently assigned to the HNP-2 staff. In the event additional technical support to the HNP-2 staff is determined to be necessary, such a determination will be made by the HNP-2 operations superintendent. The operations

superintendent in that event would review and approve the qualifications of any such additional support personnel.

14.2.2.2 GPC Production - GPC Construction Department

The GPC construction department is responsible for final turnover of all plant systems and equipment to the GPC production department once satisfied that the systems and equipment are functional and installed according to approved drawings, procedures, and specifications. The GPC production department accepts systems and equipment from the GPC construction department according to a written turnover procedure. After turnover, the GPC production department will perform the necessary testing according to written procedures. Deficiencies may occur during any phase of the testing. When a deficiency occurs, procedures will utilize the existing channels now in use by construction to notify the appropriate design discipline in Bechtel or GE that a problem exists and a resolution is required.

14.2.2.3 GPC Production - GE

The GE operations manager will review and approve all preoperational test procedures, procedure changes, and test results. The GE operations superintendent, along with the GE shift superintendents, will be responsible for providing technical direction for all nuclear system startup tests. In general, beginning with startup testing, each operating shift will have one GPC production shift supervisor working side by side with one GE shift superintendent. Technical direction by the GE shift superintendent will be in the form of guidance to ensure that the inherent safety and reliability of the nuclear systems are not jeopardized; however, the direct responsibility for shift operations and plant equipment rests with the GPC production supervision. GE shift coverage will be on a 24-h/day, 7-day/week basis, as required.

14.2.2.4 PC Production Field Quality Assurance (Engineering and Construction)

The site quality assurance (QA) field representative (engineering and construction) is responsible for reviewing and auditing, according to written procedures, GPC production activities, during construction assurance, startup, and preoperational testing.

The specific duties for the field QA group include reviewing completeness of documentation for construction assurance tests, reviewing test procedures and operating procedures to be in accordance with the latest drawings and/or specifications, reviewing preoperational test documentation for completeness, and witnessing certain preoperational tests being conducted.

14.2.2.5 GPC Production - Consultants

The Bechtel site consultant will review and approve all preoperational test procedures, procedure changes, and test results to ensure that the acceptance criteria listed in these specifications have been met.

14.2.3 PERSONNEL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

The functions, responsibilities, and authorities of key augmenting personnel positions are described in subsection 14.2.1.

14.2.4 PERSONNEL QUALIFICATION

The qualifications of the key augmenting personnel will be reviewed by plant management.

SUPPLEMENT 14A

PREOPERATIONAL TESTS

14A.1 EMERGENCY CORE COOLING SYSTEM INTEGRATED PREOPERATIONAL TEST (2A81-3510)

A. Test objective - To demonstrate the response of the emergency core cooling system (ECCS) and support system to loss-of-site power and loss-of-coolant accident (LOCA).

B. Prerequisites - The applicable test procedure has been reviewed and approved.

C. General test methods - The ECCS test will be performed in separate distinct tests to demonstrate the following:

- *Fast transfer of loads from startup transformer 2D to startup transformer 2C without loss of the emergency loads.*
- *LOCA with startup transformer 2D deenergized and startup transformer 2C supplying 4160-V buses 2E, 2F, and 2G.*
- *Simultaneous loss of startup transformers 2D and 2C to demonstrate load shed, diesel self start, bus reenergization, and sequencing of the bus loading.*
- *LOCA with no loss-of-site power to demonstrate diesel start with no load shed and the automatic initiation of ECCS.*
- *LOCA with loss-of-site power to demonstrate diesels' capability to supply emergency core cooling demands.*
- *LOCA with loss-of-site power and dc switchgear 2A failure to demonstrate diesels' capability to supply emergency buses and automatic initiation of Division II ECCS equipment.*
- *LOCA with loss-of-site power and dc switchgear 2B failure to demonstrate diesels' capability to supply emergency buses and automatic initiation of Division I ECCS equipment.*

D. Acceptance criteria - That the components and systems function to their design as demonstrated by the above tests.

14A.2 NUCLEAR BOILER SYSTEM PREOPERATIONAL TEST (2B21-3510)

A. *Test objective - To verify proper operation of the nuclear boiler system, including main steam line isolation valves (MSIV), safety relief valves, and related controls and logic. (MSIV leakage is measured in the containment integrated leak rate test.)*

B. *Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The safety relief valves have been previously bench tested.*

C. *General test method - Functional tests, other than manual initiation, are not performed; verification of the NSSS capability is demonstrated by the integrated operation of the following:*

- *System valves and related sensors and logic.*
- *MSIVs.*
- *Automatic isolation function of MSIV's main steam line drain valves, and reactor water sample isolation valves. The MSIV and other valve closing times specified in the Technical Specifications shall be similarly demonstrated.*
- *Isolation and leak detection system (LDS).*
- *Automatic depressurization system logic.*
- *Accumulator capacity test.*
- *Safety relief valves.*
- *Reactor head seal leak detection.*
- *Alarms and annunciators.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. MSIVs and other valves closing times shall be demonstrated.*

14A.3 <u>REACTOR RECIRCULATION SYSTEM (INCLUDING MOTOR-GENERATOR SETS) PREOPERATIONAL TESTS (2B31-3510)</u>

A. Test objective - To verify the operation of the reactor recirculation system (RRS), including pumps, and their associated motors and motor-generator sets, valves, instrumentation, and controls. The rated conditions tests will be conducted during the startup test program.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Equipment required for preoperational testing of the RRS shall have been tested, including operation of the motor-generator sets and fluid coupling, recirculation pump motor (uncoupled), and the control loops.

C. General test method - After the prerequisites are met, verification of system capability is demonstrated by the integrated operation of the following:

- *System valves.*
- *Logic and interlocks.*
- *Recirculation pumps and related controls and interlocks.*
- *Annunciators.*
- *Motor-hydraulic coupling-generator set operation and generator speed control and voltage.*
- *Pump cavitation check.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.4 REACTOR SYSTEM HYDROSTATIC TEST (HNP-2-10007)

A. Test objective - To demonstrate the pressure retaining integrity of the reactor pressure vessel (RPV) and all connecting piping welds out to and including the welds connecting the first isolation valve in each connecting pipe.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Related support systems are available.

C. General test method - Safety and limitation requirements will be listed. The RPV hydro will include heating, pressurization, and depressurization requirements.

D. Acceptance criteria - The test shall demonstrate zero leakage at all welded connections at test pressure and all intermediate pressures.

14A.5 CONTROL ROD DRIVE MANUAL CONTROL SYSTEM PREOPERATIONAL TEST (2C11-3510)

A. Test objective - To verify the operation of the reactor manual control system (RMCS), including relays, control circuitry, switches and indicating lights, and control valves.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Control rod drive (CRD) pump, pump motor support, and protective instrumentation systems must be operational.

C. General test method - Verification of RMCS capability is demonstrated by the integrated operation of the following:

- *Control valve sensor and logic.*
- *Rod blocks, interlocks, and alarms.*
- *CRD position indication, alarms, and interlocks.*
- *Alarms, annunciators, and system timer.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; rod insertion, withdrawal and single-rod scram rates must be similarly demonstrated. Rod worth minimizer (RWM) acceptance of an operator initialized group reset must be demonstrated.

14A.6 CRD HYDRAULIC SYSTEM PREOPERATIONAL TEST (2C11-3520)

A. Test objective - To verify the operation of the CRD hydraulic system, including CRD mechanisms, hydraulic control units, hydraulic power supply, instrumentation, and controls.

B. Prerequisites - The applicable construction acceptance tests have been completed and the test procedure has been reviewed and approved.

C. General test method - Verification of CRD system capability is demonstrated by the integrated operation of the following:

- *Logic and interlocks.*
- *CRD pumps and related controls and interlocks.*
- *Flow controller, pressure control valves, and stabilizer valves.*
- *Scram discharge level switches and CRD position indication, alarms, and interlocks.*
- *CRDs including latching and position indication.*
- *Scram testing of control rods at atmospheric pressure.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specification; full scram capability must be demonstrated.

14A.7 FEEDWATER CONTROL SYSTEM PREOPERATIONAL TEST (2C32-3510)

A. Test objective - To verify proper operation of the feedwater level control system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the feedwater control system capability is demonstrated by the integrated operation of the following:

- *Reactor feed pump speed regulation motor and control unit.*
- *Startup (low-flow) valve regulator.*
- *Interlocks.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.8 STANDBY LIQUID CONTROL SYSTEM PREOPERATIONAL TEST (2C41-3510)

A. Test objective - To verify the operation of the standby liquid control system (SLCS) including pumps, tanks, control, logic, and instrumentation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The RPV should be available for injecting demineralized water.

C. General test method - Verification of the SLCS capability is demonstrated by the integrated operations of the following:

- *SLCS tank level instrumentation.*
- *Heaters.*
- *Alarms and logic.*
- *Relief Valves.*
- *Pumps and related controls and logic.*
- *Flow testing with different flowpaths.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.9 NEUTRON MONITORING SYSTEM PREOPERATIONAL TEST (2C51-3510)

A. Test objective - To verify the operation of the neutron monitoring system (NMS) including source, intermediate, and power range detectors, rod block monitor, and their related equipment.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Additionally, source range monitors (SRMs) and pulse preamplifiers, intermediate range monitors (IRMs) and voltage preamplifiers, and average power range monitors (APRMs), will have been calibrated.

C. General test method - Verification of the NMS capability is demonstrated by the operation of the following:

- *SRM detectors, their respective insert and retract mechanisms, and cables.*
- *SRM channel including pulse preamp, remote meter and recorder, trip logic, logic bypass and related lamps and annunciators, control system interlocks, refueling instrument trips, and power supply.*
- *IRM detectors and their respective insert and retract mechanisms and cables.*
- *IRM channels including voltage preamps, remote recorders, RMCS interlocks, reactor protection system (RPS) trips, annunciators and lamps, and power supplies.*
- *Local power range monitor (LPRM) detectors and their respective cables and power supplies.*
- *APRM channels, including trips, trip bypasses, annunciators and lamps, remote recorders, RMCS interlocks, RPS interlocks, and power supplies.*
- *Recirculation flow bias signal, including flow unit, flow transmitters, and related annunciators, interlocks, and power supplies.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.10 PRIMARY CONTAINMENT ISOLATION SYSTEM (2C61-3510)

A. Test objective - To verify proper operation of the primary containment isolation system as designed to perform containment isolation valve closure upon receipt of prespecified signals.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - The test of the primary containment isolation system shall be accomplished by simulating appropriate containment isolation initiation signals and demonstrating containment isolation valve response.

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.11 RPS PREOPERATIONAL TEST (2C71-3510)

A. Test objective - To verify the proper operation of the RPS including sensor logic, neutron monitoring channels and their respective scram relays, scram reset time delay, annunciators, and motor-generator set power supply.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the RPS capability is demonstrated by the integrated operation of the following:

- *Motor-generator set sensor logic and scram relay.*
- *NMS logic and scram relay.*
- *Scram reset time delay.*
- *System sensors.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; the ability of the system to scram the reactor within a specified time must be similarly demonstrated.

NOTE:

Sensor response time testing relative to the boiling water reactor is largely concerned with pressure, Δ pressure measurements, and the associated sensors. While the basic methods for measuring sensor response time for this class of sensor are available, it is only very recently that designs for standard test equipment have been proposed. In order that preoperational tests be fully developed, it is necessary to identify the actual test equipment that is to be employed. Consequently, it is not possible at this stage to provide test details in the area of sensor response time testing.

Each instrument in the RPS will be calibrated and its trip setpoint adjusted to meet the plant operating Technical Specifications, Final Safety Analysis Report (FSAR), system design specifications, and instrument data sheets. If any conflict exists for these setpoints, the plant operating Technical Specifications take precedence with the FSAR, system design specifications, and instrument data sheets following in that order. Calibration records will be on file showing that the test equipment has been calibrated with standards traceable to the National Bureau of Standards. Test records will be kept on file showing the calibration date and data obtained from the various instruments and sensors and the serial numbers of the test equipment used for calibration.

14A.12 <u>REMOTE SHUTDOWN SYSTEM (2C82-3510)</u>

A. Test objective - To verify the operability of the remote shutdown system and to demonstrate its ability to carry out the shutdown functions necessary for the control of reactor pressure and water level following a reactor scram with closure of the MSIVs.

B. Prerequisites - Since signals from the remote shutdown instrument and control panel affect the CRD hydraulic, residual heat removal (RHR), plant service water (PSW), automatic depressurization, reactor core isolation cooling (RCIC), reactor recirculation, and RHR service water (RHRSW) systems, care must be taken to make sure that these systems can accept the signals without harm to personnel or equipment. The test procedure has been reviewed and approved.

C. General test method - Testing shall include verification of operation of all valves, controls, instrumentation, and pumps on systems available from the remote shutdown instrument and control panel.

Testing shall include verification of transfer switch operation [transfer of control of identified items from the main control room (MCR) panels to the remote shutdown instrument and control panel].

Testing shall also include verification of independence of power supply voltage.

D. Acceptance criteria - Satisfactory operation of all valves, controls, instrumentation, transfer switches, and pumps on systems available from the remote shutdown instrument and control panels.

14A.13 PROCESS COMPUTER INTERFACE SYSTEM PREOPERATIONAL TEST (2C91-3510)

A. Test objective - To verify the operation of the process computer interface system including computer inputs and printout.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the process computer interface system is demonstrated by operation of the following:

- *Analog input signals.*
- *Computer printout.*
- *Digital input signals.*
- *Digital output signals.*

D. Acceptance criteria - System components must be either verified or demonstrated to be within their respective engineering design specifications.

14A.14 <u>ROD WORTH MINIMIZER SYSTEM PREOPERATIONAL TEST (2C91-3520)</u>

A. Test objective - To verify the operation of the rod worth minimizer (RWM) system under its various modes of operation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Additionally, the rod position indication system will have been shown to be operational and computer diagnostic and special tests complete.

C. General test method - Verification of the RWM system is demonstrated by the computer initiation of the following:

- *Rod test sequence block.*
- *System initialization both above and below the low-power setpoints and above and below the low-power alarm points.*
- *RWM program.*
- *Rod withdrawal and insertion error block.*
- *Notch error block.*
- *Rod drift scan.*

D. Acceptance criteria - System operations must be either verified or demonstrated to be within their respective engineering design criteria; RWM program acceptance of an operator-supplied rod position value must be demonstrated.

14A.15 OFF-GAS RADIATION MONITOR (2D11-3510)

A. Test objective - To verify the operation of the off-gas radiation monitoring system, including annunciators and trip function. Additionally, vital sampling racks, off-gas sample racks, and vacuum pump will be functionally tested.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the off-gas radiation monitoring system is demonstrated by the integrated operation of the following:

- *Pretreatment monitor system alarms, recorders, trip points.*
- *Post-treatment monitor system alarms, recorders, trip points.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.16 MAIN STEAM LINE RADIATION MONITOR (2D11-3520)

A. Test objective - The main steam line radiation monitor will be shown to be operable in calibration, have correct trip settings, and perform its specified annunciator functions.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the main steam line radiation monitoring system is demonstrated by the integrated operation of the following:

- *Trip points.*
- *Annunciators.*
- *Recorders.*
- *Source check.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.17 <u>PROCESS LIQUID RADIATION MONITOR SYSTEM (2D11-3530)</u>

A. Test objective - The process liquid radiation monitor will be shown to be operable in calibration, to have correct trip settings, and to perform its required annunciator functions.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the process liquid radiation monitoring system is demonstrated by the integrated operation of alarms and trip points and by establishing a calibrated discriminator curve.

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.18 <u>REACTOR BUILDING EXHAUST RADIATION MONITORING (2D11-3550)</u>

A. Test objective - To verify proper operation of the reactor building exhaust radiation monitoring system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the reactor building exhaust radiation monitoring system is demonstrated by the integrated operation of the following:

- *Drywell and torus vent monitors.*
- *Refueling floor vent exhaust monitors.*
- *Standby gas treatment monitors.*
- *Reactor building access area monitors.*
- *Reactor building vent filter discharge.*
- *Refueling floor vent filter discharge.*
- *Turbine building vent filter discharge.*
- *Turbine building vent filter intake.*
- *Reactor building vent filter sample rack.*
- *Reactor building potential contaminate area vent exhaust.*
- *Annunciators.*
- *Recorders.*
- *Trip points.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.19 TRAVERSING INCORE PROBE SYSTEM PREOPERATIONAL TEST (2D12-3510)

A. *Test objective - To verify the operation of the traversing incore probe (TIP) system including the TIP detector, controls and interlocks, containment secure, and squib circuits.*

B. *Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.*

C. *General test method - With the exception of the shear valve, which is not tested, verification of the TIP system is demonstrated by the integrated operation of the following:*

- *Indexer cross-calibration interlock.*
- *Shear valve control monitor.*
- *Drive motor manual control and override, automatic control and stop, and low-speed control.*
- *TIP automatic detector withdrawal.*
- *Containment secure and squib circuits.*
- *Ball valve control.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.*

14A.20 AREA RADIATION MONITORING SYSTEM PREOPERATIONAL TEST (2D21-3510)

A. Test objective - To verify the operation of the area radiation monitoring system (ARMS) including sensors and channels, trip units, alarms, and recorder.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the ARMS capability is demonstrated by the integrated operation of the following:

- *Sensor/converter and associated channels.*
- *Channel trip units.*
- *Alarm annunciators and lights.*
- *Recorder.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.21 __FISSION PRODUCTS MONITOR (2D23-3510)__

A. Test objective - To show that the primary containment fission products monitors is operable, is in calibration, has correct trip settings, and performs its specified annunciator functions.

B. Prerequisites - This test requires the applicable construction acceptance tests to have been completed and the test procedure reviewed and approved. Calibration of instruments is to have been completed.

C. General test method - After the prerequisites are met, verification of system capability is demonstrated by the integrated operation of system valves, sample pumps, detectors, monitors and trip units, recorders, and annunciators.

D. Acceptance criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.22 RESIDUAL HEAT REMOVAL SYSTEM PREOPERATIONAL TEST (2E11-3510)

A. Test objective - To verify the operation of the RHR system under its various modes of operation: standby, low-pressure coolant injection (LPCI), shutdown cooling and vessel head spray, containment spray, suppression pool water cooling, and fuel pool cooling.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The RPV and recirculation loops shall be intact and capable of receiving water for the vessel injection portion of the preoperational test.

C. General test method - Verification of the RHR system capability is demonstrated by the operation of the following:

- *System isolation valve control and logic test.*
- *RHR pumps, motors, controls, and related logic features.*
- *Automatic LPCI initiation logic.*
- *Verification of critical flow paths. The time from initiation signal to full flow should be similarly verified to be within design specifications.*
- *Alarms and annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; system flow path under various modes of operation must be similarly demonstrated.

The time from initiation signal to full flow should be verified to be within design specifications.

1. *LPCI injection valves, maximum opening, closing time is within limits.*
2. *SDC suction valves maximum closing time is within limits.*
3. *Pump flow meets requirements of process flow diagram 761E292BA.*
4. *Minimum net positive suction head (NPSH) (two pumps per loop running) is within limits.*
5. *Full flow (two pumps per loop, reactor pressure 20 psig) meets minimum requirements.*
6. *Pump runout limiting orifice limits pumps flow within limits.*

14A.23 <u>RHRSW SYSTEM PREOPERATIONAL TEST (2E11-3520)</u>

A. Test objective - To verify the operation of the RHRSW system including pumps, motors, and valves.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the RHRSW system capability is demonstrated by the operation of the following:

- *Pump operational check.*
- *Modulating valves.*
- *Crosstie operational check.*
- *Pump logic check.*
- *Annunciators.*

D. Acceptance criteria - System components will either be verified for proper operation or demonstrated to be within their respective engineering design specifications; no attempt will be made to simulate design heat loads.

14A.24 CORE SPRAY SYSTEM PREOPERATIONAL TEST (2E21-3510)

A. Test objective - To verify the operation of the core spray (CS) system including spray pumps, sparger ring, spray nozzles, controls, valves, and instrumentation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The RPV must be available and ready to receive water. Jockey pumps must be available.

C. General test method - Verification of CS system capability is demonstrated by the integrated operation of the following:

- *Logic and interlocks.*
- *CS system pumps, including auto initiation.*
- *Flow path verification.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; system flowrates and patterns must be demonstrated.

1. *Spray flow pattern is satisfactory and documented by photograph.*
2. *Injection valve full stroke time is within minimum limits.*
3. *Interlocks and logic function as specified in system elementary diagrams.*
4. *Minimum flow at 113 psi above suppression pool pressure satisfies limits.*
5. *NPSH with strainers 50% blocked satisfies requirements of process flow diagram 161F338.*

14A.25 JOCKEY PUMP SYSTEM (2E21-3520) *Error! Bookmark not defined.*

A. Test objective - To demonstrate proper operation of the jockey pumps in providing demineralized water to the RHR and CS pumps discharge headers.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the jockey pump system is demonstrated by the integrated operation of the following:

- *Pumps.*
- *Valves.*
- *Annunciators.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.26 HIGH-PRESSURE COOLANT INJECTION SYSTEM PREOPERATIONAL TEST (2E41-3510)

A. Test objective - To verify the operation of the high-pressure coolant injection (HPCI) system including turbine and related auxiliary equipment, pumps, valves, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The turbine initially shall be disconnected from the driven equipment for testing.

During the uncoupled turbine run:

1. *Turbine oil circulation shall be verified to be satisfactory.*
2. *Turbine vibration shall be checked within acceptable limits.*
3. *There will be no evidence of rubbing or unusual noises.*
4. *General turbine operation will be satisfactory.*

C. General test method - Verification of HPCI system capability is demonstrated by the integrated operation of the following:

- *Automatic initiation and automatic isolation including leak detection and interlocks.*
- *Valve controls and interlocks.*
- *Turbine test mode and trip.*
- *Gland condenser condensate pump, vacuum pump, and interlocks.*
- *Flow path verification.*
- *Limited turbine operation using auxiliary steam.*
- *Alarms and annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

1. *Pump NPSH meets minimum established limit.*
2. *Interlocks and logic function as specified in system elementary diagrams.*
3. *Turbine parameters function as specified in vendor's instruction manual.*

4. *System valve operating time are satisfactory.*

5. *Pump suction relief setting functions properly.*

6. *Gland-seal condensing system is capable of maintaining system vacuum within minimum limits.*

7. *Flow and minimum start time criteria cannot be demonstrated until nuclear steam is available during power test program.*

14A.27 RCIC SYSTEM PREOPERATIONAL TEST (2E51-3510)

A. *Test objective - To verify the operation of the RCIC system including turbine, pump, valves, instrumentation, and control.*

B. *Prerequisites - The applicable construction assurance tests have been completed, and the test procedure has been reviewed and approved. The turbine initially shall be disconnected from the driven equipment for testing.*

   1. *Turbine oil circulation shall be verified to be satisfactory.*

   2. *Turbine vibration shall be within acceptance limits.*

   3. *There will be no evidence of rubbing or unusual noises.*

   4. *General turbine operation will be satisfactory.*

C. *General test method - Verification of system capability is demonstrated by the integrated operation of the following:*

   - *Valves and related controls, interlocks, and indicators.*
   - *Manual and automatic initiation.*
   - *Automatic isolation including LDS logic.*
   - *Turbine speed control, trip mode selection, and test mode.*
   - *Barometric condenser condensate pump, and vacuum pump controls.*
   - *Flow path verification.*
   - *Modified turbine operation using auxiliary steam.*
   - *Annunciators.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; pump performance under various flow path must be demonstrated.*

   1. *Pump NPSH meets minimum established limit.*

   2. *Interlocks and logic function as specified in system elementary diagrams.*

   3. *Turbine parameters function as specified in vendor's instruction manual.*

   4. *System valve operating times are satisfactory.*

5. *Gland-seal condensing system is capable of maintaining system vacuum within minimum limits.*

6. *Flow and minimum start time criteria cannot be demonstrated until nuclear steam is available during power test program.*

14A.28 FUEL-HANDLING AND VESSEL-SERVICING EQUIPMENT PREOPERATIONAL TEST (2F11-3510)

A. Test objective - To verify the operation of the fuel-handling and vessel-servicing equipment including tools used in the servicing of control rods, fuel assemblies, LPRMs and dry tubes, and vacuum cleaning equipment.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Additionally, the refueling platform fuel preparation machine, and fuel racks must be installed and operational; slings and lifting devices must be certified at their design load.

C. General test method - Verification of the fuel-handling and vessel-servicing equipment is demonstrated by dry operation of the following equipment:

- *Bundle disassembly tools.*
- *Channel replacement tools.*
- *Instrument handling tools.*
- *Vacuum cleaning equipment.*
- *Interlocks and logic associated with the refueling platform verified.**
- *Proper operation of refueling platform verified.**

D. Acceptance criteria - Tools must be verified for proper operation; additionally, logic and interlocks and sling and grapple load cells must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

**RPV service platform is no longer available.*

14A.29 LIQUID AND SOLID RADWASTE SYSTEM PREOPERATIONAL TEST (2G11-3510)

Test objective - To verify the operation of the radwaste system including pumps, filters and demineralizers, centrifuge and hoppers, and solid radwaste handling equipment.

Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

General test methods - Verification of the radwaste system capability is demonstrated by the integrated operation of the following:

- *System pumps under designed flow paths and component operation.*
- *Isolation valve operation including logic and related annunciators.*
- *Filters and demineralizers.*
- *Solid handling equipment.*
- *Phase separator and waste sludge subsystems.*
- *Detergent drain, chemical waste, and spent-resin subsystems.*

Acceptance criteria - System and subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.30 REACTOR WATER CLEANUP SYSTEM PREOPERATIONAL TEST (2G31-3510)

B. Test objective - To verify the operation of the reactor water cleanup (RWC) system including pumps, valves, and demineralizers.

C. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Reactor building closed cooling water system (RBCCWS) and control air must have readiness verification.

D. General test methods - Verification of the RWC system capability is demonstrated by the integrated operation of the following:

- *Drain flow regulator interlocks.*
- *Valve-operating sequence.*
- *Pumps with related controls and logic.*
- *Annunciators.*
- *Filter-demineralizer operation.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.31 FUEL POOL COOLING AND CLEANUP SYSTEM PREOPERATIONAL TEST (2G41-3510)

A. Test objective - To verify the operation of the fuel pool cooling and cleanup (FPCC) system including valves, pumps, and demineralizer.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The related supported systems, the RBCCWS, control air, and portions of the radwaste system must be available.

C. General test method - Verification of the FPCC system is demonstrated by the integrated operation of the following:

- *Control air-operated valves and related sequence logic.*
- *Flow path verification.*
- *Pumps including related automatic controls, interlocks, and vacuum break verification.*
- *Demineralizer operation.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.32 TORUS DRAINAGE AND PURIFICATION SYSTEM (2G51-3510)

A. *Test objective - To verify operation of the torus drainage and purification system including containment isolation valves, pump and flow paths, and related controls and interlocks.*

B. *Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.*

C. *General test method - The system is tested by demonstrating the capability to transfer torus/suppression pool waters through the various flow paths and by verifying flow path isolation capability through the operation of the various interlocks and controls.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.*

14A.33 <u>FIRE PROTECTION SYSTEM PREOPERATIONAL TEST (2L43-3510)</u>

A. Test objective - To verify the operation of the fire protection system (FPS) including normal and emergency water supplies, heat and smoke detection equipment and alarms, and carbon dioxide systems.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The PSW system must be available.

C. General test method - Verification of the FPS capability is demonstrated by the integrated operation of the following:

- *Deluge and sprinkler systems solenoid, pneumatic, or manual valves and their related alarms and detectors.*
- *Oil reservoir and standby gas treatment system (SGTS) area heat sensors.*
- *MCR smoke detectors and alarms.*
- *Turbine building heat and smoke vents, outbuildings smoke and fire detectors, and diesel generator building smoke and fire detectors.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

<u>NOTE:</u>

Several portions of the FPS are shared by HNP-1 and HNP-2. These shared portions were preoperationally tested in accordance with HNP-1 procedures during the preoperational test program on HNP-1. Some exceptions to the HNP-1 preoperational test were written on those components that were unique to HNP-2 but on the shared system. These exceptions and any portion of the HNP-2 system not shared with HNP-1 and not thereby previously tested shall be tested during the HNP-2 preoperational test 2L43-3510 on the HNP-2 FPS.

The FPS pumps, water storage tanks, etc., were preoperationally tested with and are operational on HNP-1 and, thus, functional capability of these parts of the FPS has been proven adequately.

14A.34 SEISMIC MONITORING SYSTEM PREOPERATIONAL TEST (2L46-3510)

A. Test objective - To verify the operation of the seismic monitoring system including accelerometers and recorders.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Electronic equipment is calibrated according to the vendor's instructions.

C. General test method - Verification of the seismic monitoring system capability is demonstrated by the integrated operation using simulated signals of the following:

- *Triaxial accelerometers.*
- *Signal conditioners and magnetic tape recorders.*
- *Seismic trigger and logic.*
- *Strip chart recorder.*
- *Alarm circuits and annunciators.*
- *Batteries.*

D. Acceptance criteria - System components must either be verified for proper operation or demonstrated to be within their respective engineering design specifications. Accelerometer signal input will be simulated with a signal generator.

14A.35 CONTROLLED ACCESS BARRIERS (2L48-3510)

A. Test objective - To check operation of the controlled access barrier system to give proper annunciation of entry through any controlled access barrier.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the system is demonstrated by proper annunciation of the following:

- *Controlled access barriers.*
- *Reactor building airlocks.*
- *Turbine and reactor building roof tornado vents.*

D. Acceptance criteria - System components must be verified for proper operation.

14A.36 <u>CONDENSATE SYSTEM PREOPERATIONAL TEST (2N21-3510)</u>

A. Test objective - To verify the operation of the condensate system including pumps, motors, controls and interlocks, feedwater heaters, control valves, condensers, and flow and pressure instrumentation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Related support systems (condensate makeup demineralizer, condensate storage, service water, and control air) must have readiness verification.

C. General test methods - With the exception of the condensate storage, condenser vacuum, and condensate makeup demineralizer systems, which are the subjects of their own preoperational tests, verification of the condensate system capability is demonstrated by the integrated operation of the following:

- *Condensate pumps, motors, controls, and interlocks.*
- *Condensate booster pumps, motors, controls, and interlocks.*
- *Off-gas, steam jet air ejector and gland-steam condensers, and their related water control valves.*
- *System minimum recirculation flow and bypass control valves.*
- *Condenser hot well level controls.*
- *System normal and emergency makeup valves and control.*
- *Feedwater heater isolation and bypass valves, motors, controls, and interlocks.*
- *System flow and pressure instrumentation.*
- *Low-pressure feedwater heaters and control valves.*
- *Annunciators.*
- *Polishing demineralizer logic and operation.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.37 REACTOR FEEDWATER SYSTEM PREOPERATIONAL TEST (2N21-3520)

A. Test objective - To verify the proper operation of the reactor feedwater system including valves, controls, interlocks, alarms, and annunciators.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Condensate system and auxiliary boiler are available.

C. General test method - With the exception of the feedwater control system, which is the subject of its own preoperational test, verification of the feedwater system capability is demonstrated by the integrated operation of the following:

- *Reactor feedpump and turbine.*
- *Automatic valves and interlocks.*
- *System minimum recirculation flow control valves.*
- *Annunciators.*
- *Flow paths.*

D. Acceptance criteria - In addition to automatic valve, interlock and annunciator verification, minimum flow detection, recirculation line flow, and automatic level control, total system performance must be shown to be within its respective engineering design specifications.

14A.38 TURBINE AND AUXILIARIES PREOPERATIONAL TEST (2N30-3510)

A. Test objective - To verify the operation of the electrohydraulic control (EHC) system including speed governor equipment, reactor pressure control equipment valves, and instrumentation and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Turbine cannot be tested until nuclear steam is available but auxiliary systems will be tested. The EHC system and hydraulic fluid cooling system must be available.

C. General test method - Verification of the turbine auxiliary systems is demonstrated by the integrated operation of the following:

- *Hydraulic fluid pumps, motors and their controls, fluid test valve, fluid heaters, coolers, fans and their respective controls, alarms, and annunciators.*
- *EHC transfer and filter pump.*
- *Stop valves, control valves, intercept valves, bypass valves opening, closing, and logic.*
- *Speed governor and reactor pressure control equipment (using signal generator).*
- *Lube oil.*
- *Steam seal.*
- *Exhaust hood spray.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.39 EXTRACTION AND FEEDWATER HEATER CONTROLS (2N36-3510)

A. Test objective - To demonstrate the operability of the air-operated and motor-operated valves, pumps, and related instrumentation in the system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Instrument air must be available.

C. General test method - Verification of the extraction and feedwater heater control system is demonstrated by the integrated operation of the following:

- *Feedwater heaters.*
- *Moisture separator/reheater drains.*
- *Extraction.*
- *Moisture separator/reheater drain tank spray.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.40 GENERATOR AND AUXILIARIES (2N40-3510)

A. Test objective - To demonstrate operation of the generator protective circuitry and auxiliary equipment.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the generator and auxiliaries is demonstrated by the operation of the following:

- *Excitation.*
- *Seal oil.*
- *Isophase bus cooling.*
- *Stator cooling.*
- *Hydrogen cooling.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.41 CONDENSER AND AUXILIARIES (2N61-3510)

A. Test objective - To demonstrate operability of the condenser and the mechanical vacuum pump.

B. Prerequisites - The applicable construction acceptance tests have been reviewed and approved. The condenser is ready to receive water. Circulating water system, PSW, instrument air, the steam seal system, and the auxiliary boiler are available.

C. General test method - Verification of the condenser and auxiliaries is demonstrated by the integrated operation of the following:

- *Condenser circulating water flow.*
- *Mechanical vacuum pump.*
- *Alarms.*
- *Vacuum breakers.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.42 OFF-GAS SYSTEM PREOPERATIONAL TEST (2N62-3510)

A. Test objective - To verify the operation of the off-gas system including pumps, motors, fans, gas treatment equipment, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Demineralized water and control air systems must be available.

C. General test methods - No attempt is made to demonstrate actual system gas handling ability; verification of the off-gas system capability is demonstrated by the integrated operation of the following:

- *Motor-operated pumps, compressors, fans and their related controls, and logic.*
- *System instrumentation.*
- *System valves.*
- *Annunciators.*

D. Acceptance criteria - System components will be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.43 CIRCULATING WATER SYSTEM PREOPERATIONAL TEST (2N71-3510)

A. Purpose - To verify the operation of the circulating water system including pumps and motors, chemical subsystems, cooling towers, and screens.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The PSW system, cooling tower fans, and control air system must be available. Cooling towers must be available to receive flow.

C. General test method - Functional verification of the circulating water system is demonstrated by the operation of the following:

- *Circulating water pumps and related motors, pump and motor cooling, discharge valve operation, automatic controls, and trips.*
- *Cooling tower isolation and bypass valves.*
- *Reservoir decanting pumps and related controls and interlocks.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.44 CONDENSATE STORAGE SYSTEM PREOPERATIONAL TEST (2P11-3510)

A. Test objective - To verify the operation of the condensate storage system, including tanks, pumps, valves, instrumentation and controls.

B. Prerequisites - The applicable construction acceptance tests have been completed and the test procedure has been reviewed and approved. The related support systems, the condensate makeup demineralizer, and demineralized water supply header must be available.

C. General test methods - Verification of the condensate storage system capability is demonstrated by the integrated operation of the following:

- *System pumps, motors, and their related automatic controls and interlocks.*
- *Automatic valve operation.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.45 HYDROGEN AND OXYGEN ANALYZER SYSTEM (2P33-3510)

A. Test objective - To demonstrate proper functioning of valves, pumps, and equipment in the H_2 and O_2 analyzer system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved and instrument air is available.

C. General test method - Verification of the hydrogen and oxygen analyzer system is demonstrated by the integrated operation of the following:

- *Valve operation.*
- *System logic including isolations.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.46 PSW SYSTEM PREOPERATIONAL TEST (2P41-3510)

A. Test objective - To verify the operation of the PSW system including PSW pumps and motors, and PSW pump strainers with motors, valves, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the PSW system capability is demonstrated by the integrated operation of the following:

- *PSW pumps including controls, interlocks, and alarms.*
- *PSW pump strainer controls.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; however, no attempt will be made to simulate design heat loads or design flowrate through the various heat exchangers.

14A.47 RBCCWS PREOPERATIONAL TEST (2P42-3510)

A. Test objective - To verify the operation of the RBCCWS including pumps and associated motors, heat exchangers, makeup tank, valves, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The related support systems, demineralized water, and instrument air must be available.

C. General test methods - Capability of the RBCCWS is demonstrated by the integrated operation of the following:

- *Pumps, motors, and associated controls, interlocks, and alarms.*
- *System flow-through heat exchangers and coolers.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flowrates through the various coolers and heat exchangers.

14A.48 PLANT HEATING SYSTEM (2P44-3510)

A. Test objective - To verify operation of the plant heating system including pumps and flow paths, valves, instrumentation, and controls.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - After the prerequisites are met, verification of system capability is demonstrated by integrated operation of the plant heating system and the building ventilation systems as necessary to maintain minimum building ambient temperatures.

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.49 SERVICE AIR SYSTEM (2P51-3510)
14A.50 INSTRUMENT AIR SYSTEM (2P52-3510)

A. Test objective - To demonstrate and verify the ability of the instrument and service air systems to meet their demands and requirements.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedures have been reviewed and approved.

C. General test method - Verification of the service air and instrument air systems is demonstrated by the following:

1. The station service air compressors, aftercoolers, receivers, automatic drains, cooling water pumps, heat exchangers, fans, and temperature controls are tested to verify proper operation. The procedure includes testing the unloaders, the automatic operation, the manual starting and stopping, and all alarms.

2. The instrument air dryer is run through at least one regeneration cycle. All alarms and automatic operations are verified in the test.

3. The maximum flowrate through the dryer is verified as is the instrument air pressure. By operating the instrument air system and noting that all the equipment can be operated, the system flowrate is verified.

4. The moisture content of the instrument air system is tested to determine whether the dryer is performing to specification requirements.

5. The cleanliness of the instrument air system is determined by the initial system flushing procedure and by verifying acceptable pressure drops through the prefilters and afterfilters during instrument airflow testing.

6. A loss-of-instrument air test is conducted as follows:

a. With the instrument air system at normal operating pressure, the air-operated valves in essential, and safety-related systems in the nonfailed position, the air system compressors are stopped manually.

b. The system is then vented to reduce system pressure, and the air-operated valves mentioned above are observed to reposition to their fail position.

7. The results of all the tests are recorded in the preoperational startup report.

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

<u>NOTE:</u>

Instrument air testing is in compliance with Regulatory Guide 1.80. Exceptions to Regulatory Guide positions C.8, C.9, and C.10 are justified below.

<u>Position C.8</u> - The minimum test described is an instantaneous loss-of-air supply and depressurization to as many air piping headers as can be adequately managed on an integrated basis. This test further requires that as many valves as practicable be demonstrated to move from the nonfailed position to the failed position. Section 14A.50, paragraph C.6 above, describes this preoperational test. The capacity of individual air accumulators provided for safety system valves will be demonstrated in the performance of the respective system preoperational tests by valve operation using the accumulators.

The preoperational test does not address a check to verify that branches of smaller pipe sizes are not starved by flow to branches of larger capacity as recommended in position C.8. There is no practical procedure to demonstrate this in a meaningful fashion. Additionally, this exception is justified because the instrument air system is not safety related.

<u>Position C.9</u> - The test described for this position is similar to the test described in C.8 with the exception that the air supply is shut off slowly to simulate a plug of ice forming in an air header. This test is not addressed in section 14A.50 or the preoperational test because piping to safety-related systems is routed within plant buildings and will not be subjected to freezing temperatures. Furthermore, it is believed that the test of position C.8 provided the same results with the possible exception of line depressurization rates and test duration.

<u>Position C.10</u> - This position would repeat the test of C.8 with the exception that the only valves to be demonstrated are those valves normally aligned in the nonfailed position. The test is not performed since it only reduces the number of valves already tested by C.8. No different valves are cycled.

14A.51 TURBINE BUILDING CHILLED WATER SYSTEM PREOPERATIONAL TEST (2P63-3510)

A. Test objective - To verify the operation of the turbine building chilled water system (TBCWS) including pumps and associated motors, heat exchangers, makeup tank, valves, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The related support systems, PSW, condensate storage, and control air must be available.

C. General test methods - Verification of the TBCWS is demonstrated by the integrated operation of the following:

- *Pumps, motors, and associated controls, interlocks, and alarms.*
- *Automatic makeup to head tank and control valve operation.*
- *System flow through heat exchangers and coolers.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flowrates through the various coolers and heat exchangers.

14A.52 REACTOR BUILDING AND DRYWELL CHILLED WATER SYSTEM (2P64-3510)

A. Test objective - To verify the operation of the reactor building and drywell chilled water system (RB & DCWS) including pumps and associated motors, heat exchangers, makeup tank, valves, instrumentation, and control.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The related support systems and condensate storage and instrument control air must be available.

C. General test methods - Verification of the RB & DCWS is demonstrated by the integrated operation of the following:

- *Pumps, motors and associated controls, interlocks, and alarms.*
- *Automatic makeup to head tank and control valve operation.*
- *System flow through heat exchangers and coolers.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flowrates through the various coolers and heat exchangers.

14A.53 DRYWELL PNEUMATIC SYSTEM (2P70-3510)

A. Test objective - To demonstrate proper operation of the drywell pneumatics system and system components.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the drywell pneumatic system is demonstrated by the following:

1. *The compressor, aftercooler, and receiver are tested to verify the proper operation according to system design. The testing procedure includes checking operation of the compressor, automatic and manual start and stop, and high- and low-pressure alarms.*

2. *All alarms and automatic operations are verified in the test.*

3. *The drywell pneumatic system pressure and flowrate are verified by the test and are recorded in the preoperational startup report.*

4. *The drywell pneumatic system initial flushing procedure provides the system cleanliness requirements.*

5. *A loss-of-drywell pneumatic air test is conducted as follows:*

    a. *With the system at normal operating pressure and the air-operated valves in other than their failed position, the drywell pneumatic gas compressors are stopped manually.*

    b. *The system is then vented to reduce system pressure, and the air-operated valves are observed to reposition to their fail (safe) position.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.54 <u>GROUNDING (2R34-3510)</u>

A. Test objective - To verify the integrity of the grounding resistance at various locations in the system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the grounding resistance is demonstrated by proper indications in the various structure and equipment ground tests.

D. Acceptance criteria - Subsystem components must be demonstrated to be within their respective engineering design specifications.

14A.55 <u>24-48 V-dc POWER SYSTEM PREOPERATION TEST (2R41-3510)</u>

A. Test objective - To verify the operation of the 24-48 V-dc power system including batteries, battery chargers, distribution panels, and alarms.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The ac supply power, batteries, and system components must have readiness verification.

C. General test method - Verification of the 24-48 V-dc power system is demonstrated by the operation of the following:

- *Batteries and related chargers.*
- *dc power distribution panels.*
- *Protective relaying.*
- *Annunciators and alarms.*
- *Discharge-charge tests.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; battery capacities under specified discharge rates must be demonstrated.

Battery terminal voltages and individual cell voltage will remain within limits specified in the preoperational test during the discharge test. Pilot cell temperature will be recorded periodically during battery discharge, and individual cell specific gravity measurements are made and recorded upon completion of the battery discharge test. The pilot cell temperature and a final set of individual cell voltage and specific gravity measurements will be recorded after completion of battery recharge.

14A.56 125-250 V-dc POWER SYSTEM (2R42-3510)
14A.57 125 V-dc DIESEL AUXILIARY POWER SYSTEM (2R42-3510)

A. Test objectives

- *To verify the battery meets the equipment specification requirements.*
- *To verify the distribution and control instrumentation systems meet the equipment specification requirements.*

B. Prerequisites

- *The availability of the auxiliary systems that are vital to the proper operation of the dc power system.*
- *The completion of the dc power system construction acceptance tests.*

C. General test methods

1. *Battery capacity tests satisfy the requirements of Section 4 of IEEE Std. 450-1972.*
   - *Acceptance test - to be performed at the factory.*
   - *Performance test - to be performed as an acceptance test during the preoperational test.*
2. *System preoperational test procedure satisfies the requirements of Section 6.1 of IEEE Std. 308-1971.*

D. Acceptance criteria

1. *Each battery is capable of delivering the minimum power for a specified period with the associated battery charger not in operation.*
2. *Each battery charger is capable of recharging its associated battery from the minimum discharged condition in 24 h while supplying a normal steady-state dc load.*
3. *Battery terminal voltages and individual cell voltages will remain within limits specified in the preoperational test during the discharge test. Pilot cell temperature will be recorded periodically during battery discharge, and individual cell specific gravity measurements are made and recorded upon completion of the battery discharge test. The pilot cell temperature and a final set of individual cell voltage and specific gravity measurements will be recorded after completion of battery recharge.*
4. *All system interlocks and alarms function properly.*

NOTE:

All the dc loads will not be available at the time the tests are conducted, and therefore the dc loads cannot be verified. The tests will verify that the batteries function within their respective engineering design specifications for the duration of the tests. These design specifications are based on the dc loads that will be on the batteries.

The measurements referred to in the above test summaries will be made at intervals and on pilot cells, as applicable, during the tests.

The dc equipment loads will not be available at the end of the battery discharge tests. During recharge an equivalent simulated steady-state dc load is put on the battery chargers to simulate the dc equipment loads.

14A.58 STANDBY DIESEL AND STANDBY ac POWER SYSTEM (2R43-3510)

A. Test objective - To demonstrate the capability of each diesel generator to supply specified essential loads and to verify interlocks and automatic starting initiation, load shedding, sequential loading, diesel engine and generator protection.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The FPS is operable. Heating, ventilation, and air conditioning (HVAC), PSW, and fuel oil are available.

C. General test method - Verification of the standby diesel and standby ac power system is demonstrated by the integrated operation of the following:

- *Trip logics.*
- *Heating and cooling system.*
- *Annunciators.*
- *Manual controls.*
- *Automatic controls.*
- *Load rejection.*
- *Integrated diesel sequencing.*
- *Load capability test.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.59 <u>DIESEL FUEL OIL SUPPLY (2R43-3520)</u>

A. Test objective - To verify flow paths, system capacities, and automatic controls and interlocks.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The HVAC system and FPS are operable.

C. General test method - Verification of the diesel fuel oil supply system is demonstrated by the integrated operation of the following:

- *Pumps and controls.*

- *Annunciators.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.60 HVAC - DIESEL GENERATOR BUILDING (2R43-3530)

A. Test objective - To check for proper operation of the roof ventilators, heaters, louvers, fire dampers, and controls and to verify interlocks and system operation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the diesel generator building HVAC system is demonstrated by the integrated operation of the following:

- *Fans.*
- *Heaters.*
- *Louvers.*
- *Fire dampers.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.61 <u>20-240-V VITAL ac POWER SYSTEM (2R44-3510)</u>

A. Test objective - To demonstrate proper operation of the 120-240 vital ac power system.

B. Prerequisites - The vital ac power system and the alternate ac source battery are available. The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the 120-240 vital ac power system is demonstrated by the integrated operation of the following:

- *Vital ac power system.*
- *Load test.*
- *Annunciators.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective design specifications.

14A.62 COMMUNICATION AND EVACUATION ALARM SYSTEM PREOPERATIONAL TEST (2R51-3510)

A. Test objective - To verify the operation of the communication and evacuation alarm system including the public address, telephone, sound-powered phones, and emergency alarm.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the communication and evacuation alarm system capability is demonstrated by the integrated alarm operation of the following:

- *Public address including amplifiers, speakers, microphones, tone generator, signal relays, and control switches.*
- *Telephones and switching equipment.*
- *Sound-powered phone equipment.*
- *Emergency alarm system and alarm devices.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.63 LIGHTING - 277-480 V-ac (2R52-3510)

A. Test objective - To demonstrate that the 277-480 V-ac system provides a reliable supply to the lighting switchgear.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the 277-480 V-ac lighting system is demonstrated by operation of the following:

- *Control centers and panels.*
- *Automatic power supply transfer.*
- *Alarms.*
- *Energization of transformers.*
- *Protective relaying logic.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.64 4160 V-ac SYSTEM (2R71-3510)

A. Test objective - To verify the capability of the system to make suitable electrical service available to all buses from any of their sources and to verify protective device calibration and functional operation.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Auxiliary transformers 2A, 2B, 2C, 2D, 125-250 V-dc power system, the main transformer, 4160 V-dc buses, interconnecting buses, and the 230-kV substation are available.

C. General test method - Verification of the 4160 V-ac system is demonstrated by the operation of the following:

- *dc control power.*
- *Protective relaying logic.*
- *Breaker logic and breakers.*
- *Energization of buses and controls.*
- *Alarms.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.65 600-V-ac SYSTEM (2R71-3520)

A. Test objective - To verify the ability of the 600-V station service transformers to provide a suitable supply of power to the 600-V buses and to demonstrate verification of operability of protective relaying schemes and breaker interlocks.

B. Prerequisites - The 4160-V system is available. The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the 600-V-ac system is demonstrated by the operation of the following:

- *dc control power.*
- *Protective relaying logic.*
- *Breaker interlock checkout.*
- *Breaker logic and breakers.*
- *Energization of buses and controls including 600-V motor control centers.*
- *Alarms.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.66 <u>120/208-V-ac INSTRUMENT POWER SYSTEM (2R71-3530)</u>

A. Test objective - To demonstrate proper operation of the 120/208-V-ac system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The 600-V-ac system is available.

C. General test method - Verification of the 120/208-V-ac system is demonstrated by:

- *Energization of panels.*
- *Breaker operation.*
- *Alarm operation.*
- *Turbine building 280-V switchgear transfer to alternate supply.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.67 PRIMARY CONTAINMENT LEAK RATE PREOPERATIONAL TEST (2T23-3510)

A. Test objective - To determine the primary containment leak rate including containment penetrations and MSIVs. A drywell-to-wetwell bypass area test, which has the objective of determining the total equivalent bypass area for leakage from the drywell to the torus, is performed during the integrated leak rate test.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. A portable air compressor with filters and valves, pressure and temperature sensors, flow meters, and soap bubble and ultrasonic leak detection equipment must be available.

C. General test method - Verification of the primary containment boundaries integrity is demonstrated by leak rate testing of the following:

- *Local leak rate test of primary containment penetrations.*
- *Local leak rate test of primary containment isolation valves including MSIVs.*
- *Overall containment.*

Determination of the drywell-to-torus bypass area is made by establishing a differential pressure between the drywell and torus and by monitoring atmospheric conditions and pressure decay to compute an area.

D. Acceptance criteria - Any leak rates from penetrations, valves, and overall containment must be shown to be within the criteria established in the Technical Specifications.

The measured bypass area shall be less than the axil area of a 1-in. diameter orifice.

14A.68 MSIV LEAKAGE CONTROL SYSTEM (2E32-3510)

(This system was deleted in 1994.)

A. *Test objective - To verify operation of the MSIV leakage control system (MSIV-LCS) including blowers, valves, heaters, instrumentation, annunciation, and controls.*

B. *Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.*

C. *General test method - Verification of the MSIV-LCS is demonstrated by the integrated operation of the following:*

   - *Blowers.*
   - *Valves.*
   - *Heaters.*
   - *System logic and interlocks.*
   - *Annunciators.*
   - *Flowpaths.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.*

14A.69 <u>REACTOR BUILDING HEATING AND VENTILATION SYSTEM PREOPERATIONAL TEST (2T41-3510)</u>

A. Test objective - To verify the operation of the reactor building heating and ventilation system including filters, heaters, supply and exhaust fans and controls.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The system airflow balancing should have been completed.

C. General test method - Verification of the reactor building heating and ventilation system is demonstrated by the integrated operation of the following:

- *Fresh air intake louvers and filters.*
- *Air intake heater and controls.*
- *Supply and exhaust air fans and their related motors and controls.*
- *Response to radiation monitoring modules and related alarms.*
- *System shutoff and modulating dampers.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.70 REFUELING FLOOR VENTILATION SYSTEM (2T41-3520)

A. Test objective - To demonstrate operability of the refueling floor ventilation system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Air balancing in the system has been completed. Instrument air is available.

C. General test method - Verification of the refueling floor ventilation system is demonstrated by the integrated operation of the following:

- *Dampers.*
- *Fans.*
- *Heaters.*
- *Interlocks.*
- *Fan capacity.*
- *Response to refueling floor process radiation monitor.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.71 CS AND RHR ROOM VENTILATION (2T41-3540)
14A.72 HPCI ROOM VENTILATION (2T41-3550)
14A.73 RCIC ROOM VENTILATION (2T41-3560)
14A.74 CRD ROOM VENTILATION (2T41-3570)

A. Test objective - To demonstrate that the area coolers function properly.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedures have been reviewed and approved. Service water and instrument air are available.

C. General test method - Verification of each system is demonstrated by the integrated operation of the following:

- *Logic.*
- *Air flow.*
- *Annunciators.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.75 LEAK DETECTION SYSTEM (2T45-3510)

A. Test objective - To verify operation of system valves, instrumentation, and associated interlocks.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. Radwaste is available to receive drainage. Instrument air is available.

C. General test method - Verification of the LDS is demonstrated by the operation of valves, alarms, and annunciators.

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.76 SGTS PREOPERATIONAL TEST (2T46-3510)

A. Test objective - To verify the operation of the SGTS including system exhaust fans, decay heat removal fans, filters, air heaters, charcoal adsorber unit, isolation valves, and their controls. To verify the capability of the system to depressurize the secondary containment, and to verify the design leaktightness of the secondary containment.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The control air system must be available. System airflow balancing must have been completed.

C. General test method - Verification of the SGTS is demonstrated by the operation of the following:

- *Exhaust fans and their related motors and controls.*
- *Decay heat removal fans and their related motors and controls.*
- *Air heater and its controls.*
- *Charcoal adsorber heater and controls.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

NOTE:

After performance of system construction acceptance tests, plant procedures do not allow modification to a system without a formal design change request being processed through the technical staff and approved by the PRB. Additionally, the plant procedures manual provides for a quality control (QC) department review of any maintenance performed on equipment after preoperational testing is commenced, i.e., construction acceptance test. The QC reviewer specifies a functional test as required to ensure demonstration of system performance as applicable to the maintenance performed. The preoperational test procedure ensures that in-place testing of filters and adsorbers meet acceptance values as a prerequisite to the performance of the procedure.

14A.77 PRIMARY CONTAINMENT COOLING SYSTEM PREOPERATIONAL TEST (2T47-3510)

A. Test objective - To verify the operation of the drywell cooling system including coolers, blowers, motors, and related logic and controls. Heat load performance of the system will be checked during the startup test program.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The required support systems, reactor building chilled water, drywell pneumatic, and control air must be available. System airflow balancing must have been completed.

C. General test method - Verification of the drywell cooling system capability is demonstrated by the integrated operation of the following:

- *Cooling coils and flow balance valves.*
- *Cooling fans and their motors and related controls.*
- *Motor logic circuitry and protective features.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.78 PRIMARY CONTAINMENT ATMOSPHERE CONTROL SYSTEM PREOPERATIONAL TEST (2T48-3510)

A. Test objective - To demonstrate control and operation of system valves and automatic interlocks.

B. Prerequisites - Instrument air, reactor building service water, PCIS, and auxiliary steam are available. The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the system is demonstrated by integrated operation of the following:

- *Valves.*
- *Alarms.*
- *Torus - drywell vacuum breakers.*
- *Reactor building - torus vacuum breakers.*
- *Flow capacity.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.79 TURBINE BUILDING CRANE (2U31-3510)

A. Test objective - To demonstrate satisfactory operation of the turbine building crane.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the system is demonstrated by the integrated operation of the following:

- *Line contactor.*
- *Operation from cab.*
- *Radio control.*
- *Limit switch tests.*
- *Main hook load tests.*
- *Auxiliary hook load tests.*

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.80 TURBINE BUILDING HEATING AND VENTILATION SYSTEM PREOPERATIONAL TEST (2U41-3510)

A. Test objective - To verify the operation of the turbine building heating and ventilation system including filters, heaters, supply and exhaust fans, and related controls.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. System airflow balancing must have been completed.

C. General test method - Verification of the turbine building heating and ventilation system capability is demonstrated by the operation of the following:

- *Fresh air intake louvers, filter, heater, and controls.*
- *Supply and exhaust air fans and their related controls.*
- *Chilled water units and their related controls.*
- *System shutoff and modulating dampers.*
- *High-efficiency particulate air (HEPA) filters.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.81 RADWASTE BUILDING VENTILATION SYSTEM PREOPERATIONAL TEST (2V41-3150)

A. *Test objective - To verify the operation of the ventilation system for the radwaste building.*

B. *Prerequisites - The applicable construction assurance tests have been completed, and the test procedure has been reviewed and approved. The related support systems and control air must be available. System airflow balancing must have been completed.*

C. *General test method - Verification of the ventilation system is demonstrated by the integrated operation of the following:*

- *HEPA filters.*
- *Chilled water cooling unit fans.*
- *Isolations.*
- *Alarms.*
- *Inlet filters.*
- *Fan control logic.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.*

14A.82 <u>COOLING TOWERS (2W24-3510)</u>

A. Test objective - To demonstrate fan motor operation to support the circulating water system.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved.

C. General test method - Verification of the system is demonstrated by the integrated operation of annunciators, fans, and cooling tower controls.

D. Acceptance criteria - Subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14A.83 CONTROL BUILDING HVAC SYSTEMS PREOPERATIONAL TEST (2Z41-3510)

A. Test objective - To verify the operation of the control building HVAC system and its related heaters, chillers, fans, blowers, and controls.

B. Prerequisites - The applicable construction acceptance tests have been completed, and the test procedure has been reviewed and approved. The related support systems, the PSW, and control air must be available. The system airflow balancing should have been completed.

C. General test method - Verification of the system is demonstrated by the integrated operation of the following:

- *Refrigeration compressors, condensers, and evaporators.*
- *Emergency recirculation fans, motors, and filters.*
- *Air-operated valves and dampers.*
- *Return-air fans and related controls.*
- *Annunciators.*

D. Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

NOTE:

Portions of the main control room environmental control system (MCRECS) were preoperationally tested during the HNP-1 preoperational test. This testing covered the equipment of the MCRECS that serves the common control room for both units.

14A.84 COMBUSTIBLE GAS CONTROL SYSTEM (2T49-3510)

(This system was deleted in 2007.)

A. *Test objective - To verify the operation of the post-LOCA hydrogen recombiners of the combustible gas control system including heaters, blowers, spray coolers, valves, instrumentation and control, and alarm annunciation.*

B. *Prerequisites - The applicable construction tests have been completed, and the test procedure has been reviewed and approved. The related support systems and the RHR system are available.*

C. *General test method - Verification of the post-LOCA hydrogen recombiners is demonstrated by the integrated operation of the following:*

- *Blowers.*
- *Flow-control valves.*
- *Heaters.*
- *Spray coolers.*
- *Flow paths.*
- *Annunciators.*
- *System instrumentation and control.*

D. *Acceptance criteria - System components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; however, no attempt will be made actually to recombine hydrogen and oxygen gases.*

14A.85 REACTOR INTERNAL FLOW-INDUCED VIBRATION TEST AND INSPECTION

This test and inspection is described in section 3.9.

SUPPLEMENT 14B

STARTUP TESTS

14B.1 CHEMICAL AND RADIOCHEMICAL TESTS (STI-1)

A. Purpose

- *To maintain control of and knowledge of the quality of the reactor coolant chemistry.*

- *To determine that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the coolant chemistry meets water quality specifications and process requirements.*

- *To monitor the integrity of the fuel, operation of the demineralizers and filters, condenser integrity, operation of the off-gas system, and calibration of certain process instruments.*

B. Description - Prior to fuel loading, a complete set of chemical and radiochemical samples will be taken to ensure that all sample stations are functioning properly and to determine initial concentrations. Subsequent to fuel loading, during reactor heatup, and at each major power level change, samples will be taken and measurements will be made to determine the chemical and radiochemical quality of reactor water and reactor feedwater, amount of radiolytic gas in the steam, gaseous activities leaving the air ejectors, decay times in the off-gas lines, and performance of filters and demineralizers. Calibrations will be made of monitors in the liquid waste system and liquid process lines.

C. Acceptance Criteria

Level 1

Water quality must be known and must conform to the water quality specifications.

The activities of gaseous and liquid effluents must be known and must be within license limitations.

Chemical factors defined in the Technical Specifications must be maintained within the limits specified.

14B.2 RADIATION MEASUREMENTS (STI-2)

A. Purpose

- *To determine the background gamma and neutron radiation levels in the plant environ prior to operation in order to provide base data on activity buildup.*

- *To monitor radiation at selected power levels to ensure the protection of personnel and continuous compliance with the guideline standards of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) during plant operation.*

B. Description - A survey of natural background radiation throughout the plant site will be made prior to fuel loading. Subsequent to fuel loading, during reactor heatup, and at various power levels, gamma radiation levels measurements and (where appropriate) thermal and fast neutron dose rate measurements will be made at significant locations throughout the plant. Potentially high radiation areas will be surveyed.

C. Acceptance Criteria

Level 1 - The radiation doses of plant origin and occupancy times shall be controlled consistent with the guidelines of the standards for protection against radiation outlined in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

14B.3 FUEL LOADING (STI-3)

A. Purpose - To load fuel safely and efficiently to the full core size.

B. Prerequisites - The following prerequisites will be met prior to commencing fuel loading to ensure that this operation is performed in a safe manner:

1. *The status of systems required for fuel loading will be specified and will be in the status required.*

2. *Fuel and control rod inspections will be complete. Control rods will be installed and tested.*

3. *At least three movable neutron detectors will be calibrated and operable. At least three neutron detectors will be connected to the high flux scram trips. They will be located so as to provide acceptable signals during fuel loading.*

4. *Nuclear instruments will be source checked with a neutron source prior to loading.*

5. *The status of secondary containment will be specified and established.*

6. *Reactor pressure vessel (RPV) water level status will be established and minimum water level prescribed.*

7. *The standby liquid control system (SLCS) will be operable and in readiness.*

8. *Fuel handling equipment will have been checked and dry runs completed.*

9. *The status of protection systems, interlocks, mode switches, alarms, and radiation protection equipment will be prescribed and verified. The high flux trip points will be set for a relatively low-power level.*

10. *Reactor water quality must meet required specifications.*

11. *At least one neutron source will be installed in the core.*

C. Description - Basically fuel loading will begin at the center of the core and proceed to the fully loaded configuration. The detailed procedure will address itself to the following items:

- *The loading sequence and pattern for fuel, control rods, and other components.*

- *Maintaining a display indicating the status of the core and maintaining appropriate records of core loading.*

- *Proper seating and orientation of fuel elements and components.*

- *Functional testing of the associated control rod as the installation of each fuel cell is completed.*

- *Nuclear instrumentation and neutron source requirements for monitoring subcritical multiplication. A minimum of three source range channels will be required to be operable whenever operations are performed that will effect core reactivity.*

- *Flux monitoring including recording of neutron flux.*

- *The expected subcritical multiplication behavior.*

- *Determining adherence to the shutdown margin and the frequency of determination. The shutdown margin will be proven periodically during loading and at the completion of loading.*

- *Actions, especially those pertaining to flux monitoring, for periods when fuel loading is interrupted.*

- *Maintaining continuous voice communication between the main control room (MCR) and refueling floor.*

The fuel loading procedure will also address itself to the following safety requirements:

- *Criteria for stopping fuel loading. Some actions that might warrant this are unexpected subcritical multiplication behavior, loss of communications between MCR and fuel loading station, inoperable source range detector, and inoperability of the SLCS.*

- *Criteria for reducing the fuel loading increment.*

- *Criteria for emergency boron injection.*

- *Criteria for secondary containment evacuation.*

- *Actions to be followed in the event of fuel damage.*

- *Actions to be followed or approvals to be obtained before routine loading may resume, after a limitation has been reached.*

The fuel loading procedure will include the following checks, which will be performed during the fuel loading sequence:

1. *Subcriticality check - A control rod surrounded by fuel in the vicinity of the cell to be loaded will be completely withdrawn; the core must remain subcritical. The rod will be reinserted prior to continuation of the loading sequence.*

2. *Control rod functional test - The rod in the cell to be loaded will have been completely withdrawn and reinserted prior to loading the cell.*

3. *Fuel loading - Two fuel assemblies will be loaded, the blade guides removed, and the remaining two fuel assemblies loaded to complete the four assembly cells.*

4. *The control rod functional test will be repeated. This also serves as a subcriticality check on the loaded fuel cell.*

D. *Acceptance Criteria*

Level 1 - The partially loaded core must be subcritical by at least 0.38% $\Delta k/k$ with the analytically strongest rod fully withdrawn.

14B.4 SHUTDOWN MARGIN (STI-4)

A. Purpose - To demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

B. Description - This test will be performed by comparing the full core actual critical rod pattern with a predicted pattern, based on computer code, calculations and verifying the model of the computer code. This calibrated code is then used to calculate the shutdown margin.

C. Acceptance Criteria

1. *Level 1 - The shutdown margin of the fully loaded core with the analytically strongest rod withdrawn must be at least 0.38% Δ k/k during the most reactive time in core life. (See note.)*

2. *Level 2 - Criticality should occur within ± 1.0% Δ k/k of the predicted critical.*

NOTE:

The acceptance criteria for STI-4, shutdown margin, are in full agreement with the values used in the BWR Standard Technical Specifications as explained below. The apparent difference results because the Technical Specification is not completely definitive of the principle involved.

The purpose of the shutdown margin test is to demonstrate that the reactor will be subcritical throughout the fuel cycle with the highest worth control rod fully withdrawn. Since the test is performed with zero exposure on the core, additional margin must be demonstrated if the core reactivity increases as a function of exposure. This margin is obtained by calculation (Value = R). The uncertainty in the calculation of k_{eff} for the core was explored by comparing the calculated and measured eigenvalues for a number of critical experiments on operating reactors. From this comparison the standard deviation was established as 0.0014 and a value of 2 σ was chosen as the shutdown margin to allow for calculational errors, namely 0.28% Δk.

The test should consider removal of the highest worth rod. In determining the analytically highest worth rod, it is assumed that every control cell has identical material properties but, in the actual core, the control cell material properties vary within allowed manufacturing tolerances so the highest worth rod is determined by a combination of control cell geometry and tolerance stackup. An additional margin is included in the shutdown margin test to account for the fact that the analytically highest worth rod is not necessarily the highest worth rod in the core. To investigate the stackup of allowed manufacturing tolerances in control cell material properties, a number of critical experiments were performed in an identical manner and based on exact geometric core locations and environments. After correcting for measurement errors (instrument calibration and meter readings) and calculational

errors (period measurements and graphs) the standard deviation was established as 1.27×10^{-3} relative to stackup tolerances.

By combining the standard deviations for calculational errors (1.4×10^{-3}) and stackup tolerances (1.27×10^{-3}) in the normal manner, an overall standard deviation of 1.9×10^{-3} results. Thus, taking a 2σ value for the shutdown margin gives a value of 0.0038 or 0.38% Δk.

In summary, the demonstrated shutdown margin will be R + 0.28% Δk if all rods are withdrawn one at a time for the test. Alternatively, the demonstrated margin will be R + 0.38% Δk if an analytically determined highest worth rod is chosen. Normally, the latter option is used because only one test is required, and the margin available is more than adequate to meet this requirement.

14B.5 CONTROL ROD DRIVE (STI-5)

A. *Purpose*

- *To demonstrate that the control rod drive (CRD) system operates properly over the full range of primary coolant temperatures and pressures, from ambient to operating.*

- *To determine the initial operating characteristics of the entire CRD system.*

B. *Description - The CRD tests performed during phases II through IV of the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all CRDs operate properly when installed, they are tested periodically during heatup to assure that there is no significant binding caused by thermal expansion of the core components. A list of all CRD tests to be performed during startup testing is given below.*

CRD SYSTEM TESTS

Test Description	Accumulator Pressure	Preop Tests	Reactor Pressure With Core Loaded psig (kg/cm^2) 0	600(42.2)	800(56.2)	Rated
Position indication		All	All			
Normal stroke time/insert withdraw		All	All			4[(a)]
Coupling		All	All[(b)]			
Friction			All			4[(a)]
Scram	Normal	All	All	4[(a)]	4[(a)]	All
Scram	Minimum		4[(a)]			
Scram (scram discharge volume high level)	Normal					(full core scram)
Scram	Normal					4[(c)]

NOTE:

Single CRD scrams should be performed with the charging valve closed. (Do not ride the charging pump head.)

a. *Refers to four CRDs selected for continuous monitoring based on slow normal accumulator pressure scram times or unusual operating characteristics at zero reactor pressure. The four selected CRDs must be compatible with the rod worth minimizer (RWM) and CRD sequence requirements.*
b. *Establish initially that this check is a normal operating procedure.*
c. *Scram times of the four slowest CRDs will be determined at test conditions 2 and 6 during planned reactor scrams.*

C. Acceptance Criteria

1. Level 1

Each CRD must have a normal withdraw speed ≤ 3.6 in./s (9.14 cm/s) indicated by a full 12-ft stroke in ≥ 40 s.

The criterion required to meet the design bases is the scram time at > 950 psig. If this criterion is met, the scram time at lower pressures is assured. The characteristics of the rod drive system are to have slightly slower scram times at pressures < 950 psig, and the lower acceptance criteria are used for tests at lower pressure. Meeting the criteria at the lower pressure does not remove the requirement for testing at the higher pressure.

The mean scram time for all operable CRDs with functioning accumulators must not exceed the following times: (Scram time is measured from the time the pilot scram valve solenoids are deenergized.)

Position Inserted From Fully Withdrawn	Scram Time (s) Vessel Dome Pressure ≥ 950 psig (66.9 kg/cm^2)	Scram Time (s) Vessel Dome Pressure < 950 psig (66.9 kg/cm^2)
46	0.358	0.454
36	1.096	1.260
26	1.860	1.885
06	3.419	4.838

The mean scram time of the three fastest CRDs in a two-by-two array must not exceed the following times: (Scram time is measured from the time the pilot scram valve solenoids are deenergized.)

Position Inserted From Fully Withdrawn	Scram Time (s) Vessel Dome Pressure ≥ 950 psig (66.9 kg/cm^2)	Scram Time (s) Vessel Dome Pressure < 950 psig (66.9 kg/cm^2)
46	0.379	0.482
36	1.161	1.335
26	1.971	1.998
06	3.624	5.128

2. Level 2

Each CRD must have a normal insert or withdraw speed of 3.0 ± 0.6 in./s (7.62 ± 1.52 cm/s) indicated by a full 12-ft stroke 40 s to 60 s.

With respect to the CRD friction tests, if the differential pressure variation exceeds 15 psid (1.1 kg/cm^2) for a continuous drive, a settling test must be performed in which case the differential settling pressure should not be < 30 psid (2.1 kg/cm^2) nor should it vary by >10 psid (0.7 kg/cm^2) over a full stroke.

Scram times with normal and minimum accumulator charge should all fall within the design time limits indicated in figure 17 of HNP-2-10001.

14B.6 SOURCE RANGE MONITOR PERFORMANCE AND CONTROL ROD SEQUENCE (STI-6)

A. *Purpose - To demonstrate that the operational sources, source range monitor (SRM) instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality in a safe and efficient manner for each of the specified withdrawal sequences.*

B. *Prerequisites for initial criticality - The following are examples of tests and checks that will be performed before the initial approach to criticality to ensure that this important operation is performed under the safest possible conditions:*

- *Chemical and radiochemical tests to establish water quality.*
- *Evaluation of control rod sequences to verify safety criteria and check operation of RWM during approach to criticality.*
- *Calibration and neutron response check of SRMs.*

C. *Description*

Control rod withdrawal sequences have been calculated, which completely specify control rod withdrawals from the all-rods-in condition to the rated power configuration. Each sequence will be used to attain cold criticality. Critical rod patterns will be recorded periodically as the reactor is heated to rated temperature. As each rod group is completed during the power ascension, the electrical power, steam flow, and average power range monitor (APRM) readings will be recorded.

D. *Acceptance Criteria*

Level 1

There must be a neutron signal count-to-noise ratio of at least two to one on the required operable SRMs or fuel loading chambers.

There must be a minimum count rate of three counts/second on the required operable SRMs or fuel loading chambers.

The IRMs must be on scale before the SRMs exceed the rod block setpoint.

14B.7 <u>ROD SEQUENCE EXCHANGE (STI-8)</u>

A. Purpose - To perform a representative sequence exchange of control rod pattern at a significant power level.

B. Description

Rod patterns will be periodically exchanged during plant operation to more nearly equalize fuel assembly exposures. This test is performed as an example of the exchanges that will be made throughout lifetime and is provided to illustrate the principles involved.

In practice the first step of a control rod sequence exchange will be to reduce power by core flow and control rods to the region of minimum core flow and power between about 30% (RWM low-power setpoint) and 50% of rated power. The actual control rod sequence exchange test will be done in this region.

The exchange is performed a row or column at a time, starting at one side of the core and working row by row or column by column across the core. For a given row or column, the exchange begins at one end and works across the row or column to the other end.

This method minimizes power level disturbances throughout the exchange once the base power and core flow are established.

C. Acceptance Criteria

1. *Level 1 - All licensed core limits will be satisfied during this test. (See core performance evaluation test.)*

2. *Level 2 - All nodal powers shall remain below their threshold limits during this test.*

14B.8 WATER LEVEL MEASUREMENT (STI-9)

A. Purpose - To verify the calibration of the GEMAC and YARWAY water level instrumentation under various conditions.

B. Description - The reference leg temperature of the YARWAY will be verified, at rated temperature and pressure, to be the value assumed during initial calibration. If it is not, the instrument will be recalibrated and the GEMAC and YARWAY indication checked for reasonable agreement.

C. Acceptance Criteria

Level 1

Not applicable

Level 2

The narrow range level system readings should agree with each other within ± 1.5 in. of the average reading.

The wide range level indicators should agree with each other within ± 6 in. of the average reading.

14B.9 INTERMEDIATE RANGE MONITOR PERFORMANCE (STI-10)

A. Purpose - To adjust the intermediate range monitor (IRM) system to obtain an optimum overlap with the SRM and APRM systems.

B. Description - Initially the IRM system is set to maximum gain. After the APRM calibration, the IRM gains will be adjusted to optimize the IRM overlap with the SRMs and APRMs.

C. Acceptance Criteria

Level 1 - Each IRM channel must be adjusted so that overlap with the SRMs and APRMs is assured. The IRMs must produce a scram at 96% of full scale.

14B.10 LOCAL POWER RANGE MONITOR CALIBRATION (STI-11)

A. Purpose - To calibrate the local power range monitor (LPRM) system.

B. Description - The LPRM channels will be calibrated to make the LPRM readings proportional to the neutron flux in the narrow-narrow water gap at the chamber elevation. Calibration factors will be obtained through the use of either an off-line or process computer calculation that relates the LPRM reading to average fuel assembly power at the chamber height.

C. Acceptance Criteria

Level 1 - The meter readings for each LPRM shall accurately provide the necessary incore local power information used in the determination of the local neutron flux at the respective LPRM location.

14B.11 AVERAGE POWER RANGE MONITOR CALIBRATION (STI-12)

A. Purpose - To calibrate the APRM systems.

B. Description - A heat balance is made after each major power level change and as required. Each APRM channel reading will be adjusted to be consistent with the core thermal power as determined from the heat balance. During heatup, a preliminary calibration will be made by adjusting the APRM amplifier gains so that the APRM readings agree with an initial heat balance based on coolant temperature rise data.

C. Acceptance Criteria

1. Level 1

The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

Technical specification on APRM scram and rod block shall not be exceeded.

In the startup mode, all APRM channels must produce a scram at ≤ 15% of rated thermal power.

Recalibration of the APRM system will not be necessary from safety considerations if at least two APRM channels per RPS trip circuit have readings greater than or equal to core power.

2. Level 2

If the above criteria are satisfied, the APRM channels will be considered to be reading accurately if they agree with the heat balance to within + 7, - 0% of rated power.

14B.12 PROCESS COMPUTER (STI-13)

A. Purpose - To verify the performance of the process computer under operating conditions.

B. Description - The GE computer system program verifications and calculational program validations at static and at simulated dynamic input conditions will be preoperationally tested at the computer supplier's site and following delivery to the plant site. Following fuel loading and during plant heatup and the ascension to rated power, the nuclear steam supply system (NSSS) and the balance-of-plant (BOP) system process variables sensed by the computer as digital or analog signals will become available. Verify that the computer is receiving correct values of sensed process variables and that the results of performance calculations of the NSSS and the BOP are correct. Verify proper operation of all computer functions at rated power operating conditions.

C. Acceptance Criteria

Level 2

Programs OD-1 and P-1 will be considered operational when the minimum critical power ratio (MCPR), maximum average planer linear heat generation rate (MAPLHGR), and maximum linear heat generation rate (MLHGR) calculated by the process computer and by BUCLE are in the same fuel assembly and differ in value by ≤ 2 % or if different limiting assemblies are calculated by the process computer and BUCLE, then the MCPR, MAPLHGR, and MLHGR in the same fuel bundle and location shall differ by ≤ 2%. The LPRM gain adjustment factors calculated by the process computer and by BUCLE shall differ by ≤ 2%.

The remaining programs will be considered operational upon successful completion of static and dynamic testing.

14B.13 REACTOR CORE ISOLATION COOLING SYSTEM (STI-14)

A. Purpose - To verify the operation of the reactor core isolation cooling (RCIC) system over its required operating pressure range.

B. Description - A controlled start and a quick start of the RCIC system will be done at a reactor pressure of ~ 150 psig and at rated pressure. Verify proper operation of the RCIC system and determine time to reach rated flow. These tests may first be performed with the system in the test mode so that discharge flow will not be routed to the RPV. The final demonstration will be made so that discharge flow will be routed to the RPV while the reactor is at partial power.

C. Acceptance Criteria

1. Level 1

The average pump discharge flow must be ≥ 100% rated value after 30 s have elapsed from initiation on auto starts at any reactor pressure between 150 psig (10.5 kg/cm^2) and rated.

With pump discharge at any pressure between 250 psig (17.57 kg/cm^2) and 1220 psig (85.9 kg/cm^2), the required flow is 400 gal/min (25.2 liter/s). The limit of 1220 psig includes a conservatively high value of 100 psi for line losses. (The measured value may be used if available.)

The RCIC turbine shall not trip on overspeed during auto or manual starts.

2. Level 2

The turbine gland-seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The WP switch for the RCIC steam supply line high-flow isolation trip shall be adjusted to actuate at 300% of the maximum required steady-state flow, with the reactor pressure near rated.

For small speed or flow changes in either manual or automatic mode, the decay ratio of each recorded RCIC system variable must be < 0.25 in order to demonstrate acceptable stability.

The margins to avoid the overspeed trip shall be at least 10% of the trip value.

14B.14 HIGH-PRESSURE COOLANT INJECTION (STI-15)

A. *Purpose - To verify the proper operation of the high-pressure coolant injection (HPCI) system over its required operating pressure range.*

B. *Description - Controlled and quick starts of the HPCI system will be done at reactor pressures near 150 psig and rated pressure during the heatup phase. Controlled and quick starts will be initiated during power testing to verify proper operation of the HPCI system, determine time to reach rated flow, adjust flow controller in the HPCI system for proper flowrate, and adjust overspeed trip of HPCI turbine. These tests will be performed with the system in the test mode so that discharge flow will not be routed to the RPV. The final demonstration will be made so that discharge flow will be routed to the RPV while the reactor is at partial power.*

C. *Acceptance Criteria*

1. *Level 1*

The time for actuating signal to required flow must be $<$25 s with reactor pressure between 150 psig and rated. With pump discharge pressure between 150 psig and 1220 psig, the flow should be at least 4250 gal/min. The HPCI turbine must not trip on overspeed during startup.

2. *Level 2*

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The ΔP switch for the HPCI steam supply line high-flow isolation trip shall be adjusted to actuate at 300% of the maximum required steady-state steam flow.

For small speed or flow command changes in either manual or automatic mode, the decay ratio of each recorded HPCI system variable must be $<$0.25 in order to demonstrate acceptable stability.

The margin to avoid the overspeed trip shall be at least 10% of the trip value.

14B.15 SELECTED PROCESS TEMPERATURES (STI-16)

A. Purpose

- *To establish the proper setting for the low speed limiter for the recirculation pumps.*
- *To provide assurance that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations.*

B. Description - Selected temperature readings from the thermocouples at various locations on the reactor system will be monitored during reactor heatup and cooldown, e.g., temperature readings from thermocouples at various locations on the RPV, coolant temperatures (including recirculation loop and feedwater), saturation temperature, recirculation and feedwater flows, and reactor water level.

C. Acceptance Criteria

Level 2 - During two-pump operation at rated core flow, the bottom head coolant temperature as measured by the bottom drain line thermocouple should be within 30°F (17°C) of the recirculation loop temperatures.

14B.16 SYSTEM EXPANSION (STI-17)

A. Purpose

- *To verify that the reactor drywell piping system is free and unrestrained in regard to thermal expansion and that suspension components are functioning in the specified manner.*

- *To provide data for calculation of stress levels in nozzles and weldments.*

B. Description - Observations and recordings of the horizontal and vertical movements of major equipment and piping in the NSSS and auxiliary systems will be made in order to ensure that components are free to move as designed. Adjustments will be made as necessary for freedom of movement.

C. Acceptance Criteria

1. Level 1

There shall be no evidence of blocking of the displacement of any system component caused by thermal expansion of the system.

Hangers shall not be bottomed out nor have spring fully stretched.

The shock suppressor piston must be centered about the midpoint of the total travel range at operating temperature.

Electrical cables shall not be fully stretched.

2. Level 2

At the steady-state condition, the displacement in the X, Y, and Z directions at locations with displacement measuring devices shall not vary from the calculated values by more than 50% or ± 0.25 in. (0.635 cm), whichever is less.

During the heatup cycle, the trace of the instrumented points shall fall within a range of 150% of the calculated value from the initial cold position in the direction of the calculated value or 50% of the calculated value from the initial position in the opposite direction of the calculated value.

Hangers shall be in their operating range (between the hot and cold settings).

NOTE:

A. The design reports for the respective piping systems provide a detailed list of the expected deflections for given points in each piping system. These expected deflections are calculated with

respect to specified X, Y, and Z reference axes. Instrument locations will be determined based on the maximum expected deflections and accessibility.

B. *The above discussion is applicable to the original recirculation piping. For restart testing following 1984 recirculation piping replacement, reference paragraph 3.9.1.1.1(A).*

Other Piping Systems

1. *Verification that other systems are free to expand without constraint within acceptable limits and that associated suspension components and restraints function properly will be provided through visual inspection or measurement during initial testing and subsequently during plant operation or shutdown periods when the systems will be available for inspection. The following systems will be visually inspected or monitored during one heatup/cooldown cycle (to include normal modes of operation) for evidence of unexpected expansion or binding of components:*

    - *Main steam relief valve piping.*
    - *RCIC system.*
    - *HPCI system.*
    - *Feedwater system.*
    - *Reactor water cleanup (RWC) system.*
    - *Residual heat removal (RHR) system.*
    - *Main steam line leakage control system.*
    - *Core spray (CS) (inside drywell only).*
    - *Class 2 main steam lines in turbine building.*
    - *Standby liquid control system (inside drywell only).*

2. *Plant systems will be visually inspected for evidence of unexpected expansion or binding of components. Inspection of these systems for dents in insulation and for misalignment or misadjustment of supports and restraints during periods of accessibility will provide assurance that system behavior is within design allowances.*

3. *In the design of the respective systems, provision is made for unrestricted thermal expansion of piping and components. Clearances are provided to accommodate allowed expansion. Visual inspection of the individual systems, with emphasis on critical locations where the maximum deflection for a run of piping is expected, will detect abnormalities, which would require further investigation. Redundant systems with symmetrical*

configurations will be monitored for thermal movement. Cold portions of systems would not require verification when free-end displacements are negligible.

4. *Acceptance criteria will be based on evidence that there is no binding or constraint to free expansion other than that which was intended and on evidence that suspension components and restraints function with the designed operating range.*

5. *All piping supports will be installed and adjusted to proper specifications. Should any of these components require modification or adjustment so that there would be any significant effect on a system, that portion of the system would subsequently be monitored through another heatup/cooldown cycle.*

14B.17 CORE POWER DISTRIBUTION (STI-18)

A. Purpose

- *To determine the core power distribution in three dimensions.*
- *To confirm the reproducibility of the traversing incore probe (TIP) system readings.*
- *To determine core power symmetry.*

B. Description

Core power distribution data will be obtained during the power ascension program by using complete sets of axial power traces taken with the TIP system. At intermediate- and high-power levels, several sets of TIP data will be obtained to determine the overall TIP uncertainty.

TIP data will be obtained with the reactor operating with a symmetric rod pattern and at steady-state conditions. The total TIP uncertainty for the test will be calculated by averaging the total TIP uncertainty determined from each set of TIP data taken. The total TIP uncertainty is made up of random noise and geometric components.

Core power symmetry will also be calculated by using the TIP data. As determined from this analysis, any asymmetry will be accounted for in the calculation for MCPR, using the General Electric thermal analysis basis method.

C. Acceptance Criteria

Level 1 - The total TIP uncertainty (including random noise and geometrical uncertainties obtained by averaging the uncertainties for all data sets) must be < 7.8%.

NOTE:

A minimum of two and up to six data sets may be used to meet the above criteria. If the 7.8% total TIP uncertainty criteria cannot be met by the six sets of data, testing may continue provided the MCPR limit is adjusted to reflect the TIP uncertainty.

Additional data sets may be obtained to improve the TIP uncertainty by increasing the TIP data base, and the MCPR limit will be adjusted accordingly. If the 7.8% total TIP uncertainty becomes satisfied, the MCPR limit can be returned to its original value.

14B.18 CORE PERFORMANCE (STI-19)

A. Purpose - To evaluate the core performance parameters of core thermal power level, maximum fuel rod surface heat flux, MAPLHGR, and MCPR.

B. Description - Core power level, maximum heat flux, hot channel coolant flow, MCPR, and fuel assembly power will be determined at existing power levels and assumed overpower conditions. Plant and incore instrumentation, conventional heat balance techniques and core performance worksheets and nomograms will be used. This will be performed above 10% power at various pumping conditions, and can be done independently of the process computer functions.

C. Acceptance Criteria

Level 1

The MLHGR of any rod during steady-state conditions shall not exceed the limit specified by the HNP-2 Technical Specifications.

The steady-state MCPR shall not exceed the limits specified by the HNP-2 Technical Specifications.

The MAPLHGR shall not exceed the limits specified by the HNP-2 Technical Specifications.

Steady-state reactor power shall be limited to 2436 MWt and values on or below the design flow control line.

14B.19 STEAM PRODUCTION (STI-20)

A. Purpose - To demonstrate that the reactor steam production rate is satisfied.

B. Description - The steam production test is designed to operate continuously for 100 h at rated reactor conditions. When it is determined that all plant conditions are stabilized, the steam production rate will be measured during a 2-h period at conditions prescribed in the NSSS warranty.

C. Acceptance Criteria

Level 1

The NSSS parameters, as determined by using normal operating procedures, shall be within the appropriate license restrictions.

The NSSS shall produce steam of not < 99.7% quality at a pressure of 985 psia at the second main steam isolation valve (MSIV) in accordance with the following equation:

$$W_{PV} = \frac{8288.2}{1191.5 - h_{FW}} + 0.03 \text{ (Mlb/h)}$$

where:

h_{FW} = *average feedwater inlet enthalpy*

NOTE:

The above equation is applicable when the reactor is operating at rated core thermal power of 2436 MW, a moisture fraction at the second MSIV of 0.3%, and the CRD flow is 0.03 Mlb/h at 80°F. Correction techniques for conditions that differ from these conditions shall be mutually agreed to prior to performance of the test.

14B.20 CORE POWER-VOID MODE TEST (STI-21)

A. Purpose

- *To demonstrate stability in the power reactivity feedback loop with increasing reactor power.*

- *To determine the effect of control rod movement on reactor stability.*

B. Description - Rod movement tests will be made at chosen power levels to demonstrate that the transient response of the reactor to a reactivity perturbation is stable for the full range of reactor power. A centrally located rod will be moved, and the neutron flux signal will be measured and evaluated to determine the dynamic effects of rod movement.

C. Acceptance Criteria

1. *Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to control rod movement.*

2. *Level 2 - The decay ratio is expected to be ≤ 0.25 for each total core process variable and ≤ 0.50 for each localized process variable (LPRM) that exhibits oscillatory response to control rod movement when the plant is operating above the lower-limit setting of the master flow controller.*

14B.21 PRESSURE REGULATOR (STI-22)

A. Purpose

- *To determine the reactor pressure control system responses to pressure regulator setpoint changes.*
- *To demonstrate the stability of the reactivity-void feedback loop to pressure perturbation.*
- *To demonstrate the control characteristics of the bypass and control valves.*
- *To demonstrate the takeover capabilities of the backup pressure regulator.*
- *To optimize the pressure regulator settings to give the best combination of fast response and small overshoot.*

B. Description - The pressure setpoint will be decreased rapidly and then increased rapidly 5 to 10 psi. The response of the system will be measured in each case. The backup regulator will be tested by increasing the operating pressure regulator setpoint rapidly until the backup regulator takes over control. The load reference setpoint will be reduced and the test repeated with the bypass valve having control. The response of the system will be measured and evaluated, and regulator settings will be optimized.

C. Acceptance Criteria

1. Level 1

The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to pressure regulator changes.

2. Level 2

The decay ratio of any oscillatory-controlled variable must be ≤ 0.25 when operating above the minimum core flow of the master flow control range. Below this minimum core flow, the decay ratio must be ≤ 0.50, with the recommendation that each control system be adjusted to meet ≤ 0.25 unless there is an identifiable performance loss involved at higher power levels.

The response time from setpoint input until the pressure peak of the turbine inlet pressure must be in accordance with design requirements in the recirculation manual mode only.

Pressure control system deadband, delay, etc., shall be small enough that steady-state limit cycles (if any) shall produce steam flow variations no larger than ± 0.5% of rated steam flow.

The normal difference between regulator setpoints must be small enough that the peak neutron flux and/or peak vessel pressure remain below the scram settings by 7.5% and 10 psi, respectively, for the regulator failure test performed at test condition 6. (Maintain a plot of power versus the peak variable values along the 100% rod line.)

14B.22 FEEDWATER CONTROL SYSTEM (STI-23)

A. Purpose

- *To evaluate and adjust feedwater controls.*
- *To demonstrate capability of automatic flow runback feature to prevent low water level scram following trip of one feedwater pump.*
- *To demonstrate adequate response to feedwater heater loss.*
- *To demonstrate general reactor response to inlet subcooling changes.*
- *To demonstrate acceptable reactor water level control.*

B. Description

Reactor water level setpoint changes of ~ ± 6 in. will be used to evaluate and acceptably adjust the feedwater control system settings for all power and feedwater pump modes.

One of the two operating feedwater pumps will be tripped at full power while the automatic flow runback circuit acts to drop power to within the capacity of the remaining pump.

The resulting transients from the loss of a feedwater heater will also be evaluated.

C. Acceptance Criteria

1. Level 1

Response of any level-related variable to any test input change or disturbance must not diverge.

For the feedwater temperature loss test, the maximum feedwater temperature decrease due to a single-failure case must be ≤ 100°F. The resultant MCPR must be greater than the fuel thermal safety limit.

For the feedwater temperature loss test, the increase in simulated heat flux cannot exceed the predicted level-2 value by > 2%. The predicted value will be based on the actual test values of feedwater temperature change and power level.

The feedwater flow runout capability must not exceed the assumed value of the Final Safety Analysis Report.

2. Level 2

The decay ratio of any oscillatory-controlled variable must be ≤ 0.25 when operating above the minimum core flow of the master flow control range. Below this minimum core flow, the decay ratio must be ≤ 0.50, with the recommendation that each control system be adjusted to meet ≤ 0.25 unless there is an identifiable performance loss involved at higher power levels.

A scram must not occur from low water level following a trip of one of the operating feedwater pumps. There should be > a 3-in. water-level + margin to scram for a feedwater pump trip initiated at 100% power conditions.

The flow deviation between any two feedwater risers shall be < 1.0% of the average riser flow (total flow divided by the number of risers).

For the feedwater temperature loss test, the increase in simulated heat flux cannot exceed the predicted value referenced to the actual feedwater temperature change and power level. The predicted values are presented in the Transient Safety Analysis Report, MPL-A41-5010.

The average rate of response of the feedwater actuator to large (< 20%) step disturbances shall be between 10 and 25% of pump rated feedwater flow/second. This average response rate will be assessed by determining the time required to pass linearly through the 10 and 90% response points.

The dynamic flow response of each feedwater actuator to small (< 10%) step disturbances shall be:

- *Maximum time to 10%[a].* *1.1 s*
- *Maximum time from 10 to 90%[a].* *1.9 s*
- *Settling time to within ± 5 %[a] of the final value.* *14.0 s*
- *Peak overshoot.* *15%[a]*

a. Percent of step disturbance.

14B.23 TURBINE VALVE SURVEILLANCE (STI-24)

A. Purpose

- *To demonstrate the ability of the pressure regulator to minimize the reactor disturbance during an abrupt change in reactor steam flow.*

- *To demonstrate that main turbine valves can be tested for proper functioning along the rated power load line without causing a high flux scram.*

B. Description - Turbine valves will be operated by a test switch. The pressure transient will be measured and evaluated to aid in making final adjustments to the pressure regulator.

C. Acceptance Criteria

1. Level 1

The decay ratio of any oscillatory response must be < 1.0.

2. Level 2

Peak neutron flux must be at least 7.5% below the scram trip setting. Peak vessel pressure must remain at least 10 psi below the high-pressure scram setting.

Peak steam flow in each line must remain 10% below the high-flow isolation trip setting.

The decay ratio of any oscillatory response must be < 0.25 when operating above the minimum core flow of the recirculation master manual mode.

14B.24 MAIN STEAM LINE ISOLATION VALVES (STI-25)

A. Purpose

- *To functionally check the MSIVs for proper operation at selected power levels.*
- *To determine reactor transient behavior during and following simultaneous full closure of all MSIVs and following closure of one valve. To determine isolation valve closure time.*
- *To determine the maximum power at which a single valve may be closed without a reactor scram.*

B. Description - Functional checks (10% closure) of each isolation valve will be performed at selected reactor power levels. A test of the simultaneous full closure of all MSIVs will be performed at about 100% of rated thermal power. Operation of the RCIC and safety relief valves will be shown. Reactor process variables will be monitored to determine the transient behavior of the system during and following full isolation. The MSIVs closure times will be determined. The maximum power conditions at which individual valve full closure tests can be performed without a reactor scram is to be established.

C. Acceptance Criteria

1. Level 1

MSIV closure time, exclusive of electrical delay, shall be no faster than 3.0 s and no slower than 5.0 s including electrical delay (each valve, not averaged).

Assuming no equipment failures and applying appropriate parametric corrections, predicted analytical results based on the design basis analysis for the beginning of cycle will be used as the basis to which the actual transient is compared for the full MSIV closure from full power. The following specifies the upper limits of these criteria during the first 30 s following initiation of the indicated conditions.

Initial Conditions		Criteria	
Power (%)	Dome Pressure (psia)	Increase in Heat Flux (%)	Increase in Dome Pressure (psi)
100	1020	1[(a)]	153[(a)]

Feedwater control system settings must prevent flooding of the steam lines.

2. Level 2

During full closure of individual valves, peak vessel pressure must be 10 psi (1.4 kg/cm^2) below scram, peak neutron flux must be 7.5% below scram, and steam flow in individual lines must be 10% below the isolation trip setting.

The RCIC system shall adequately take over water level protection. The relief valves must reclose properly (without leakage) following the pressure transient.

Assuming no equipment failures and applying appropriate parametric corrections, predicted analytical results based on the design basis analysis for the beginning of cycle will be used as the basis to which the actual transient is compared for the full MSIV closure from full power. The following specifies the upper limits of these criteria during the first 30 s following initiation of the indicated conditions.

Initial Conditions		Criteria	
Power (%)	Dome Pressure (psia)	Increase in Heat Flux (%)	Increase in Dome Pressure (psi)
100	1020	0[a]	128[a]

a. Nominal value, actual acceptance criteria are to be determined based on actual test conditions.

14B.25 SAFETY RELIEF VALVES (STI-26)

A. Purpose - To verify the proper operation of the dual purpose safety relief valves, to determine their capacity, and to verify their leaktightness following operation.

B. Description - The main steam safety relief valves are opened manually so that only one is opened at any time. Capacity of each safety relief valve is determined by the amount the bypass or control valves close to maintain reactor pressure. Proper reseating of each safety relief valve is verified by observation of temperatures in the safety relief valve discharge piping.

C. Acceptance Criteria

1. Level 1

There should be positive indication of steam discharge during the manual actuation of each valve.

The sum total of capacity measurements from the 11 relief valves shall be $\geq 9.46 \times 10^6$ lb/h corrected to an inlet pressure of 1112 psig.

2. Level 2

Relief valve leakage shall be low enough that the temperature measured by the thermocouples in the discharge side of the valves returns to within 10°F (5.6°C) of the temperature recorded before the valve was opened.

The pressure regulator must satisfactorily control the reactor transient and close the control valves or bypass valves by an amount equivalent to the relief valve discharge.

The transient recorder signatures for each instrumented valve must be analyzed for a relative implied valve time response comparison.

No individual safety relief valve may have a corrected flowrate that is < 90% or > 122.5% at its expected flowrate of 1112 psig.

NOTE:

Relief valve flowrates are to be calculated at their setpoint pressures. This requires the use of a pressure ratio correction to the observed valve steam flowrate. Multiply by the ratio of the setpoint pressure divided by the calculated local steam line pressure when the valve is open.

No more than 25% of the installed relief valves may have an individual corrected flowrate that is < 100% of their expected flowrates.

14B.26 TURBINE TRIP AND GENERATOR LOAD REJECTION (STI-27)

A. Purpose

- *To determine the response of the reactor system to a fast closure of the turbine-generator stop valves or control valves.*

- *To evaluate the response of the bypass system, safety relief valve system and reactor protection system (RPS). (The parametric responses of particular interest are the peak values and the rate of change of both reactor power and reactor steam dome pressure.)*

B. Description - The transients will be initiated at selected reactor power levels. Neutron flux, feedwater flow and temperature, vessel water level and pressure will be monitored. Responses of selected control valves, stop valves, safety relief valves, and bypass valves will be recorded.

C. Acceptance Criteria

1. Level 1 - For high-power trips:

Predicted analytical results based on beginning-of-cycle design basis analysis, assuming no equipment failure and applying appropriate parametric corrections, will be used as the bases to which actual transient results are compared. The following specifies the appropriate upper limits for these criteria during the first 30 s following initiation at the indicated conditions.

	Initial Conditions			*Criteria*	
Transient	*Test Condition*	*Power (%)*	*Dome Pressure (psia)*	*Increase in Heat Flux (%)*	*Increase in Dome Pressure (psia)*
Turbine trip	*3*	*75*	*990*	*2*[a]	*135*[a]
Generator breaker trip	*6*	*100*	*1020*	*2*[a]	*147*[a]

Feedwater system settings must prevent flooding of the steam line following these transients.

The two-pump drive flow coastdown transient during the first 3 s must be equal to, or faster than, that which was assumed in the transient analysis.

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a. Nominal value, actual acceptance criteria to be determined based on actual test conditions.

During the turbine trip, the bypass valve opening should begin by 0.1 s after start of stop valve closure, and flow should be 80% of total bypass capacity within another 0.2 s, i.e., within 0.3 s of start of stop valve closure.

2. *Level 2*

Predicted analytical results based on beginning-of-cycle design basis analysis, assuming no equipment failure and applying appropriate parametric corrections, will be used as the bases to which actual transient results are compared. The following specifies the appropriate upper limits for these criteria during the first 30 s following initiation at the indicated conditions.

	Initial Conditions			*Criteria*	
Transient	*Test Condition*	*Power (%)*	*Dome Pressure (psia)*	*Increase in Heat Flux (%)*	*Increase in Dome Pressure (psia)*
Turbine trip	*3*	*75*	*990*	*0*[a]	*110*[a]
Generator breaker trip	*6*	*100*	*1020*	*0*[a]	*122*[a]

The MSIVs shall not be tripped closed at any time during the test transient.

The load rejection within bypass capacity must not cause a scram. The trip scram function for higher power levels must meet RPS specifications.

a. *Nominal value, actual acceptance criteria to be determined based on actual test conditions.*

14B.27 SHUTDOWN FROM OUTSIDE THE MCR (STI-28)

A. Purpose - To demonstrate that the reactor can be brought from a normal initial steady-state power level to the point where cooldown is initiated and under control with RPV pressure and water level controlled from outside the MCR.

B. Description - The test will simulate reactor shutdown following a MCR evacuation. With the generator output at > 10% power, a reactor scram will be initiated from a location outside the MCR. Vessel water level and pressure will be stabilized, and the capability for cooldown will be demonstrated from outside the MCR by an operating crew equal to the minimum required operating crew. Additional operating personnel will stand by in the MCR.

C. Acceptance Criteria

Level 2 - During a simulated MCR evacuation, the reactor must be brought to the point where cooldown is initiated and under control. The reactor vessel pressure and water level are controlled using equipment and controls outside the MCR.

14B.28 FLOW CONTROL (STI-29)

A. Purpose

- *To determine the plant response to changes in recirculation flow and thereby adjust the local control loops.*

- *To examine the plant overall load following capability in order to establish correct interfacing of the pressure and flow control systems including final settings for the master and local flow controllers.*

B. Description - Various process variables will be recorded while step changes are introduced into the recirculation flow control system (increased and decreased) at chosen points. Load-following capability will be demonstrated in the automatic flow-control mode.

C. Acceptance Criteria

1. Level 1

The decay ratio of any oscillatory variable must be < 1.0.

2. Level 2

The decay ratio of any oscillatory-controlled variable must be ≤ 0.25 when operating above the minimum core flow of the master flow control range.

Flow control system limit cycles (if any) must produce turbine steam flow variation no longer than ± 0.5% of the rated steam flow value.

Reactor scram shall not occur due to flow control system maneuvers. The APRM flux margin shall be ≤ 7.5%.

The automatic load following range along the full-power rod line shall be at least 35% of rated power, i.e., 65 to 100%.

The load change resulting from a maximum ramp increase in load reference within the limits of the automatic flow control range shall be achieved within 60 s if operating restrictions permit. In addition, ± 10 and 20% power step changes must be performed within 40 s.

Following a 10% speed demand step, at the low end of the speed control range, the time from the step demand until generator speed peak occurs must be ≤ 25 s.

Dynamic response of each speed control (closed) loop following a step input, between 90 and 100% speed, shall be adjusted so that 10% of the demanded change will be reached within 2 s and the response time between 10 and 90% of the demanded change will be no

> 5 s. Deviations from this response below 90% speed shall not prevent complying with the first criteria, above.

14B.29 RECIRCULATION SYSTEM (STI-30)

A. Purpose

- *To determine transient responses and steady-state conditions following recirculation pump trips (RPTs) at selected reactor power levels, and to obtain jet pump performance data.*

- *To verify that no recirculation system cavitation will occur in the operable region of the power flow map.*

B. Description - Both recirculation pumps will be simultaneously tripped at a power level of 50 to 75% of rated power. The pumps will be tested by opening the pump motor breakers at > 95% flow and 50% power. Single pump trips will be performed at 50 to 75% and 100% of rated power. Reactor pressure, steam and feedwater flow, jet pump WP, and neutron flux will be recorded during the transient and at steady-state conditions. MCPR evaluations will be made for conditions encountered during the transient.

C. Acceptance Criteria

1. *Level 1 - The two-pump drive flow coastdown transient during the first 3 s must be equal to or faster than that specified in the startup test instructions.*

2. *Level 2 - The single pump trips shall not result in a high-water-level turbine trip. The level margin shall be at least 3.0 in. at test condition 6. The reactor shall not scram during the pump restart. The scram avoidance margins will be 7.5% for neutron flux.*

14B.30 LOSS OF TURBINE-GENERATOR AND OFFSITE POWER (STI-31)

A. Purpose - To demonstrate proper performance of the reactor and the plant electrical equipment and systems during the loss of auxiliary power transient.

B. Description - The loss of auxiliary power test will be performed at 20 to 30% of rated power. The proper response of reactor plant equipment, automatic switching equipment, and the proper sequencing of the diesel generator load will be checked. Appropriate reactor parameters will be recorded during the resultant transient.

C. Acceptance Criteria

1. Level 1

RPS actions shall prevent violation of neutron flux and simulated fuel surface heat flux thermal power limitations.

The peak vessel dome pressure rise shall be less than that predicted at the actual test conditions.

All safety systems, such as the RPS, the diesel generator, RCIC, and HPCI, must function properly without manual assistance, and HPCI and/or RCIC system action, if necessary, shall keep the reactor water level above the initiation level of CS, LPCI, and automatic depressurization.

2. Level 2

Normal reactor cooling systems should be able to maintain adequate suppression pool water temperature and drywell cooling and prevent actuation of the automatic depressurization system.

The RCIC system shall adequately take over water level protection.

14B.31 DRYWELL PIPING VIBRATION (STI-33)

A. Purpose - To verify that the reactor main steam and recirculation piping vibration is responding as predicted.

B. Description - During reactor operation, it is desirable to show that destructive level piping vibrations do not occur by measuring vibration in the recirculation and main steam lines at steady state and during various planned transients.

C. Acceptance Criteria[a]

1. Level 1

Flow-induced or continuous (steady state) vibration range displacement measurements for the recirculation and steam lines shall not exceed 0.2 in. at any measured point.

The measured range of displacement for vibration of the recirculation system due to RPT shall not exceed 0.4 in.

The measured range of displacements in the main steam lines for the relief valve operation will be less than the calculated displacements.

2. Level 2

Vibration shall not reach 80% of the applicable level 1 criteria.

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a. For restart testing following the 1984 recirculation piping replacement, see paragraph 3.9.1.1.1(A).

14B.32 RECIRCULATION SYSTEM FLOW CALIBRATION (STI-35)

A. Purpose - To perform a complete calibration of the installed recirculation system flow instrumentation.

B. Description - The single tap jet-pump instrumentation calibration will be performed using the double tapped jet pump flows and the associated single-tap ΔP for those pumps. This calibration will then be used to calibrate all the single-tap instrumentation so that the loop flow indicators and core flow recorders read correctly. Once the relationship between drive flow and core flow is established, the flow-biased system settings for APRM and rod block monitor (RBM) will be adjusted to match this relationship.

C. Acceptance Criteria

Level 2

Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide a correct core flow indication at rated conditions.

The APRM/RBM flow-bias instrumentation shall be adjusted to function properly at rated conditions.

14B.33 RWC SYSTEM (STI-70)

A. Purpose - To demonstrate specific aspects of the mechanical operability of the RWC system.

B. Description - Process variables during steady state operations are recorded with the RWC system in the blowdown mode, the hot standby mode, and the normal mode.

C. Acceptance Criteria

Level 2

The temperature at the tube side outlet of the nonregenerative heat exchangers shall not exceed 140°F in any mode.

The pump available net positive suction head will be ≥ 10 ft during the hot standby mode defined in the process diagrams.

The cooling water supplied to the nonregenerative heat exchangers shall be within the flow and outlet temperature limits indicated in the process diagrams.

14B.34 <u>RHR SYSTEM (STI-71)</u>

A. Purpose

- *To demonstrate the ability of the RHR system to remove residual and decay heat from the nuclear system so that the refueling and nuclear system servicing can be performed.*

- *To condense steam while the reactor is isolated from the main condenser.*

B. Description

With the reactor ≥ 25% power, the condensing mode of the RHR system will be demonstrated. Condensing heat exchanger performance characteristics will be demonstrated.

During the first suitable reactor cooldown, the shutdown cooling mode of the RHR system will be demonstrated and the torus cooling mode will also be demonstrated.

C. Acceptance Criteria

Level 2

The RHR system shall be capable of operating in the steam condensing mode (with both one and two heat exchangers) at the flowrate indicated on the process diagrams.

In the steam condensing mode, for small disturbances, each system variable must have a decay ratio less than 0.25 throughout each controller's expected operating range.

The time to place the RHR heat exchangers in the steam condensing mode with the RCIC using the heat exchanger condensate flow for suction shall average 1/2 h or less.

Operation within the required engineering design specification will be verified for the shutdown cooling mode and the torus cooling mode.

14B.35 <u>OFF-GAS (STI-74)</u>

A. Purpose

- *To verify the proper operation of the off-gas system over its expected operating parameters.*

- *To determine the performance of the activated carbon adsorbers.*

B. Description - At startup flow and again at normal flow the pressures at selected locations will be recorded and checked to see that they are within design specifications. The hydrogen analyzer, relative humidity, temperature, recombiner performance, dilution steam flow, radionuclide residence times, and before and after filters will be checked periodically throughout plant startup while at steady-state conditions.

C. Acceptance Criteria

1. Level 1

The release of radioactive gaseous and particulate effluents must not exceed the limits specified in the Offsite Dose Calculation Manual, the Technical Specifications, and plant procedures.

There shall be no loss of flow of dilution steam to the noncondensing stage when the steam jet air ejectors are pumping.

2. Level 2

The system flow, pressure, temperature, and relative humidity shall comply with the design specifications. The catalytic recombiner, the hydrogen analyzer, the activated carbon beds, and the filters shall be working properly during operation.

14B.36 MSIV LEAKAGE CONTROL SYSTEM

(This system has been deleted.)

14B.37 HYDROGEN RECOMBINERS

The hydrogen recombiners system is tested during the preoperational test program. The conditions for testing the system are independent of the operational condition of the plant.

14B.38 <u>PRIMARY CONTAINMENT COOLING SYSTEM (STI-44)</u>

A. Purpose - To demonstrate the ability of the primary containment cooling system to maintain drywell temperatures within the temperature limits assumed for safety analysis.

B. Description - At each major power level, air temperatures at various locations throughout the drywell, cooling unit discharge air temperature, cooling water inlet, and cooling water outlet temperatures will be recorded for each of six cooling units to assure correct performance and compliance with design specifications.

C. Acceptance Criteria

Level 2

The primary containment cooling system will maintain drywell atmosphere temperatures at ≤ 135°F.

15.0 SAFETY ANALYSIS (HNP-1 AND HNP-2)

15.1 GENERAL

15.1.1 ANALYTICAL APPROACH

The objective of the plant safety analysis is to demonstrate that the plant can operate without undue risk to the health and safety of the public.

Previous chapters of the Edwin I. Hatch Nuclear Plant (HNP) Unit 1 (HNP-1) and Unit 2 (HNP-2) Final Safety Analysis Reports (FSARs) provide the objectives, design bases, and a description of each major system, structure, and component. Systems that have unique requirements arising from nuclear safety considerations are evaluated in the individual chapters under the heading "Safety Evaluation." The individual system safety evaluations include consideration of the system-unique safety-related performance requirements, including the ability of each system to perform the prevention and mitigation functions required by the safety analysis.

This chapter provides the results of the combined safety analysis for HNP-1 and HNP-2. The two units have virtually identical system designs, and similar thermal-hydraulic and transient behavior characteristics.

The combined safety analysis resulted in the evaluation of the following 13 additional events for HNP-1:

- Shutdown cooling [residual heat removal (RHR)] malfunction - decreasing temperature.
- Pressure regulator failure - closed.
- Loss of condenser vacuum.
- Feedwater line break.
- Generator load rejection with flux scram and no bypass or recirculation pump trip (RPT).
- Turbine trip with flux scram and no bypass or RPT.
- Loss of one dc system.
- Loss of instrument air.
- Loss of service water.

- Miscellaneous small releases outside containment.
- Instrument line breaks.
- Liquid radwaste tank failure.
- Gaseous radwaste tank failure.

Because of the similarity in the design and performance of the two units, the HNP-2 results for the additional events are considered applicable to HNP-1.

The original FSAR documented the results of required analyses to demonstrate the adequacy of plant design during normal operations and transient conditions [i.e., anticipated operational occurrences (AOOs)] and to demonstrate the adequacy of plant design to prevent or mitigate the consequences of accidents. Also included were the results of special analyses performed to demonstrate the plant's capability to respond to selected events performed in response to regulatory requirements and guidance and specific licensing commitments.

Subsequent to the issuance of the original operating license, additional events were analyzed in response to changing regulatory requirements, licensing commitments, reloads, and plant modifications. The plant safety analysis was updated, as required, to reflect the uprate in licensed plant power level to its current licensed power level of 2804 MWt. Additionally, selected events were updated to implement an alternative source term (AST) in accordance with 10 CFR 50.67 as described in subsection 15.1.11.

The safety analysis process does not require that all the events considered part of the plant safety analysis be reanalyzed for each plant modification, because some events are either not affected by the modification or are bounded by other event analyses. As a result, only the potentially limiting events (i.e., events that pose the most significant challenge to the applicable event acceptance limits) affected by a specific plant modification are evaluated. Consistent with this approach, some of the event analyses do not require a revision to reflect current plant design and configuration. Thus, each event evaluation indicates the last time it was updated.

The original FSAR event analyses play an important role in the overall safety analysis process. Performing a wide spectrum of event analyses as part of the overall safety analysis process establishes a baseline analysis for the plant. The baseline analysis results play a key role in defining the potentially limiting events that require reanalysis for reloads and specific plant modifications.

The reload analysis process described in ***NEDE-24011-P-A, "GESTAR II - General Electric Standard Application for Reactor Fuel," (incorporated by reference into the FSAR)*** uses the results of previous event analyses to establish which events require reevaluation for each reload. The cycle-specific supplemental reload licensing reports provide the reload analysis results used to establish the appropriate core operating limits that ensure conformance to the applicable event acceptance limits.

The cycle-specific reload licensing reports for HNP-1 and HNP-2 are listed in table 15.1-1. The core operating limits are provided in each unit's cycle-specific ***Core Operating Limits Report (incorporated by reference into the FSAR)***.

The combined nuclear safety operational analysis (NSOA) (supplement 15C) identifies, for each event in the safety analysis, the system-level requirements that ensure the plant can be brought to a stable condition consistent with the plant licensing basis. The NSOA also identifies the operator actions necessary to preserve the assumptions of the safety analysis. The event paths analyzed as "limiting" in the safety analysis generally correspond to one, or a conservative representation of one, of the event paths for each event analyzed in the NSOA. Thus, the safety analysis is consequences oriented, focusing on the limiting short-term response to the event, and the NSOA is event/system oriented, focusing on the system-level required actions necessary over the entire duration of the event (long-term response) to bring the plant to a stable configuration.

A list of the events that have been updated for some selected major modifications, including power uprate to a rated thermal power (RTP) of 2804 MWt, and the events that are routinely either reevaluated or reanalyzed as part of the reload analysis process is provided in table 15.1-2.

15.1.2 PROBABILISTIC SAFETY ASSESSMENTS

Probabilistic safety assessments (PSAs) of the plant's response to postulated events can be used as an analytical tool in the plant safety analysis process. The PSA approach allows for:

- Quantification of the probability of exceeding pre-established standards of acceptance (success criteria).
- Categorization and evaluation of failures by relative event probability.
- Measure of overall risk due to plant operation under adverse circumstances.

The compilation of a substantial amount of probabilistic data on component failure rates, types of failures, repair times, and human error is required. Using these data, models are constructed and analyzed to establish realistic risk changes due to failure of various plant functions and systems. The nuclear industry is compiling sources of data and advancing PSA techniques. As these techniques mature and gain acceptance, they are increasingly being used to provide an appropriate perspective relative to overall plant safety. However, the PSA approach has not matured to the point it is accepted in the overall safety analysis process.

HNP will continue to use a deterministic process of evaluating a wide spectrum of postulated events. Events are analyzed using conservative assumptions to account for uncertainties in the analysis process and are compared to conservative event acceptance limits based upon a qualitative assessment of the relative event probability. As a result, the overall safety analysis process implemented for HNP-1 and HNP-2 has a substantial amount of inherent conservatism.

15.1.3 SELECTION OF EVENTS

The safety analysis contains the evaluation of a wide spectrum of postulated events. Based upon the relative event probabilities and failure assumptions, events are separated into the following three categories:

A. AOOs

AOOs are conditions of normal operation expected to occur one or more times during the life of the plant.

B. Accidents

Accidents are postulated events that may affect one or more of the barriers to the release of radioactive material to the environs. These events are not expected to occur during the life of the plant but are used to establish the design basis for many systems.

C. Special Events

Special events are postulated occurrences analyzed to demonstrate different plant capabilities required by regulatory requirements and guidance, industry codes and standards, and licensing commitments applicable to the plant. Special events may require failure assumptions in excess of AOOs and accidents. This category also encompasses some events that are not considered credible but are, nonetheless, conservatively analyzed consistent with plant-specific licensing commitments.

The analysis results for each event are presented for the conditions that present the most limiting challenge to the overall event acceptance limits. The conditions are selected consistent with the NSOA methodology (supplement 15C), which evaluates all the significant event paths from within the operating envelope for each event. Therefore, analysis of the selected conditions bounds the potential event paths from the perspective of potential risk to the health and safety of the public.

The event numbers shown in FSAR paragraphs 15.1.3.1, 15.1.3.2, and 15.1.3.3 correspond to the event numbers shown in the NSOA.

15.1.3.1 AOOs

In selecting the AOOs to be analyzed as part of the plant safety analysis, the eight nuclear system parameter variations listed below are considered possible initiating causes of challenges to the fuel or the reactor coolant pressure boundary (RCPB).

- Decrease in core coolant temperature.
  - Loss of feedwater heating (LFWH) (Event 1).
  - Inadvertent start of the high-pressure coolant injection (HPCI) pump (Event 2).
  - Shutdown cooling (RHR) malfunction - decreasing temperature (Event 3).
- Increase in core coolant temperature.
  - Loss of RHR shutdown cooling (Event 4).
- Increase in reactor pressure.
  - Generator load rejection with no bypass (LRNBP) (Event 5).
  - Generator load rejection with bypass (LRBP)(Event 6).
  - Turbine trip with no bypass (TTNBP) (Event 7).
  - Loss of condenser vacuum (Event 8).
  - Turbine trip with bypass (TTBP) (Event 9).
  - Closure of all main steam line isolation valves (MSIVs) (MSIVD) (Event 10).
  - Closure of one MSIV (Event 11).
  - Pressure regulator failure - closed (Event 12).
- Decrease in reactor core coolant flowrate.
  - Trip of one recirculation pump (Event 13).
  - Trip of two recirculation pumps (Event 14).
  - Recirculation flow controller failure - decreasing flow (Event 15).
- Increase in reactor core coolant flowrate.
  - Recirculation flow controller failure - increasing flow (Event 16).
  - Startup of idle recirculation pump (Event 17).

- Reactivity and power distribution anomalies.
  - Control rod withdrawal error (RWE) during power operation (Event 18).
  - Control rod removal error during refueling (Event 19).
  - Fuel assembly insertion error during refueling (Event 20).
- Increase in reactor coolant inventory.
  - Feedwater controller failure - maximum demand (FWCF) (Event 21).
- Decrease in reactor coolant inventory.
  - Inadvertent opening of a safety relief valve (SRV) (Event 22).
  - Pressure regulator failure - open (Event 23).
  - Loss of auxiliary power (Event 24).
  - Loss of feedwater flow (LOFW) (Event 25).

The eight parameter variations listed above include all the effects within the nuclear system (caused by AOOs) that can challenge the integrity of the reactor fuel or RCPB. The variation of any one parameter may cause a change in another parameter; however, for analysis purposes, challenges to barrier integrity are evaluated by groups according to the parameter variation initiating the plant challenge, which typically dominates the event response.

As discussed in ***NEDE-24011-P-A (GESTAR II)***, the following potentially limiting AOOs may require evaluation for each reload:

- TTNBP or LRNBP.
- LFWH or inadvertent start of the HPCI pump.
- FWCF.
- RWE.

The AOOs listed under each of the above parameter variations are discussed in detail in section 15.2.

15.1.3.2 Accidents

Accidents have the potential to release radioactive material as follows:

- From the fuel with the RCPB, primary containment, and secondary containment initially intact.
- Directly to the primary containment.
- Directly to the secondary containment with the primary containment initially intact.
- Directly to the secondary containment with the primary containment not intact.
- Outside the secondary containment.

The effects of the various accident types are investigated, with a consideration for the full spectrum of plant conditions, to examine events that result in the release of radioactive material. The accidents that represent the most significant radiological consequences and establish the design requirements for a number of systems are typically referred to as design basis accidents (DBAs). Examples of accident types are as follows:

A. Mechanical failure of various components leading to the release of radioactive material from one or more of the fission product barriers.

   The failed components do not act as radioactive material barriers. Examples of mechanical failures are breakage of the coupling between a control rod drive (CRD) and the control rod, failure of a crane cable, and failure of a spring used to close an isolation valve.

B. Events that can cause overheating of the fuel pellet and cladding barrier.

   This includes overheating as a result of reactivity insertion or loss of cooling. Other radioactive material barriers are not considered susceptible to failure from any potential overheating phenomenon.

C. Arbitrary rupture of any single pipe up to and including complete severance of the largest pipe in the nuclear system process barrier.

   This type of rupture is assumed only if the component postulated to rupture is subjected to significant pressure.

The following accidents are considered in the plant safety analysis:

- Control rod drop accident (CRDA) (Event 31).
- Loss-of-coolant accident (LOCA) (Event 32).

- Main steam line break accident (MSLBA) (Event 33).
- Fuel-handling accident (Event 34).
- Fuel assembly loading error (Event 35).
- Recirculation pump seizure (Event 36).
- Feedwater line break (Event 37).

The following four accidents pose the most limiting challenge to plant design and radiological exposure limits and are referred to as the DBAs for HNP-1 and HNP-2:

- MSLBA.
- LOCA.
- Fuel-handling accident.
- CRDA.

The fuel assembly loading error is evaluated for each reload to meet the fuel cladding integrity safety limit minimum critical power ratio (SLMCPR). The LOCA is evaluated each reload as part of the process for establishing the core operating limits for new fuel types.

Each accident listed above is discussed in detail in section 15.3.

15.1.3.3 Special Events

The following special events are evaluated as part of the plant safety analysis:

- Stability (Event 41).
- Overpressure protection (Event 42).
- Shutdown without control rod insertion [standby liquid control system (SLCS) capability] (Event 43).
- Main control room (MCR) uninhabitability (Event 44).
- Anticipated transient without scram (ATWS) (Event 45).
- Generator load rejection with flux scram and no bypass or RPT (Event 46).
- Turbine trip with flux scram and no bypass or RPT (Event 47).

- Loss of one dc system (Event 48).
- Loss of instrument air (Event 49).
- Loss of service water system (Event 50).
- Fire (Event 51).
- Miscellaneous small releases outside containment (Event 52).
- Instrument line break (Event 53).
- Liquid radwaste tank failure (Event 54).
- Gaseous radwaste tank failure (Event 55).
- Station blackout (SBO) (Event 56).

Stability is evaluated for each reload to meet the fuel cladding integrity SLMCPR. Overpressure protection and shutdown without control rod insertion capability are also evaluated for each reload. Consistent with ***NEDE-24011-P-A (GESTAR II)***, ATWS is evaluated for new fuel designs.

Each special event listed above is discussed in detail in section 15.4.

15.1.4 EVENT ANALYSIS FORMAT

With the exception of operator actions, the analysis format for each event is consistent with Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 1. Operator actions necessary to preserve the assumptions of the safety analysis are identified in the NSOA (supplement 15C).

HNP has implemented emergency operating procedures (EOPs) based upon industry and Nuclear Regulatory Commission (NRC)-approved EOP guidelines. In some cases, the EOP-specified operator actions may differ from the operator actions identified in the safety analysis and the NSOA for mitigating the same or similar event. The licensee and General Electric Company reviewed the differences and determined they do not violate the overall licensing basis of the plant. In addition, these differences were reviewed by the NRC. The specific differences and their resolutions are documented in references 1 through 4.

Upon implementation of the revised EOPs and the severe accident guidelines (SAGs) in 1998, the EOPs and the SAGs were again reviewed against the operator actions identified in the safety analysis and the NSOA. The differences were reviewed(5) and found not to violate the overall licensing basis of the plant.(6)

15.1.5 EVENT ACCEPTANCE LIMITS

The results of the safety analysis for each event must demonstrate conformance to the applicable event acceptance limits that are event specific across the three event categories. The event acceptance limits, the primary regulatory requirements from which the limits are derived, and the associated event acceptance limit values are provided in table 15.1-3 and described in more detail in the remainder of this subsection.

Event acceptance limits that are also fission product barriers, as referenced in 10 CFR 50.59(c)(2)(vii), are also identified in table 15.1-3. The respective design bases limits fundamental to barrier integrity are provided in the Values column of the table.

The event acceptance limits and the primary regulatory requirements from which the limits are derived reflect a qualitative assessment of the relative probability of the various events. The more probable events have more restrictive event acceptance limits. The event acceptance limits are associated with overall plant performance for specific events. Conformance with the event acceptance limits is demonstrated by the analyses and evaluations of the specific events discussed in sections 15.2, 15.3, and 15.4. Specific system design bases for systems whose performance is evaluated in the safety analysis are provided in previous chapters of the HNP-1 and HNP-2 FSARs.

The event acceptance limits based upon Title 10 Code of Federal Regulations (CFR) Part 20 require additional explanation. All of these event acceptance limits have a value of 0.5 rem, equivalent to the allowable yearly exposure at the site boundary, which was derived from the version of 10 CFR 20 applicable at the time HNP-1 and HNP-2 operating licenses were issued. For the original event analyses, the acceptance limits based upon 10 CFR 20 were associated with AOOs and selected special events involving nonsafety-related equipment failures. The current version of 10 CFR 20 is used to establish the release limits for normal plant operation.

15.1.5.1 AOOs

The following four event acceptance limits apply to AOOs:

1. Radioactive Effluents.

   The limit for radioactive effluents released as a result of AOOs is based upon 10 CFR 20. By demonstrating the specified acceptable fuel design limits (SAFDLs) are not exceeded during AOOs, no fuel failures are predicted. Therefore, conformance to this limit is demonstrated in the safety analysis by satisfying the SAFDLs.

   Only the five types of AOOs listed below can lead to radioactive releases other than the normal operational release paths:

   - Type I - pressure relief to the suppression pool (e.g., turbine trip or generator load rejection).

- Type II - main steam path isolation (e.g., MSIV closure while operating at power).
- Type III - inadvertent opening of an SRV.
- Type IV - MSIV closure with control rods inserted while the reactor is being cooled down (causing some SRV discharge to the suppression pool).
- Type V - reactor core isolation cooling (RCIC) or HPCI operation discharging exhaust steam to the suppression pool.

The radiological consequences of the five types of AOOs are of little consequence. The analysis of AOOs does not result in any calculated fuel failures during these events. The reactor coolant activity, which is due to coolant activation and preexisting fuel defects, is contained within the reactor vessel and the primary containment. As a result, offsite releases are negligible, and no radiological evaluations for AOOs are required as long as the SAFDLs are satisfied.

2. Peak RPV Pressure.

The peak RPV safety limit (1325 psig) is used as an event acceptance limit for AOOs to demonstrate RCPB design limits are not exceeded. It should be noted that the safety limit is a measured parameter (steam dome pressure) selected as a conservative value relative to the ASME Code upset limit of 1375 psig at the bottom of the RPV.

3. SAFDLs.

SAFDLs are used as an event acceptance limits for AOOs to demonstrate there are no calculated fuel failures. Four SAFDLs are used as event acceptance limits for the analysis of AOOs:

a. SLMCPR.

The SLMCPR is used as an event acceptance limit to protect the fuel cladding from overheating. For normal recirculation and pressure operation, the specific value for this limit is core- and fuel-design dependent. For low core flow or low-pressure operation, the SL is 25% of rated power.

b. Plastic Strain.

A 1% plastic strain limit is used as an event acceptance limit to protect the fuel cladding from mechanical failure.

c. Centerline Melt.

The centerline melt is used for core-wide AOOs.

d. Peak Fuel Enthalpy.

The fuel enthalpy limit is provided to protect fuel from rapid energy deposition events. The fuel enthalpy limit for AOOs is 170 cal/g and is applicable only to the RWE in the STARTUP mode.

The specific values for these limits are fuel-design dependent and are identified in ***NEDE-24011-P-A, (GESTAR II)***.

4. RHR Capability.

The suppression pool heat capacity temperature limit is used as an event acceptance limit for AOOs to ensure the availability of the suppression pool as a heat sink for the SRVs and a water source for makeup to the RPV. The heat capacity temperature limit is a function of RPV pressure and suppression pool temperature.

15.1.5.2 Accidents

The event acceptance limits for accidents are dependent upon the specific event being analyzed. The limits for accidents are described below:

1. CRDA.

Three basic event acceptance limits apply:

a. Offsite and Onsite Radiological Effects.

The limits for offsite radiological effects are 25% of the guideline dose values of 10 CFR 50.67 per Regulatory Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” dated July 2000. The event acceptance limits for onsite radiological effects are the limits identified in General Design Criterion (GDC) 19.

b. Peak Fuel Enthalpy.

The peak fuel enthalpy limit is a calculated peak fuel enthalpy of 280 cal/g to ensure the integrity of the RCPB.

c. Peak RPV Pressure.

Peak RPV pressure is used as an acceptance limit to demonstrate RCPB design limits are not exceeded. The ASME Code emergency limit of peak RPV pressure of 1500 psig is used for this limit. Generic analyses[7] demonstrate that if the peak fuel enthalpy limit is satisfied, RPV design limits are also satisfied.

2. LOCA.

Four basic event acceptance limits apply:

a. Offsite and Onsite Radiological Effects.

The limits for offsite radiological effects are the guideline dose values of 10 CFR 50.67 per RG 1.183. The event acceptance limits for onsite radiological effects are the limits identified in GDC 19.

b. Emergency Core Cooling System (ECCS) Acceptance Criteria of 10 CFR 50.46.

The five event acceptance limits associated with the ECCS acceptance criteria are as follows:

1) The calculated peak fuel-cladding temperature is not to exceed 2200°F.

2) The calculated local cladding oxidation is not to exceed 0.17 times the local cladding thickness before oxidation.

3) The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam is not to exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, except the cladding surrounding the plenum volume, were to react.

4) Calculated changes in core geometry are to be such that the core remains amenable to cooling.

5) After any calculated successful operation of the ECCS, the calculated core temperature shall be maintained for the extended period of time required by the long-lived radioactivity remaining in the core.

c. Peak RPV Pressure.

Peak RPV pressure is used as an acceptance limit to demonstrate RCPB design conditions are not exceeded. The ASME Code emergency limit of peak RPV pressure of 1500 psig is used for this limit.

d. Primary Containment Design.

The event acceptance limits are the ASME Code upset limit of peak containment pressure of 62 psig, and the peak containment design temperature of 281°F for HNP-1 and 340°F for HNP-2.

3. Fuel-Handling Accident.

   The limits for offsite radiological effects are 25% of the guideline dose values of 10 CFR 50.67 per RG 1.183. The event acceptance limits for onsite radiological effects are the limits identified in GDC 19.

4. MSLBA (Pipe Breaks Outside Containment)

   Two basic event acceptance limits apply:

   a. Offsite and Onsite Radiological Effects

      Offsite radiological effects are dependent upon plant operation as constrained by the Technical Specifications. The event acceptance limits for offsite radiological effects for unrestricted operation are 10% of the guideline dose values of 10 CFR 50.67 per RG 1.183. For restricted operation, the limits are the guideline dose values of 10 CFR 50.67 per RG 1.183. The event acceptance limits for onsite radiological effects are the limits identified in GDC 19.

   b. Peak RPV Pressure

      Peak RPV pressure is used as an acceptance limit to demonstrate RCPB design limits are not exceeded. The ASME Code emergency limit of peak RPV pressure of 1500 psig is used for this limit.

5. Feedwater Line Break (Pipe Breaks Outside Containment).

   Two basic event acceptance limits apply:

   a. Offsite and Onsite Radiological Effects.

      Offsite radiological effects are dependent upon plant operation as constrained by the Technical Specifications. The event acceptance limits for offsite radiological effects for unrestricted operation are 10% of the guideline dose values of 10 CFR 100. For restricted operation, the limits are the guideline dose values of 10 CFR 100. The event acceptance limits for onsite radiological effects are the limits identified in GDC 19.

   b. Peak RPV Pressure.

      Peak RPV pressure is used as an acceptance limit to demonstrate RCPB design limits are not exceeded. The ASME Code emergency limit of peak RPV pressure of 1500 psig is used for this limit.

6. Fuel Assembly Loading Error.

   The event acceptance limit is the SLMCPR, which is core- and fuel-design dependent and is used to preclude long-term operation with the potential for transition boiling, which could lead to fuel-cladding degradation and subsequent offsite radiological releases.

7. Recirculation Pump Seizure.

   The offsite radiological effects are the event acceptance limits, which are 10% of the guideline dose values of 10 CFR 100.

15.1.5.3 <u>Special Events</u>

The event acceptance limits for special events are dependent upon the specific event being analyzed. The limits for special events are described below.

1. Stability.

   The event acceptance limit for stability is the SLMCPR.

2. Overpressure Protection.

   The peak RPV pressure limit is used as an event acceptance limit to demonstrate RCPB design conditions are not exceeded. The ASME Code upset limit of peak RPV pressure of 1375 psig is conservatively used for this limit.

3. Shutdown Without Control Rod Insertion (SLCS Capability).

   The event acceptance limit is a k_{eff} of < 1.0 at the most reactive condition each cycle. This value ensures the reactor will be subcritical.

4. MCR Uninhabitability.

   Safe reactor shutdown to the cold shutdown condition is used as an event acceptance limit. Conformance to this limit is provided by demonstrating the appropriate equipment necessary to achieve a safe shutdown is available for operation from outside the MCR.

5. ATWS.

   Six basic event acceptance limits apply:

   a. RCPB Pressure Limit.

      The event acceptance limit is the ASME Code emergency limit of peak RPV pressure of 1500 psig.

b. Containment Limit.

The event acceptance limit is the ASME Code upset limit of a peak containment pressure of 62 psig, and a containment temperature of 281°F for HNP-1 and 340°F for HNP-2.

c. Coolable Geometry.

The event acceptance limits are a calculated peak fuel-cladding temperature of 2200°F and local cladding oxidation of 17%.

d. Offsite Radiological Effects.

The event acceptance limits are the guideline dose values of 10 CFR 100, which are satisfied by demonstrating the first three event acceptance limits are met. This approach limits fuel rod failures to < 100% perforations, which assures the dose will be less than the dose calculated for the LOCA, using conservative NRC assumptions.

e. Equipment Availability.

The event acceptance limit ensures the equipment will function in the environment predicted to occur as a result of an ATWS event.

f. Suppression Pool Temperature.

The event acceptance limit is the local saturation temperature.

6. Generator Load Rejection with Flux Scram and No Bypass or RPT.

The offsite radiological effects establish the event acceptance limits, which are the guideline dose values of 10 CFR 100.

7. Turbine Trip with Flux Scram and No Bypass or RPT.

The offsite radiological effects establish the event acceptance limits, which are the guideline dose values of 10 CFR 100.

8. Loss of One dc System.

The event acceptance limits are established by the radiological effects, which are dependent upon whether or not the event is assumed to occur during normal operation or concurrent with a LOCA. For the event occurring during normal operation, the event acceptance limit for offsite radiological effects is based upon 10 CFR 20.

9. Loss of Instrument Air.

   The offsite radiological effects establish the event acceptance limits. Because the instrument air system is not considered safety related, the event acceptance limit is based upon 10 CFR 20.

10. Loss of Service Water.

    The event acceptance limits are established by the radiological effects, which are dependent upon whether or not the event is assumed to occur during normal operation or concurrent with a LOCA. For the event occurring during normal operation, the event acceptance limit is based upon 10 CFR 20.

11. Fire.

    Safe reactor shutdown to the cold condition is used as an event acceptance limit. Conformance to this event acceptance limit is provided by:

    - Demonstrating one train of systems necessary to achieve and maintain hot shutdown from either the MCR or the emergency control station(s) is free of fire damage.

    - Ensuring the systems necessary to achieve and maintain cold shutdown from either the MCR or the emergency control station(s) can be repaired within 72 hours.

12. Miscellaneous Small Releases Outside Containment.

    The offsite radiological effects establish the event acceptance limits. Because many of the systems containing radioactive fluids are not considered safety related, the event acceptance limit is based upon 10 CFR 20.

13. Instrument Line Break.

    The event acceptance limits are established by the offsite radiological effects, which are 10% of the guideline dose values of 10 CFR 100.

14. Liquid Radwaste Tank Failure.

    The offsite radiological effects establish the event acceptance limits. Because the liquid radwaste tanks are not considered safety related, the event acceptance limit is based upon 10 CFR 20.

15. Gaseous Radwaste Tank Failure.

    The offsite radiological effects establish the event acceptance limits. Because the gaseous radwaste systems are not considered safety related, the event acceptance limit is based upon 10 CFR 20.

16. SBO

    a. Core Cooling.

       To ensure the automatic depressurization system (ADS) will not be activated, the core cooling limit is the maintenance of the water level above the level 1 setpoint.

    b. Containment Limit.

       The containment limit is the ASME Code upset limit of peak containment pressure of 62 psig, and a containment temperature of 281°F for HNP-1 and 340°F for HNP-2.

    c. Suppression Pool Temperature.

       To ensure the availability of the suppression pool as a heat sink for the SRVs and a water source for makeup to the RPV, the suppression pool heat capacity temperature limit is used as an event acceptance limit. The heat capacity temperature limit is a function of RPV pressure and suppression pool temperature.

15.1.6 SINGLE FAILURE

This subsection describes the application of single failure relative to AOOs and accidents. Single failure is defined in 10 CFR 50, Appendix A, and is specifically applied to multiple GDCs.

The treatment of special events is consistent with their specific event definitions that are typically beyond the original safety design bases of the plant. As a result, an additional single failure is not applied unless there is a specific licensing commitment.

The types of single failures considered in the safety analysis and NSOA processes are:

- The opening or closing of any single valve. (A check valve is not assumed to close against normal flow.)

- The starting or stopping of any single component.

- The malfunction or maloperation of any single control device.

- Any single electrical failure.

15.1.6.1 Application of Single-Failure Criteria

The single-failure requirements for AOOs and accidents in the safety analysis and the NSOA are applied as follows:

1. For AOOs and accidents, the protection sequences within mitigation systems are to be single-component-failure-proof. This requirement is in addition to any single-component failure or single operator error that is assumed as the event initiator. The requirement for assuming an additional single failure in the mitigation system adds a significant level of conservatism to the safety analysis. However, the event acceptance limits for AOOs and accidents are not changed by the application of an additional single-failure requirement.

2. For AOOs, it is not necessary to assume a single failure in normal operating systems in addition to the failure assumed as the event initiator. The basic logic for this assumption is based upon the probability of occurrence of a double failure in normal operating systems, which is less than once per plant lifetime and exceeds the probability of occurrence definition for AOOs in the GDC.

3. For accidents, single failures are considered consistent with plant-specific licensing commitments (e.g., valve malfunctions for LOCA).

4. Multiple (consequential) failures from a single failure (e.g., the unavailability of ac power to components because of a failure in the standby ac power system) are considered part of the single failure. Single failures are independently postulated in each operating unit or one failure is postulated in the common systems.

5. For mitigation systems included in the NSOA, single failures of active electrical and fluid components, and passive electrical components are treated in the same manner in the development of the event diagrams. Single failures in passive fluid components are treated consistent with plant-specific licensing commitments. More specifically, the only single failure in a passive fluid component considered in the plant design is long-term leakage in the ECCS suction piping following a LOCA.

6. During Technical Specifications surveillance testing or when complying with the limiting conditions for operation, applying the single-failure criteria for affected components/systems is not required. This is consistent with component/system reliability assumptions that form the bases for the plant Technical Specifications.

The single failures identified above are considered in the design of the plant, as required by the specific GDC, and are utilized in the safety analysis of the specific events.

15.1.6.2 Single Failures as Event Initiators

The AOOs identified in the safety analysis are frequently associated with transients that result from a single component failure or operator error, and are postulated during specific, applicable mode(s) of normal plant operation. Operator error is only considered as an event initiator.

Operator error is defined as a deviation from written operating procedures or operating practices. An operator error includes action(s) that are a direct consequence of one operator's single erroneous decision. An operator error does not include subsequent actions performed in response to the initiating event that resulted from the initial operator error.

Operator errors include:

- An increase in power above established power and flow, limited by control rod withdrawal in a specified sequence.

- The incorrect calibration of an average power range monitor (APRM).

- The manual isolation of the main steam lines caused by operator misinterpretation of an alarm or indicator.

15.1.7 ANALYSIS METHODS

An overview of safety analysis methods is shown in figure 15.1-1.

The fuel thermal mechanical methods, lattice physics methods, and 3-D simulator are used in the fuel and core design. The fuel thermal mechanical methods used in the initial core design were TEXICO/CLAM, and the methods used for power uprate were GESTR-M. The lattice physics methods and 3-D simulator used in the initial core design were the GENESIS methods, and the GEMINI methods were used for power uprate. The methods used in the reload analyses are identified in the cycle-specific reload licensing reports identified in table 15.1-1.

The LOCA analysis methods are identified in section 6.3. The CRDA analysis methods used are consistent with ***NEDE-24011-P-A (GESTAR II)*** for GNF fuel and Section 5.5.2 of reference 13 for the four Westinghouse SVEA-96 Optima2 lead use assemblies loaded into HNP-1.

The radiological evaluation methods are identified on an event-specific basis in subsection 15.3. Two types of evaluations are performed, realistic and conservative. The realistic evaluation methods reflect the analysis results of the accidents, considering the performance of the fission product barriers. The conservative evaluation methods include additional conservatism required by the NRC for site suitability evaluations.

The transient analysis methods used to analyze transient (dynamic) events are shown in figure 15.1-2. The transient analysis methods are used to perform the required analyses of AOOs, the fuel assembly loading error and recirculation pump seizure accidents, and the

majority of special events. These analyses establish the operating limit MCPR and demonstrate conformance to the applicable event acceptance limits.

The REDY transient analysis model was used for the original event analyses. ODYN was used for the power uprate analyses of pressurization events. The transient analysis model used in the reload analyses is identified in the cycle-specific reload licensing reports identified in table 15.1-1.

The hot channel analysis methods and the transient critical power methods used in the original event, power uprate, and reload analyses are consistent with ***NEDE-24011-P-A (GESTAR II)***.

15.1.8 ANALYSIS INPUTS

Inputs to the plant safety analysis are developed and maintained in accordance with applicable quality assurance programs. Selected safety analysis input parameters, with emphasis on parameters that may be affected by plant modifications and impact the reload analysis, are provided in table 15.1-4.

15.1.9 INCREASE IN RATED THERMAL POWER

The plant safety analysis demonstrates that HNP-1 and HNP-2 can operate at an RTP of 2804 MWt, which represents a 1.5% increase from the previous licensed power level of 2763 MWt and a 15.1% increase above the original plant licensed power level of 2436 MWt.

To confirm the acceptability of operation with a licensed power level of 2804 MWt, the applicable safety analysis events were reevaluated for the increase in RTP.[8,10] Specifically, all events in the safety analysis were reviewed. The review considered all plant modifications implemented prior to implementation of the power uprate. The review confirmed that potentially limiting events for reloads remain as identified in ***NEDE-24011-P-A (GESTAR II)***. The potentially limiting events were reevaluated and the power uprate results were documented for the affected events in sections 15.2, 15.3, and 15.4. The power uprate analysis trends were consistent with previous analysis results. The power uprate analyses were performed using a representative core. The reload analysis was used to establish the appropriate core operating limits based upon the cycle-specific reload for power uprate. Finally, the review, power uprate analyses, and reload analysis process demonstrated the acceptability of the allowable regions of the power-to-flow map (figure 15.1-3).

The reactor pressure vessel increase maintains the power level at 2804 MWt. The 10 CFR 50 Appendix K limit of 2818 MWt remains unchanged. The results of the evaluations performed for reactor operating pressure increase from 1050 psia to 1060 psia are addressed in reference 12.

The power-to-flow map for an RTP of 2804 MWt (figure 15.1-3) includes operation in the following regions:

- The maximum extended load line limit (MELLL) region, which allows plant operation with core flows as low as 92.9% of rated at 100% rated power.

- The increased core flow (ICF) region is bounded by the constant recirculation pump speed line corresponding to 105% core flow at 100% rated power.

15.1.10 PERFORMANCE IMPROVEMENT FEATURES

The following operating flexibility options described in ***NEDE-24011-P-A (GESTAR II)*** have been implemented at HNP:

1. Single-loop operation (SLO).

2. APRM/RBM Technical Specification Improvement (ARTS) Program.[9]

3. MELLL region.

4. ICF operation.

5. Final feedwater temperature reduction (FFWTR).

   HNP-1 and HNP-2 have a maximum acceptable FFWTR temperature of 80°F for operation at RTP. Intermittent FFWTR of 80°F may be used on HNP-1 or HNP-2 for a maximum of 45 days prior to the start of an end-of-cycle (EOC) power coastdown. An additional 90 days of FFWTR may be used during the coastdown from 100% of RTP down to 70% of RTP.

The following margin improvement options described in ***NEDE-24011-P-A (GESTAR II)*** have been implemented at HNP:

- EOC-RPT.

- Simulated thermal power monitor.

- Exposure-dependent limits.

- Improved scram times (ODYN option B).

In addition, the low-low set relief logic system was implemented, and the main steam isolation valve (MSIV) water level trip was lowered.[11]

15.1.11 IMPLEMENTATION OF ALTERNATIVE SOURCE TERM (AST)

10 CFR 50.67, "Accident Source Term," provides a mechanism for revising the accident source term used in the radiological consequences analyses for the DBAs. Full scope AST analyses were implemented for the DBAs for HNP-1 and HNP-2, specifically the LOCA, CRDA, MSLBA, and fuel-handling accident. The AST analyses for the HNP DBAs have been performed on a

bounding basis to apply to both HNP-1 and HNP-2. The AST analyses predominantly conform to the guidance in RG 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” dated July 2000.

The AST analyses include determination of the onsite radiological doses, specifically the MCR and technical support center, and offsite radiological doses resulting from the HNP DBAs. The analyses demonstrate that, using AST methodologies, the post-accident onsite and offsite doses remain within the applicable regulatory acceptance limits of 10 CFR 50.67 and GDC 19.

NRC Generic Letter (GL) 2003-01, “Control Room Habitability,” was written to inform licensees that the design basis assumptions used for control room unfiltered inleakage, even with a pressurized control room, could be nonconservative. Enhanced DBA radiological dose modeling employing new dose migrating features was required to conservatively model unfiltered inleakage into the pressurized HNP MCR as required and develop a reasonable unfiltered inleakage design margin due to the unique location of the MCR. The MCR, as part of the control building, is located between the open end bays of the HNP-1 and HNP-2 turbine buildings. The majority of the ductwork associated with the main control room environmental control (MCREC) system, which encompasses two independent filter trains for pressurizing the control room post-accident, is located external to the control room boundary on top of the control building within the confines of the HNP-1 and HNP-2 turbine buildings.

Due to the HNP MCR location in the turbine buildings, activity released into the turbine buildings during three of the DBAs, specifically the LOCA, MSLBA, and CRDA, had to be modeled to determine MCR doses. To support a reasonable unfiltered inleakage design margin, new dose mitigating design features needed to be credited as part of AST implementation as listed below.

- The HNP-1 and HNP-2 nonsafety-related turbine building ventilation exhaust systems are credited in AST with purging the area around the main control room following a LOCA, MSLBA, and CRDA. Applying the precedent established by NRC approval of the nonsafety-related main steam isolation valve alternate leakage treatment path, seismic verifications were developed and are maintained to demonstrate that the HNP-1 and HNP-2 turbine building exhaust ductwork will remain in place and maintain exhaust flow in the event of a design basis earthquake. These verifications are based on earthquake experience data and use the methodology documented in Electric Power Research Institute (EPRI) Technical Report 1007896, “Seismic Evaluation Guidelines for HVAC Duct and Damper Systems,” dated April 2003.

- Following a LOCA, a nonsafety-related main steam isolation valve alternate leakage treatment path is credited in AST for HNP-1. For a LOCA, the NRC previously approved a similar revision for HNP-2. RG 1.183, Appendix A, section 6, allows credit for reduction in MSIV releases due to holdup and deposition if the components and piping systems used in the release path are capable of performing their safety function during and following a safe shutdown earthquake. This seismic capability is demonstrated and maintained via development of a seismic verification. A seismic verification of the HNP-1 alternate leakage treatment path was developed and is maintained that conforms to the NRC safety evaluation, dated March 3, 1999, of the GE topical report NEDC-31858P, Revision 2, “BWROG Report for Increasing MSIV Leakage Limits and

Elimination of Leakage Control Systems." A seismic verification of the HNP-2 alternate leakage treatment path is also maintained and was developed to earlier guidance.

- Following a LOCA, for both HNP-1 and HNP-2, deposition in the main condenser is credited for those nonsafety-related secondary containment bypass leakage paths that terminate in the main condenser. Therefore, seismic verifications for the Units 1 and 2 bypass paths were developed and are maintained that also conform to the referenced March 3, 1999, NRC SER.

- Following a LOCA, a new design function is added for the standby liquid control system to buffer the suppression pool, preventing iodine re-evolution, by injection of a sufficient amount of sodium pentaborate solution to the suppression pool.

- Following a LOCA, containment spray is credited for fission product removal and primary containment pressure and temperature reduction.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

"GESTAR II - General Electric Standard Application for Reactor Fuel, <u>NEDE-24011-P-A</u>."

Unit 1 and Unit 2 Core Operating Limits Reports (located in each unit's Technical Requirements Manual, Appendix A).

REFERENCES

1. Letter REA-1-8-0665, "EOP/FSAR Comparison Update," W. F. Garner [Southern Company Services , Inc. (SCS) Hatch Project] to D. R. Madison [Southern Nuclear Operating Company (SNC) Hatch Project], dated August 13, 1991.

2. Letter REA-1-8-0694, "EOP/FSAR Comparison Update," W. F. Garner (SCS Hatch Project) to D. R. Madison (SNC Hatch Project), dated August 30, 1991.

3. Letter ARS 92/063, "Transmittal of Final Results of GE's Review of Plant Hatch EOPs vs. FSAR Differences," A. R. Smith (General Electric) to S. J. Bethay (SNC Hatch Project), dated March 20, 1992.

4. Letter ARS 92/063, "Offsite Doses from Post-LOCA Flooding and Venting of Hatch Containment Atmosphere," A. R. Smith (GE) to S. J. Bethay (SNC Hatch Project), dated March 20, 1992.

5. Letter B-GP-17314, "Response to Request for Engineering Assistance - Revised EOPs and SAGs - Review Against FSAR Design Bases," L. L. Rowe (Bechtel) to G. K. McElroy (SNC), dated July 14, 1998.

6. 10 CFR 50.59 Evaluation No. CP-3, "Safety Evaluation for Emergency Operating Procedures and Severe Accident Guidelines," 31EO-EOP-001-1 and -2, dated July 15, 1998.

7. F. E. Cooke, <u>et al</u>., "Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," <u>NEDO-21778</u>, January 1978.

8. "Safety Analysis Report for Edwin I. Hatch Nuclear Plant Units 1 and 2 Thermal Power Optimization," <u>NEDC-33085P</u>, GE Nuclear Energy, December 2002.

9. "General Electric BWR Licensing Report: Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for Edwin I. Hatch Nuclear Plant, Units 1 and 2," <u>NEDC-30474</u>, General Electric, December 1983.

10. "Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization," <u>NEDC-32938</u>, GE Nuclear Energy, July 2000.

11. "Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for Edwin I. Hatch Nuclear Plant, Units 1 and 2," <u>NEDE-22224</u>, December 1982.

12. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

13. Westinghouse Report NF-BSN-10-10, "Supplemental Licensing Report, SVEA-96 Optima2 Lead Use Fuel Assemblies for Edwin I. Hatch Nuclear Plant, Unit 1," Revision 0, February 2010.

TABLE 15.1-1 (SHEET 1 OF 7)

SUPPLEMENTAL RELOAD LICENSING REPORTS

HNP-1

Reload No.	Report No./Title
1	NEDO-21580; NEDO-21491
2	NEDO-24078; NEDO-24040
3	NEDO-24175
4	Y1003J01A13
5	Y1003J01A38, Revision 1
6	Y1003J01A50, Revision 1
7	23A1723, Revision 1
8	23A1830
9	23A4728
10	23A4846
11	23A5939, Revision 0
12	23A6504, Revision 0
13	23A7131, Revision 0
14	23A7206, Revision 0
15	24A5156, Revision 1
16	24A5353, Revision 0
	Letter REK:96-146, "Feedwater Controller Failure Transients for Hatch 1 Cycle 17," R. E. Kingston (GE) to K. S. Folk (SNC), April 25, 1996.
	Letter LDN97093, "Hatch 1 Cycle 17 ARTS Limits for PROOS," L. D. Noble (GE) to K. S. Folk (SNC), August 15, 1997.
	Letter LDN97094, "Hatch 1 Cycle 17 Updated MCPR Operating Limits, MAPHLGRs, and Process Computer Update," L. D. Noble (GE) to K. S. Folk (SNC), August 18, 1997.
	Letter LDN97106, "New MAPHLGR Limits for Bundle 2190," L. D. Noble (GE) to K. S. Folk (SNC), September 9, 1997.
17	24A5413, Revision 0
18	J11-03434SRLR, Revision 0
19	J11-03674SRLR, Revision 0

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HNP-1 (continued)

Reload No.	Report No./Title
20	0000-0002-7058-SRLR, Revision 0
	Letter CAH-NF-2370, "Hatch-1 Cycle 21 Pressure Regulator Out-of-Service ARTS Limits," E. B. Gibson (SNC) to K. S. Folk (SNC), April 8, 2002.
	Letter CAH-NF-2371, "GE14 Low Power ARTS Below P_{BYP} With Bypass Valves Inoperable," W. R. Mertz (SNC) to K. S. Folk (SNC), April 8, 2002.
	GNF Letter VRU-03-005, V. Ruiz-Ugalde to E. B. Gibson, “Hatch 1 and 2 Improved MPLHGR Limits,” June 26, 2003.
	GNF Letter EWG-S-03-011, E. W. Gibbs to E. B. Gibson, “Hatch-1 Bundle 2255 Improved MAPLHGRs,” July 17, 2003.
	SNC Letter CAH-NF-2435, “Addendum to Hatch-1 Cycle 21 SRLR for TPO Uprate,” W. R. Mertz to G. K. McElroy, September 12, 2003.
	SNC Letter CAH-NF-2436, “H1C21 TPO Low Power ARTS Multipliers,” W. R. Mertz to K. S. Folk, September 12, 2003.
21	Global Nuclear Fuel document 0000-0018-9797-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1 Reload 21 Cycle 22,” Revision 0, March 2004.
	Global Nuclear Fuel document 0000-0018-9797-FBIR, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 21 Cycle 22,” Revision 0, March 2004.
	SNC Memo CAH-NF-2464, “H1C22 Pressure Regulator Failure Downscale (PRFDS) Analysis,” W. R. Mertz to K. S. Folk, March 1, 2004.
	SNC Memo CAH-NF-2465, “TPO Low Power ARTS Multipliers,” W. R. Mertz to K. S. Folk, March 1, 2004.
22	Global Nuclear Fuel document 0000-0042-2576-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 22 Cycle 23,” Revision 0, February 2006.
	Global Nuclear Fuel document 0000-0042-2576-FBIR, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 22 Cycle 23,” Revision 0, February 2006.

TABLE 15.1-1 (SHEET 3 OF 7)

HNP-1 (continued)

Reload No.	Report No./Title
	SNC Letter CAH-NF-2502, "Generic Pressure Regulator Failure Downscale (PRFDS) Analysis," W. R. Mertz to K. S. Folk, February 16, 2005.
	SNC Letter CAH-NF-2465, "TPO Low Power ARTS Multipliers," W. R. Mertz to K. S. Folk, March 1, 2004.
	GNF Letter RA-SNC-HT1-06-015, Rev. 2, "GE14 LHGR Curves," R. Augi to W. Mertz, February 13, 2006.
23	Global Nuclear Fuel document 0000-0067-2863-SRLR, "Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 23 Cycle 24," Revision 0, December 2007.
	Global Nuclear Fuel document 0000-0067-2863-FBIR, "Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 23 Cycle 24," Revision 0, December 2007.
	SNC Nuclear Fuel document NF-07-125, "Hatch-1 Cycle 24 Reload Licensing Analysis Report," Version 1, February 2008.
24	Global Nuclear Fuel document 0000-0099-0707-SRLR, "Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 24 Cycle 25," Revision 0, November 2009.
	Global Nuclear Fuel document 0000-0099-0707-FBIR, "Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 24 Cycle 25," Revision 0, November 2009.
	SNC Nuclear Fuel document NF-10-13, "Hatch-1 Cycle 25 Reload Licensing Analysis Report," Version 1, February 2010.
25	Global Nuclear Fuel document 0000-0132-7784-SRLR, "Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 25 Cycle 26," Revision 0, December 2011.
	Global Nuclear Fuel document 0000-0132-7784-FBIR, "Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 25 Cycle 26," Revision 0, December 2011.
	SNC Nuclear Fuel document NF-11-130, "Hatch-1 Cycle 26 Reload Licensing Analysis Report," Version 1, December 2011.

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HNP-1 (continued)

26	Global Nuclear Fuel document 000N0481-SRLR, "Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 26 Cycle 27," Revision 0, December 2013.
	Global Nuclear Fuel document 000N0481-FBIR, "Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 1, Reload 26 Cycle 27," Revision 0, December 2013.
	SNC Nuclear Fuel document NF-13-171, "Hatch-1 Cycle 27 Reload Licensing Analysis Report," Version 2, December 2014.
27	Global Nuclear Fuel document 003N2016-SRLR, "Supplemental Reload Licensing Report for Hatch 1, Reload 27 Cycle 28," Revision 0, November 2015.
	Global Nuclear Fuel document 003N2033-FBIR, "Fuel Bundle Information Report for Hatch 1, Reload 27 Cycle 28," Revision 0, November 2015.
	SNC Nuclear Fuel document NFD-H-15-120, "Hatch-1 Cycle 28 Reload Licensing Analysis Report," Version 1, November 2015.

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HNP-2

Reload No.	Report No./Title
1	Y1003J01A10
2	Y1003J01A32, Revision 1
3	Y1003J01A57, Revision 2
4	23A1784, Revision 1
5	23A4686, Revision 1
6	23A4795, Revision 0
7	23A5884, Revision 0
8	23A6470, Revision 0
9	23A6549, Revision 0
10	23A7191, Revision 0
11	23A7241, Revision 1
12	24A5186, Revision 2
13	24A5401, Revision 0
14	24A5421, Revision 1
15	J11-036205RLR, Revision 0
15	Letter TGO: 00-027, "Transmittal of Hatch-2 Cycle 16 Miscellaneous ARTS Curves," T.G. Orr (GNF) to K.S. Folk (SNC), March 17, 2000.
16	J11-03922SRLR, Revision 0
	Memo CAH-NF-2339, "Hatch-2 Cycle 17 Power-Dependent APLHGR Multipliers for Operation with High Pressure Feedwater Heaters Out of Service," W. R. Mertz (SNC) to B. Quintero-leyva, October 15, 2001.
17	0000-0007-0430-SRLR, Revision 1
	Letter CAH-NF-2410, "H2C18 SNC ARTS Analyses," W. R. Mertz to K. S. Folk, March 11, 2003.
18	Global Nuclear Fuel document 0000-0030-0566-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 18 Cycle 19, “ Revision 1, February 2005.
	Global Nuclear Fuel document 0000-0030-0566-FBIR, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 18 Cycle 19,” January 2005.

TABLE 15.1-1 (SHEET 6 OF 7)

HNP-2

Reload No.	Report No./Title
	SNC Letter CAH-NF-2410, “H2C18 SNC ARTS Analyses,” W. R. Mertz to K. S. Folk, March 11, 2003.
	SNC Letter CAH-NF-2501, “H2C19 SNC Reload Licensing Analyses,” W. R. Mertz to K. S. Folk, February 16, 2005.
	SNC Letter CAH-NF-2502, “Generic Pressure Regulator Failure Downscale (PRFDS) Analysis,” W. R. Mertz to K. S. Folk, February 16, 2005.
19	Global Nuclear Fuel document 0000-0045-1586-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 19 Cycle 20, “ Revision 0, December 2006.
	Global Nuclear Fuel document 0000-0045-1586-FBIR, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 19 Cycle 20,” December 2006.
	SNC Letter CAH-NF-2599, “H2C20 SNC Reload Licensing Analyses,” W. R. Mertz to K. S. Folk, January 16, 2007.
20	Global Nuclear Fuel document 0000-0083-5389-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 20 Cycle 21, “ Revision 0, December 2008.
	Global Nuclear Fuel document 0000-0083-5389-FBIR, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 20 Cycle 21,” December 2008.
	SNC Nuclear Fuel Document NF-09-005, “Hatch-2 Cycle 21 Reload Licensing Analysis Report,: Version 1, February 2009.
21	Global Nuclear Fuel document 0000-0116-1536-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 21 Cycle 22,” Revision 0, December 2010.
	Global Nuclear Fuel document 0000-0116-1536-FBIR-P, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 21 Cycle 22,” Revision 0, December 2010.
	SNC Nuclear Fuel Document NF-11-020, “Hatch-2 Cycle 22 Reload Licensing Analysis Report,” Version 1, February 2011.

TABLE 15.1-1 (SHEET 7 OF 7)

HNP-2

Reload No.	Report No./Title
22	Global Nuclear Fuel document 0000-0145-7166-SRLR, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 22 Cycle 23,” Revision 0, December 2012.
	Global Nuclear Fuel document 0000-0145-7166-FBIR-P, “Fuel Bundle Information Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 22 Cycle 23,” Revision 0, December 2012.
	SNC Nuclear Fuel Document NF-13-005, “Hatch-2 Cycle 23 Reload Licensing Analysis Report,” Version 2, December 2014.
23	Global Nuclear Fuel Document 000N9122, “Supplemental Reload Licensing Report for Edwin I. Hatch Nuclear Power Plant Unit 2, Reload 23 Cycle 24,” Revision 0, January 2015.
	Global Nuclear Fuel Document 000N9123, “Fuel Bundle Information Report for Hatch 2, Reload 23 Cycle 24,” Revision 0, November 2014.
	SNC Nuclear Fuel Document NF-14-020 “Hatch-2 Cycle 24 Reload Licensing Analysis Report,” Version 1, December 2014.

TABLE 15.1-2 (SHEET 1 OF 3)

MAJOR EVENT UPDATES

Event	Event No.	Original FSAR	ARTS[(a)]	Power Uprate	Reloads[(b,d)]
AOOs					
Loss of feedwater heating (LFWH)	1	X		X	X
Inadvertent start of the HPCI pump	2	X			X
Shutdown cooling (RHR) malfunction - decreasing temperature	3	X			
Loss of RHR shutdown cooling	4	X			
Generator load rejection with no bypass (LRNBP)	5	X	X	X	X
Generator load rejection with bypass (LRBP)	6	X		X	
Turbine trip with no bypass (TTNBP)	7	X		X	X
Loss of condenser vacuum	8	X			
Turbine trip with bypass (TTBP)	9	X			
Closure of all MSIVs (MSIVD)	10	X		X	
Closure of one MSIV	11	X			
Pressure regulator failure - closed	12	X			
Trip of one recirculation pump	13	X			
Trip of two recirculation pumps	14	X			
Recirculation flow controller failure - decreasing flow	15	X			
Recirculation flow controller failure - increasing flow	16	X	X		
Startup of idle recirculation pump	17	X	X		

TABLE 15.1-2 (SHEET 2 OF 3)

Event	Event No.	Original FSAR	ARTS[(a)]	Power Uprate	Reloads[(b,d)]
AOOs (continued)					
RWE during power operation	18	X	X	X	X
Control rod removal during refueling	19	X			
Fuel assembly insertion error during refueling	20	X			
Feedwater controller failure - maximum demand (FWCF)	21	X	X	X	X
Inadvertent opening of SRV	22	X			
Pressure regulator failure - open	23	X			
Loss of auxiliary power	24	X			
Loss of feedwater flow (LOFW)	25	X		X	
ACCIDENTS					
CRDA	31	X		X	
LOCA	32	X		X	X
MSLBA	33	X		X	
Fuel handling accident	34	X		X	
Fuel assembly loading error	35	X			X
Recirculation pump seizure	36	X			
Feedwater line break	37	X			
SPECIAL EVENTS					
Stability	41	X			X
Overpressure protection	42	X		X	X

TABLE 15.1-2 (SHEET 3 OF 3)

Event	Event No.	Original FSAR	ARTS[a]	Power Uprate	Reloads[b,d]
SPECIAL EVENTS (continued)					
Shutdown without control rod insertion (SLCS capability)	43	X			X
MCR uninhabitability	44	X			
ATWS	45	10 CFR 50.62[c]		X	X[e]
Generator load rejection with flux scram & no bypass or RPT	46	X			
Turbine trip with flux scram & no bypass or RPT	47	X			
Loss of one dc system	48	X			
Loss of instrument air	49	X			
Loss of service water system	50	X			
Fire	51	10 CFR 50.48[c]		X	
Miscellaneous small releases outside containment	52	X			
Instrument line break	53	X			
Liquid radwaste tank failure	54	X			
Gaseous radwaste tank failure	55	X			
SBO	56	10 CFR 50.63[c]		X	

a. APRM/RBM Technical Specification Improvement (ARTS) Program[9] is a performance improvement feature as described in subsection 15.1.10.
b. An event identified in the reload column may either be qualitatively reevaluated or reanalyzed as discussed in ***NEDE- 24011-P-A (GESTAR II)***.
c. Regulation requiring a new evaluation after issuance of the original operating license.
d. Analysis reflects power operation for 2804 MWt at 1045 psig RPV pressure.
e. ATWS analysis performed for 1.5% power uprate and ROPI, not required for subsequent reload analyses.

TABLE 15.1-3 (SHEET 1 OF 6) [(a)]

EVENT ACCEPTANCE LIMITS

ANTICIPATED OPERATIONAL OCCURRENCES

Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
Control of releases of radioactive material to the environment (GDC 60)	Limit based upon 10 CFR 20	N/A	0.5 rem
RCPB design limits (GDC 15)	RPV safety limit	RCS pressure boundary	1325 psig in steam dome
Reactor design (GDC 10)	SAFDLs	Fuel cladding	SLMCPR or 25% power at low core flow (< 10%) or low pressure (< 785 psig)
		Fuel cladding	1% fuel-cladding plastic strain
		Fuel cladding	Fuel centerline melt (core-wide AOOs only)
		Fuel cladding	170 cal/g (RWE during startup only)
RHR capability (GDC 34)	Primary containment design limits	N/A	Suppression pool heat capacity temperature limit (only events involving loss of feedwater or main heat sink)

TABLE 15.1-3 (SHEET 2 OF 6) [(a)]

ACCIDENTS

Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
CRDA			
Alternative Source Term (10 CFR 50.67)	25% of the guideline dose values of 10 CFR 50.67 per RG 1.183	N/A	6.3 rem TEDE
Operator exposure (GDC 19)	Exposure limits of GDC 19	N/A	5 rem TEDE
Reactivity limits (GDC 28)	Peak fuel enthalpy design limits	Fuel cladding	280 cal/g
RCPB limits (10 CFR 50.55a)	ASME Code limits	RCS pressure boundary	1500 psig
LOCA			
Alternative Source Term (10 CFR 50.67)	Guideline dose values of 10 CFR 50.67 per RG 1.183	N/A	25 rem TEDE
Operator exposure (GDC 19)	Exposure limits of GDC 19	N/A	5 rem TEDE
Emergency core cooling (GDC 35)	ECCS limits (10 CFR 50.46)	Fuel cladding	2200°F peak fuel-cladding temperature
		Fuel cladding	17% local cladding oxidation
		Containment	1% core-wide metal water reaction
		N/A	Coolable geometry
		N/A	Long-term cooling capability
RCPB limits (10 CFR 50.55a)	ASME Code limits	RCS pressure boundary	1500 psig
Containment design (GDC 50)	Primary containment design limits	Containment	62 psig
		Containment	281°F (HNP-1) 340°F (HNP-2)

TABLE 15.1-3 (SHEET 3 OF 6) [(a)]

ACCIDENTS (Continued)

Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
Fuel-handling accident			
Alternative Source Term (10 CFR 50.67)	25% of the guideline dose values of 10 CFR 50.67 per RG 1.183	N/A	6.3 rem TEDE
Operator exposure (GDC 19)	Exposure limits of GDC 19	N/A	5 rem TEDE
MSLBA (Pipe breaks outside containment)			
Alternative Source Term (10 CFR 50.67)	Guideline dose values of 10 CFR 50.67 per RG 1.183	N/A	25 rem TEDE (maximum Technical Specifications reactor coolant activity)
	10% of the guideline dose values of 10 CFR 50.67 per RG 1.183	N/A	2.5 rem TEDE (unrestricted operation Technical Specifications reactor coolant activity)
Operator exposure (GDC 19)	Exposure limits of GDC 19	N/A	5 rem TEDE
RCPB limits (10 CFR 50.55a)	ASME Code limits	RCS pressure boundary	1500 psig
Feedwater line break (pipe breaks outside containment)			
Siting criteria (10 CFR 100)	Guideline dose values of 10 CFR 100.11	N/A	25 rem whole body or 300 rem thyroid
	Small fraction of guideline dose values of 10 CFR 100	N/A	2.5 rem whole body or 30 rem thyroid

TABLE 15.1-3 (SHEET 4 OF 6) [(a)]

SPECIAL EVENTS

Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
Stability			
Suppression of power oscillation (GDC 12)	SAFDLs	Fuel cladding	SLMCPR
Overpressure protection			
RCPB design limits (GDC 15)	ASME Code limits	RCS pressure boundary	1375 psig peak RPV pressure
Shutdown without control rod insertion (SLCS capability)			
Reactivity control system capability (GDC 26)	Cold shutdown	N/A	$K_{eff} < 1.0$
MCR uninhabitability			
Equipment outside MCR (GDC 19)	Cold shutdown capability	N/A	Cold shutdown
ATWS Rule (10 CFR 50.62)	Limits based upon ATWS Rule	RCS pressure boundary	1500 psig peak RPV pressure
		Containment	62 psig containment pressure
		Containment	Containment temperature: 281°F (HNP-1) 340°F (HNP-2)
		Fuel cladding	2200°F peak fuel-cladding temperature
		Fuel cladding	17% local cladding oxidation
		N/A	25 rem whole body or 300 rem thyroid
		N/A	Equipment availability
		N/A	Local saturation temperature for suppression pool

TABLE 15.1-3 (SHEET 5 OF 6) [(a)]

SPECIAL EVENTS (Continued)

Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
Generator load rejection with flux scram & no bypass or RPT			
Siting criteria (10 CFR 100)	Guideline dose values of 10 CFR 100.11	N/A	25 rem whole body or 300 rem thyroid
Turbine trip with flux scram & no bypass or RPT			
Siting criteria (10 CFR 100)	Guideline dose values of 10 CFR 100.11	N/A	25 rem whole body or 300 rem thyroid
Loss of one dc system			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem
Loss of instrument air			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem
Loss of service water system			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem
Fire			
Fire protection criteria (10 CFR 50.48)	Cold shutdown capability	N/A	Cold shutdown
Miscellaneous small releases outside containment			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem

TABLE 15.1-3 (SHEET 6 OF 6) [(a)]

SPECIAL EVENTS (Continued)

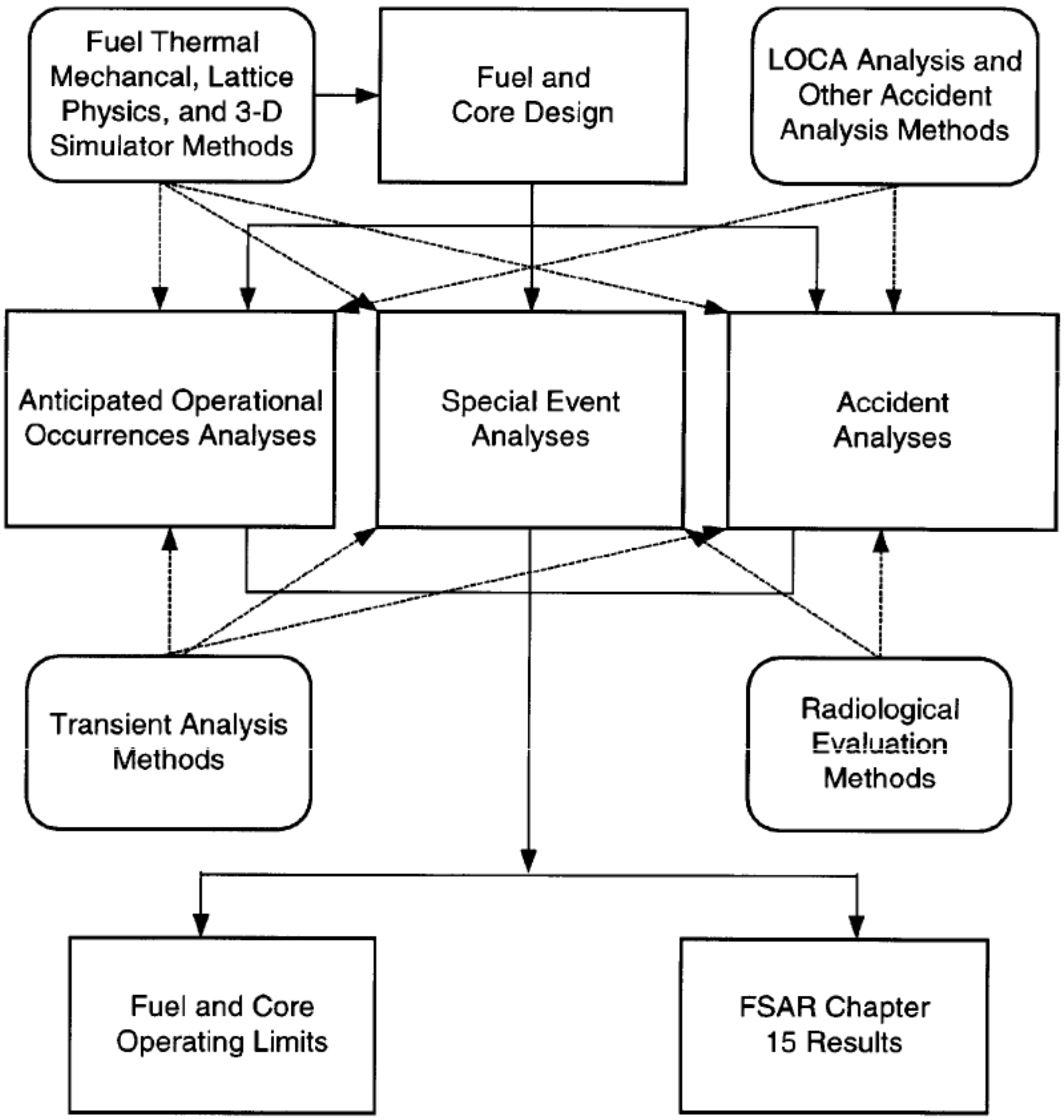
Event Acceptance Criteria[(b)]	Event Acceptance Limits[(c)]	Fission Product Barrier[(d)]	Values[(e)]
Instrument line break			
Siting criteria (10 CFR 100)	Small fraction of guideline dose values of 10 CFR 100.11	N/A	2.5 rem whole body or 30 rem thyroid
Liquid radwaste tank failure			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem
Gaseous radwaste tank failure			
Release of radioactive effluents to unrestricted areas (10 CFR 20)	Limit based upon 10 CFR 20	N/A	0.5 rem
SBO			
SBO (10 CFR 50.63)	Coping capability (4 h)	N/A	RPV water level > level 1
		Containment	62 psig containment pressure
		Containment	Containment temperature: 281°F (HNP-1) 340°F (HNP-2)
		N/A	Suppression pool heat capacity temperature limit

a. Conformance with the event acceptance limits is demonstrated by the analyses and evaluations of the specific events discussed in sections 15.2, 15.3, and 15.4.
b. Event acceptance criteria are derived from specific regulatory requirements (10 CFR), including the GDCs (10 CFR 50, Appendix A). The primary regulatory requirement used to provide guidance in developing the basis for establishing the specific limit is identified.
c. Event acceptance limits are the specific requirements that must be satisfied in the safety analysis process. The primary source used as guidance to establish the specific limit is identified.
d. Event acceptance limits that are also fission product barriers, as referenced in 10 CFR 50.59(c)(2)(vii), are identified. The respective design bases units fundamental to barrier integrity are provided in the Values column.
e. The specific values for the event acceptance limits are identified.

TABLE 15.1-4

SELECTED SAFETY ANALYSIS INPUT PARAMETERS

1. Thermal power level
   - License value
   - Analysis value
2. Steam flow
   - License value
   - Analysis value
3. Power-to-flow operating map
4. Core flowrate
5. Normal water level
6. Main steam line and bypass line lengths and volumes
7. Core plate pressure drop
8. Steam line pressure drop
9. Feedwater temperature and flowrate
10. RPV dome pressure
    - License value
    - Analysis value
11. Turbine bypass capacity
12. Core coolant inlet enthalpy
13. Turbine inlet pressure
14. Core bypass flow
15. New fuel types
16. Reload fuel types
17. CRD scram times
18. Recirculation pump characteristics
19. SRV number and characteristics
20. SRV opening and reclosure setpoints
21. Scram setpoints, instrument time constants, and time constants
22. Water level setpoints
23. RPT setpoints and delay times
24. Recirculation pump inertia
25. RCIC and HPCI system flow
26. Margin improvement options
27. Cycle extension options
28. Operating flexibility options
29. Equipment out-of-service options
30. SLC system parameters
31. Control blade characteristics
32. Maximum feedwater flow
33. Maximum feedwater temperature loss
34. Condensate storage tank temperature
35. Turbine control valve characteristics
36. Condenser vacuum setpoints
37. MSIV closure time



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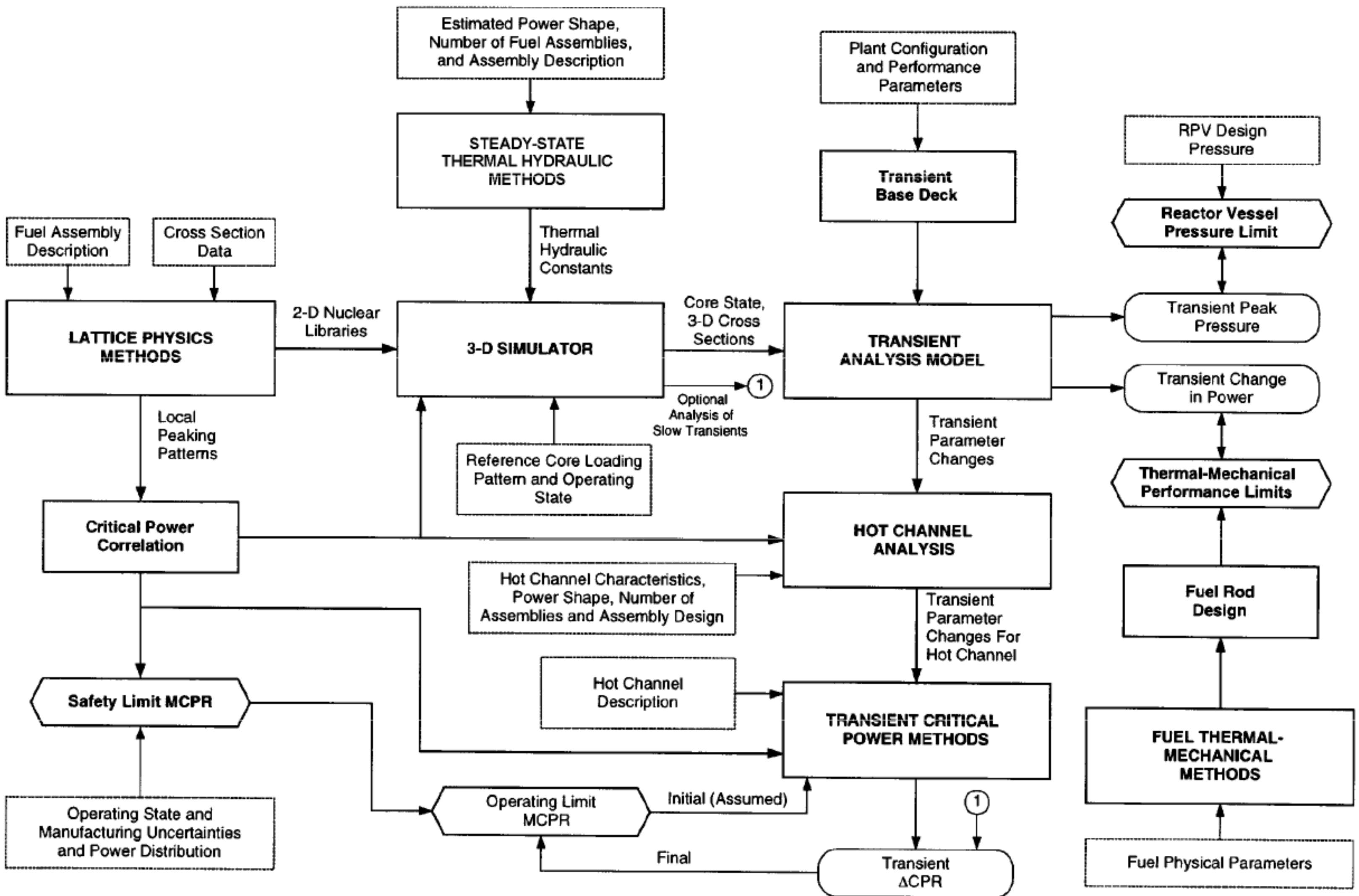
UNIT 1 AND UNIT 2

SAFETY ANALYSIS METHODS (TYPICAL)

FIGURE 15.1-1



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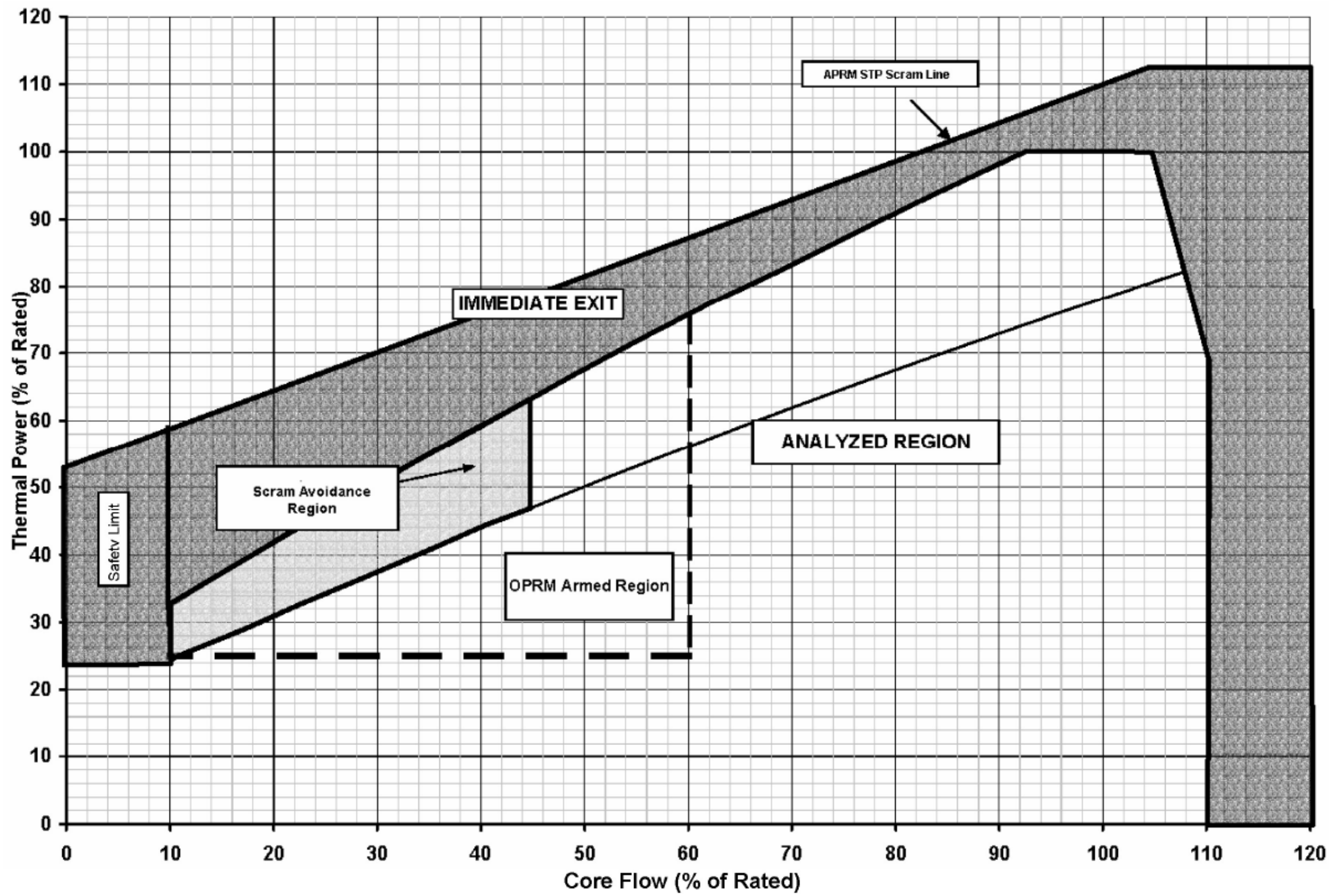
TRANSIENT ANALYSIS METHODS (TYPICAL)

FIGURE 15.1-2



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POWER-TO-FLOW MAP
RTP OF 2804 MWt

FIGURE 15.1-3

15.2 ANALYSES OF ANTICIPATED OPERATIONAL OCCURRENCES

The specific safety analysis results for anticipated operational occurrences (AOOs) presented in this section are the results for HNP-2. Because of the essentially identical design of the two units, the conclusions for HNP-2 apply also to HNP-1.

15.2.1 DECREASE IN CORE COOLANT TEMPERATURE

15.2.1.1 Loss of Feedwater Heating (Event 1)

The loss of feedwater heating (LFWH) event is a potentially limiting AOO for reloads and plant modifications that can impact the magnitude of the moderator temperature decrease due to an LFWH.

Consistent with ***NEDE-24011-P-A,"GESTAR II - General Electric Standard Application for Reactor Fuel" (incorporated by reference into the FSAR)***, the LFWH event is reevaluated each operating cycle to establish the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions, and event description applicable to each reload evaluation. A maximum decrease in feedwater temperature of 100°F from rated conditions is assumed in the standard reload evaluation. For the special case when Unit 2 is intentionally operating with the high pressure feedwater heaters out of service, an additional severe loss of feedwater heating event analysis is performed which assumes the maximum feedwater temperature decrease is 256.4ºF. The additional analysis is necessary because there is only one power supply source for all the low pressure feedwater heater controls. In the event of a single electrical bus fault for that power supply source, extraction steam to all the low pressure heaters would be shut off resulting in a reduction in feedwater temperature down to the condensate temperature in the condenser hotwell. For the current reload, the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with Final Safety Analysis Report (FSAR) update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in each unit's ***Core Operating Limits Report (COLR) (incorporated by reference into the FSAR)***.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The LWFH event was reanalyzed for power uprate at a rated thermal power (RTP) of 2763 MWt.(1) The following discussion provides the results of the power uprate analysis.

15.2.1.1.1 Identification of Causes

15.2.1.1.1.1 **Starting Conditions and Assumptions.** The following plant operating conditions and assumptions form the principal bases for the LFWH analysis:

A. The plant is operating at full power.

B. The plant is operating in the manual flow control mode.

15.2.1.1.1.2 **Event Description.** Feedwater heating can be lost in at least two ways:

- Steam extraction line to the heater is closed (steam bypassed).

- Feedwater is bypassed around the heater.

The first case produces a gradual cooling of the feedwater due to the stored heat capacity of the heater. In the second case, the feedwater bypasses the heater, and the change in heating occurs during the stroke time of the bypass valve. In either case, the reactor pressure vessel (RPV) receives cooler feedwater. The maximum number of feedwater heaters that can be either tripped or bypassed by a single event represents the most severe transient for analysis considerations. The feedwater heaters are assumed to trip instantaneously. This event causes an increase in core inlet subcooling, which increases core power due to the negative void reactivity coefficient.

For the analysis at 2763 MWt, a bounding value of 108°F for the feedwater temperature decrease was used.

15.2.1.1.2 Analysis of Effects and Consequences

15.2.1.1.2.1 **Methods, Assumptions, and Conditions.** For the analysis for power uprate (2763 MWt), the analysis methods described in section 15.1.7 were used. The 3-D simulator was used to analyze two state points with a difference of 108°F in feedwater temperature. The two separate exposure points considered in the analysis are end-of-cycle (EOC) at rated conditions and maximum extended load line limit middle-of-cycle (MOC). The key analysis input parameters are identified in table 15.2-3.

15.2.1.1.2.2 **Results and Consequences.** The analysis results for power uprate are provided in table 15.2-1.

Previous analyses demonstrate the LFWH event is less severe from lower initial power levels for two main reasons:

A. Lower initial power levels have initial minimum critical power ratio (MCPR) values greater than the assumed limiting initial value.

B. The magnitude of the power rise decreases with lower initial power conditions. Therefore, events from lower power levels are less severe.

15.2.1.1.2.3 Consideration of Uncertainties. Important factors (i.e., cycle exposure, plant operating conditions, and magnitude of feedwater temperature change) are assumed to be at the worst value; thus, any deviations in actual plant operation reduce the severity of the event.

15.2.1.2 Inadvertent Start of the HPCI Pump (Event 2)

The inadvertent start of the high-pressure coolant injection (HPCI) pump is a potentially limiting AOO for reloads and plant modifications that can impact the magnitude of the moderator temperature decrease due to inadvertent actuation of a high-pressure makeup system.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, the inadvertent start of the HPCI pump is reevaluated each operating cycle to establish the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions, and event description applicable to each reload evaluation. For the current reload, the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in each unit's ***COLR***.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The inadvertent start of the HPCI pump was evaluated for power uprate at an RTP of 2763 MWt and found to be less limiting than the LFWH event; thus, the inadvertent start of the HPCI pump was not reanalyzed for power uprate. The following discussion provides the results of the analysis for the initial core for the original rated conditions.

15.2.1.2.1 Identification of Causes

15.2.1.2.1.1 Starting Conditions and Assumptions. For the analysis for original rated conditions (2436 MWt), the reactor is operating at 105% of nuclear boiler rated steam flow

power (2535 MWt) with thermally limited conditions. All systems are assumed to be operational in their normal modes of operation.

The inadvertent actuation of the low-pressure ECCS requires that multiple failures occur during the limited time when the reactor is operating in either the startup or the shutdown mode. This is clearly a very low probability event and, thus, is not considered an AOO.

15.2.1.2.1.2 Event Description. The HPCI system introduces cold water through the feedwater sparger at ~ 20.1% of the original rated feedwater flow. The water level controls correspondingly reduce normal feedwater flow. In the manual mode of recirculation flow control, no flow adjustments are made, and the excursions of related system variables are greater.

15.2.1.2.2 Analysis of Effects and Consequences

15.2.1.2.2.1 Methods, Assumptions, and Conditions. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[2] was used to simulate the inadvertent start of the HPCI pump. An analysis for the manual mode of recirculation flow control was performed. HPCI water was assumed to be at a temperature of 40°F with an equivalent enthalpy of 11.0 Btu/lb. The key analysis input parameters are identified in table 15.2-3.

15.2.1.2.2.2 Results and Consequences. For the analysis for the original rated conditions (2436 MWt), the event that occurs is similar to the LFWH event, although somewhat faster. The inadvertent start of the HPCI pump is less severe than the LFWH event, because the effect on mixed feedwater temperature produces a smaller temperature change than 100°F cooler total feedwater flow. The MCPR is greater than the safety limit (SL) MCPR. The neutron flux peak reaches the flow-referenced flux scram setpoint, but the pressure transients do not approach any pressure limit. At full power, the transient power peak is higher than at lower powers, thus, producing a lower MCPR during the event. The peak pressures reached during this event at full power are also higher than at lower power. The transient response of the plant variables for the inadvertent startup of the HPCI pump is shown in figure 15.2-1.

15.2.1.2.2.3 Consideration of Uncertainties. Although no aspects of reactor design are threatened by the inadvertent startup of the HPCI pump, the analysis assumed conservative (most severe) characteristics for HPCI startup. Actual plant deviations are expected to make the results of the event less severe.

15.2.1.3 Shutdown Cooling (RHR) Malfunction - Decreasing Temperature (Event 3)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated a malfunction of the shutdown cooling mode of the residual heat

removal (RHR) system with decreasing temperature is a nonlimiting AOO and does not require reevaluation for reloads.

At design power conditions, the shutdown cooling mode of RHR is not operable, and no conceivable malfunction causing temperature reduction is possible considering the spectrum of potential single failures in the RHR system.

A shutdown cooling malfunction leading to a moderator temperature decrease can result from a malfunctioning of the cooling water controls for the RHR heat exchangers. If the reactor is critical, or near critical, a very slow increase in reactor power can result. If the operator does not act to control power level, a high neutron flux reactor scram will terminate the transient without fuel damage and without any measurable increase in nuclear system pressure.

15.2.2 INCREASE IN CORE COOLANT TEMPERATURE

15.2.2.1 Loss of RHR Shutdown Cooling (Event 4)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the loss of RHR shutdown cooling is a nonlimiting AOO and does not require reevaluation for reloads, because it is bounded by other events for the purpose of establishing core operating limits.

The design evaluation of the plant’s capability to meet the Nuclear Regulatory Commission's (NRC's) position on General Design Criterion (GDC) 34 is discussed in paragraph 15.2.2.2.

15.2.2.1.1 Identification of Causes

15.2.2.1.1.1 Starting Conditions and Assumptions. When initially operating in the shutdown cooling mode, the reactor is assumed to be undergoing normal shutdown and cooldown when an RHR shutdown cooling system failure that reduces the capability to remove decay heat occurs.

15.2.2.1.1.2 Event Description. When initially operating in the shutdown cooling mode, the loss of RHR shutdown cooling capability increases core coolant temperature.

15.2.2.1.2 Analysis of Effects and Consequences

15.2.2.1.2.1 Methods, Assumptions, and Conditions. When initially operating in the shutdown cooling mode, the loss of RHR shutdown cooling capability directly causes an RPV water temperature increase, because the energy removal rate is less than the decay heat rate. This event can occur only during the low-pressure portion of a normal reactor shutdown and

cooldown when the RHR system is operating in the shutdown cooling mode. No cladding temperature increase occurs, because boiling transition is never observed. Maximum heat flux at 4 h following shutdown (the earliest time the shutdown cooling system can be actuated due to cooldown rate limitations) is 4700 Btu/h/ft^2, assuming ANS + 20% decay heat power generation. This surface heat flux is significantly below the condition resulting in boiling transition, and thus, nucleate boiling heat transfer is maintained. Since MCPR remains high, a plot of MCPR versus time of operator initiation of ECCS serves no purpose in evaluating operator response time. The 10-min time period approximated for operator action is an estimate of how long it will take the operator to initiate the necessary actions and is not a time by which the action must be initiated.

15.2.2.1.2.2 <u>Results and Consequences</u>. For most single failures that can result from the loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply reestablished using other normal shutdown cooling equipment. In cases where the RHR system shutdown cooling suction line becomes inoperative, a unique requirement for cooling arises. In operating states in which the RPV head is off, the low-pressure coolant injection (LPCI) mode of the RHR system, can be used to maintain water level. In states in which the RPV head is on and the system can be pressurized, the low-pressure cooling systems, the safety relief valves (SRVs) (manually operated), and the RHR system suppression pool cooling mode can be used to maintain water level and remove decay heat.

The most limiting single failure that can be postulated for this event is failure of a diesel generator. However, loss of either Division I or Division II does not negate the core cooling capability of the RHR system. Failure of Division I disables RHR loop A and the core spray (CS) system. In this case, RHR loop B is available to cool the core in the shutdown cooling mode. Failure of Division II disables loop B and the inboard isolation valve in the RHR suction line attached to the recirculation loop. In this case, RPV steam is relieved to the suppression pool through the SRVs. The heat is removed from the suppression pool by pumping water from the pool through the RHR loop A heat exchanger. The cooled water is then returned to the RPV to maintain level and continue core cooling. No single failure can simultaneously preclude the RHR system's ability to draw water from the suppression pool and the recirculation loop.

15.2.2.1.2.3 <u>Consideration of Uncertainties</u>. The multiplicity of operator actions available to mitigate the effects of the loss of RHR shutdown cooling ensures reactor cooldown can be accomplished.

15.2.2.2 <u>Compliance with GDC 34</u>

The following design evaluation describes the plant’s capability to meet the NRC's position on GDC 34, assuming the failure of one of the shutdown cooling valves in the closed position.

The design evaluation is divided into two phases:

- Full power operation to ~ 100-psig RPV pressure.
- ~ 100-psig RPV pressure to cold shutdown conditions.

The success paths are shown in figure 15.2-2.

Full Power to ~ 100 psig

Independent of the event that initiated plant shutdown (whether it be a normal plant shutdown or a forced plant shutdown), the reactor is normally brought to ~ 100 psig by using either the main condenser or, in the case where the main condenser is unavailable, the reactor core isolation cooling (RCIC) and the HPCI systems and/or the SRVs.

For evaluation purposes, a loss of offsite power (LOSP) is assumed to initiate a plant shutdown, which results in SRV actuation and subsequent suppression pool heatup. For this postulated condition, the reactor is shut down, and RPV pressure and temperature are reduced to and maintained at saturated conditions of ~ 100 psig.

Using the automatic depressurization system (ADS) SRVs to control pressure, RPV makeup water is automatically provided via the RCIC and HPCI systems. While in this condition, the RHR system (suppression pool cooling mode) is used to maintain suppression pool temperature within shutdown limits.

These systems are designed to routinely perform their functions for both normal and forced plant shutdowns. Since the RCIC, HPCI, and RHR systems are divisionally separated, no single failure, together with an LOSP, is capable of preventing system pressure from reaching the 100-psig level.

~ 100 psig to Cold Shutdown

The following assumptions are used in analyzing the procedures for attaining cold shutdown from a pressure of ~ 100 psig:

A. The RPV is at 100 psig and saturated conditions.

B. A worst-case single failure is assumed to occur (i.e., loss of a division of emergency power).

C. No offsite power is available.

If the RHR shutdown suction line is not available because of single failure, the first action to be taken is to maintain the 100-psig level while personnel gain access and effect repairs. For example, a handwheel on the valve is provided to allow manual operation. Nevertheless, if for some reason the normal shutdown cooling suction line cannot be repaired, the capabilities

described below will satisfy the normal shutdown cooling requirements and, thus, comply fully with GDC 34.

To satisfy containment isolation criteria, the RHR shutdown cooling line valves are in two divisions: Division I (the inboard valve) and Division II (the outboard valve). For evaluation purposes, the worst-case failure is assumed to be the loss of a division of emergency power, since this also prevents actuation of one shutdown cooling line valve. Engineered safety feature (ESF) equipment available for accomplishing the shutdown cooling function includes (for the selected path):

ADS (dc Division I and dc Division II)

Division I	Division II
RHR pump 2A	RHR pump 2B
RHR pump 2C	RHR pump 2D
RHR service water (RHRSW) pump 2A	RHRSW pump 2B
RHRSW pump 2C	RHRSW pump 2D
CS pump 2A	CS pump 2B
RCIC	HPCI

For failure of either Division I or II, the following systems are assumed to be functional:

Failure of Division I (Equipment Functional)	Failure of Division II (Equipment Functional)
ADS	ADS
RHR pump 2B	RHR pump 2A
RHR pump 2D	RHR pump 2C
RHRSW pump 2B	RHRSW pump 2A
RHRSW pump 2D	RHRSW pump 2C
CS pump 2B	CS pump 2A
HPCI	RCIC

Assuming the single failure is the failure of Division I, the safety function is accomplished by establishing the cooling loops described in activity C1 of figure 15.2-3. (The notes for figure 15.2-3 are located in table 15.2-2.) Similarly, activity C2 relates to the failure of Division II. Figures 15.2-4 and 15.2-5 show the simplified arrangement of the various cooling loops for activities C1 and C2, respectively. The preceding evaluation demonstrates that, even under worst-case conditions (failure of an emergency power division), a cooling path is available to remove residual heat from the core and, thus, complies fully with GDC 34.

15.2.3 INCREASE IN REACTOR PRESSURE

15.2.3.1 Generator Load Rejection with No Bypass (Event 5)

The generator load rejection with no bypass (LRNBP) event is a potentially limiting AOO for reloads and plant modifications that can impact the rapid pressurization event.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, the LRNBP event is reevaluated each operating cycle as a part of the process for establishing the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions, and event description applicable to the reload evaluation. The limiting power-to-flow conditions identified in EAS 65-1088[3] are used as initial conditions. To bound the potential unavailability of the EOC-recirculation pump trip (RPT) feature during normal plant operation, two LRNBP cases are typically evaluated for reloads: EOC-RPT available and EOC-RPT out of service. For the current reload, the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in the ***COLR***.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase. Reference 14 provides the evaluation of the impact on AOOs of the installation of adjustable speed drives (ASD) to provide power to the recirculation pump motors. The ASDs replace the recirculation pump motor-generator (M-G) sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

The LRNBP event was reanalyzed for power uprate at an RTP of 2763 MWt.[1] The following discussion provides the results of the power uprate analysis.

15.2.3.1.1 Identification of Causes

Fast closure of the turbine control valves (TCVs) is initiated whenever electrical grid disturbances that result in significant loss of load on the generator occur. TCV rapid closure is required to prevent overspeed of the turbine-generator rotor. TCV fast closure causes a sudden reduction in steam flow, which results in an RPV pressure increase. TCV fast closure scrams the reactor.

15.2.3.1.1.1 Starting Conditions and Assumptions. The following plant operating conditions and assumptions form the principal bases for the LRNBP analysis for power uprate:

A. The reactor and the turbine are initially operating at rated power with a dome pressure of 1035 psig when load rejection occurs.

B. The turbine electrohydraulic control (EHC) system power/load imbalance device detects load rejection before a measurable speed change takes place.

C. A scram and an EOC-RPT are automatically initiated upon sensing TCV fast closure.

D. All plant control systems, with the exception of the turbine bypass system, continue normal operation.

E. Auxiliary power is continuously supplied at rated frequency.

F. The reactor is operating in the manual flow control mode when load rejection occurs.

G. The turbine bypass valve system is failed in the closed position.

H. One SRV is assumed to be out of service.

15.2.3.1.1.2 <u>Event Description</u>. For the analysis of power uprate conditions, the complete loss of generator load produces the following sequence of events:

A. The power/load imbalance device steps the load reference signal to zero and closes the TCVs and intermediate (intercept) valves at the earliest possible time. The turbine accelerates at a maximum rate until the valves close at a maximum rate by means of fast acting, solenoid-operated, disc-dump valve action. The TCVs close at a full stroke rate of ~ 0.150 s.

B. A reactor scram and an EOC-RPT are initiated upon sensing TCV fast closure.

C. The pressure rises to the SRV setpoints. The SRVs open, discharging steam to the suppression pool, to limit the pressure increase.

15.2.3.1.2 Analysis of Effects and Consequences

15.2.3.1.2.1 <u>Methods, Assumptions, and Conditions</u>. For the analysis for power uprate (2763 MWt), the analysis methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key analysis input parameters are identified in table 15.2-3.

15.2.3.1.2.2 <u>Results and Consequences</u>. For the analysis for power uprate (2763 MWt), the LRNBP event was analyzed for three power-to-flow conditions:

- 100% power and 100% flow (figure 15.2-6).
- 100% power and 105% flow (figure 15.2-7).
- 100% power and 91% flow.

The analysis results for the three power-to-flow conditions are provided in table 15.2-1.

15.2.3.1.3 Generator Load Rejection with No Bypass - Low Power

The load rejection scram trip and EOC-RPT are bypassed at an RTP < 27.6%. In this case, the other protection system trips (high flux or high pressure) are used to initiate safe shutdown of the reactor. This is one of the events analyzed to establish the core operating limits at reduced power levels implemented with the Average Power Range Monitor/Rod Block Monitor Technical Specification Improvement Program (ARTS) documented in NEDC-30474-P.[4] The power uprate evaluations confirmed the applicability of the ARTS operating limits.[1]

15.2.3.2 <u>Generator Load Rejection with Bypass (Event 6)</u>

The generator load rejection with bypass (LRBP) event is a nonlimiting AOO and does not require reanalysis for reloads. However, due to a power increase of more than 10% of the original licensed power level, the LRBP event was required to be reanalyzed for power uprate at an RTP of 2763 MWt.[10] The power uprate analysis confirms that the LRBP event bounds the LRNBP event.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The following discussion presents the results of the 2763 MWt power uprate analysis.

15.2.3.2.1 Identification of Causes

The causes of the LRBP event are the same as the causes of the LRNBP event (paragraph 15.2.3.1.1).

15.2.3.2.1.1 <u>Starting Conditions and Assumptions</u>. The starting conditions and assumptions for the LRBP are the same as the starting conditions and assumptions for the

LRNBP (paragraph 15.2.3.1.1.1), with one exception: the turbine bypass system is assumed to be operable.

15.2.3.2.1.2 **Event Description.** The event description for the LRBP is the same as the event description for the LRNBP (paragraph 15.2.3.1.1.2), with the following exception: the turbine bypass valves are opened simultaneously with TCV fast closure when the load demand is stepped to zero.

15.2.3.2.2 Analysis of Effects and Consequences

15.2.3.2.2.1 **Methods, Assumptions, and Conditions.** For the analysis for power uprate (2763 MWt), the analysis methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key analysis input parameters are identified in table 15.2-3.

15.2.3.2.2.2 **Results and Consequences.** For the analysis for power uprate (2763 MWt), the LRBP event was analyzed at rated power and flow. The analysis results for power uprate are provided in table 15.2-1.

15.2.3.2.3 Generator Load Rejection with Bypass - Low Power

The load rejection scram trip and EOC-RPT are bypassed at an RTP < 28%. In this case, the other protection system trips (high flux or high pressure) are used to initiate safe shutdown of the reactor. Operator action can prevent a scram from high flux or pressure, depending upon how much the actual bypass is exceeded.

For an initial power level less than the turbine bypass capacity, a reactor shutdown is not expected, since rapid operation of the bypass will divert the excess steam to the main condenser. The consequences of this event on the fuel and RPV overpressure are considerably less than the full-power case described above.

15.2.3.3 Turbine Trip with No Bypass (Event 7)

When the TCVs are operating in the partial arc mode, the turbine trip with no bypass (TTNBP) event is a potentially limiting AOO for reloads and plant modifications that can impact rapid pressurization events.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, the TTNBP event is reevaluated each operating cycle to establish the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions, and event description applicable to the reload evaluation. The limiting power-to-flow conditions identified in EAS 65-1088[3] are used as initial conditions. To bound the potential unavailability of the EOC-RPT feature during normal plant operation, two

TTNBP cases are typically evaluated for reloads: EOC-RPT available and EOC-RPT out of service. For the current reload, the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in the ***COLR*.**

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase. Reference 14 provides the evaluation of the impact on AOOs of the installation of adjustable speed drives (ASDs) to provide power to the recirculation pump motors. The ASDs replace the recirculation pump motor-generator (M-G) sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

The TTNBP event was reanalyzed for power uprate at an RTP of 2763 MWt.[1] The following discussion provides the results of the power uprate analysis.

15.2.3.3.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are:

- Moisture-separator and heater drain tank high levels.
- Large vibrations.
- Operator lockout.
- Loss of control fluid pressure.
- Low condenser pressure (paragraph 15.2.3.4).
- RPV water level - high.

15.2.3.3.1.1 <u>Starting Conditions and Assumptions</u>. For the analysis of the TTNBP event for power uprate (2763 MWt), the following assumptions were used:

A. A turbine trip initiates the events that result in a fast closure of the TSVs (0.1 s).

B. The position switches on the TSVs initiate a reactor scram and an EOC-RPT when the valves are < 90% open.

C. The scram is automatically bypassed when the reactor is < 28% of RTP.

D. An RPV pressure rise opens the SRVs.

E. The TCVs are operating in the partial-arc mode.

15.2.3.3.1.2 Event Description. The sequence of events for a turbine trip is similar to the sequence of events for a generator load rejection. TSV closure occurs over a period of ~ 0.1 s. Position switches at the TSVs sense the turbine trip and initiate a reactor scram and an EOC-RPT. The pressure rises to the SRV setpoints, and the SRVs open, discharging steam to the suppression pool.

15.2.3.3.2 Analysis of Effects and Consequences

15.2.3.3.2.1 Methods, Assumptions, and Conditions. For the analysis for power uprate (2763 MWt), the analysis methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key analysis input parameters are identified in table 15.2-3.

For the analysis of the TTNBP event in the partial arc mode for power uprate conditions, the following assumptions were used:

A. A turbine trip initiates events that result in a fast closure of the TSVs (0.1 s).

B. Position switches on the TSVs initiate a reactor scram and an EOC-RPT when the valves are < 90% open.

C. The scram is automatically bypassed when the reactor is < 28% of RTP.

15.2.3.3.2.2 Results and Consequences. For the analysis for power uprate (2763 MWt), the TTNBP event was analyzed for three power-to-flow conditions:

- 100% power and 100% flow (figure 15.2-8).
- 100% power and 105% flow (figure 15.2-9).
- 100% power and 91% flow.

The analysis results for these three power-to-flow conditions are provided in table 15.2-1.

15.2.3.3.2.3 **Consideration of Uncertainties.** Key uncertainties involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values were used; e.g.:

A. The slowest allowable control rod scram time.

B. The scram worth shape for all-rod-out conditions.

C. The minimum specified valve capacities for overpressure protection.

D. The conservative SRV setpoints.

Considering these conservative factors, the analyses adequately cover expected uncertainties.

15.2.3.3.3 Turbine Trip with No Bypass - Low Power

The turbine trip with no bypass at low power is less severe than a similar event at high power. However, this event is of interest, because the TSV closure and TCV closure scrams are automatically bypassed when the reactor is < 27.6% of RTP. At these lower power levels, turbine first-stage pressure is used to initiate the scram logic bypass. High RPV pressure terminates the scram that terminates the event. Because the bypass valves are assumed to fail, the SRVs must open partially to relieve the pressure transient.

The turbine trip with no bypass at low power is one of the events analyzed to establish the core operating limits at reduced power levels implemented with the ARTS program documented in NEDC-30474-P.[4] The power uprate (2763 MWt) evaluations confirm the applicability of the ARTS operating limits.[1]

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

15.2.3.4 <u>Loss of Condenser Vacuum (Event 8)</u>

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the loss of condenser vacuum event is a nonlimiting AOO and does not require reevaluation for reloads.

The reduction in or the loss of vacuum in the main turbine condenser can sequentially trip the main and feedwater turbines, and finally close the main steam isolation valves (MSIVs) and bypass valves. Other resultant actions include a scram from TSV closure, an EOC-RPT, and

bypass valve opening initiated with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which vacuum pressure is lost and is less limiting than the TTNBP.

Vacuum (in. Hg)	Protective Action Initiated
27 to 28	Normal vacuum range.
20	Main turbine trip and feedwater turbine trip (TSV closure).
7	MSIV and bypass valve closure.

Normal loss of vacuum due to the loss of a steam jet air ejector (SJAE), or a similar problem, produces a very slow rate of loss of vacuum (minutes, not seconds). If operator corrective action is not successful, the vacuum loss will sequentially actuate a simultaneous trip of the main turbine and feedwater turbines. Complete isolation results from closing the bypass valves (opened with the main turbine trip) and the MSIVs.

Since the bypass valves are closed more quickly, their overall effectiveness is reduced.

The effect of MSIV closure tends to be minimal, since TSV closure, and subsequently, bypass valve closure, shut off main steam line (MSL) flow prior to MSIV closure.

The maximum rate of loss of condenser vacuum expected for a loss of all condenser cooling water pumps at maximum power conditions is ~ 2 in. Hg/s. If this rate of decrease is applied to the items listed above, TSV closure will initiate a scram, and full isolation will occur after 5 to 10 s. The RCIC and HPCI systems provide long-term water inventory supply.

15.2.3.5 Turbine Trip with Bypass (Event 9)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the turbine trip with bypass (TTBP) event is a nonlimiting AOO and does not require reevaluation for reloads.

15.2.3.5.1 Identification of Causes

The causes of the TTBP event are the same as the causes of the TTNBP event (paragraph 15.2.3.3.1).

15.2.3.5.1.1 Starting Conditions and Assumptions. The reactor is initially operating at 105% of nuclear boiler rated steam flow power (2535 MWt) with an RPV dome pressure of 1020 psig.

15.2.3.5.1.2 Event Description. The sequence of events for a TTBP event is similar to the sequence of events for a TTNBP event; however, but the results are slightly less severe. TSV closure occurs over a period of ~ 0.1 s. Position switches at the TSVs sense the turbine trip and initiate a reactor scram and an EOC-RPT. The turbine control system immediately initiates bypass valve opening. The SRVs open to help relieve pressure. Following these actions, the bypass valves are used to control reactor pressure during shutdown.

15.2.3.5.2 Analysis of Effects and Consequences

15.2.3.5.2.1 Methods, Assumptions, and Conditions. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in detail in NEDO-10802[2] was used to simulate this event. The key analysis input parameters are identified in table 15.2-3.

The assumptions and conditions relative to the TTBP event analysis are as follows:

A. A turbine trip initiates the events that result in a fast closure of the TSVs (0.1 s).

B. The position switches on the TSVs initiate a reactor scram when the valves are < 90% open.

C. The scram is automatically bypassed when the reactor is < 30% of RTP.

D. The SRVs open at their maximum setpoints.

E. The steam bypass system operates at its design capacity.

15.2.3.5.2.2 Results and Consequences. Figure 15.2-10 shows the transient expected from 105% of nuclear boiler rated steam flow power conditions (2535 MWt). Neutron flux increases rapidly because of the void reduction caused by the pressure increase. However, the TSV scram and the EOC-RPT limit the flux increase to 179% of rated. Peak fuel surface heat flux does not exceed 102.7% of its rated value. Peak pressure in the bottom of the RPV reaches 1176 psig, which is below the ASME Code limit of 1375 psig for the reactor coolant pressure boundary (RCPB). RPV dome pressure does not exceed 1148 psig. The severity of turbine trips from lower initial power levels decreases to the point where a scram can be avoided if auxiliary power is available from an external source, and power level is within bypass capability.

15.2.3.5.2.3 Consideration of Uncertainties. The key uncertainties for the TTBP event are the same as the key uncertainties for the TTNBP event (paragraph 15.2.3.3.2.3).

15.2.3.6 <u>Closure of All MSIVs (MSIVD) (Event 10)</u>

The MSIVD event is a nonlimiting AOO and does not require reanalysis for reloads.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The MSIVD event was evaluated for power uprate at an RTP of 2763 MWt to determine whether this previously nonlimiting event would become more severe, and possibly limiting, under power uprate operating parameters.(10) The following discussion presents the results of the power uprate analysis.

15.2.3.6.1 Identification of Causes

Various malfunctions or operator actions can initiate MSIV closure. Examples are:

- Low steam line pressure.
- High steam line flow.
- Low water level.
- Manual action.

15.2.3.6.1.1 <u>Starting Conditions and Assumptions</u>. The reactor was initially operating at rated conditions (2763 MWt) with an RPV dome pressure of 1035 psig.

15.2.3.6.1.2 <u>Event Description</u>. As MSIVs close, position switches on the valves initiate a reactor scram when the valves on three or more MSLs are < 90% open and the reactor mode switch is in the RUN position. Protection system logic permits the test closure of one valve without initiating a reactor scram.

15.2.3.6.2 Analysis of Effects and Consequences

15.2.3.6.2.1 **Methods, Assumptions, and Conditions.** For the power uprate analysis, the transient analysis methods described in subsection 15.1.7 were used. The key analysis input parameters are identified in table 15.2-3.

For the MSIVD analysis, the following assumptions and conditions were used:

A. The closure of all MSIVs initiates the event.

B. The MSIVs close in 3 to 5 s. The worst case, the 3-s closure time, is assumed.

C. Position switches on the MSIVs initiate a reactor scram when the valves are < 90% open. MSIV closure inhibits steam flow to the feedwater turbines, terminating feedwater flow.

D. Valve closure indirectly causes a trip of the main turbine and generator, but late enough into the event so that no significant impact occurs.

   Following the initial drop in RPV water level due to void collapse, which results from the initial pressure transient, water level is recovered. The recovery arises from the pressure-reducing action of the SRVs and the fact that some feedwater is still entering the RPV following isolation. The transient water level on recovery may be sufficiently high to produce a TSV trip on high water level. If a TSV trip occurs, it will occur ~ 6 to 8 s following the initial MSIV closure and will not impact the event.

E. Because of the loss of feedwater flow, RPV water level is eventually decreased sufficiently to initiate an RPT and operation of the HPCI and RCIC systems.

15.2.3.6.2.2 **Results and Consequences.** The results and consequences for an MSIVD event are provided below:

A. Analysis Results

   Figure 15.2-11 shows the plant response to an MSIVD event. The analysis results are provided in table 15.2-1.

B. Fission Product Released from the Fuel

   The activity released is related to the activity in the reactor coolant and the activity released as a consequence of a reactor scram and an RPV depressurization from any fuel defects that existed prior to the event.

C. Activity Released to the Environment

The activity released during this event is contained in the RPV and the suppression pool. Very little activity is released to the environment.

D. Radiological Effects

The offsite doses resulting from this event are inconsequential.

15.2.3.6.2.3 Consideration of Uncertainties. Uncertainties in the analysis of MSIV closure include all the factors identified for the TTNBP event in paragraph 15.2.3.3.2.3. An additional variation is the closure time of the MSIVs. The time assumed in this analysis is 3 s, the fastest, and thereby the most conservative, closure time allowed by the Technical Specifications.

15.2.3.7 Closure of One MSIV (Event 11)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the closure of one MSIV event is a nonlimiting AOO and does not require reevaluation for reloads.

Only one isolation valve at a time is permitted to be closed for testing purposes. This precludes a reactor scram from the position switch signals. Normal test procedure requires an initial power reduction to ~ 80 to 90% of design conditions to avoid a high-flux scram, a high-pressure scram, or full isolation from high steam flow in the steam lines. With a 3-s closure of one MSIV from 105% of the nuclear boiler rated steam flow conditions (2535 MWt), the steam flow disturbance raises RPV pressure and reactor power enough to initiate a high neutron flux scram. Peak surface heat flux and peak center fuel temperature increase slightly. However, no significant decrease in thermal margins is experienced. Peak pressure remains below the lowest SRV setpoint. This event is considerably milder than the full-closure case.

Inadvertent closure of one MSIV while the reactor is shutdown will produce no significant event. Closures during plant heatup are less severe than the maximum power cases (maximum stored and decay heat).

15.2.3.8 Pressure Regulator Failure - Closed (Event 12)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt) demonstrated the pressure regulator failure - closed event is a nonlimiting AOO and does not require reevaluation for reloads.

If one pressure controller fails, an alarm will be generated and a very small change in control valve position may be noticed as the pressure regulator adjusts to the new median select between the remaining two controllers. The Mark VI pressure regulation and turbine control system will continue to regulate pressure and will maintain control of the bypass valves and the turbine valves. The disturbance is mild, similar to a pressure setpoint change, and no significant

reductions in fuel thermal margins occur. The pressure regulator failure - closed event is much less severe than the LRNBP and the TTNBP events described in paragraphs 15.2.3.1 and 15.2.3.3, respectively.

15.2.4 DECREASE IN REACTOR CORE COOLANT FLOWRATE

15.2.4.1 Trip of One Recirculation Pump (Event 13)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the trip of one recirculation pump event is a nonlimiting AOO and does not require reevaluation for reloads.

Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

15.2.4.1.1 Identification of Causes

15.2.4.1.1.1 Starting Conditions and Assumptions. The event begins with the trip and coastdown of one recirculation pump from 105% of nuclear boiler rated steam flow (2535 MWt), causing a core coolant flow decrease. Initially limiting fuel thermal conditions are assumed.

15.2.4.1.1.2 Event Description. Normal coastdown of one recirculation pump can occur through the trip of its drive motor breaker or the deenergization of the generator field, which causes the fastest coastdown. The FSAR does not contain a quantitative analysis for the one-pump trip for the case where a generator field is deenergized, because the trip of both recirculation pumps is more severe.

No single action can produce a simultaneous trip of the generator field breakers in both loops. This is why the drive motors were tripped in the two-pump trip event. The trip of both recirculation drive motors is more severe than the deenergization of one field breaker.

15.2.4.1.2 Analysis of Effects and Consequences

15.2.4.1.2.1 Methods, Assumptions, and Conditions. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[2] was used to simulate this event. The key analysis parameters are identified in table 15.2-3.

The EOC-RPT system trips the line breakers located between the motor-generator (M-G) and the pump motor. Thus, for events during which the EOC-RPT system is activated, the

coastdown characteristics of the pump, pump motor, and the pump shaft are the important parameters of interest. The inertial time used in the analysis for the pump/motor combination was 4.0 s, which is an equipment specification for the pump motor and pump shaft combination. The actual equipment inertia constant is expected to be conservatively less than the value used in the analysis. The reason for using the higher value for the time constant is to account for any inaccuracies in the analysis, such as those due to jet pump efficiencies. A larger value of the inertia constant is conservative, since it results in a slower core flow coastdown. Hence, power is reduced at a slower rate. The flow coastdown characteristics of the recirculation loop were verified during startup testing.

For the two-drive motor trip event in which the total inertia of the drive motor, M-G, pump motor, and pump sets is included, a conservatively smaller inertia than expected was used in the analysis. The value of the inertial time constant used in the analysis was 5 s. This was also verified during startup testing and found to be conservatively small, resulting in a more rapid flow coastdown in the analyzed event. Section 2.12 of reference 2 provides the following equation for the shaft speed of the form:

$$\frac{\pi J}{30 g_C} \frac{dn}{dt} = \Delta T$$

where:

J = inertia.

n = speed.

T = torque.

Normalizing to an initial torque and speed (T_O, n_O):

$$\Delta T = \left(\frac{\pi J n_o}{30 g_c T_o} \right) \frac{1}{n_o} \frac{dn}{dt}$$

This equation is of the form:

$$\frac{Y}{Y_o} = \tau \frac{dx}{dt}$$

where: τ = the effective inertial time constant, and for this system, is defined as:

$$\tau = \left(\frac{\pi J n_o}{30 g_c T_o} \right)$$

Since the more negative void reactivity coefficient assumed for the pressurization transients is nonconservative for flow decreases, this event was evaluated with the conservatively reduced void coefficient given in table 15.2-3.

15.2.4.1.2.2 Results and Consequences. Diffuser flow on the tripped side reverses; however, the M-ratio in the active jet pumps increases considerably. The power drops with flow decrease. The results and consequences of the trip of one recirculation pump are milder than the results and consequences of the trip of two recirculation pumps described in paragraph 15.2.4.2. No reduction in thermal margin occurs.

15.2.4.1.2.3 Consideration of Uncertainties. The initial conservative, limited conditions chosen for this analysis force the analytical results to appear more severe than actually expected. Actual rotating equipment inertia is also expected to be somewhat larger than the minimum design value assumed in these calculations. Any deviations from the assumed conditions are expected to make the results of the trip of one recirculation pump less severe.

15.2.4.2 Trip of Two Recirculation Pumps (Event 14)

This analysis, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the trip of two recirculation pumps is a nonlimiting AOO and does not require reevaluation for reloads.

Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

15.2.4.2.1 Identification of Causes

15.2.4.2.1.1 Starting Conditions and Assumptions. Steady-state operation of the plant at 105% of nuclear boiler rated steam flow power (2535 MWt) and 100% of rated core flow with thermally limited conditions is assumed.

15.2.4.2.1.2 Event Description. The two-loop pump coastdown can occur only from the simultaneous loss of power to both pump drive motors. No single operator action or plant protection action can produce the simultaneous trip of the generator field breakers in both loops. The electrical circuits controlling the M-G field circuit breakers are entirely separate. The field circuit breaker trip coils must be energized to open the breakers. Because of the separation and disposition of these two independent circuits, no event that can simultaneously trip both circuit breakers is postulated. This analysis provides the evaluation of the fuel thermal margins maintained by rotating inertia of the pumps, M-G sets, and drive motors.

As in all core flow decrease events, the abrupt reduction in core flow increases the core void fraction, thereby reducing power. The fuel surface heat flux decreases more slowly than the flow because of the fuel time constants; thus, fuel thermal margins can momentarily decrease. It is unlikely MCPR will fall below 1.30, and in any case, such a decrease will be minimal.

15.2.4.2.2 Analysis of Effects and Consequences

15.2.4.2.2.1 <u>Methods, Assumptions, and Conditions</u>. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[2] was used to simulate the trip of two recirculation pumps event. The minimum specified rotating inertia and a conservatively reduced void coefficient were assumed. The key analysis input parameters are identified in table 15.2-3.

15.2.4.2.2.2 <u>Results and Consequences</u>. Figure 15.2-12 shows the event with the minimum design rotating inertia from 105% of nuclear boiler rated steam flow conditions. MCPR remains above the initial operating limit of 1.30. High water level is reached at 4.76 s, causing a turbine trip, a trip of the feedwater pumps, and a reactor scram. The neutron flux and surface heat flux do not increase over the initial conditions; thus, fuel thermal margins are not affected. The pressure increases during the trip of two recirculation pumps do not significantly affect the RCPB.

15.2.4.2.2.3 <u>Consideration of Uncertainties</u>. Assuming the reactor is initially at limiting conditions conservatively forces the calculated results for this two-pump trip event to be more severe than actually expected. The actual rotating equipment inertia is also expected to be somewhat larger than the minimum design value assumed herein, thus, assuring the calculated results will be more severe than those actually expected.

15.2.4.3 <u>Recirculation Flow Control Failure - Decreasing Flow (Event 15)</u>

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the recirculation flow control failure with decreasing flow is a nonlimiting AOO and does not require reevaluation for reloads.

Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

15.2.4.3.1 Identification of Causes

15.2.4.3.1.1 <u>Starting Conditions and Assumptions</u>. This event starts at 105% of nuclear boiler rated steam flow power (2535 MWt) with thermally limiting conditions.

15.2.4.3.1.2 <u>Event Description</u>. Several possible flow controller malfunctions can cause a decrease in core coolant flow:

A. Either a downscale failure of the master flow controller or an excessive manual speed demand setpoint change can generate a zero flow demand signal to both recirculation flow control loops.

B. Failure of either an individual recirculation flow controller (one/loop) or the positioning servo in an individual scoop tube actuator can result in a rapid flow decrease in only one recirculation loop.

15.2.4.3.2 Analysis of Effects and Consequences.

The most severe condition (zero flow demand signals to both recirculation flow controls) was considered for this event.

15.2.4.3.2.1 <u>Methods, Assumptions, and Conditions</u>. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[(2)] was used to simulate the recirculation flow control failure with decreasing flow event. Additionally, recirculation loop flow was allowed to decrease. Minimum specified rotating inertia was assumed. Since the more negative void reactivity coefficient assumed for the pressurization transients is nonconservative for flow decreases, these events were evaluated with the reduced void coefficient multiplier given in table 15.2-3.

15.2.4.3.2.2 <u>Results and Consequences</u>. In the case of zero demand to both controllers, each M-G set speed controller has a rate limiter that limits the maximum rate of change of speed in each loop by limiting the integration rate of each speed controller. Thus, this transient can never be more severe than the simultaneous trip of both recirculation pumps. In the case of failure of one controller, the scoop tube positioners are designed so that the inherent limitation of their stroking rate is ~ 25%/s.

The results of this transient are similar to the trip of one recirculation pump and less severe than the transient that results from the simultaneous trip of both recirculation pumps. Thermal consequences are insignificant. Since pressure remains below the design level, no threat to the RCPB exists.

15.2.4.3.2.3 <u>Consideration of Uncertainties</u>. The key uncertainties for the recirculation flow control failure with decreasing flow event are the same as the key uncertainties for the trip of two recirculation pumps event discussed in paragraph 15.2.4.2.2.3.

15.2.5 INCREASE IN REACTOR CORE COOLANT FLOWRATE

15.2.5.1 Recirculation Flow Control Failure - Increasing Flow (Event 16)

This analysis, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the recirculation flow control failure with a rapid increase in flow is a nonlimiting AOO and is not required to be reevaluated for reloads.

Two kinds of recirculation flow control failure with increasing flow are considered: a slow flow increase and a rapid increase in recirculation flow.

The slow recirculation flow increase is considered a potentially limiting AOO for plant operation at reduced recirculation flow conditions. The currently applicable analyses of the slow recirculation flow increase event to establish the core operating limits for reduced flow conditions were performed for the implementation of the ARTS program documented in NEDC-30474-P.[(4)] The applicability of the ARTS limits for reduced flow conditions is confirmed each reload.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The recirculation flow controller failure - increasing flow event was evaluated for power uprate at an RTP of 2763 MWt.[(1)] The results of the study demonstrated the following:

A. The maximum core flow runout is unchanged.

B. The slope of the maximum extended load line limit analysis (MELLLA) is unchanged.

C. The expected change in ΔCPR remains well within the margins provided by flow-dependent limits.

Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

The following discussion provides the analysis results for the most rapid increase in recirculation flow.

15.2.5.1.1 Identification of Causes

15.2.5.1.1.1 <u>Starting Conditions and Assumptions</u>. The reactor is considered to be running at the low end of the rated flow control range (65% of nuclear boiler rated steam flow power and 50% core flow). This set of initial conditions results in the most severe event, considering the most rapid flow increase.

15.2.5.1.1.2 <u>Event Description</u>. Failure of the master flow controller can cause a speed increase for both recirculation pumps. However, both speed controllers have error limiters so that this case is less severe than the failure (maximum demand) of one M-G set speed controllers. A rapid swing of the couples is simulated at its maximum rate of 25%/s.

15.2.5.1.2 Analysis of Effects and Consequences

15.2.5.1.2.1 <u>Methods, Assumptions, and Conditions</u>. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[(2)] was used to simulate this event. The same void reactivity coefficient multiplier used for the pressurization transient was applied, since it increases the severity of the power increase. In addition, a conservative representation of the scram characteristics as shown in figure 15.2-13 was assumed. The key analysis input parameters are provided in table 15.2-3.

15.2.5.1.2.2 <u>Results and Consequences</u>. Figure 15.2-14 shows the results of the event due to the failure of one of the M-G set speed controllers. The changes in nuclear system pressure with regard to overpressure are insignificant. Pressure decreases for most of the event. The rapid increase in core coolant flow causes an increase in neutron flux, which initiates a reactor average power range monitor (APRM) high-flux scram.

The peak neutron flux rise reaches 264% of nuclear boiler rated flux, and the accompanying transient fuel surface heat flux reaches 84% of rated. This barely exceeds the steady-state recirculation flow-control line. MCPR remains considerably above the SLMCPR of 1.06, and fuel center temperature increases only 365°F.

15.2.5.1.2.3 <u>Consideration of Uncertainties</u>. Variations of coupler rate of change, void reactivity characteristics, scram time, and rod worth are all expected to be in the direction of reducing the severity of the event.

15.2.5.2 <u>Startup of Idle Recirculation Pump (Event 17)</u>

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the startup of the idle recirculation pump is a nonlimiting AOO and does not require reevaluation for reloads.

The startup of an idle recirculation pump was considered in the development of the ARTS limits at reduced flow conditions for the implementation of the ARTS program documented in NEDC-30474-P.[(4)] For the ARTS program, the slow recirculation flow increase event was demonstrated to be more limiting than the startup of an idle recirculation loop. In the ARTS program analysis, the temperature between the recirculation loops was limited to 50°F, consistent with the Technical Specifications requirements.

Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

15.2.5.2.1 Identification of Causes

15.2.5.2.1.1 <u>Starting Conditions and Assumptions</u>. The following starting conditions and assumptions apply to the startup of an idle recirculation event:

A. One drive loop is shut down and filled with cold water (100°F). (Plant procedures require warming this loop.)

B. In the active recirculation loop, ~ 72% of normal rated diffuser flow goes down through the active jet pumps.

C. The core is receiving 50% of its normal rated flow, while the remainder of the flow is reversed up through the inactive jet pumps.

D. Reactor power is 55% of nuclear boiler rated power conditions. (Plant procedures require start up of an idle loop at a lower power.)

E. The idle recirculation pump suction valve is open, but the pump discharge valve is closed.

F. The idle pump fluid coupler is at a setting that approximates 50% of generator speed demand.

15.2.5.2.1.2 <u>Event Description</u>. The loop startup sequence is as follows:

A. The pump is started at t = 0.

B. Initial power level and core flow are such that the initial reverse flow in the previously idle loop jet pump diffuser does not change back to normal flow. As a result, no flow direction change that will cause an increase in core inlet subcooling due to water from the cold loop reaching the core will occur.

15.2.5.2.2 Analysis of Effects and Consequences

15.2.5.2.2.1 **Methods, Assumptions, and Conditions.** For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[(2)] was used to simulate this event. The void reactivity coefficient multiplier (positive reactivity insertion) used for pressurization events was also used in this analysis. The key analysis input parameters are provided in table 15.2-3.

15.2.5.2.2.2 **Results and Consequences.** The event response to the startup of an idle recirculation loop without warming the drive loop water is shown in figure 15.2-15. Shortly after the pump begins to move, a reduction in reverse flow at the activated jet pump diffuser gives the core inlet flow a sharp rise. The neutron flux begins to rise and reaches the flow-referenced APRM flux setpoint at 10 s. The neutron flux peaks at 148% of nuclear boiler rated. Surface heat flux follows the slower response of the fuel and peaks at 70% of nuclear boiler rated. Nuclear system pressures do not increase significantly above initial pressure. Throughout the analyzed portion of the event, diffuser flow in the startup loop jet pumps is reversed. Therefore, a significant amount of cold water does not reach the core. Water level does not reach either the high- or the low-level trip setpoint.

15.2.5.2.2.3 **Consideration of Uncertainties.** Various combinations of operator procedures, initial power, and flow conditions are expected to reduce the actual severity of the transient below that conservatively calculated for this event.

15.2.6 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.2.6.1 RWE During Power Operation (Event 18)

The control rod withdrawal error (RWE) is a potentially limiting AOO for reloads and plant modifications that can impact the control rod withdrawal process.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, the RWE is reevaluated each operating cycle to establish the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions and event description applicable to the reload evaluation. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in the ***COLR***.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the

standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The RWE was reanalyzed for power uprate at an RTP of 2763 MWt.[1] The power uprate analysis is consistent with the implementation of the ARTS program documented in NEDC-30474-P.[4] The following discussion provides the results of the power uprate analysis.

15.2.6.1.1 Identification of Causes

15.2.6.1.1.1 <u>Starting Conditions and Assumptions</u>. The reactor is operating at a power level above 75% of rated power at the time the RWE occurs. The reactor operator has followed procedures, and up to the point of the RWE, the reactor is in a normal mode of operation (i.e., the control rod pattern and flow setpoints are all within normal operating limits). For these conditions, the RWE is assumed to occur with the maximum-worth control rod. Therefore, the maximum positive reactivity insertion will occur.

15.2.6.1.1.2 <u>Event Description</u>. While the reactor is operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and withdraws the maximum-worth control rod to its rod block position. Due to the positive reactivity insertion, core average power increases. More importantly, the local power in the vicinity of the withdrawn control rod increases and can potentially cause cladding damage due to overheating that may accompany the occurrence of boiling transition, which is an assumed AOO failure threshold. The following list depicts the sequence of events for this AOO:

A. The event begins; the operator selects the maximum-worth control rod, acknowledges any alarms, and withdraws the rod at the maximum rod speed.

B. Core average power and local power increase, causing a local power range monitor (LPRM) alarm.

C. The event ends; the rod block monitor (RBM) initiates the rod block.

15.2.6.1.2 Analysis of Effects and Consequences

15.2.6.1.2.1 <u>Methods, Assumptions, and Consequences</u>. For the analysis for power uprate (2763 MWt), the analysis methods using the 3-D simulator described in subsection 15.1.7 were used. The key parameter inputs for the power uprate analysis are provided in table 15.2-3.

15.2.6.1.2.2 <u>Results and Consequences</u>. The results of the power uprate analysis confirmed the ARTS statistical limits identified in NEDC-30474-P[4] are applicable. For an

RBM setpoint of 108%, the analysis results are provided in table 15.2-1. The results of the statistical evaluation are documented in NEDC-32749-P.[1]

15.2.6.1.3 RWE During Reactor Startup

This analysis, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the RWE during reactor startup is a nonlimiting AOO and does not require reevaluation for reloads. Because the event can only occur at low-power levels during startup, it is not impacted by an increase in RTP of 2804 MWt.

15.2.6.1.3.1 Event Description. The RWE analysis in the startup range was performed to demonstrate the peak fuel enthalpy event acceptance limit for fuel failure will not be exceeded when an out-of-sequence control rod is withdrawn at the maximum allowable normal drive speed.

The rod worth minimizer (RWM) constraints on rod sequences prevent the continuous withdrawal of an out-of-sequence rod. However, these analyses are performed to demonstrate, even for the unlikely event where the RWM fails to block the continuous withdrawal of an out-of-sequence rod, the peak fuel enthalpy design limit for fuel failure is still satisfied.

The method and design basis used for performing the detailed analysis for this event are similar to the method and design basis previously approved for the CRDA.[5] Additional simplified point model kinetics calculations were performed to evaluate the dependence of peak fuel enthalpy on the control blade worth. For the detailed calculation, the 50% control rod density pattern was selected as the initial starting condition, consistent with the approved design basis for the CRDA.[5]

The peak fuel enthalpy event acceptance limit for this event is that the contained energy of a fuel pellet located in the peak power region of the core shall not exceed 170 cal/g UO_2.

The sequence of events for this analysis and the approximate times of occurrence are as follows:

	Event Sequence[a]	Time
1.	The reactor is critical and operating in the startup range.	0
2.	The operator selects and withdraws an out-of-sequence control rod at a maximum normal drive speed of 3.6 in./s.	> 0
3.	The RWM fails to block selection (selection error) and continuous withdrawal (withdrawal error) of the out-of-sequence rod.	~ 4 s
4.	The intermediate range monitor (IRM) system or APRM (setdown) initiates a reactor scram depending upon which scram setpoint is reached first.	~ 4 - 8 s

	Event Sequence[a]	Time
5.	A combination of Doppler and/or scram feedback terminates the prompt power burst.	~ 5 - 9 s
6.	A scram of all rods, including the control rod being withdrawn, finally terminates the transient.	< 10 s

15.2.6.1.3.2 **Methods of Analysis.** Since the rod worth calculations using the approved design basis methods use three-dimensional geometry, it is not practical to do a detailed analysis of the event parameterizing control rod worths.[5] Therefore, the methods of analysis are to:

- Perform a detailed evaluation of the event for a typical BWR and control rod worth.
- Use a point model calculation to evaluate the results over the expected ranges of out-of-sequence control rod worths.

The detailed calculations are performed to demonstrate the following:

- The consequences of this event over the expected power operating range.
- The validity of the approximate point model calculation.

The point model calculations demonstrate the peak fuel enthalpy event acceptance limit for fuel failure is easily satisfied over the range of expected out-of-sequence control rod worths. These methods are described in more detail in the following paragraphs.

The method used to perform the detailed calculations is identical to the method used to perform the design basis CRDA with the following exceptions:

A. The rod withdrawal rate is 3.6 in./s rather than the blade drop velocity of 3.11 ft/s.

B. Either the IRM or a 15% APRM scram in the startup range initiates the scram. The IRM system is assumed to be in the worst bypass condition allowed by the Technical Specifications.

C. The blade being withdrawn, along with the remaining drives, inserts at Technical Specifications insertion rates upon initiation of scram signal.

Examination of a number of rod withdrawal events in the low-power startup range, using an R-Z model, has shown clearly that higher fuel enthalpy addition will result from the event starting at the 1% power level rather than from lower power levels. The analysis was performed assuming a 15% APRM scram.

The point model kinetics calculations use the same equations employed in the adiabatic approximation described in reference 5. The rod reactivity characteristics and scram reactivity functions are input to the adiabatic calculations, and the Doppler reactivity is input as a function of core average fuel enthalpy. The Doppler reactivity feedback function input to the point model calculations was derived from the detailed analysis for a 1.6% Δk rod-worth case.

This is a conservative assumption for higher rod worths, since the power peaking and, hence, spatial Doppler feedback are larger for higher rod worths. All other inputs are consistent with the detailed transient calculation.

The point model kinetics calculations result in core average enthalpies. The peak enthalpies were calculated using the following equation:

$$\hat{h} = ho + (P/A)_T \left(\overline{h}_f - ho\right)$$

where:

$\hat{h}$ = final peak fuel enthalpy.

ho = initial fuel enthalpy.

$\overline{h}_f$ = final core average fuel enthalpy.

$(P / A)_T$ = total peaking factor (radial peaking) x (axial peaking) x (local fuel pin peaking).

For these calculations, the (radial x axial) peaking factors as a function of rod worth were obtained from the calculations performed in reference 5. (See figure 15.2-17.) It was conservatively assumed no power flattening due to Doppler feedback occurred during the course of the event.

15.2.6.1.3.3 **<u>Results</u>.** For the point kinetics calculations, the reactivity insertion resulting from withdrawing the control rod is shown in figure 15.2-16. The core average power versus time and the global peaking factors from section 3.6 of reference 5 are shown in figures 15.2-18 and 15.2-17, respectively. The results of the point kinetics calculations, along with the results of the detailed analysis, are summarized in table 15.2-4.

Figure 15.2-18 and table 15.2-4 show that the core average energy deposition is insensitive to control rod worth; therefore, the only change in peak enthalpy as a function of rod worth will result from differences in the global peaking that increases with rod worth. Comparison of the global peaking factors of figure 15.2-17 with the value used in the detailed calculations demonstrates the reference 5 values are reasonable for their application in this study. For all cases, the peak fuel enthalpy is well below the event acceptance limit of 170 cal/g.

Cases 4 and 5 of table 15.2-4 show that the point kinetics calculations give conservative results relative to the detailed evaluations. The primary difference is that global peaking flattens during the event due to Doppler feedback. This is accounted for in the detailed calculation, but the point kinetics calculations conservatively assumed peaking remains constant at its initial value. The differences in core average and peak enthalpy between cases 1 and 5 are because, for case 1, a 15% APRM scram initiated the scram; whereas in case 5, the IRM initiated the scram. As seen in figure 15.2-19, the scram occurred at a core average power of 21%. Since the APRM trip point is reached first, it is reasonable to take credit for the APRM scram.

15.2.6.1.3.4 Conclusions. Based upon the results of this study, the following conclusions can be stated:

A. The resultant peak fuel enthalpies due to the continuous withdrawal of an out-of-sequence rod in the startup range results in peak fuel enthalpies that are significantly less than the event acceptance limit of 170 cal/g.

B. The point model calculations used to assess the sensitivity of peak enthalpy as a function of control rod worth are in agreement with and slightly conservative relative to the more detailed design basis model employed to evaluate the continuous rod withdrawal event in the startup range.

15.2.6.2 Control Rod Removal Error During Refueling (Event 19)

The shutdown margin analysis performed for each reload assures the core will remain subcritical considering the withdrawal of the highest-worth control rod. Therefore, the control rod removal error during refueling event does not require reevaluation for reloads.

15.2.6.2.1 Identification of Causes

15.2.6.2.1.1 Starting Conditions and Assumptions. The RWE during refueling considers the full withdrawal of the most reactive control rod during refueling.

15.2.6.2.1.2 Event Description. The RWE during refueling results in a positive reactivity insertion due to the withdrawal of the most reactive control rod during refueling.

15.2.6.2.2 Analysis of Effects and Consequences

15.2.6.2.2.1 Methods, Assumptions, and Conditions. The 3-D simulator described in subsection 15.1.7 is used in the analysis of the shutdown margin each operating cycle. Shutdown margin analysis is discussed in section 3.2.4.1 of ***NEDE-24011-P-A (GESTAR II)***.

15.2.6.2.2.2 Results and Consequences. When the mode switch is in the REFUEL position, only one control rod can be withdrawn. Selection of a second rod initiates a rod block and thereby, prevents the withdrawal of more than one rod at a time.
The core (shutdown margin analysis) is designed to remain subcritical at the most reactive point in the cycle with the highest-worth control rod fully withdrawn. The refueling interlocks prevent any condition that can lead to inadvertent criticality resulting from a control rod withdrawal error during refueling. In addition, the design of the control rod, incorporating the velocity limiter, does not physically permit the upward removal of the control rod without the simultaneous or prior removal of the four adjacent fuel bundles. This precludes an inadvertent criticality from occurring due to the withdrawal of any control rod.

15.2.6.2.2.3 Consideration of Uncertainties. The shutdown margin is analytically determined for each reload and experimentally verified during reactor startup.

15.2.6.3 Fuel Assembly Insertion Error During Refueling (Event 20)

This evaluation, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the fuel assembly insertion error during refueling is a nonlimiting AOO and does not require reevaluation for reloads. Because the event can only occur during refueling, it is not impacted by an increase in the rated power level.

15.2.6.3.1 Starting Conditions and Assumptions. Any single fuel bundle may be positioned in any available position. All control rods are fully inserted.

15.2.6.3.1.1 Event Description. This event considers a fuel assembly insertion error when all control rods are fully inserted. The event may result in positive reactivity insertion. The insertion error is assumed to be discovered and corrected during the core verification process.

15.2.6.3.2 Analysis of Effects and Consequences

15.2.6.3.2.1 Methods, Assumptions, and Conditions. Shutdown margin analysis is discussed in section 3.2.4.1 of ***NEDE-24011-P-A (GESTAR II)***.

15.2.6.3.2.2 Results and Consequences. The core is designed so that it can be made subcritical under the most reactive conditions with the strongest control rod fully withdrawn. Therefore, any single fuel bundle can be positioned in any available location without violating the shutdown criteria, provided all control rods are fully inserted. The refueling interlocks require that all control rods be fully inserted before a fuel bundle can be inserted into the core. Verification of correct core loading (fuel assembly location and orientation) is performed prior to any control rod withdrawal following fuel assembly movements during refueling. This core verification provides further assurance that the core will remain subcritical for the withdrawal of

any single control rod. This process precludes an inadvertent criticality occurring due to a fuel assembly insertion error during refueling.

15.2.6.3.2.3 <u>Consideration of Uncertainties</u>. The shutdown margin is analytically determined for each reload and experimentally verified during startup.

15.2.7 INCREASE IN REACTOR COOLANT INVENTORY

15.2.7.1 <u>Feedwater Controller Failure – Maximum Demand (Event 21)</u>

The feedwater controller failure - maximum demand (FWCF) event is considered a potentially limiting AOO for reloads and plant modifications that can impact the rate of inventory increase.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, FWCF event demand is reevaluated each operating cycle to establish the core operating limits. ***NEDE-24011-P-A*** provides the starting conditions and assumptions, and event description applicable to the reload evaluation. For the current reload, the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in the ***COLR***.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase. Reference 14 provides the evaluation of the impact on AOOs of the installation of ASDs to provide power to the recirculation pump motors. The ASDs replace the recirculation pump M-G sets. While certain recirculation pump characteristics changed as a result of this plant modification, the following analysis results remained bounding.

The FWCF event was reanalyzed for power uprate at an RTP of 2763 MWt.[1] The following discussion provides the results of the power uprate analysis.

15.2.7.1.1 Identification of Causes

This event is postulated on the basis of a single failure of a control device, specifically, one which can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe event is a feedwater controller failure initiating a maximum flow demand signal.

15.2.7.1.1.1 Starting Conditions and Assumptions. The starting conditions and assumptions considered in this analysis are as follows:

A. The feedwater controller fails, creating a maximum flow demand.

B. The maximum feedwater pump runout flow is assumed.

C. The reactor is operating in a manual flow control mode, which provides for the most severe transient.

15.2.7.1.1.2 Event Description. A FWCF event produces the following sequence of events:

A. The RPV receives an excess of feedwater flow.

B. This excess flow results in an increase in core subcooling, which results in a rise in both core power and RPV water level.

C. The rise in RPV water level eventually leads to a high water level turbine trip and feedwater pump trip. The position switches on the TSVs initiate a scram and an EOC-RPT.

15.2.7.1.2 Analysis of Effects and Consequences

15.2.7.1.2.1 Methods, Assumptions, and Conditions. For the power uprate analysis (2763 MWt), the 1-D transient analysis model described in subsection 15.1.7 was used to simulate the FWCF event. The key analysis input parameters are identified in table 15.2-3.

15.2.7.1.2.2 Results and Consequences. For power uprate, the FWCF event was analyzed for the following three power-to-flow conditions:

- 100% power and 100% flow (figure 15.2-20).
- 100% power and 105% flow (figure 15.2-21).
- 100% power and 91% flow.

The analysis results for these three power-to-flow conditions are provided in table 15.2-1.

15.2.7.1.2.3 Consideration of Uncertainties. All systems utilized for protection in this event are assumed to have a conservative response (e.g., SRV setpoints, scram stroke time, and instrument setpoints). Expected deviations in actual plant behavior are, therefore, expected to reduce the severity of the results.

15.2.8 DECREASE IN REACTOR COOLANT INVENTORY

15.2.8.1 Inadvertent Opening of an SRV (Event 22)

This analysis, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the inadvertent opening of an SRV is a nonlimiting AOO with respect to the core operating limits and, thus, is not reanalyzed each reload.

The inadvertent opening of an SRV results in the transfer of a significant amount of mass and energy to the suppression pool. This is one of the events evaluated with respect to suppression pool heat capacity. Therefore, the inadvertent opening of an SRV is evaluated for changes that can significantly impact suppression pool temperature.

15.2.8.1.1 Identification of Causes

15.2.8.1.1.1 Starting Conditions and Assumptions. The reactor is operating at an initial power level corresponding to 105% of nuclear boiler rated steam flow power (2535 MWt) conditions when an SRV is inadvertently opened.

15.2.8.1.1.2 Event Description. The opening of an SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the RPV causes a mild depressurization transient.

15.2.8.1.2 Analysis of Effects and Consequences

15.2.8.1.2.1 Methods, Assumptions, and Conditions. For the analysis for the original rated conditions (2436 MWt), the reactor transient model described in NEDO-10802[2] was used to simulate this event. The key analysis input parameters are identified in table 15.2-3.

The 10% of nuclear boiler rated flow is expected to be the upper limit on the relative size of a single SRV. The recirculation flow control system, being near full-flow capability at the start of the event, can influence this event very little, whether in either the automatic or the manual mode.

The main difference between a type III event, as defined in paragraph 15.1.5.2, and the other events identified for SRV discharge is the type of activity released. For a type II or IV event, the activity released to the containment is principally noble gas. For the type III event considered herein, the principal source is N-16. To evaluate the consequences of a type III event, it is assumed an SRV is opened for some undefined reason while the reactor is at full power. Since no significant RPV pressure or power transient will occur, the principal source of activity is N-16.

15.2.8.1.2.2 **Results and Consequences.** The pressure regulator senses the nuclear system pressure decrease and closes the TCVs far enough to stabilize RPV pressure at a slightly lower value. Reactor power settles at nearly the initial power level. Thermal margins decrease only slightly throughout the event, and MCPR remains very near the operating limit. Because the event is primarily a decrease in pressure, high internal pressure does not threaten the RCPB.

A. Fission Product Released from the Fuel

   This mild depressurization transient causes a small amount of activity to be released from the fuel, assuming there are preexisting fuel defects consistent with the maximum allowable reactor coolant activity. This activity is much less than the activity resulting from a reactor scram and an RPV depressurization for a type II event.

B. Activity Released to the Environment

   The activity released from the RPV during the inadvertent opening of an SRV is contained in the RPV and the suppression pool. The N-16 activity rapidly decays. Very little activity is released to the environment.

C. Radiological Effects

   The offsite doses resulting from this event are inconsequential.

15.2.8.1.2.3 **Consideration of Uncertainties.** This event is analyzed with an upper limit value of valve capacity and is not sensitive to the opening time of the valve. Changes in other control systems have very minor influence on the results.

15.2.8.2 Pressure Regulator Failure - Open (Event 23)

This event, which was performed for the initial core for the original rated conditions (2436 MWt), demonstrated the pressure regulator failure - open event is a nonlimiting AOO and does not require reanalysis for reloads. This event is not affected by power uprate.

15.2.8.2.1 Identification of Causes

15.2.8.2.1.1 **Starting Conditions and Assumptions.** The reactor is initially operating at 105% of nuclear boiler rated steam flow power (2535 MWt) with an RPV dome pressure of 1020 psig.

15.2.8.2.1.2 **Event Description.** If either the controlling pressure regulator or the backup regulator fails in an open position, the turbine admission valves can be fully opened and the

turbine bypass valves can be partially opened. This action results in an initial RPV coolant inventory decrease as the mass flow of steam leaving the RPV exceeds the mass flow of water entering the RPV. The total steam flowrate resulting from a pressure regulator malfunction is limited by a maximum combined flow limiter (MCFL) imposed at the turbine control originally specified to be set at ~110% of nuclear boiler rated flow. Consistent with General Electric SIL-589, "Pressure Regulator Tuning," Revision 1, the MCFL is set at ~115% of rated steam flow.

15.2.8.2.2 Analysis of Effects and Consequences

15.2.8.2.2.1 <u>Methods, Assumptions, and Conditions</u>. For the analysis for the original rated conditions (2436 MWt), the nonlinear dynamic model described in NEDO-10802[2] was used to simulate this event. The key analysis input parameters are identified in table 15.2-3.

The pressure regulator failure - open event is simulated by setting the controlling regulator output to a high value, causing the turbine admission valves to open fully and the turbine bypass valves to open partially. Since a high-value gate compares the controlling and backup regulator outputs, the effect of such a failure of the backup regulator will be exactly the same. A regulator failure with 115% steam flow was simulated as a worst case since 110% is the normal flow limit.

15.2.8.2.2.2 <u>Results and Consequences</u>. Figure 15.2-22 shows the response of important nuclear system variables for this event. The water level rises to the high-level trip setpoint in 13.8 s and initiates a trip of the main turbine and feedwater pump turbines. Closure of the TSVs initiates a scram and an EOC-RPT.

In the automatic mode, the signal from the pressure regulator causes recirculation flow to decrease, thereby lowering the power at a faster rate than in the manual mode. This also causes a more rapid depressurization and level swell so that the high-water-level turbine trip will occur at an earlier time. These conditions produce insignificant differences from MCPR considerations when compared to the manual mode.

A reactor high-level trip limits the duration and severity of the depressurization so that no significant thermal stresses are imposed on the RCPB. After the rapid portion of the transient is complete, the SRVs operate intermittently to relieve the pressure rise that results from decay heat generation. No significant reductions in fuel thermal margins occur, and MCPR remains > 1.30 throughout the event. Because the rapid portion of the transient results in only momentary RPV depressurization and because the SRVs need to operate only to relieve the pressure increase caused by decay heat, high internal pressure does not threaten the RCPB.

Operation with the MCFL set at ~ 130% (rather than the 110% value used in the FSAR analyses) is acceptable for Plant Hatch. This is based upon the pressure regulator failure - open event. This event is terminated by the low-pressure isolation function, supplemented (in faster depressurization cases) by the high-water-level trips. In no case is the fuel thermal margin violated, and in no case is the depressurization allowed to continue long enough to result in any significant cooldown of the metal temperatures of the primary system.[6,7,8]

15.2.8.2.2.3 Consideration of Uncertainties. If the maximum flow limiter is set higher or lower than normal, a faster or slower loss in nuclear steam pressure will result. The rate of depressurization is ultimately limited by the bypass capacity.

15.2.8.3 Loss of Auxiliary Power (Event 24)

This evaluation, which was performed for the initial core for original rated conditions (2436 MWt), demonstrated the loss of auxiliary power event is a nonlimiting AOO and does not require reanalysis for reloads.

15.2.8.3.1 Identification of Causes

15.2.8.3.1.1 Starting Conditions and Assumptions. The reactor is running at 105% of nuclear boiler rated steam flow power (2535 MWt) with thermally limited conditions.

15.2.8.3.1.2 Event Description. The reactor is subjected to a complex sequence of events when the plant loses all auxiliary power. Estimates of the responses of the various reactor systems (assuming loss of the auxiliary transformer) provide the following simulation sequence:

A. All pumps are tripped at a reference time, t = 0, with normal coastdown times for the recirculation and feedwater pumps.

   For this event, the condensate pumps and the condensate booster pumps are assumed to have enough inertia to keep suction pressure high enough for the feedwater pumps to continue supplying water to the RPV until a high-level trip occurs. This assumption is conservative because, by allowing feedwater flow to continue, the high-level turbine trip is reached when reactor power is still ~ 25% of nuclear boiler rated (4.4 s), rather than allowing the low condenser vacuum to trip the turbine at lower power (10 s).

B. Within 10 s, the loss of the main condenser circulating water pumps causes condenser vacuum to drop to the turbine trip setting.

C. At ~ 30 s, the subsequent loss of condenser vacuum is expected to reach the bypass valve and MSIV closure points. The protection system M-G sets coast down to the point where a scram and an MSIV closure are initiated at a later time.

The loss of all grid connections is a more feasible, although improbable, way to lose all auxiliary power. This event will add a generator load rejection to the above sequence at time, t = 0. The load rejection immediately forces the TCVs closed and causes a scram.

15.2.8.3.2 Analysis of Effects and Consequences

15.2.8.3.2.1 Methods, Assumptions, and Conditions. For the analysis for the original rated conditions, the nonlinear dynamic model of the reactor described in NEDO-10802[2] was used to simulate this event. The key analysis input parameters are identified in table 15.2-3.

The EOC scram (figure 15.2-13) characteristics are assumed. Only some of the SRVs are required; however, the setpoints (nominally starting at 1090 psig) are assumed to have 1% (high) errors.

Operation of either the RCIC system or the HPCI system is not included in the simulation of the first 75 s of this event, since startup of these pumps occurs in the latter part of this time period. Therefore, these systems have no significant effect on the results of this event.

The loss of auxiliary power results in the loss of RPV water inventory; thus, it is one of the events evaluated with respect to the capability of the high-pressure makeup systems. Therefore, it is evaluated for changes that can significantly impact RPV water inventory requirements.

15.2.8.3.2.2 Results and Consequences. Figure 15.2-23 shows the simulated loss of transformer event. The initial portion of the event is similar to the trip of two recirculation pumps event until a scram and turbine trip occur at ~ 4.4 s on high water level. Then the event assumes more the nature of an isolation event. The lowest SRV group cycles open and close at a decreasing rate as the decay heat diminishes until the RHR system, operating in the shutdown cooling mode, is initiated and dissipates the heat. Sensed level drops to the RCIC and HPCI initiation setpoint in ~ 43 s following loss of auxiliary power.

Peak pressure increases by < 100 psi above nominal operating pressure, thus assuring an ample margin to RPV pressure limits remains. Because the fuel transient is similar to the trip of both recirculation drive motors, no significant changes in fuel thermal margins occur.

The transient resulting from loss of all grid connections is shown in figure 15.2-24. The small neutron flux peak is limited by scram and pump trips. A slight increase in fuel surface heat flux is experienced, and the thermal behavior is again similar to a two recirculation pump trip. Peak pressures are slightly higher than in the previous case, but there are ample pressure margins. Sensed level reaches the initiation point of the HPCI and RCIC systems ~ 1 s earlier than in the previous case.

15.2.8.3.2.3 Consideration of Uncertainties. The most conservative characteristics of the protection features (e.g., SRVs and scram) are assumed so that any actual deviations in plant performance are expected to make the analytical results of this event appear less severe.

15.2.8.4 Loss of Feedwater Flow (Event 25)

The loss of feedwater flow (LOFW) event is a nonlimiting AOO with respect to the core operating limits and, thus, is not reanalyzed each reload.

Reference 11, Appendix E provides the generic evaluations of the AOOs for the Hatch power uprate to 2804 MWt. The evaluations are based on sensitivity results from previous GE BWR power uprate analyses. These results show that the effect of the TPO is small enough that plant-specific transient analyses were not required for the TPO uprate safety analysis (reference 12). The evaluations and conclusions of reference 11, Appendix E, as well as reference 12, are applicable to the Hatch uprate to 2804 MWt and justify performance of the standard reload analyses for the first fuel cycle that implemented the TPO uprate. Reference 13 supports the AOO evaluations for the 10-psi nominal operating pressure increase.

The loss of feedwater flow results in the loss of RPV water inventory; thus, the event was reanalyzed for power uprate at an RTP of 2763 MWt to demonstrate the capability of the RCIC system.(1) The following discussion provides the results of the power uprate analysis.

15.2.8.4.1 Identification of Causes

15.2.8.4.1.1 Starting Conditions and Assumptions. The reactor is operating at rated power (2763 MWt) and 100% flow.

15.2.8.4.1.2 Event Description. Following the trip of all feedwater pumps, feedwater flow decays to essentially zero flow in ~ 5 s. Decay and stored heat continue to create steam and the level continues to drop. At the low-low level setpoint, the RCIC system is actuated.

15.2.8.4.2 Analysis of Effects and Consequences

15.2.8.4.2.1 Methods, Assumptions, and Conditions. The SAFER/GESTR-LOCA evaluation model described in NEDO-10527(9) was used in the simulation of the LOFW event. The key analysis assumptions are provided in table 15.2-5.

15.2.8.4.2.2 Results and Consequences. RPV downcomer water level and pressure are shown in figures 15.2-25 and 15.2-26, respectively. The minimum transient water level outside the shroud is 34.8 ft above RPV zero. Therefore, RCIC is able to maintain RPV water level above the low-low-low water level (level 1) setpoint (34.7 ft above RPV zero) throughout the transient.

15.2.8.4.2.3 <u>Consideration of Uncertainties</u>. The most conservative characteristics of protection features are assumed. Any actual deviations in plant performance are expected to make the results of this event less severe.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

"GESTAR II – General Electric Standard Application for Reactor Fuel," <u>NEDE-24011-P-A</u>.

Unit 1 and Unit 2 Core Operating Limits Reports (located in each unit's Technical Requirements Manual, Appendix A).

REFERENCES

1. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 and 2," <u>NEDC-32749P</u>, July 1997.

2. Linford, R., "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," <u>NEDO-10802</u>, April 1973.

3. "Limiting Reload Licensing Events for E. I. Hatch Nuclear Plant Unit 1 and Unit 2," <u>EAS 65-1088</u>, October 1988.

4. "General Electric BWR Licensing Report: Average Power Range Monitor/Rod Block Monitor Technical Specification Improvement (ARTS) Program for E. I. Hatch Nuclear Plant, Units 1 and 2," <u>NEDC-30474-P</u>, December 1983.

5. Stirn, R. C., <u>et al</u>., "Rod Drop Accident Analysis for Large Boiling Water Reactors," <u>NEDO-10527</u>, General Electric Company, Atomic Power Equipment Department, March 1972; includes Supplement 1, July 1972 and Supplement 2, January 1973).

6. General Electric Service Information Letter No. 502, Revision 1, January 19, 1990.

7. Letter G-GPC-9-335, R. P. Daly (GE) to G. K. McElroy (GPC), "Plant Hatch – Evaluation of Pressure Control Maximum Combined Flow Limit," December 28, 1989.

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10. "General Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," <u>NEDC-32424P-1</u>, February 1995.

11. "Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization," <u>NEDC-32938P</u>, July 2000.

12. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," <u>NEDC-33085P</u>, GE Nuclear Energy, December 2002.

13. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

14. "Edwin I. Hatch Nuclear Plants, Units 1 & 2 Adjustable Speed Drives Implementation Project – Transient and LOCA Support," 0000-0055-5361-R0, Revision 0, GE Hitachi nuclear Energy, October 2008.

TABLE 15.2-1

POWER UPRATE TRANSIENT ANALYSIS RESULTS

Transient[a]	Initial Power/Flow[b]	Peak Neutron Flux (%)	Peak Heat Flux (%)	Peak MSL Pressure (psig)	Peak RPV Pressure (psig)	ΔCPR[c]
LRNBP	100P/100F	347	117	1245	1271	0.22
LRNBP	100P/105F	356	117	1244	1271	0.22
LRNBP	100P/91F	324	117	1246	1271	0.22
LRBP	100P/100F	260	111	1219	1249	0.16
TTNBP	100P/100F	351	118	1245	1272	0.23
TTNBP	100P/I05F	357	118	1245	1272	0.23
TTNBP	100P/91F	327	117	1246	1271	0.23
MSIVD	100P/100F	123	108	1087	1134	0.15
FWCF[d]	100P/100F	272	119	1212	1242	0.19
FWCF[d]	100P/105F	285	120	1213	1243	0.19
FWCF[d]	100P/91F	263	118	1213	1241	0.19
RWE		N/A	N/A		N/A	0.15
LFWH - EOC	100P/100F	N/A	N/A		N/A	0.11
LFWH - MOC	100P/91F	N/A	N/A		N/A	0.13

a. LRNBP = generator load rejection with no bypass.
LRBP = generator load rejection with bypass.
TTNBP = turbine trip with no bypass.
MSIVD = closure of all MSIVs, direct scram.
FWCF = feedwater controller failure - maximum demand.
RWE = control rod withdrawal error.
LFWH = loss of feedwater heating (108°F).

b. 100P = uprated power of 2763 MWt.
100F = rated core flow of 77.0 Mlb/h.
105F = ICF flow point at uprated power.
91F = MELLLA flow point at uprated power.

c. ΔCPR based upon initial CPR that yields MCPR = 1.12, uncorrected for ODYN options A & B for LRNBP and FWCF events. Based upon limiting fuel, which is GE13 & GE9 for HNP-2.

d. Reduced feedwater temperature of 355°F (70°F reduction at rated conditions).

TABLE 15.2-2 (SHEET 1 OF 2)

NOTES FOR FIGURE 15.2-3

Activity A

Initial pressure = 1045 psia.

Initial temperature = 560°F.

For purposes of this analysis, the following worst-case conditions are assumed to exist:

A. The reactor is assumed to be operating at 105% of nuclear boiler rated steam flow.

B. A loss of power transient occurs.

C. A simultaneous loss of onsite power (Division 1 or Division 2) that eventually results in the operator not being able to open one of the RHR shutdown cooling line suction valves occurs.

Activity B

Initial system pressure = 1045 psia.

Initial system temperature = 560°F.

Operator Actions

During approximately the first 30 min, automatic operation of the SRVs passes reactor decay heat to the suppression pool. Automatic operation of either the HPCI or the RCIC system returns RPV water level to normal.

After ~ 10 min, it is assumed one RHR heat exchanger will be placed in the suppression pool cooling mode to remove decay heat. Subsequently, the operator will initiate RPV depressurization to control RPV pressure. Controlled depressurization procedures consist of controlling RPV pressure and water level by using the ADS, the RCIC system, or the HPCI system.

When RPV pressure approaches 100 psig, the operator will normally prepare for operation of the RHR system in the shutdown cooling mode.

TABLE 15.2-2 (SHEET 2 OF 2)

Activity C1 (Division I fails; Division II is available.) (See figure 15.2-4.)

System pressure = 100 psi.

System temperature = 330°F.

Operator Actions

The operator establishes a closed cooling path as follows:

A. One ADS valve (dc Division II) is manually opened.

B. Using CS loop 2B from the suppression pool through valves F019B and F001B to the pump C001B, and through valves F004B, F005B, and F006B to the RPV, the cooled suppression pool water flows through the RPV (removing decay heat), through the MSLs and the ADS valve, and back to the suppression pool. The RHR loop 2B and/or 2D is used to cool the suppression pool as required. Pumping is continued until cooldown is completed.

Activity C2 (Division II fails; Division I is available.) (See figure 15.2-5.)

The principle is the same as for activity C1 but using the alternate equipment as shown.

TABLE 15.2-3

ANALYSES OF AOOs
INITIAL CONDITIONS

Parameter	Initial Core	Power Uprate
Rated thermal power (MWt)	2436	2763
Analysis power (MWt)	2535	2763
Rated core flow (Mlb/h)	77.0	77.0
Rated power core flow range (% of rated)	100	91 to 105
Steam flow – analysis power (Mlb/h)	10.99	11.98
Dome pressure (psig)	1020	1035
Turbine inlet pressure (psig)	NA	985
Feedwater temperature (°F)	424	425.1
Steam bypass capacity (% of rated)	26	20.6
No. of SRVs available	11	10
SRV type	Target Rock	Target Rock
Opening response of SRVs (s)	< 0.1	0.15
Opening delay of SRVs (s)	< 0.4	0.4
Total SRV capacity at 1090 psig (% of rated)	89	71
SRV setpoints (psig)	4 at 1101 4 at 1111 3 at 1121	4 at 1195 4 at 1195 2 at 1195
Fuel type	Initial core - 8x8	HNP-2 cycle 14
SLMCPR	1.06	1.12
Core average gap conductance (Btu/s-ft^2-°F)	0.1667	0.3675
Point kinetics void coefficient		NA
• Nominal • Positive reactivity insertion • Negative reactivity insertion	-7.22 ¢/% -12.0 ¢/% -6.86 ¢/%	
Total scram worth	figure 15.2-13	-46.0 $
CRD speed	figure 15.2-13	GEMINI Option A

TABLE 15.2-4

SUMMARY OF RESULTS FOR DETAILED AND POINT KINETICS EVALUATIONS OF CONTINUOUS ROD WITHDRAWAL IN STARTUP RANGE (INITIAL CORE)

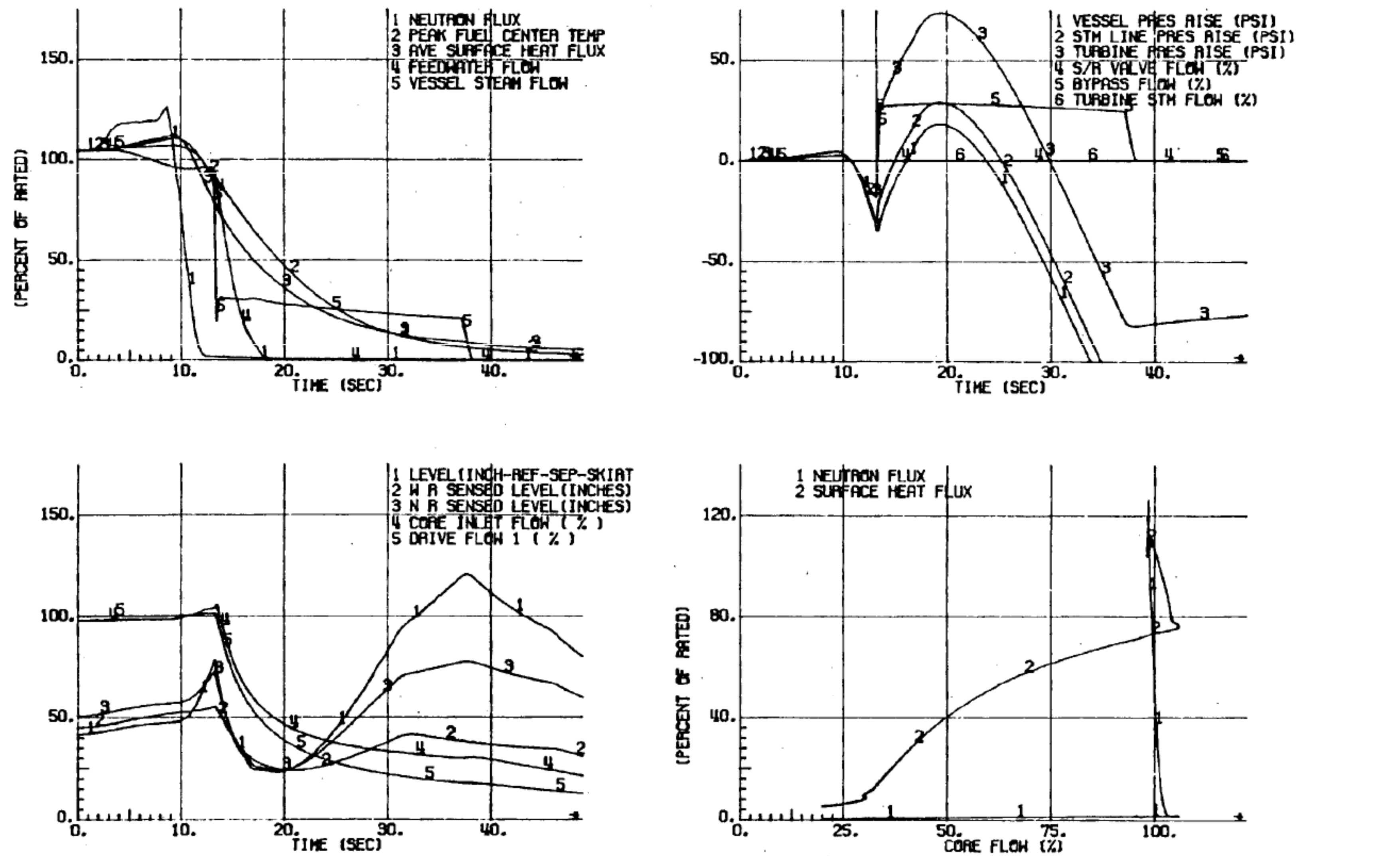
Case	Control Rod Worth (% Δk)	$\bar{h}_f$ (cal/g)	$\hat{h}$ (cal/g)	P/A[a]
1	1.6	17.3	42.7	24.2
2	2.0	17.3	50.0	30.9
3	2.5	17.2	58.5	46.0
4	1.6[b]	18.3	56.2	19.7[c]
5	1.6[d]	18.3	59.3	19.7

a. P/A = global peaking factor (radial x axial).
b. Detailed transient R-Z calculation. All other data reported are for point kinetics calculations.
c. P/A = 19.7 is the initial value. For the detailed analysis, this value decreases during the course of the transient, since the power slope flattens due to Doppler feedback.
d. Point kinetics calculation with IRM-initiated scram and R-Z global peaking.

TABLE 15.2-5

**KEY ANALYSIS ASSUMPTIONS FOR POWER UPRATE
ANALYSIS OF LOSS OF FEEDWATER FLOW**

Parameter	Value
Rated thermal power (MWt)	2763
Analysis power (% of rated)	102
Analysis core flow (%)	100
Feedwater flow decay	Ramped to zero in 5 s
MSIV closure setpoint	Level 1
RCIC initiation setpoint	Level 2
Scram	Level 3
RCIC startup time (s)	45
RCIC flowrate (gal/min)	360
Decay heat	1979 ANS5.1 + 10%



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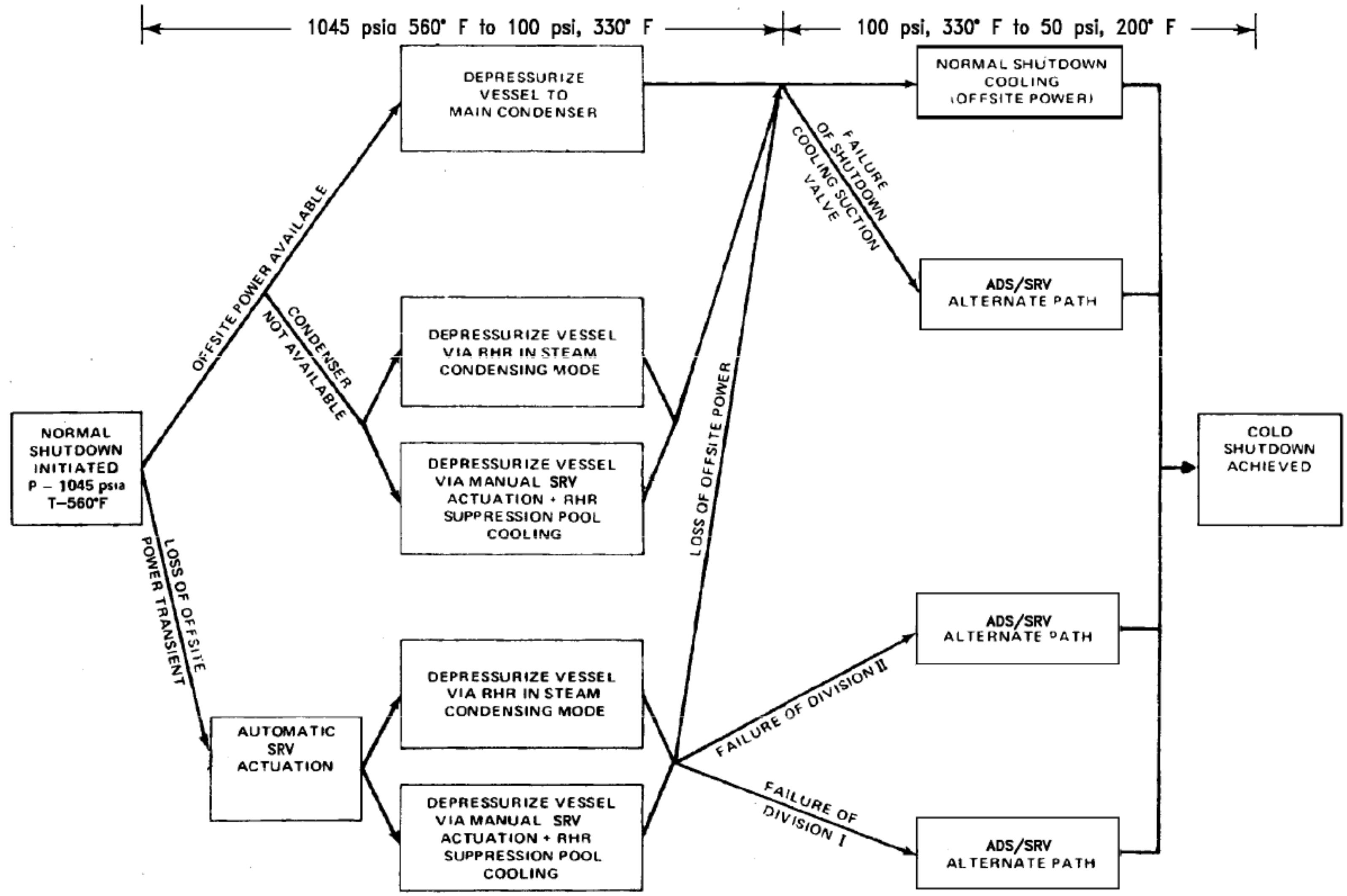
INADVERTENT HPCI INJECTION
VOID COEFFICIENT = -12.0

FIGURE 15.2-1



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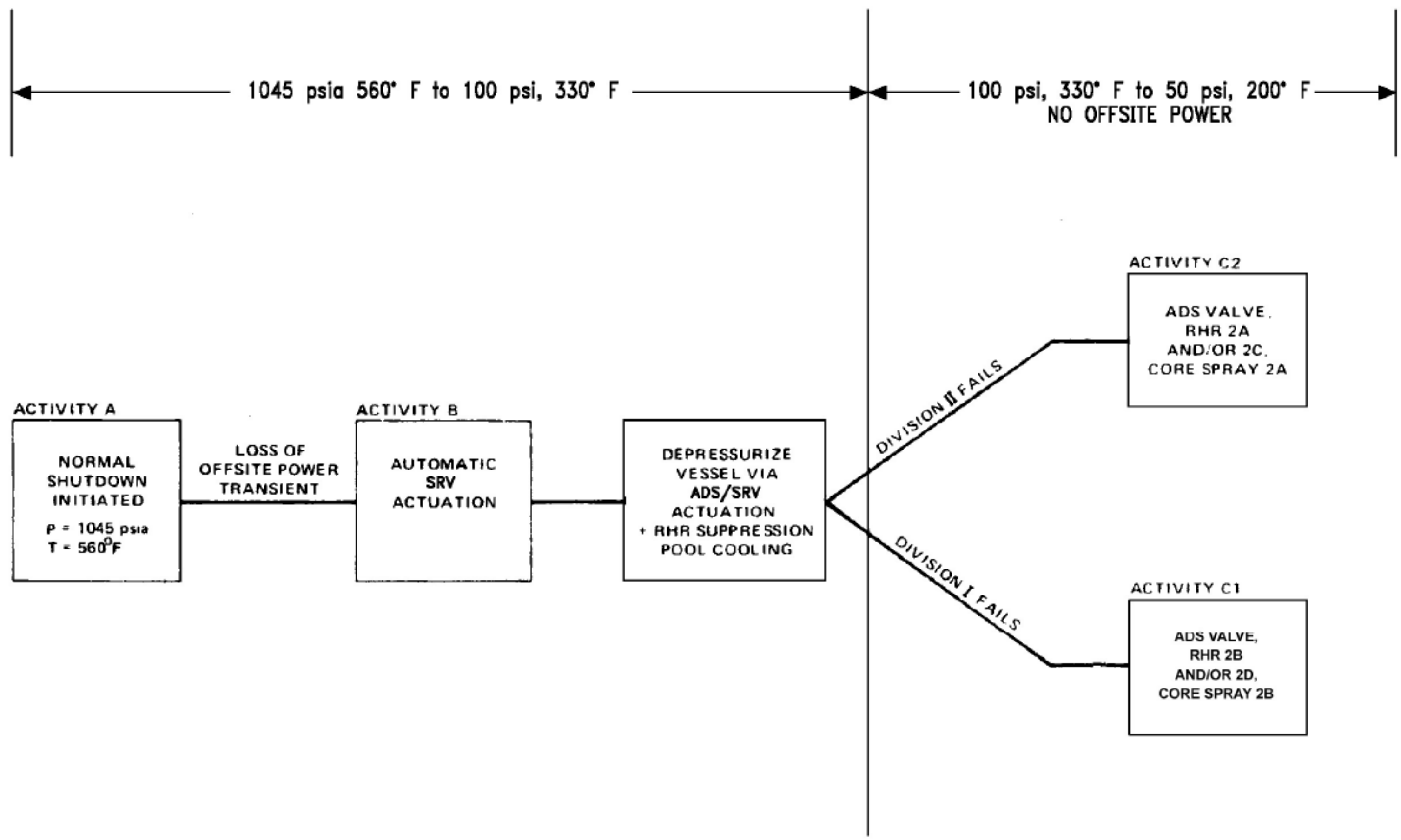
SUMMARY OF PATHS AVAILABLE TO ACHIEVE COLD SHUTDOWN

FIGURE 15.2-2



NOTE: REFERENCE HNP-2 FSAR TABLE 15.2-2 FOR NOTES.

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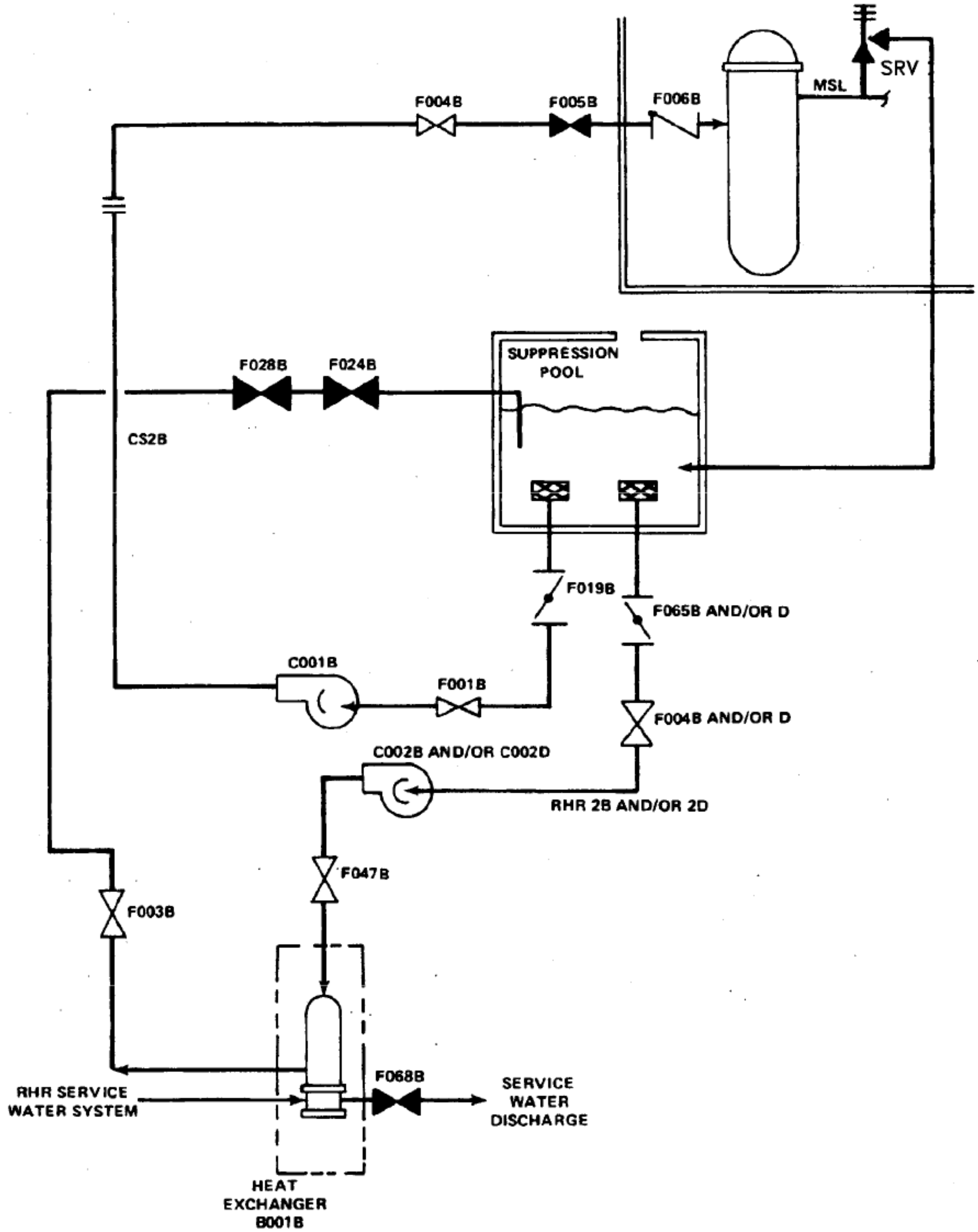
ADS/RHR/CS COOLING LOOPS

FIGURE 15.2-3



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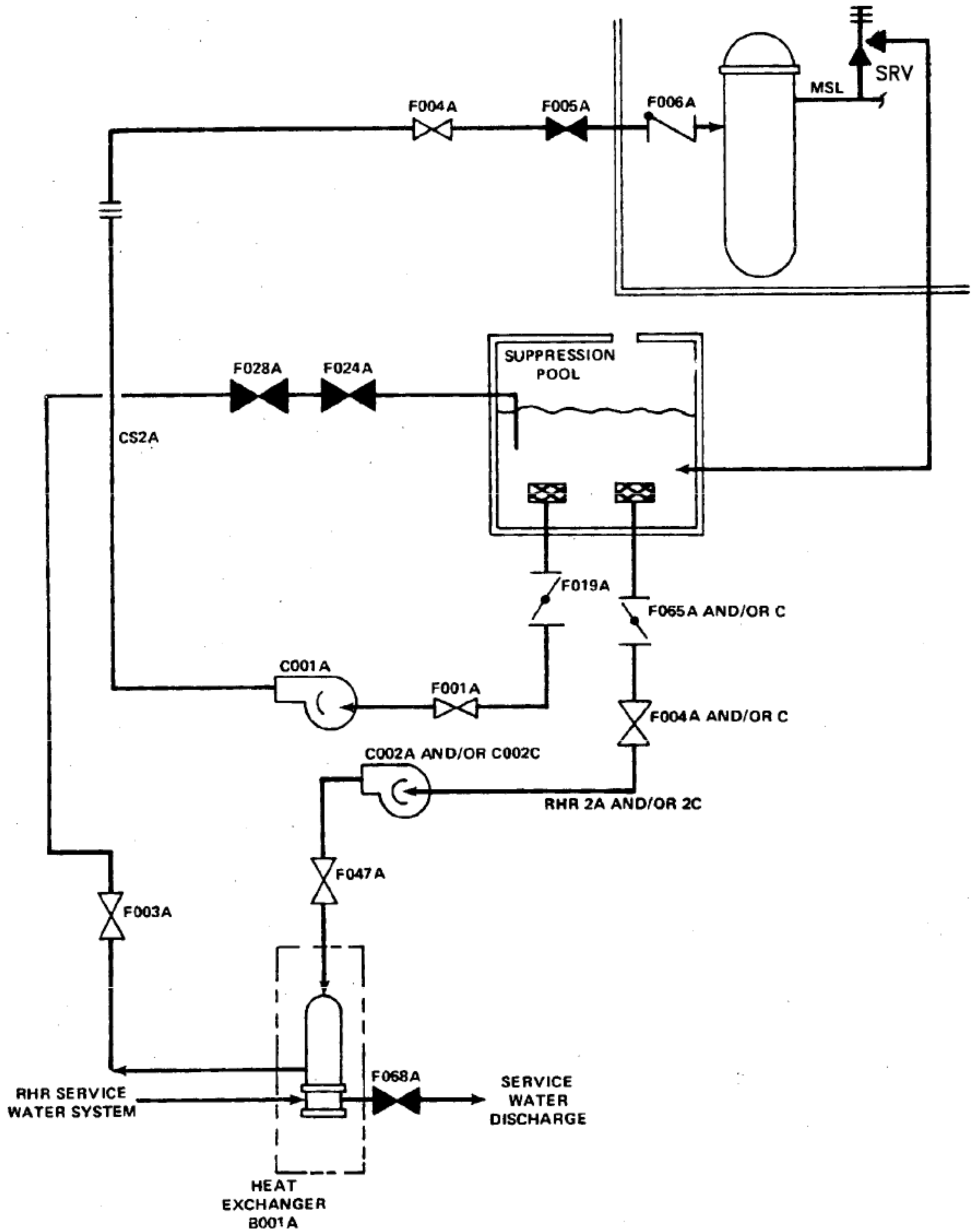
ACTIVITY C1 – DIVISION I FAILED

FIGURE 15.2-4



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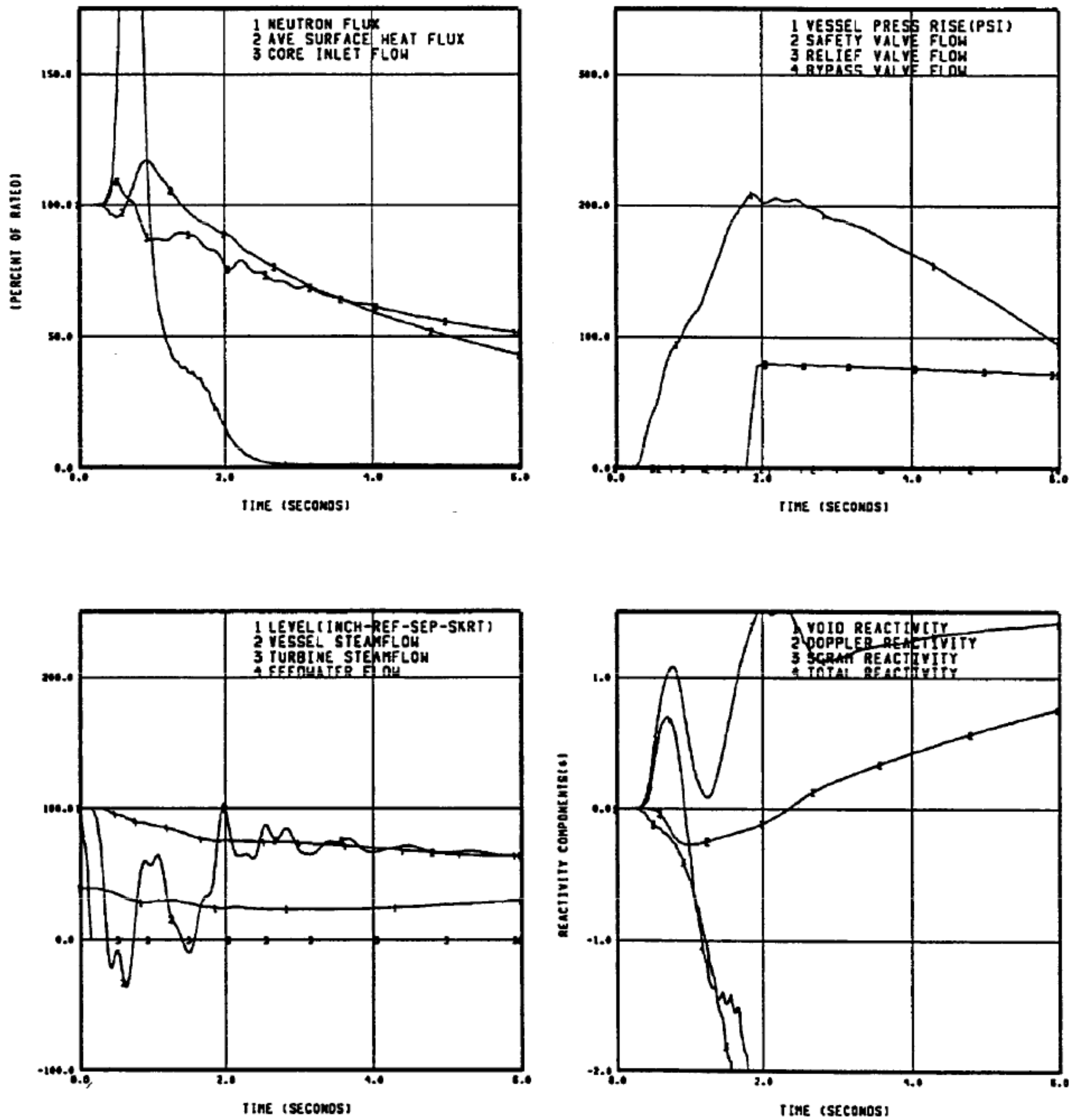
UNIT 1 AND UNIT 2

ACTIVITY C2 – DIVISION II FAILED

FIGURE 15.2-5



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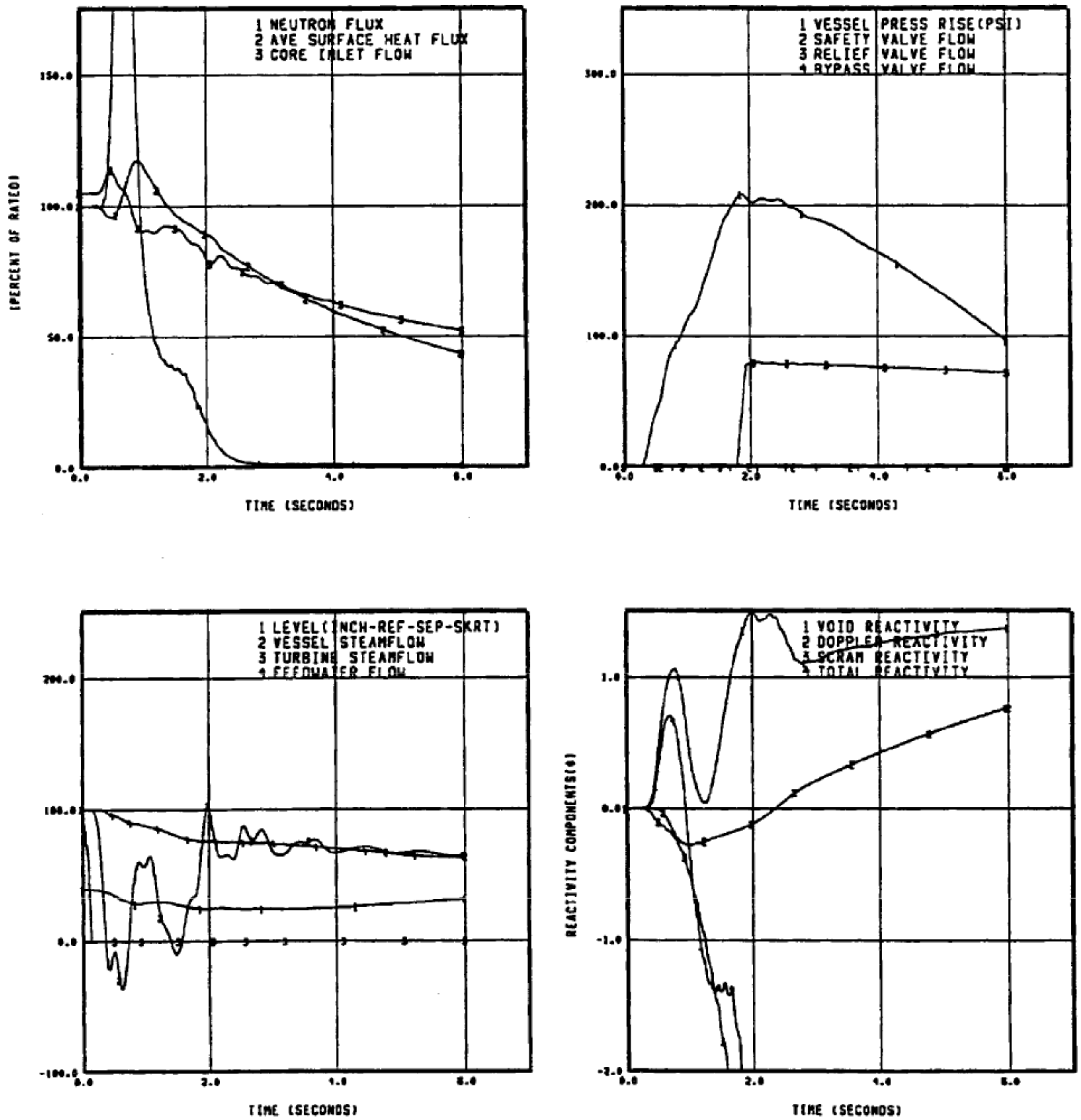
UNIT 1 AND UNIT 2

LOAD REJECTION WITH NO BYPASS
(LRNBP) (100P/100F)

FIGURE 15.2-6



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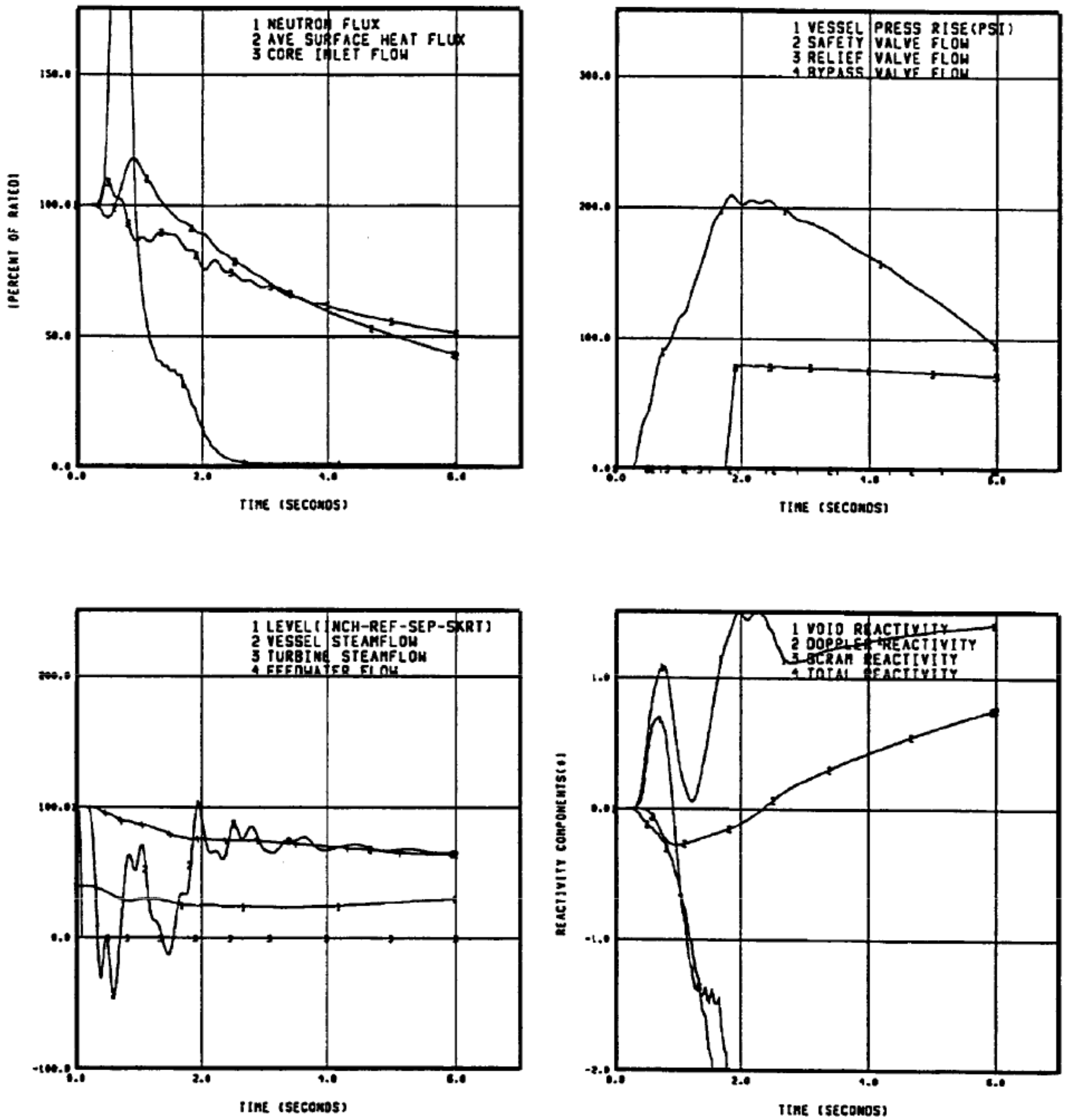
UNIT 1 AND UNIT 2

LOAD REJECTION WITH NO BYPASS
(LRNBP) (100P/105F)

FIGURE 15.2-7



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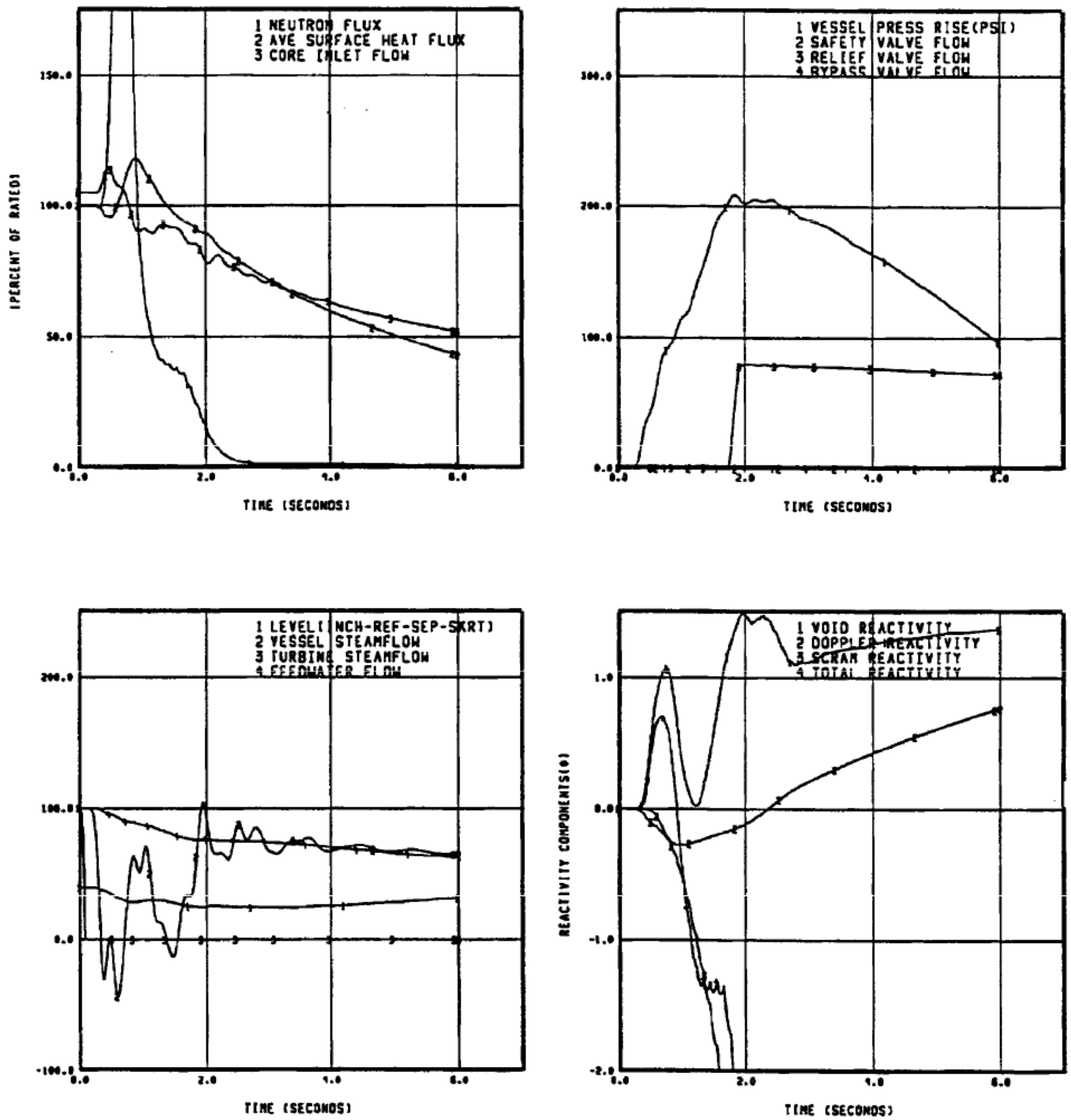
UNIT 1 AND UNIT 2

TURBINE TRIP WITH NO BYPASS
(TTNBP) (100P/100F)

FIGURE 15.2-8



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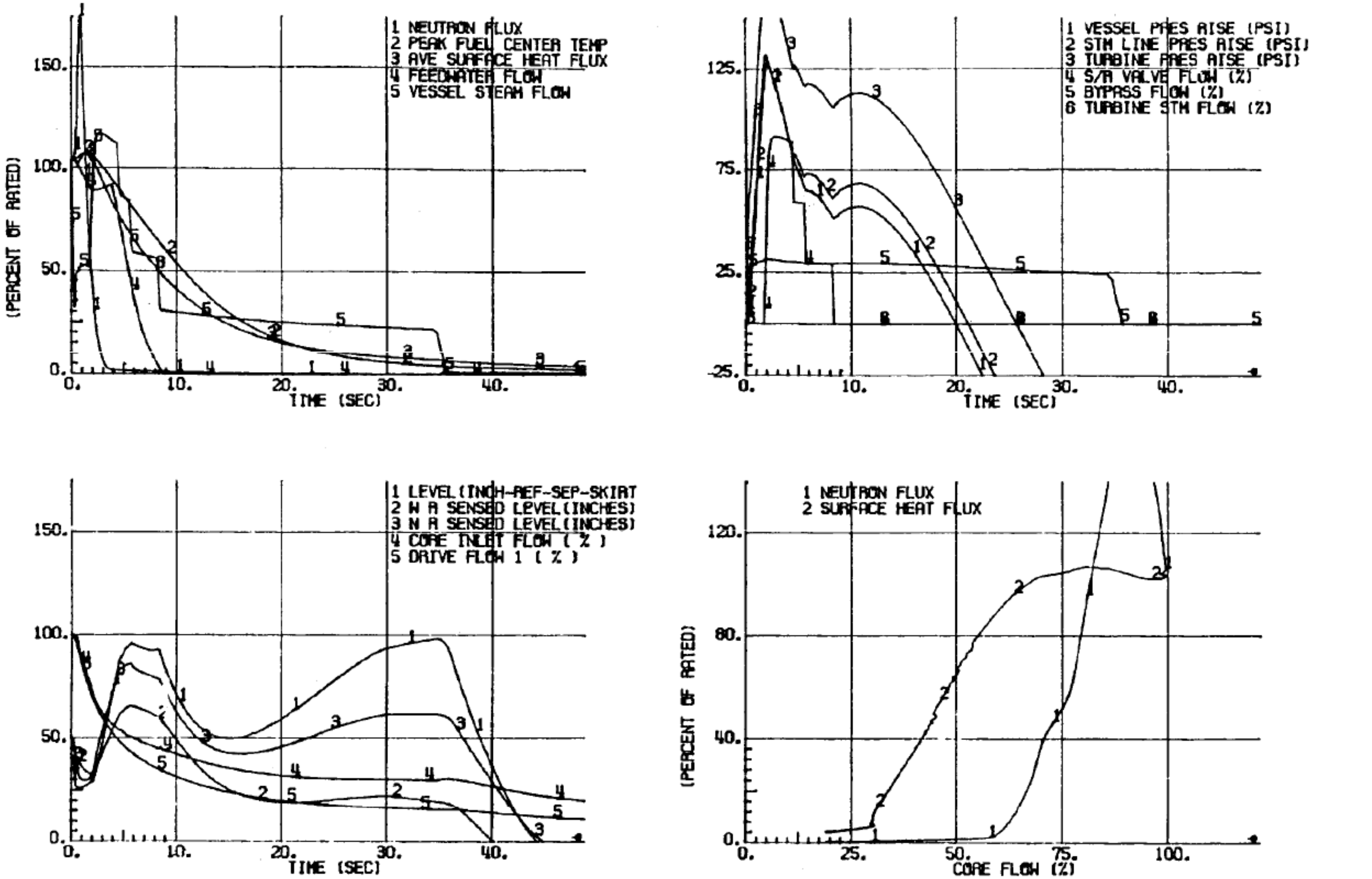
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

TURBINE TRIP WITH NO BYPASS
(TTNBP) (100P/105F)

FIGURE 15.2-9



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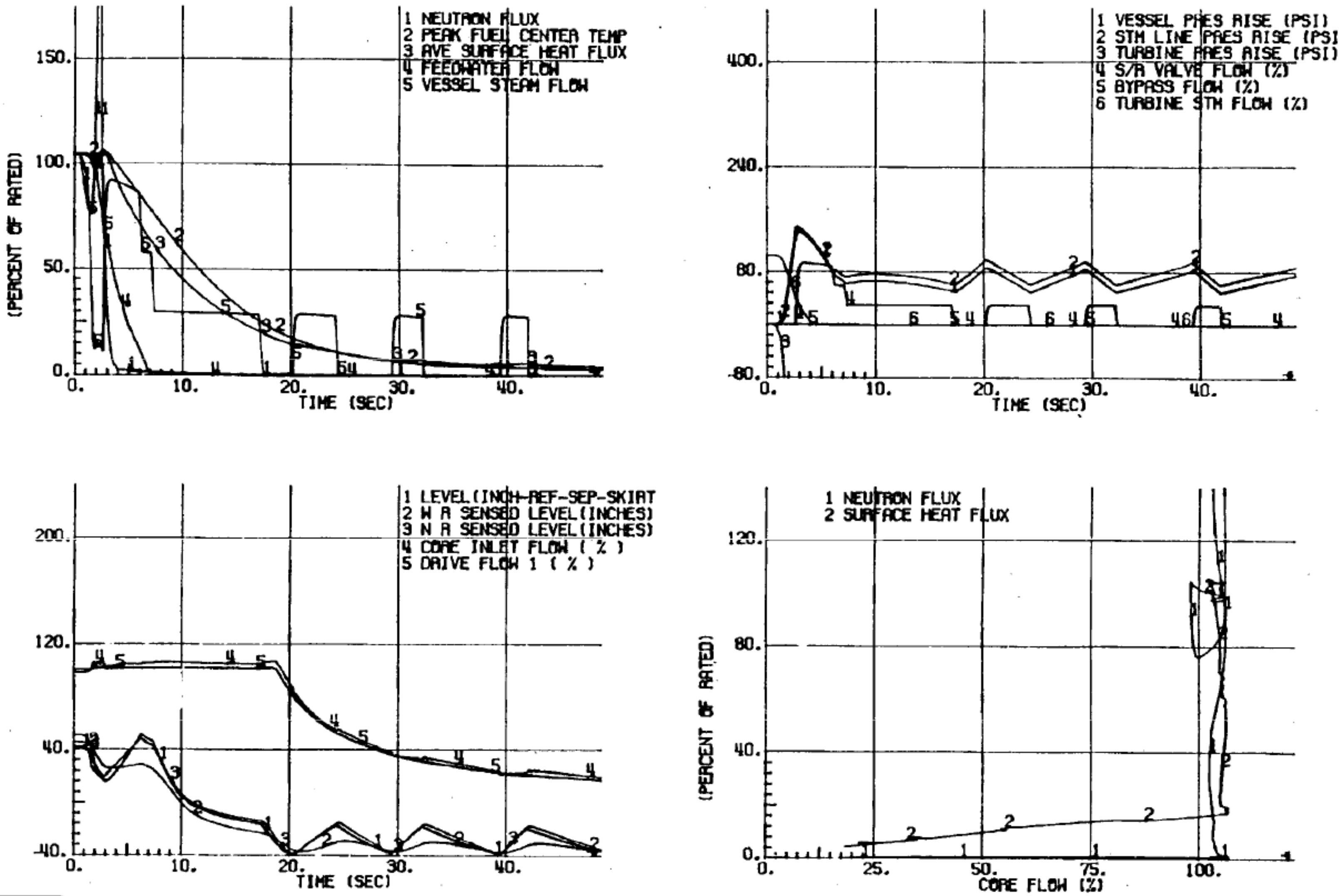
UNIT 1 AND UNIT 2

TURBINE TRIP WITH BYPASS (TTBP)
VOID COEFFICIENT = -12.0

FIGURE 15.2-10



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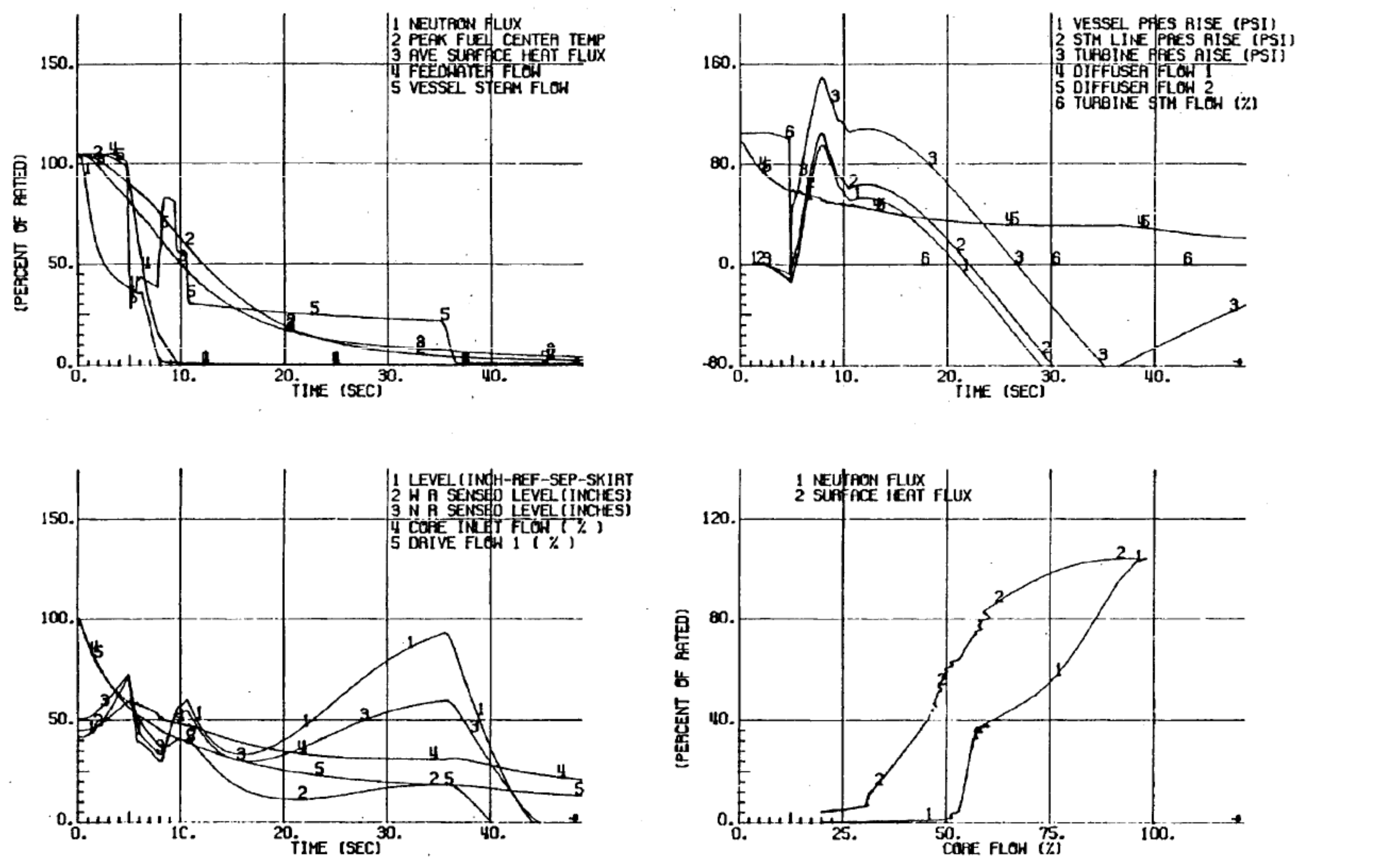
UNIT 1 AND UNIT 2

CLOSURE OF ALL MSIVs, MSIVD, TRIP SCRAM, VOID COEFFICIENT = -12.0

FIGURE 15.2-11



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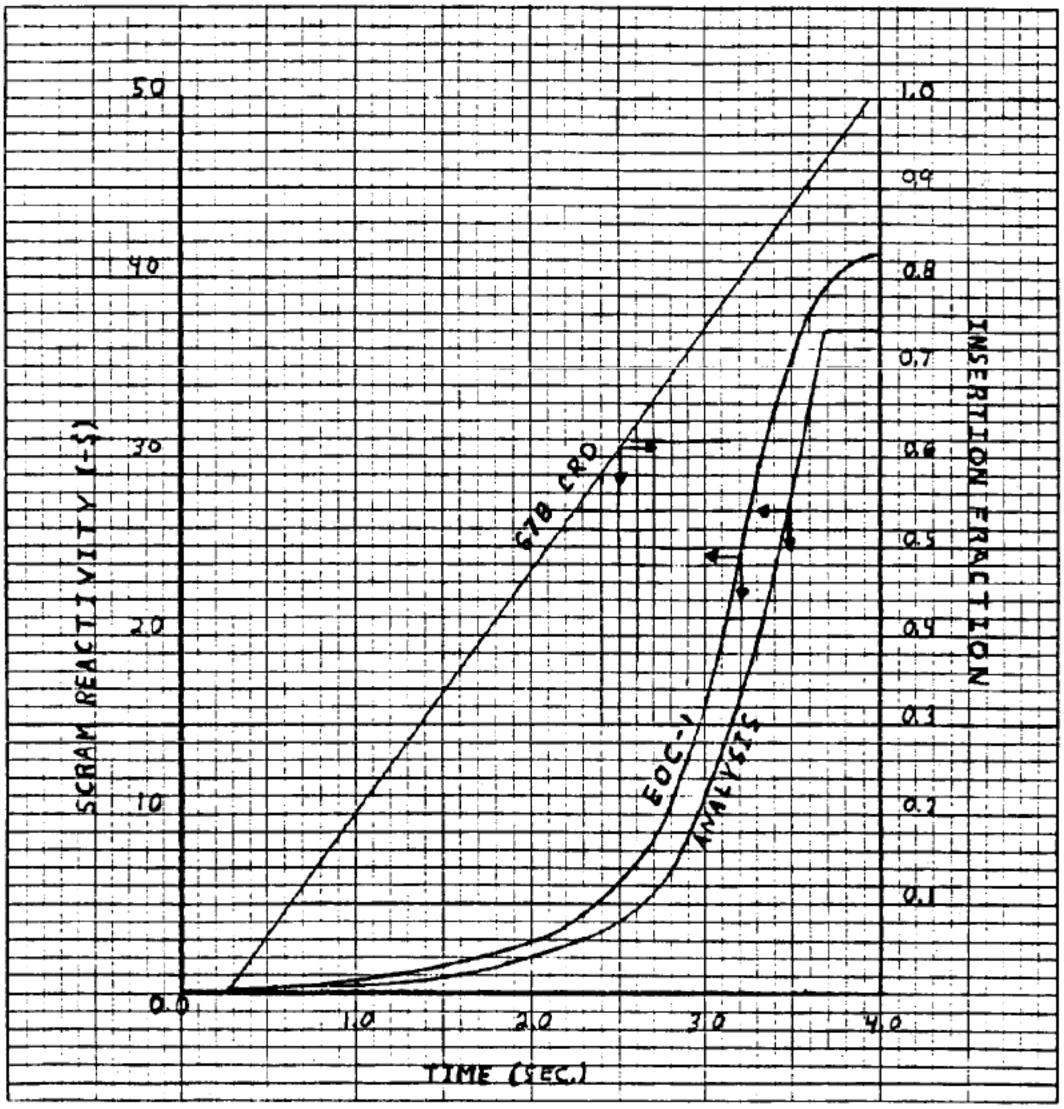
UNIT 1 AND UNIT 2

TRIP OF BOTH RECIRCULATION PUMPS
VOID COEFFICIENT = -6.86

FIGURE 15.2-12



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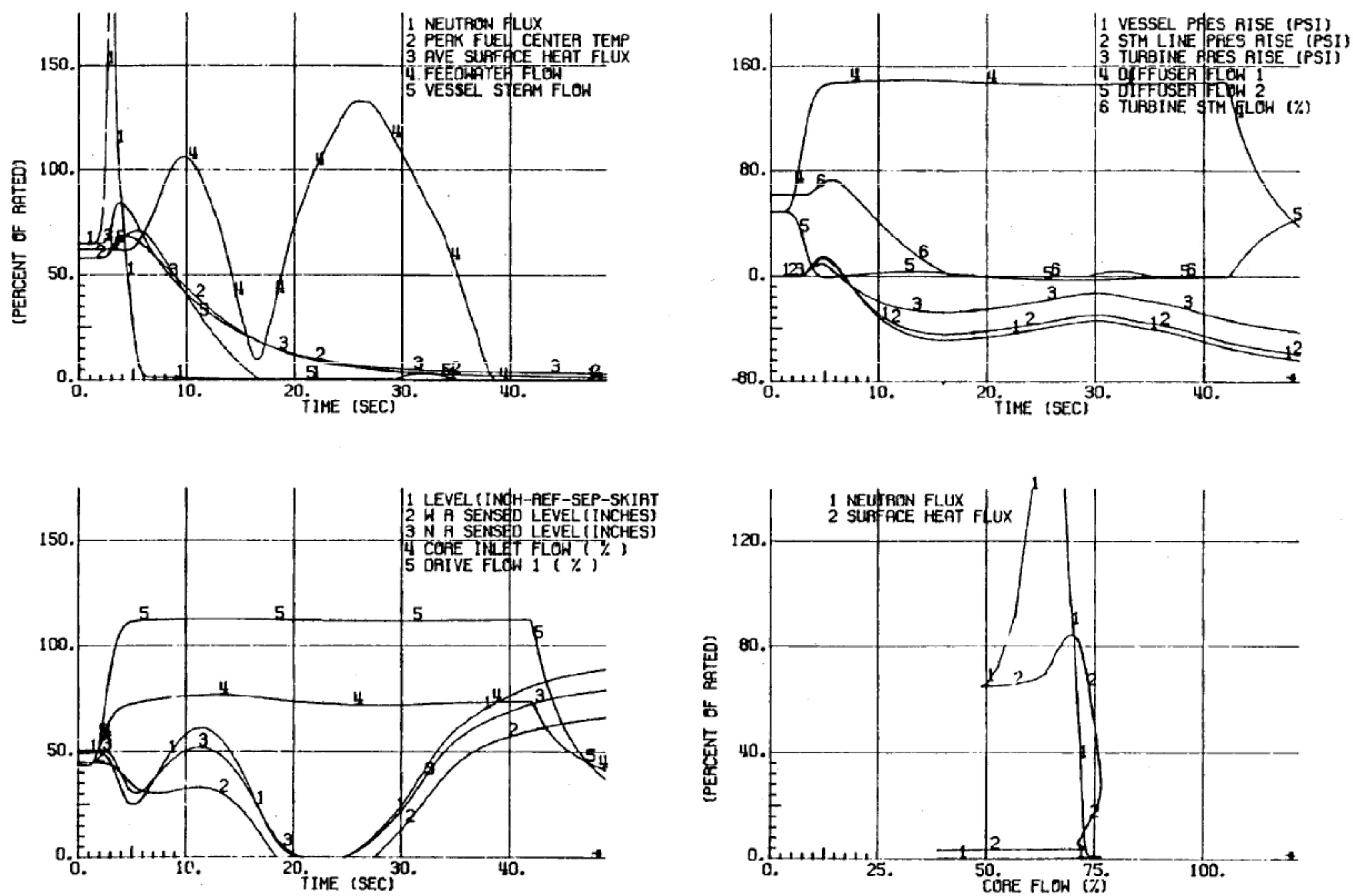
UNIT 1 AND UNIT 2

CRD, EOC 1 SCRAM CURVE, AND SCRAM CURVE USED IN ANALYSIS

FIGURE 15.2-13



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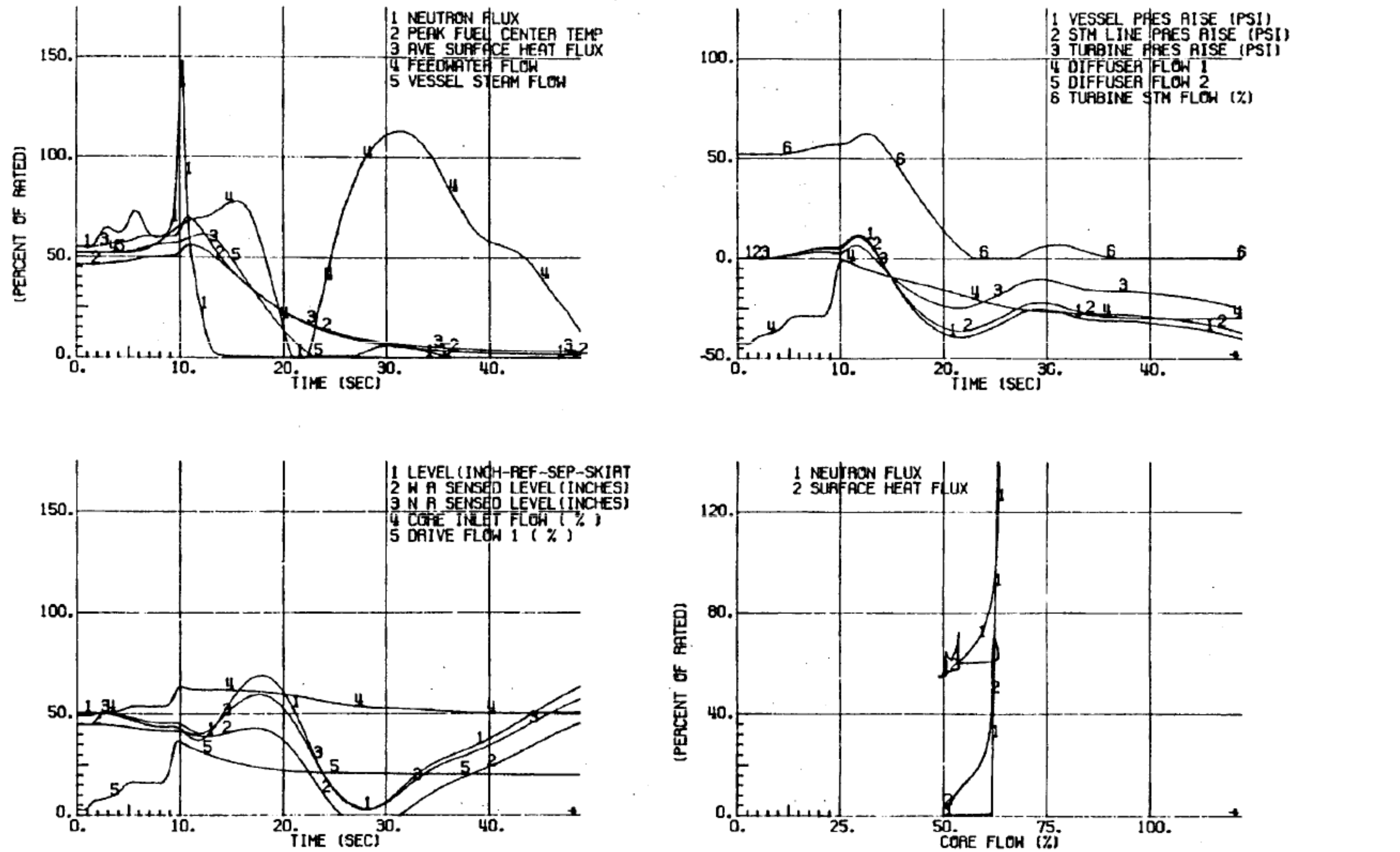
UNIT 1 AND UNIT 2

RECIRCULATION FAILURE – INCREASING FLOW, VOID COEFFICIENT = -12.0

FIGURE 15.2-14



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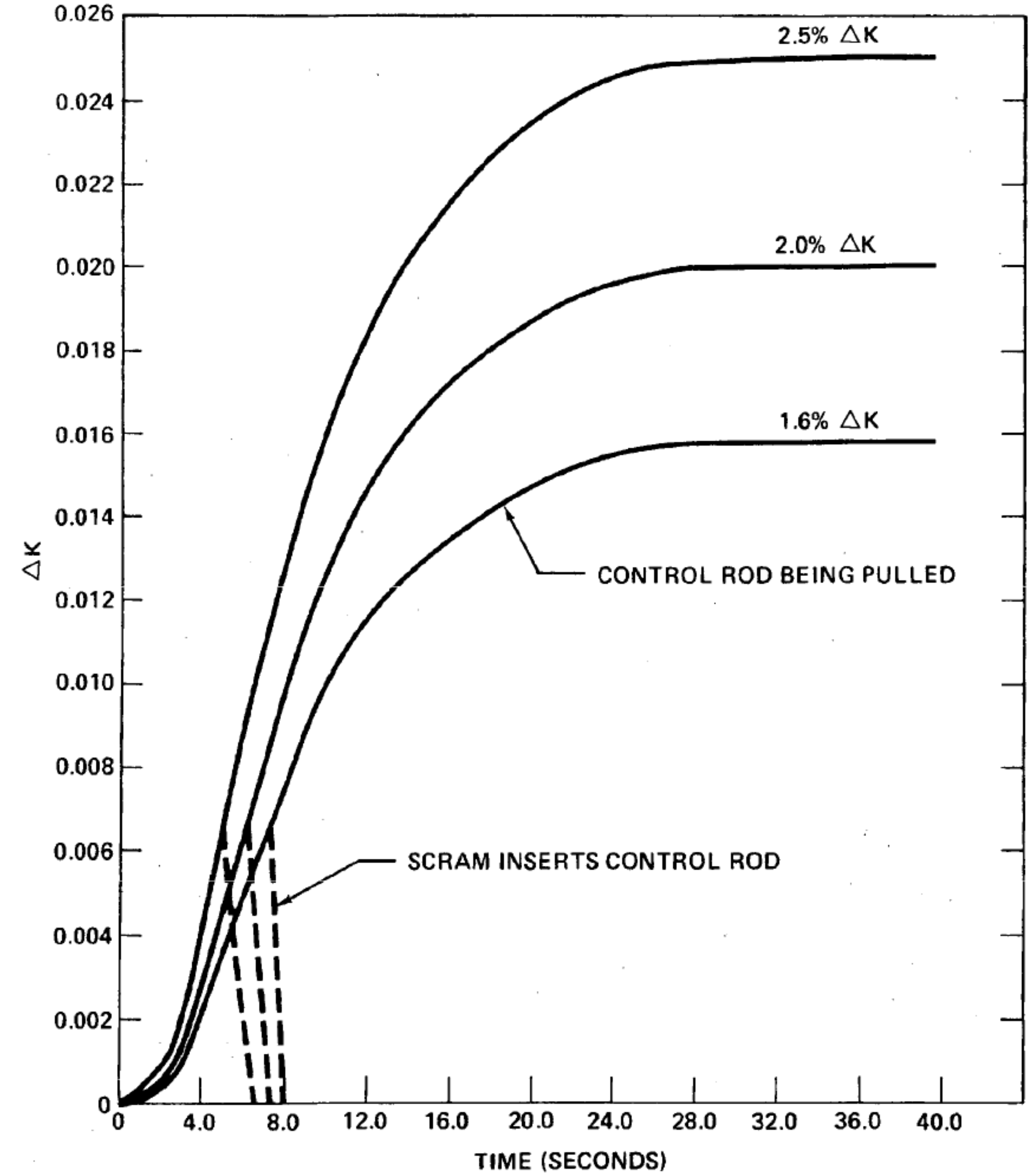
UNIT 1 AND UNIT 2

STARTUP OF IDLE RECIRCULATION LOOP
VOID COEFFICIENT = -12.0

FIGURE 15.2-15



ACAD 150216

REV 19 7/01

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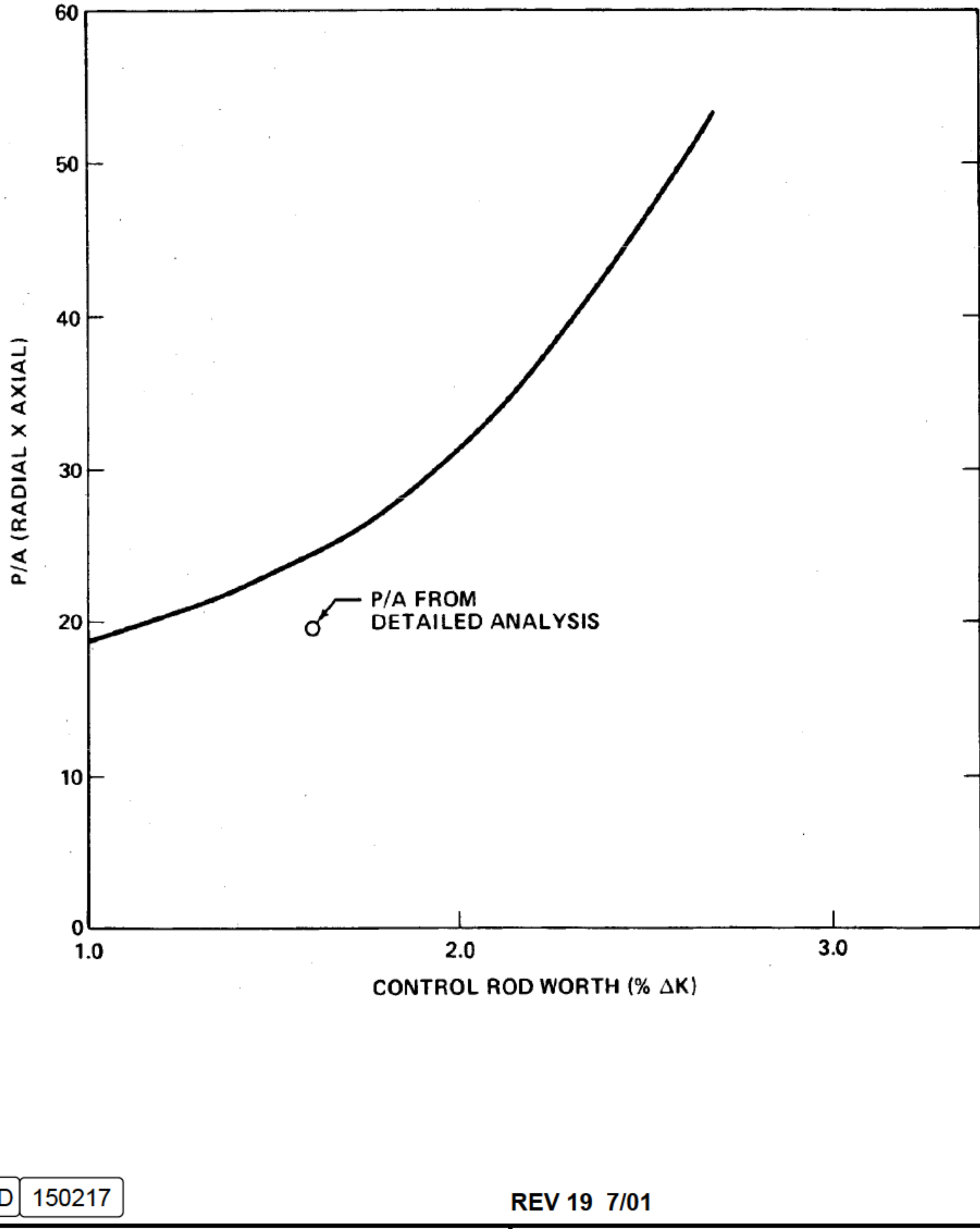
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

POINT KINETICS
CONTROL ROD REACTIVITY INSERTION
(MODIFIED TO INCLUDE SCRAM REACTIVITY)

FIGURE 15.2-16



ACAD 150217

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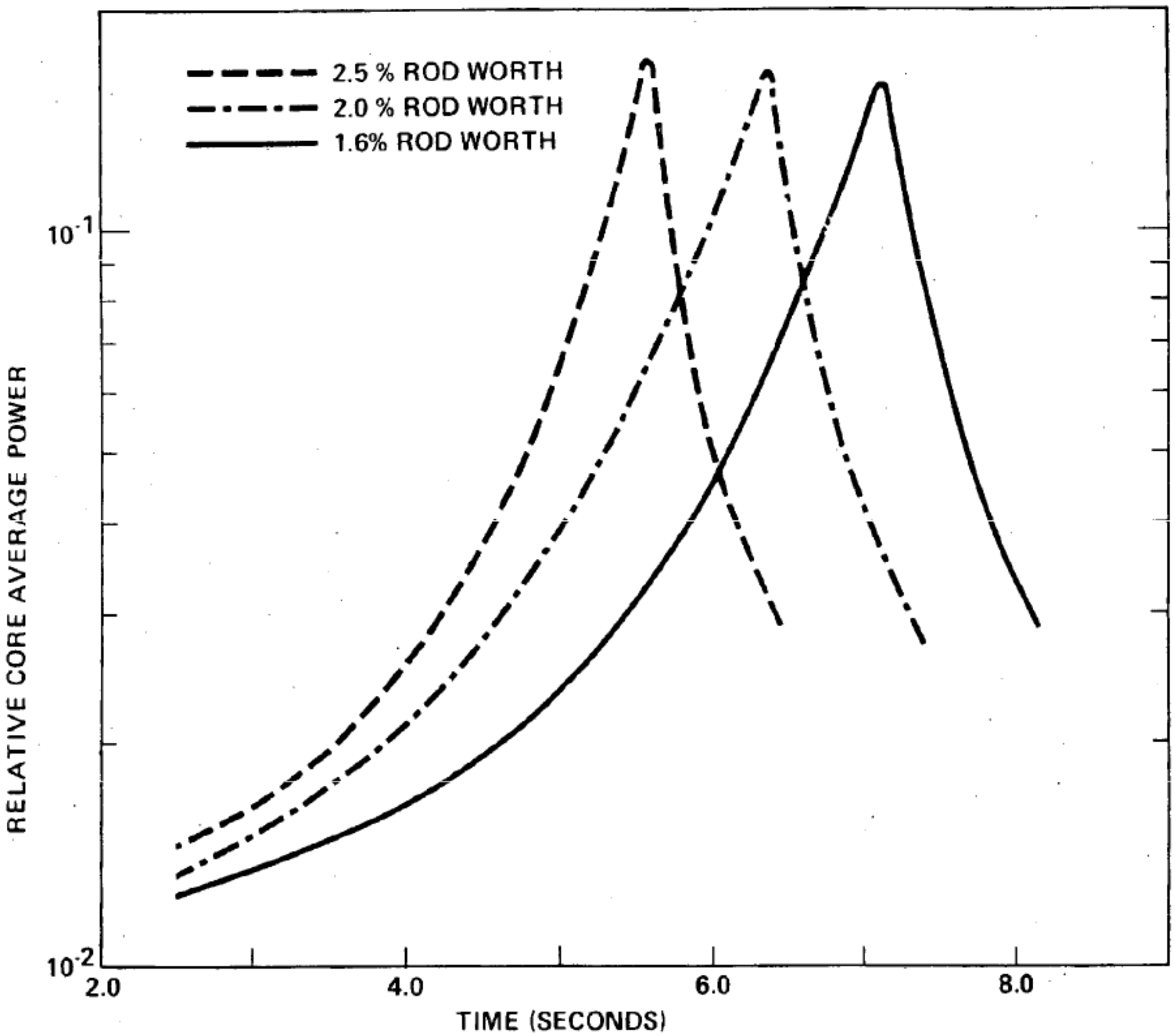
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

GLOBAL PEAKING FACTOR VERSUS ROD WORTH FROM NEDO-10527 AND DETAILED ANALYSIS

FIGURE 15.2-17



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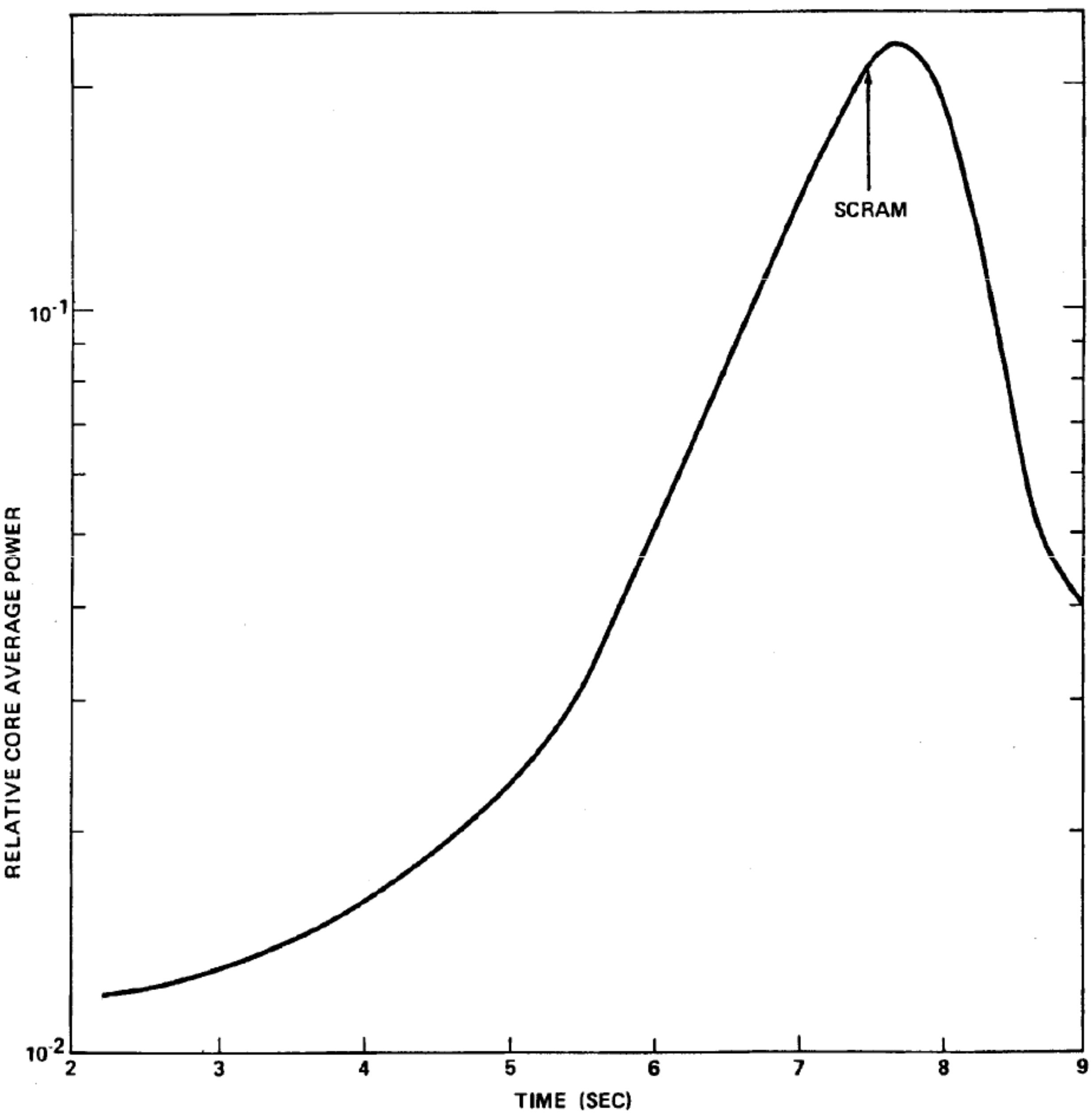
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CONTINUOUS ROD WITHDRAWAL IN STARTUP RANGE, CORE AVERAGE POWER VERSUS TIME (POINT MODEL KINETICS)

FIGURE 15.2-18

(1) 1.6% ΔK ROD
(2) 0.3 FPS WITHDRAWAL VELOCITY
(3) IRM SCRAM FOR WORST BYPASS CODITION
(4) $P_O = 10^{-2}$

(1) 1.6% ΔK ROD
(2) 0.3 FPS WITHDRAWAL VELOCITY
(3) IRM SCRAM FOR WORST BYPASS CONDITION
(4) $P_0 = 10^{-2}$ OF RATED
(5) 1967 PL TECH. SPEC. SCRAM RATE
(6) EXPOSURE = 0.0 GWD/T



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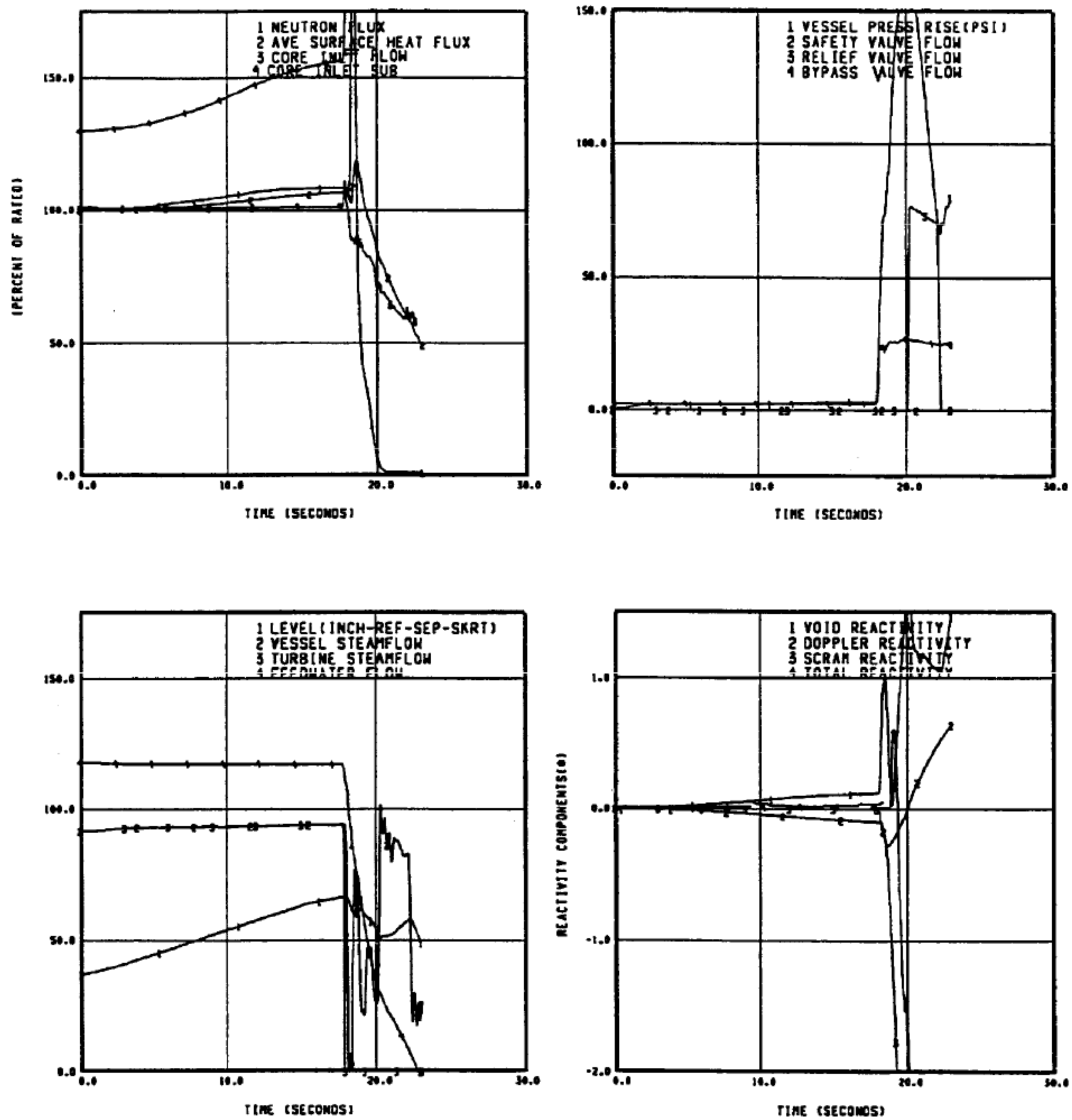
UNIT 1 AND UNIT 2

CONTINUOUS ROD WITHDRAWAL FROM HOT STARTUP, CORE AVERAGE POWER VERSUS TIME

FIGURE 15.2-19



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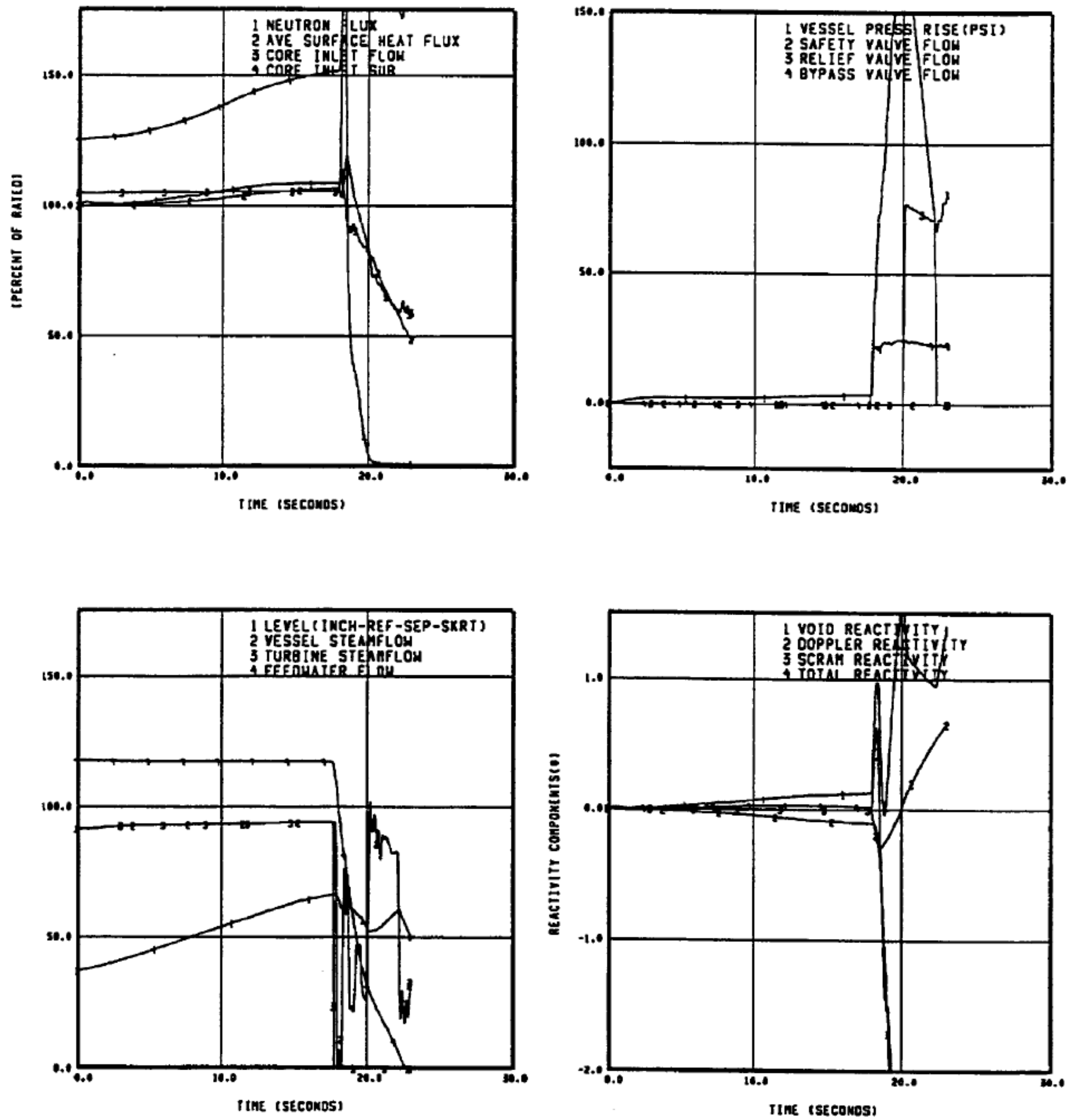
UNIT 1 AND UNIT 2

FEEDWATER CONTROLLER FAILURE
(FWCF) (100P/100F)

FIGURE 15.2-20



ACAD 150221

REV 19 7/01

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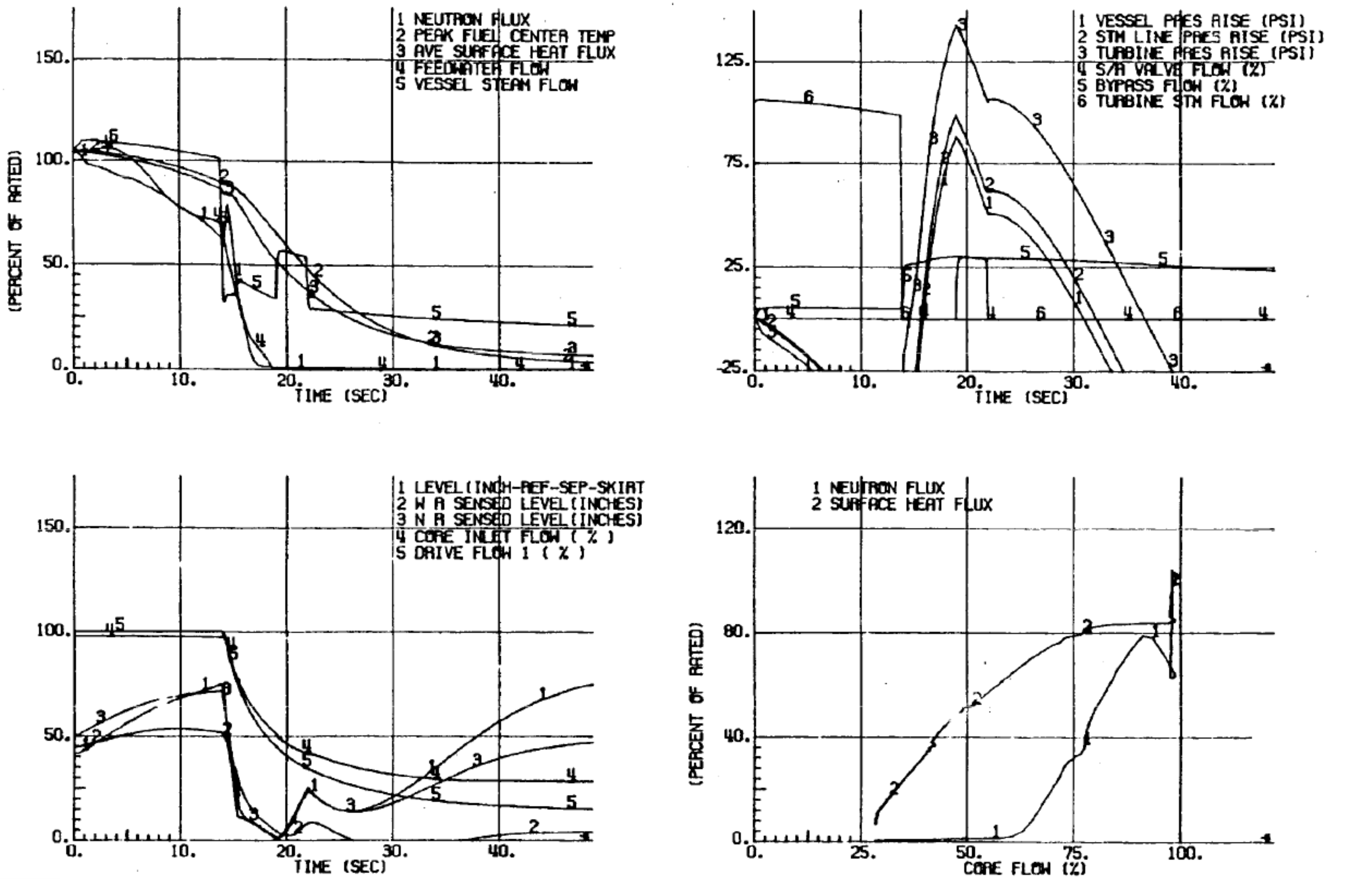
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

FEEDWATER CONTROLLER FAILURE (FWCF) (100P/105F)

FIGURE 15.2-21



ACAD 1502022

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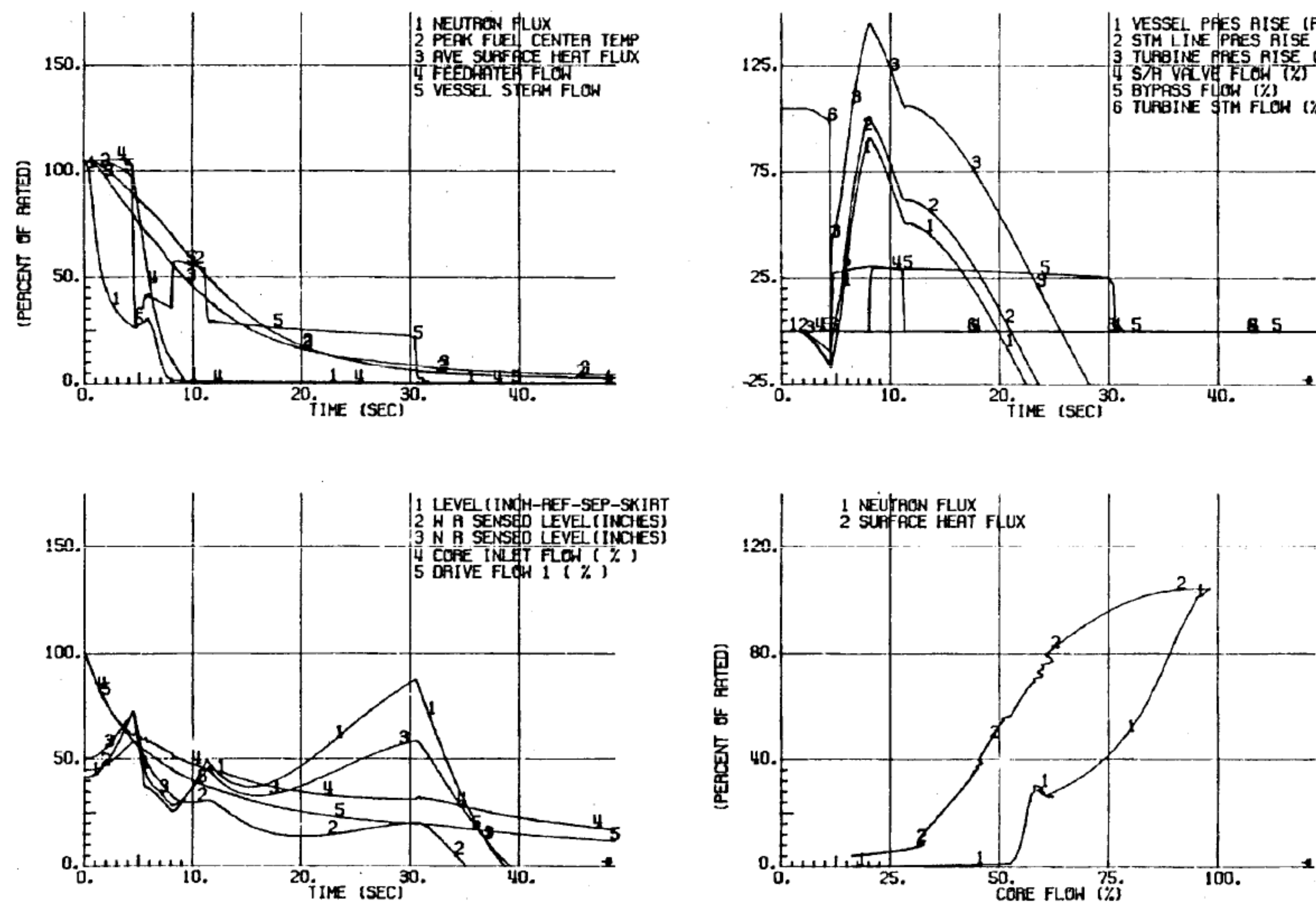
UNIT 1 AND UNIT 2

PRESSURE REGULATOR FAILURE – OPEN
VOID COEFFICIENT = -12.0

FIGURE 15.2-22



ACAD 1502023

REV 19 7/01

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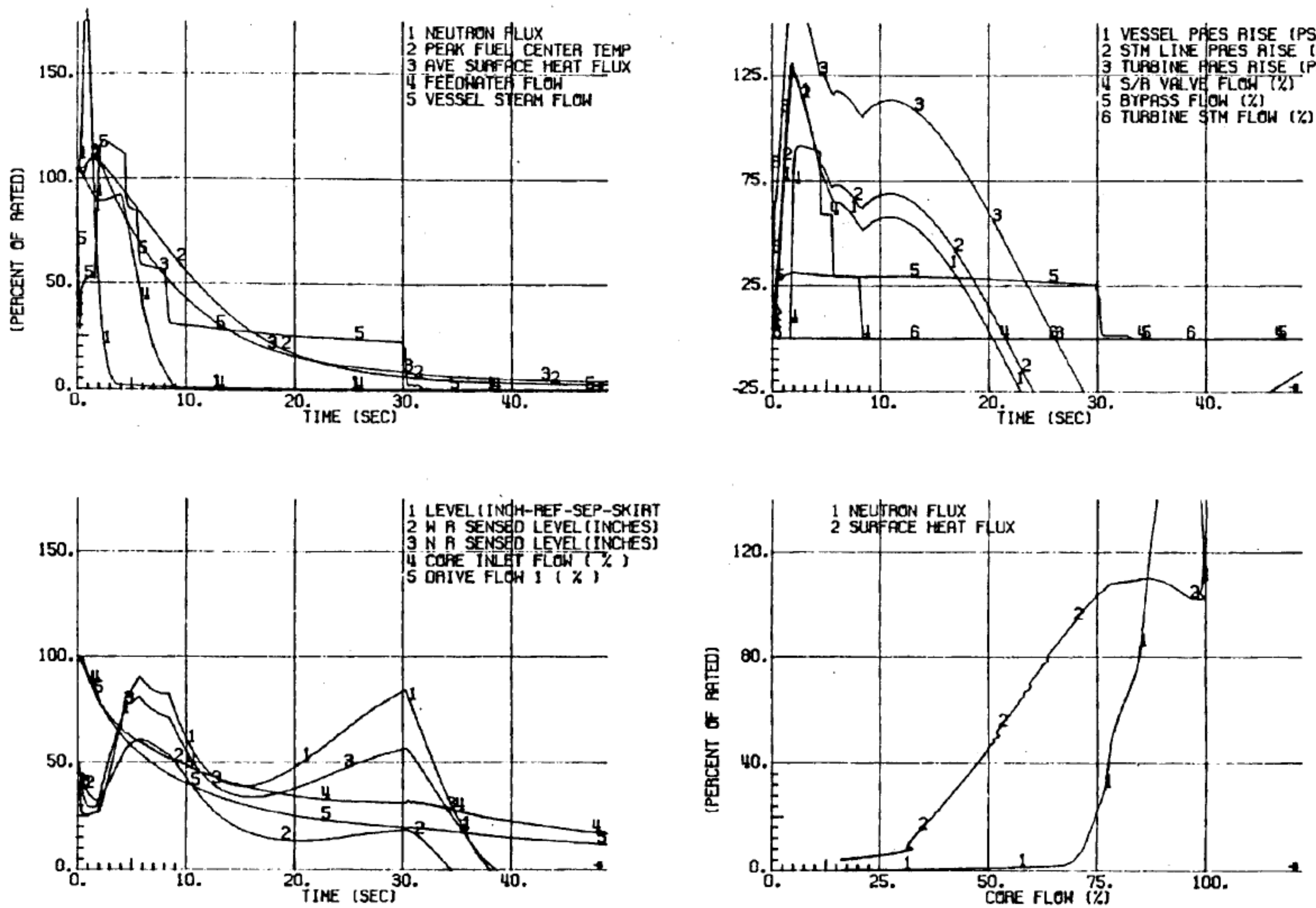
UNIT 1 AND UNIT 2

LOSS OF AUXILIARY POWER (TRANSFORMER)
VOID COEFFICIENT = -12.0

FIGURE 15.2-23



ACAD 1502024

REV 19 7/01

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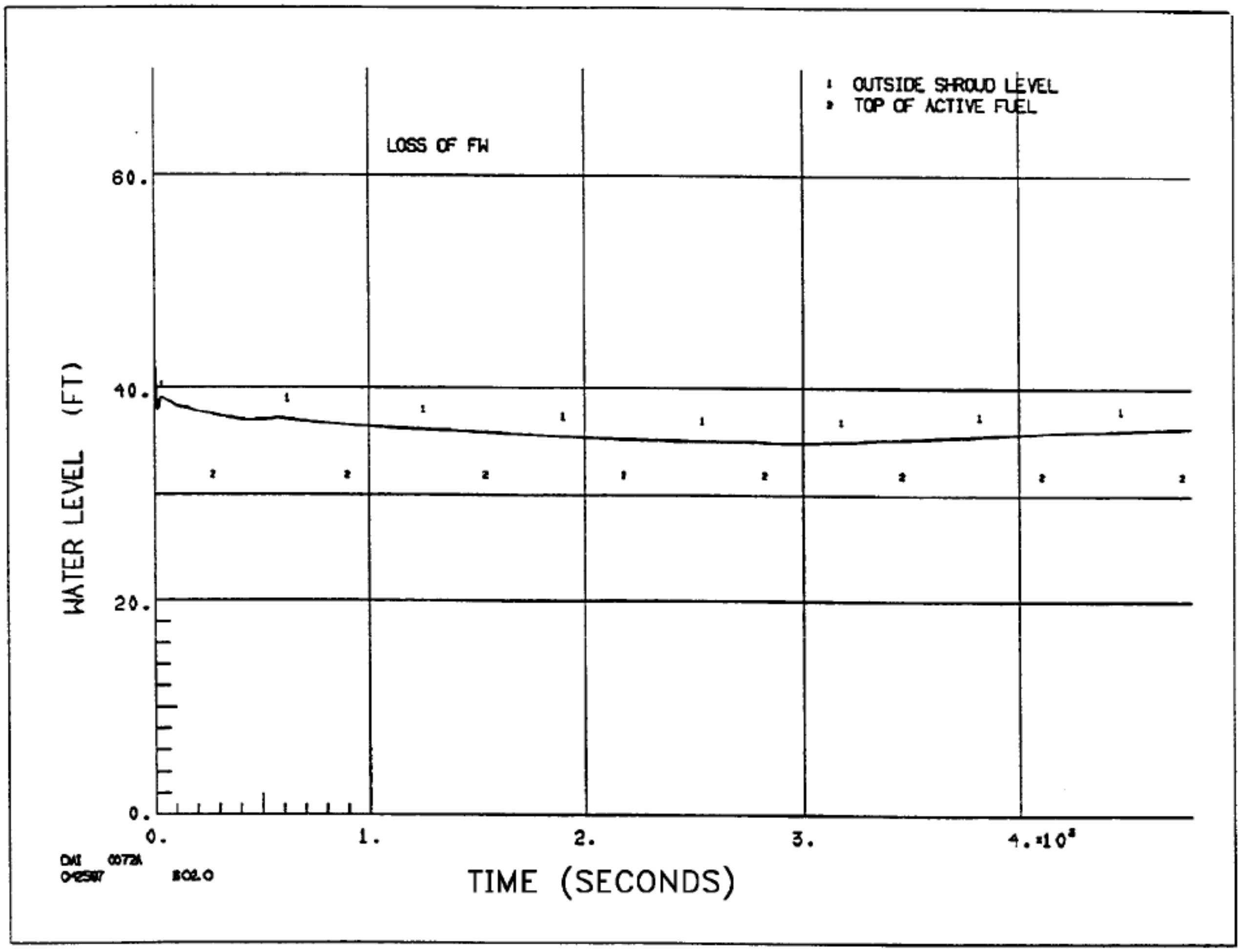
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LOSS OF AUXILIARY POWER (ALL GRID CONNECTIONS)
VOID COEFFICIENT = -12.0

FIGURE 15.2-24



ACAD 150225

REV 19 7/01

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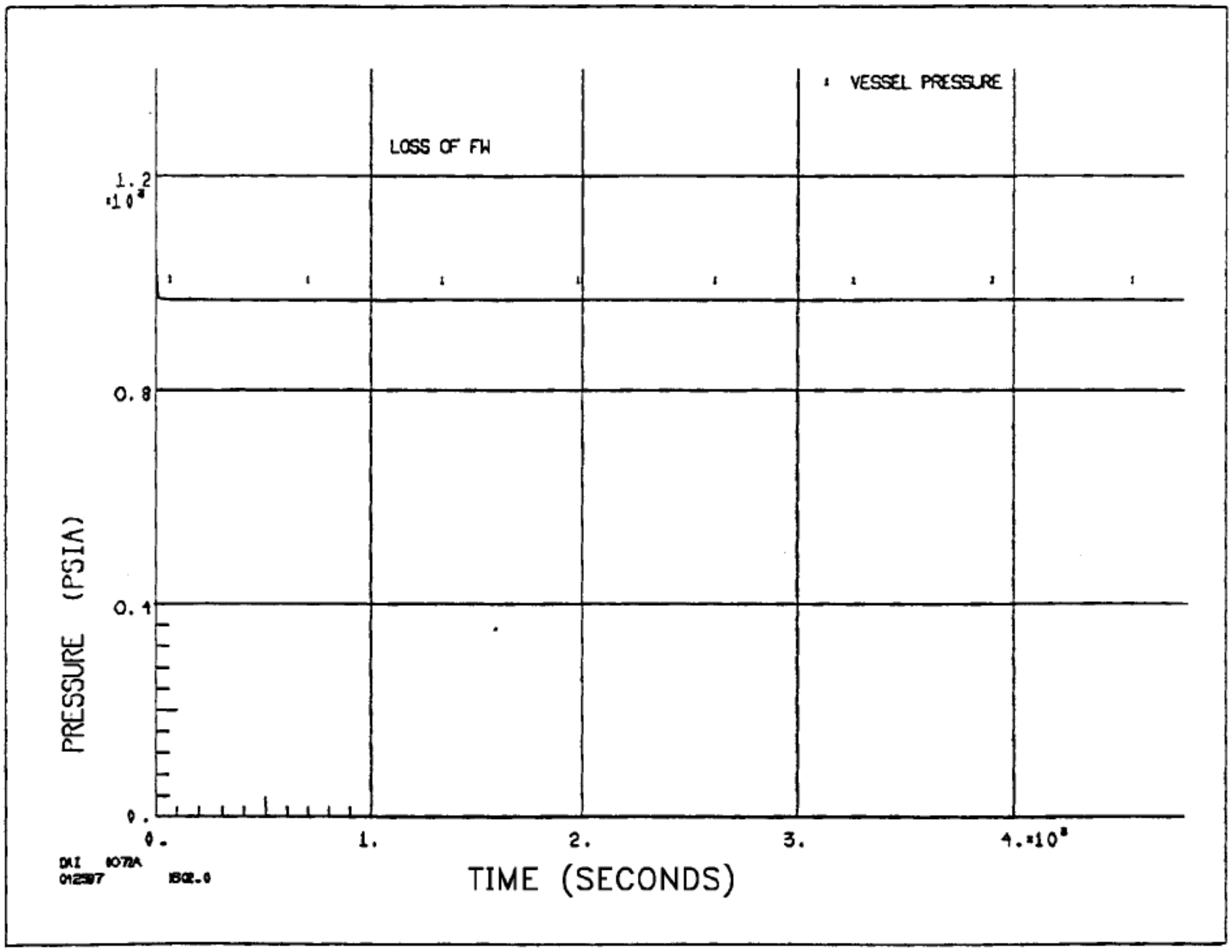
UNIT 1 AND UNIT 2

LOSS OF FEEDWATER FLOW (LOFW)
VESSEL DOWNCOMER WATER LEVEL

FIGURE 15.2-25



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LOSS OF FEEDWATER FLOW (LOFW)
VESSEL PRESSURE

FIGURE 15.2-26

15.3 ANALYSES OF ACCIDENTS

Radiological consequence analyses were performed for HNP-1 and HNP-2 design basis accidents (DBAs) using the alternative source term (AST). The AST is an accident source term that is different from the accident source term used in the original design and licensing of the facility and that has been approved for use under 10 CFR 50.67. The radiological consequence analyses using AST conform to NRC Regulatory Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July 2000, as documented in Appendix A. The design basis accident analyses apply to both HNP-1 and HNP-2.

Offsite and onsite doses are determined. Two offsite doses apply: 1) the dose to an individual located at any point on the boundary of the exclusion area (EAB) for any 2-h period following the onset of the postulated fission product release and 2) the dose to an individual located at any point on the outer boundary of the low population zone (LPZ) who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage). Two onsite doses are calculated for each design basis accident: dose to personnel in the main control room (MCR) and dose to personnel in the technical support center (TSC).

15.3.1 INTRODUCTION

The methods for identifying and evaluating accidents, as described in paragraph 15.1.3.2, have resulted in the identification of seven accidents for the following accident categories:

Accident Category	Accident
Accidents that have the potential to result in a radioactive material release:	
A. From the fuel with the reactor coolant pressure boundary (RCPB), and the primary and secondary containments initially intact.	• Control rod drop accident (CRDA)(single rod). • Fuel assembly loading error. • Recirculation pump seizure.
B. Directly to the primary containment.	• LOCA (rupture of one recirculation loop).
C. Directly to the secondary containment with the primary containment initially intact.	• Main steam line break accident (MSLBA). • Fuel-handling accident.
D. Directly to the secondary containment with the primary containment not intact.	• Fuel-handling accident.
E. Outside the secondary containment.	• MSLBA. • Feedwater line break.

The four accidents that pose the most limiting challenge to plant design and radiological exposure limits are:

- CRDA (category A).
- LOCA (category B).
- Fuel-handling accident (category D).
- MSLBA (category E).

The above four accidents are referred to as the DBAs for Plant Hatch. The fuel assembly loading error, the recirculation pump seizure, and feedwater line break are classified as accidents; however, because they do not result in radiological consequences as severe as the above four accidents, they are not classified as DBAs. Since these three events are not considered limiting DBAs, they were not updated using the AST.

According to the accident selection rules (subsection 15.1.3) applicable to category C accidents, the MSLBA inside the reactor building is the most severe accident involving the failure of the nuclear system process barrier inside the secondary containment. However, the MSLBA inside the reactor building results in a radioactive release to the environs no greater than the release resulting from the MSLBA outside the secondary containment. Similarly, the dropping of a fuel assembly into the fuel pool is the most severe accident involving the failure of fuel located outside the primary containment but inside the secondary containment. However, the dropping of a fuel assembly into the fuel pool results in a smaller radioactive release to the environs than the release resulting from the dropping of a fuel assembly onto the fuel in the reactor pressure vessel (RPV) during refueling. Because the consequences of accidents in category C are less severe than the consequences resulting from similar accidents in the categories A, B, D, and E, the accidents in category C are not described in the safety analysis.

This subsection provides an analysis of the radiological consequences for the seven accidents in categories A, B, D, and E. For the DBAs, both of the following two methods are used to evaluate radiological exposure consequences:

1. Realistic (Conservative Engineering) Evaluation Method

   This evaluation method provides consistent, yet conservative, radiological exposure consequences relative to the predicted results of the DBAs, considering fuel performance and radiological release pathways. The realistic analysis results are for the HNP-2 initial core for the original rated conditions (2436 MWt). Conservative factors are used in adjusting the results for plant and fuel changes that can significantly impact radiological evaluations.

2. Conservative (NRC) Licensing Basis Evaluation Method

   This DBA evaluation method provides for site suitability evaluations consistent with NRC requirements and uses the AST. These analyses contain additional conservatism that is inconsistent with the predicted plant response to the DBA.

15.3.1.1 Analysis Reference

The accident analyses described in ***NEDE-24011-P-A, "GESTAR II - "General Electric Standard Application for Reactor Fuel," [incorporated by reference into the Final Safety Analysis Report (FSAR)]*** are applicable to the current fuel and core designs of both HNP-1 and HNP-2. The generic analysis for banked position withdrawal sequence (BPWS) is applicable for the CRDA. The plant-specific LOCA analysis for the current core is described in subsection 6.3.3. The "Power Uprate Safety Analysis Report for Edwin I. Hatch Nuclear Plant Units 1 and 2"[(2)] also applies to the accident analyses contained in this section.

15.3.2 CRDA (RADIOLOGICAL CONSEQUENCES) (EVENT 31)

The CRDA, which is a DBA, is not reevaluated for each reload since Plant Hatch is a BPWS plant. Analyses for BPWS plants show that the peak fuel enthalpy in a CRDA is much less than the 280-cal/g event acceptance limit, even with the drop of the highest-worth rod. Accordingly, it is unnecessary to evaluate the CRDA for each reload. The NRC has found this approach acceptable.

The evaluation methodology for the CRDA is contained in the applicable version of ***NEDE-24011-P-A (GESTAR II)*** for GNF fuel and Section 5.5.2 of reference 19 for the four Westinghouse SVEA-96 Optima2 lead use assemblies loaded into HNP-1. The paragraph 15.3.2.4.1 realistic evaluation provides the CRDA analysis results for the initial core and the corresponding radiological consequences. The realistic evaluation was for 8x8 fuel for a control rod resulting in a peak fuel enthalpy of 280 cal/g. The realistic evaluation provides the baseline analysis for evaluating the radiological consequences of the CRDA for other GNF fuel designs, consistent with the methodology contained in ***NEDE-24011-P-A***.

The paragraph 15.3.2.4.2 conservative (NRC) licensing basis evaluation implements AST and conforms to RG 1.183 as documented in Appendix A. The inputs reflect the extended power uprate 10 CFR 50, Appendix K power level of 2818 MWt (100.5% of the power level of 2804 MWt) and bounds the results for thermal power optimization. The power level for reactor operating pressure increase to 1060 psia remains unchanged. The increase in reactor operating pressure does not have any impact on the results of the analysis.

15.3.2.1 Identification of Causes

Reactivity can be inserted into a boiling water reactor (BWR) in many ways. However, most insertions result in a relatively slow increase in reactivity and, therefore, pose no threat to the

RCPB. It is possible, however, that the rapid removal of a high-worth control rod can result in a potentially significant excursion. Therefore, the CRDA is the accident chosen to encompass the consequences of a reactivity excursion.

15.3.2.2 Starting Conditions and Assumptions

Before the CRDA is possible, the following sequence of events must occur:

A. The control rod drive (CRD) is completely disconnected from its cruciform control blade at or near the coupling.

B. The control rod sticks at the fully inserted position as the CRD is withdrawn.

C. The control rod drops after a high-worth pattern is established.

This unlikely set of circumstances makes possible the rapid removal of a control rod. Dropping the rod results in a high k_∞ in a small region of the core. For large, loosely coupled cores, a highly peaked power distribution and subsequent shutdown mechanisms result. Significant shifts in the spatial power generation occur during the course of the excursion. Therefore, the method of analysis should account for the power distribution shifts.

The rod worth minimizer (RWM) limits the worth of any control rod that may be dropped by regulating the withdrawal sequence. By restricting rod movement to a sequence that conforms to BPWS criteria from all rods full in to the preset power level, the incremental rod worth is significantly reduced. Any CRDA in this range of operation will not result in a peak fuel enthalpy in excess of 280 cal/g.

15.3.2.3 Accident Description

The CRDA is defined as:

A. Either the RWM is operable or a second operator manually verifies that rod motions conform to the designed and verified sequence.

B. The rod with the highest worth that can be developed within the constraints of the BPWS drops from the fully inserted position to the position of the CRD.

C. The rod drops at the maximum velocity consistent with the design of the control rod velocity limiter.

D. The scram time to the 90% insertion point is 5 s.

The sequence of events and the approximate elapsed times of occurrence are as follows:

	Event Sequence	Elapsed Time
1.	The reactor is operating within the constraints of the BPWS.	-
2.	Either the RWM is operable, or a second operator manually verifies rod motions conform to designed and verified sequence.	-
3.	The control blade becomes decoupled and stuck in its fully inserted position, and the CRD is withdrawn.	-
4.	The maximum-worth control rod pattern for the stuck control rod is formed.	-
5.	The blade becomes unstuck and drops at the maximum velocity determined by experimental data (3.11 ft/s).	-
6.	The reactor goes on a positive period, and initial power increase is terminated by the Doppler effect.	< ~ 1 s
7.	The average power range monitor (APRM) 120% power signal scrams the reactor.	-
8.	The scram terminates the accident.	< ~ 5 s

15.3.2.4 Analysis of Effects and Consequences

15.3.2.4.1 Realistic (Conservative Engineering) Evaluation Methods

The analytical methods and associated assumptions used in evaluating the CRDA are considered to provide a realistic, yet conservative, assessment of the associated consequences.

The realistic evaluation was performed for the original rated conditions (2436 MWt) with an assumed closure of the MSIVs on high main steam line (MSL) radiation. After the realistic analyses were performed, the MSIV closure on high MSL radiation was removed, and rated thermal power (RTP) was increased from 2436 MWt to 2763 MWt. The impact of the removal of the MSIV closure on high MSL radiation and power uprate from 2436 MWt to 2763 MWt on the radiological analyses for the realistic evaluation methods is less than a factor of 13 due to the change in fission products available for release during the event and the in-fission product transport to the main condenser. Even with a factor of 13 increase in radiological exposure for the realistic case, the radiological exposures are considered insignificant when compared to the event acceptance limits.

15.3.2.4.1.1 Methods, Assumptions, and Conditions. The procedure used for analyzing the CRDA is basically a boundary analysis and comparison. Reference 3 provides analyses that demonstrate that, when operating within the constraints of the BPWS, a CRDA will not

exceed the 280-cal/g design criterion. For the radiological evaluations, the number of fuel rods assumed to fail is based upon a peak fuel enthalpy event acceptance limit of 280 cal/g.

15.3.2.4.1.2 Results and Consequences. The results and consequences associated with the CRDA using the realistic evaluation methods are as follows:

Fuel Damage

The fuel damage thresholds are based upon both experimental and theoretical data. This information is presented in chapter 5 of reference 4.

The peak enthalpy resulting from the CRDA is less than the 280-cal/g design limit for all exposures. The number of failed fuel rods, due to the design basis CRDA for the initial core, is < 770 for all plant operating conditions and exposures. The radiological exposure calculations assume failure of 770 fuel rods.

Fission Product Released from the Fuel

The following assumptions are used in calculating the fission product activity Released from the fuel:

A. The reactor has been operating at design power (2535 MWt) for 1000 days until 30 min prior to the accident. When translated into actual plant operation, this assumption means the reactor was shut down from departure of design power. The 30-min time represents a conservative estimate of the shortest period in which the required plant changes can be accomplished and defines the decay time to be applied to the fission product inventory calculations.

B. An average of 1.7% of the noble gas activity and 0.34% of the halogen activity in a failed fuel rod is assumed to be released. These percentages are consistent with actual measurements made during defective fuel experiments.[5]

C. The following fission product activities are contained in the core at the time the accident occurs:

Fission Product	Activity (Ci)
Noble gases	3.0×10^8
Iodine	5.6×10^8

D. The fraction of solid fission product activity available for release from the fuel is negligible.

E. The fission products produced during the nuclear excursion are neglected. The excursion is of such short duration that the fission products generated are negligible in comparison with the fission products already present in the fuel.

Using the above assumptions, the following amounts of fission product activity are released from the failed fuel rods to the reactor coolant:

Fission Product	Activity (Ci)
Noble gases (Xe, Kr)	1.1×10^5
Iodine	4.1×10^4

Condenser Activity

The following assumptions are used in calculating the amount of fission product activity transported from the RPV to the main condenser:

A. The recirculation flowrate is 25% of rated, and the steam flow to the condenser is 5% of rated. The 25% recirculation flow and 5% steam flow are the maximum flowrates compatible with maximum fuel damage. The 5% steam flowrate is greater than the flowrate in effect at the reactor power level assumed in the initial conditions for the accident. This assumption is conservative, because it results in the transport of more fission products through the MSLs than expected. Because of the relatively long fuel-to-coolant heat transfer time constant, steam flow is not significantly affected by the increased core heat generation within the time required for the MSIVs to achieve full closure.

   In the analysis of the initial core, the MSIVs were assumed to receive an automatic closure signal in < 1.0 s after detection of high radiation in the MSLs and to be fully closed at 5.5 s from receipt of the closure signal. The automatic closure signal was assumed to originate from the MSL radiation monitors. The total time required to isolate the MSLs (6.5 s), combined with the assumptions in item A, dictate the total amount of fission product activity transported to the condenser before the MSLs are isolated.

B. Consistent with references 6 and 7, the automatic closure of the MSIVs on high MSL radiation was removed from the plant design. Removal of the MSIV closure on high MSL radiation can increase the fission product transport to the main condenser. For the realistic evaluation case, this increase, when combined with the increase in RTP, is less than a factor of 13. (The factor of 13 was not included in the following analysis results.) An increase in activity transport to the main condenser directly impacts the radiological analysis. Even with a factor of 13 increase in radiological exposures, the radiological exposures for the realistic evaluation case are considered insignificant when compared to the event acceptance limits.

C. All noble gas activity is assumed to be released to the RPV steam dome.

D. The mass ratio of the halogen concentration in steam to that of water is assumed to be 2%.

E. Fission product plateout in the RPV, MSLs, turbine, and condenser is neglected.

Of the fission products released from the fuel and transferred to the condenser, 100% of the noble gases is assumed to be airborne in the condenser. The iodine activity airborne in the condenser is a function of the partition factor, volume of air, and volume of water. The partition factor assumed applicable is 100, while the respective volumes of water and air are 7100 ft^3 and 172,00 ft^3, respectively.

Based upon the above conditions, the activity airborne in the condenser is presented in table 15.3-1.

Activity Released to the Environment

The following assumptions and conditions are used to evaluate the activity released to the environment:

A. The leak rate out of the condenser is 0.5% of the combined condenser and turbine free volume (172,000 ft^3)/day.

B. The activity released from the condenser becomes airborne in the turbine building. The turbine building ventilation rate is 8.8 air changes/day. This is based upon the combined ventilation flowrate of 55,000 ft^3/min and the combined net free volume of ~ 9 x 10^3 ft^3 of the interconnected turbine buildings.

C. No filtration or plateout of iodines occurs prior to release.

Based upon the above assumptions, the fission product released to the environment is presented in table 15.3-2.

Radiological Effects

The radiological effects are based upon the meteorology presented in HNP-2-FSAR subsection 2.3.4 and the methods presented in reference 5. Offsite doses for a release height of 30.0 m are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	2.3E-07	5.4E-06
Low population zone (LPZ) (1250 m)	6.9E-06	2.1E-04

15.3.2.4.1.3 Consideration of Uncertainties. The consideration of uncertainties relative to the core physics calculations were reported previously in reference 8. In addition, reference 4 presents a sensitivity analysis of the CRDA relative to rod drop velocities, scram insertion rates,

and control rod worth for a wide spectrum of operating conditions. This approach demonstrates the comparison between a realistic and a worst-case condition.

15.3.2.4.2 Conservative (NRC) Licensing Basis Evaluation Methods

15.3.2.4.2.1 **Methods, Assumptions, and Conditions.** See tables 15.3-11 and 15.3-12 for the key design inputs for the CRDA radiological dose consequences analysis.

Offsite doses and doses to personnel in the MCR and TSC are calculated according to the guidance in the main body and Appendix C of RG 1.183 as documented in FSAR appendix A. Two models are utilized to conservatively maximize the potential radioactivity for the dose receptor at each location. The first model considers holdup of radioactivity in the turbine building so that MCR doses are calculated conservatively. This model allows for maximum radioactivity to leak into the MCR, since the MCR is located in the turbine building. The second model does not consider holdup in the turbine building such that the maximum amount of radioactivity is available to enter the environment and the TSC. Doses are calculated using the dose conversion factors of Federal Guidance Reports 11 (reference 21) and 12 (reference 22).

The total dose to MCR operators is the sum of the dose received while occupying the MCR for 30 days plus the dose received while traveling to and from the MCR through the turbine building.

The following assumptions are utilized in developing the two dose models:

1. All activity released from the fuel is instantaneously mixed in the reacator coolant within the pressure vessel.

2. No credit is taken for partitioning in the pressure vessel or for removal by the steam separators.

3. The species of iodine released from the turbine/condenser is 97% elemental and 3% organic.

4. Turbine/condenser leak rate is 1% per day for a period of 24 h, at which time the leakage is assumed to terminate.

   For offsite and TSC doses, a second release path is evaluated. The mechanical vacuum pump is assumed to run for 24 h, discharging at 2,200 ft^3/min through the plant stack (elevated relase). After 24 h, the release is assumed to terminate. No credit is taken for filtration.

5. Turbine Building Holdup

   For calculating MCR doses, activity remains in the turbine building, maximizing the activity available to leak into the MCR.

For calculating offsite doses, activity is released from the turbine/condenser without holdup in the turbine building. The release is assumed to be a grouind release directly to the environment.

6. MCR and TSC doses are calculated for 30 days.

7. Unfiltered inleakage to the MCR from the contaminated turbine building is assumed to continue for the 30-day accident duration.

8. EAB doses are calculated for the worst 2-h period.

9. LPZ doses are calculated for a 24-h period, since the radioactive cloud is assumed to move past these locations during this time interval and no further exposure occurs.

15.3.2.4.2.2 <u>Results and Consequences</u>. For the case of doses to MCR personnel, the total dose is the sum of the dose received while in the MCR from contaminated air and the dose received while going to and from the MCR. Doses to MCR personnel, TSC personnel, and doses at the EAB and LPZ are shown below.

MCR Doses from CRDA

	Dose (rem TEDE)
MCR Air	3.61
Ingress/Egress	0.23
Total	3.8
Regulatory Limit	5

TSC Doses from CRDA

	Dose (rem TEDE)	
	TSC	Regulatory Limit
No Forced Flow	0.32	5
Forced Flow	0.81	5

Offsite Doses from CRDA

	Dose (rem TEDE)		
	EAB	LPZ	Regulatory Limit
No Forced Flow	0.047	0.094	6.3
Forced Flow	0.333	0.540	6.3

15.3.3 LOCA (RADIOLOGICAL CONSEQUENCES) (EVENT 32)

This subsection provides the analysis of the radiological consequences for the LOCA, which is a DBA evaluated for each lattice design in the core. The LOCA is also evaluated for each plant modification having the potential to significantly impact emergency core cooling system (ECCS) performance. The evaluation methodology for reloads is contained in the applicable version of ***NEDE-24011-P-A (GESTAR II)***. The paragraph 15.3.3.4.2 conservative (NRC) licensing basis evaluation implements AST and conforms to RG 1.183 as documented in appendix A.

15.3.3.1 Identification of Causes

There are no realistic, identifiable events that can result in a pipe break inside the primary containment of the magnitude assumed for a LOCA. However, since such an accident provides an upper-limit estimate to the resultant effects for this category of pipe breaks, the LOCA is evaluated without the cause being identified.

15.3.3.2 Starting Conditions and Assumptions

The LOCA is analyzed using the following assumptions:

A. The reactor is operating at the condition that maximizes the severity of the aspect of the accident being considered. Aspects considered are containment response, fission product release, and ECCS requirements.

B. A complete loss of normal power (offsite) occurs simultaneously with the pipe break. This additional condition results in the longest delay time for the ECCS to become operational. The situation in which ac power availability is retained was also investigated.

C. The recirculation line is considered to be severed instantaneously, with coolant discharged from both ends of the break. This results in the most rapid coolant loss and depressurization.

15.3.3.3 Accident Description

Accidents that can result in the release of radioactive fission products directly into the primary containment are the result of postulated RCPB pipe breaks inside the drywell.

All pipe break sizes and locations are investigated in the LOCA analysis, including the severance of small pipelines, MSLs, feedwater lines, core spray (CS) pipelines, and the recirculation loop pipelines. The most severe effects and the greatest release of radioactive material to the primary containment result from a complete circumferential break of one of the recirculation loop pipelines. This accident is established as the design basis LOCA for the plant. The sequence of events associated with this accident is as follows:

1. The event begins - sudden circumferential severance of one recirculation line.

2. The reactor scrams.

3. The required systems, including the ECCS, automatically actuate.

4. Operator action begins.

When time and conditions permit, the operator will initiate operation of the residual heat removal (RHR) system in the suppression pool cooling mode.

15.3.3.4 Analysis of Effects and Consequences

15.3.3.4.1 Realistic (Conservative Engineering) Evaluation Methods

The analytical methods and associated assumptions used in evaluating the consequences of the LOCA are considered to provide a realistic, yet conservative, assessment of the consequences.

The realistic evaluation methods are consistent with the DBA analysis results. The realistic evaluation was performed for the original rated conditions (2436 MWt). The impact of power uprate from 2436 MWt to 2763 MWt is not considered significant because the LOCA realistic analysis does not result in any calculated fuel failures. As a result, the radiological exposure is dominated by the activity in the coolant released during the accident. The design basis coolant activity was not changed for power uprate. Therefore, the fission products released during the accident are not expected to change. Since the analyses for extended power uprate were based on the 10 CFR 50, Appendix K power level of 2818 MWt, the results of the analyses for extended power uprate are bounding for thermal power optimization. Also, the ROPI to 1060 psia does not have any impact on the results of the existing analyses.

15.3.3.4.1.1 Methods, Assumptions, and Conditions. The following methods, assumptions, and conditions are used in the realistic analysis of the effects and consequences associated with the LOCA:

Thermal-Hydraulic Analysis

The methods and models used to analyze the consequences of the LOCA have been refined during the plant lifetime. The HNP-1 and HNP-2 current analysis methodology is described in subsection 6.3.3. The assumptions for the LOCA radiological consequences analysis described in this subsection are conservative with respect to the analyzed ECCS performance using the SAFER/GESTR-LOCA analysis methodology documented in subsection 6.3.3.

Containment Response Analysis

The HNP-1 and HNP-2 containment response to LOCA analysis is described in subsection 6.2.3.

Note that the peak drywell pressure of 57.5 psig used to evaluate the radiological consequences of a recirculation line break is conservative compared to the calculated peak containment pressure.

15.3.3.4.1.2 Results and Consequences. The results and consequences associated with the LOCA using the realistic evaluation methods are as follows:

Fuel Damage

The peak clad temperature for the nominal or expected case is insufficient to cause perforation of the fuel cladding. Therefore, for the realistic evaluation methodology analysis, no cladding perforations are considered for the LOCA.

Fission Product Released from the Fuel

Since the LOCA does not result in any fuel damage, the only activity released to the drywell is the activity contained in the reactor coolant, plus any additional activity that may be released as a consequence of a reactor scram and vessel depressurization on preexisting defective (leaking) fuel rods.

While various activation and corrosion products are contained in the reactor coolant, the products of primary importance are the iodine isotopes I-131 to I-135, in particular I-131. The coolant concentrations consistent with an offgas release rate of 0.1 Ci/s for the following isotopes at 30 min are:

Isotope	Concentration (µCi/g)
I-131	0.018
I-132	0.16
I-133	0.12
I-134	0.31
I-135	0.17

Consideration of the volume of liquid contained in the RCPB results in the following activities being released to the drywell:

Isotope	Concentration (Ci)
I-131	3.5
I-132	31.0
I-133	24.0
I-134	61.0
I-135	33.0

Considering that ~ 40% of the released liquid flashes to steam, it is conservatively assumed 40% of the released iodine activity is initially airborne. However, as a result of plateout and condensation effects, only 50% of the activity initially airborne remains available for release to the environment.

As a consequence of reactor scram and depressurization, additional iodine activity is released from those rods that are assumed to have experienced cladding perforation during normal operation. Typical plant shutdowns have resulted in the additional release of I-131 in the range of 0.14 Ci to 1085 Ci, the average being 85 Ci.(10)

Since this additional activity is released over a long period of time (in comparison to the time required to depressurize the reactor as a consequence of a LOCA), it is necessary to correlate the release rate of activity with the injection of the emergency core coolant. During the first 15 min of ECCS injection, ~ 10% of the coolant flashes to steam. However, after 15 min, all of the liquid leaving the vessel is subcooled. For the purpose of this analysis, 50% of the peak I-131 activity (i.e., 50% of 1085 Ci) is assumed to be released within the first 15 min. Of this activity, 5% becomes airborne as a consequence of flashing liquid and iodine plateout. Also, proportionate quantities of I-132 to I-135 are assumed to be released. The ECCS coolant is assumed to scrub the remaining activity, and an equilibrium condition between the liquid and the drywell air volume is formed.

In addition to the iodine activity released from any preexisting failed rods as a consequence of a scram and depressurization, additional noble gas activity is assumed to be released. A detailed experimental program for the measurement of noble gas release has not been conducted. However, limited experimental data were collected and used to provide an estimate of this source of activity.

Primary Containment Activity

Based upon the conditions specified in the previous subsections, the iodine and noble gas activity initially airborne in the primary containment is presented in table 15.3-3. The time dependence of the airborne activity is a function of the leakage rate and the isotopic half-lives.

Reactor Building Activity

The primary containment leak rate into the reactor building where the activity uniformly mixes in the net free air volume is assumed to be 1.2%/day. The release rate from the reactor building to the environment is 4.52 air changes/day based upon a standby gas treatment system (SGTS) flow rate of 4000 ft^3/min and a reactor building net air volume of 1,275,000 ft^3. The reactor building activity as a function of time is presented in table 15.3-4.

The LOCA analysis, using realistic evaluation methods, assumed the availability of the previously installed MSIV leakage control system (LCS), which has been removed. The impact of the removal of the MSIV LCS is considered to be within the conservatism included in the realistic evaluation methodology. Therefore, the original analysis results are considered applicable.

Also, it is assumed containment venting is not used until the activity levels in the containment are low enough to result in only a negligible contribution to the dose consequences.

Activity Released to the Environment

The fission product activity released to the environment is based upon a ventilation rate of 4.52 air changes/day and an SGTS filter efficiency of 95% for removal of all forms of iodine. The noble gas and iodine released to the environment are presented in table 15.3-5.

Radiological Effects

The radiological exposures resulting from the activity released to the environment were determined for the meteorological conditions presented in HNP-2-FSAR subsection 2.3.4. The offsite radiological exposures for a release height of 120 m are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	3.2E-09	9.5E-08
LPZ (1250 m)	1.8E-07	5.3E-06

15.3.3.4.1.3 Consideration of Uncertainties. The LOCA was conservatively analyzed. Due to this conservative approach, no uncertainties were evaluated.

15.3.3.4.2 Conservative (NRC) Licensing Basis Evaluation Methods

15.3.3.4.2.1 Methods, Assumptions, and Conditions. The assumptions for the LOCA radiological consequences analysis described in this subsection are conservative with respect to the analyzed ECCS performance using the SAFER/GESTR-LOCA analysis methodology documented in subsection 6.3.3. Reference 18 provides the evaluation of the impact on ECCS

performance of the installation of adjustable speed drives (ASDs) to provide power to the recirculation pump motors. The ASDs replace the recirculation pump motor-generator (M-G) sets. Refer to subsection 6.3.3 for more details. However, the assumptions used for the LOCA radiological consequences analysis described in this subsection remain conservative.

Design Inputs and Assumptions

See table 15.3-11 for inputs for the LOCA consequence analysis. Other inputs and assumptions are listed below.

Release from Core

The core activity is assumed to be released into the containment in two phases: gap activity release (starts at 2 min and lasts 30 min) and early in-vessel releases (starts at the conclusion of the gap activity release phase and lasts for 90 min). Release rates are shown in table 15.3-3.

Chemical Form

By adding boron to the suppression pool as a credited operator action, the pH of the torus water is maintained at a value of 7 or higher. The mass of sodium pentaborate available for injection is 1975 lbm. This is based on full mixing of the boron within the pool water within the first 24 h of the accident. With this pH, the chemical form of iodine released to the containment is assumed to be 95% cesium iodide (CsI), 4.85% elemental, and 0.15% organic. With the exception of elemental and organic iodine and noble gases, all isotopes are assumed to be in particulate form.

Containment Volume and Mixing

It is assumed that the activity released from the fuel is instantaneously and homogeneously mixed throughout the free air volume of the drywell. It is also assumed that the drywell activity starts flowing into the torus air volume at the end of the early in-vessel release phase.

Containment Activity Removal

Credit is taken for the reduction of airborne activity due to natural deposition and sprays. The removal rates for elemental iodine and particulates within the drywell due to natural deposition (sedimentation) and sprays (with the sprays assumed to start at 15 min as a credited operator action) are based on credit for one residual heat removal (RHR) pump. The manual initiation of drywell sprays is a required operator action that is initiated based upon reaching a drywell dose rate of 200,000 rem/h. Analysis of the drywell immersion dose rate following a design basis LOCA shows that this dose rate is reached within 15 min of accident initiation.

Containment Leakage

The primary containment (drywell and torus air) is assumed to leak at the peak pressure Technical Specification leak rate of 1.2% weight per day for the first 24 h of the accident, reducing by 40% from 24 to 72 h, and by 50% thereafter. Assuming the activity within the containment to be uniformly distributed, the volumetric leak rate is the same as the mass leak

rate. Starting with the gap activity release phase, all the leakage form the primary containment (excluding MSIV leakage) enters the secondary containment except for 2% that is assumed to bypass the secondary containment. The bypass leakage is assumed to be directly to the environment at ground level in evaluating offsite and TSC doses and into the condenser in evaluating MCR doses.

Secondary Containment

It is assumed that the reactor building (secondary containment) draws down to negative pressure within 2 min of the start of the accident. After secondary containment drawdown, reactor building activity is released to the environment through the plant stack at the maximum Technical Specification rate of 4,000 ft^3/min per unit. It is possible for two standby gas treatment system (SGTS) fans to be in operation at the same time, taking suction from one reactor building and the refueling floor. In order to maximize the release to the environment, it is conservatively assumed that the entire flow of 8,000 ft^3/min from two fans is from a single reactor building. The release is processed by the SGTS filters with an efficiency of 95% for all isotopes except noble gases. The activity within the reactor building is assumed to be uniformly distributed within 50% of the volume. The total volume of the reactor building is obtained by adding the individual compartment volumes, conservatively neglecting the common refueling floor to minimize the dilution.

ESF Leakage

In modeling ESF leakage, it is conservatively assumed that all the isotopes that are released to the containment except noble gases are instantaneously transported to the torus water at the onset of the gap activity release phase and mixed uniformly. Although there is no Technical Specification limit on ESF leakage, a conservatively high leakage rate of 10 gpm (1.34 ft^3/min) is assumed to start at the initiation of sprays, lasting for the duration of the accident. With the torus water temperature below 212°F, it is assumed that 10% of the iodine in the ESF leakage becomes airborne inside the reactor building while all other elements remain in the water. Of this iodine that becomes airborne, 97% is assumed to be elemental and 3% organic.

MSIV Leakage

It is assumed that the maximum leakage from all four main steam lines (MSLs) is 100 scfh, with no limit on the leakage per line. It is postulated that the inboard MSIV on one of the four steam lines fails to close, thus creating an unrestricted flow path to the outboard MSIV. It is assumed that the full leakage of 100 scfh is through this failed line with no MSIV leakage through any of the three intact lines. This is conservative as there is less activity removal due to deposition within a line with a failed MSIV than with intact MSIVs. The leakage rate is reduced by 40% at 24 h and by 50% at 72 h.

The source of the MSIV leakage is the airborne activity in the drywell. The MSIV leakage could take place in either the reactor building or the turbine building. Since a leakage in the reactor building would have the benefits of filtration and dispersion due to an elevated release through the stack after reactor building drawdown, it is assumed that all MSIV leakage occurs in the turbine building. Since the MCR is located within the turbine building, it is conservative to

calculate MCR doses assuming holdup in the turbine building as this provides a direct inleakage pathway from the turbine building to the MCR.

Main Steam Line Activity Removal

It is assumed that the particulate in the portion of the MSL 1) between the inboard and the outboard MSIVs for three lines and 2) between the outboard MSIV and the main stop valve for all lines is subject to removal by deposition. Since it may be assumed that all MSIV leakage occurs in a single line (the limiting case being the line with only one MSIV closed), the limiting case involves deposition only between the outboard MSIV and the main stop valve.

Because sedimentation is minimized by the assumption of high temperature, the steam line is conservatively assumed to remain at its maximum temperature (551°F) during the full duration of the analysis. Only horizontal runs of steam line are credited for sedimentation, and only the projected area of the steam line is used as sedimentation area.

It is also assumed that particulate mass and activity and elemental iodine activity are reduced by a factor of two due to particle impaction at the inboard or outboard MSIV, whichever is the first closed valve encountered (as noted, three lines are assumed to have both valves closed). Once the particulate enters the steam line beyond the first closed MSIV, however, no further elemental iodine removal is considered in the steam lines or main condenser. This is very conservative, because even if re-evolution from the particulate surfaces were to occur in the hot, dry conditions of the steam line, some deposition and retention would be expected on the metal surfaces in those volumes, as well.

Condenser and Turbines

Most of the MSIV leakage reaches the condenser and the low pressure turbine while a small fraction bypasses the condenser/low pressure turbine and is released through the high pressure turbine. The bypass fraction is calculated to be 0.005. It is assumed that particulates in the condenser are removed by sedimentation. Although the entering flow is 100 scfh less the bypass fraction, the condenser leak rate is assumed to be 100 scfh during the first 24 h, reducing by 40% at 24 h and by 50% at 72 h.

Particulate removal by sedimentation in the condenser is credited for both MSIV leakage and secondary containment bypass leakage.

Turbine Building

In calculating MCR doses, it is assumed that releases from the condenser and the turbines are into the turbine building, where they are available for direct inleakage into the MCR. It is assumed that the released activity is uniformly mixed within the volume of turbine building elevation 164-ft floor, which is open to both units.

Atmospheric Dispersion

All releases from the turbine building are assumed to be at ground level through the reactor building vent. The MCR values are applied to the TSC since the MCR values are bounding.

The 0-2 h EAB x/Q values are applied for the first 8 h to ensure that the EAB dose is calculated over a 2-h period that yields the maximum dose. MCR/TSC and offsite x/Q values are listed in tables 2.3-25 and 2.3-11, respectively.

Accident Duration

MCR, TSC, and LPZ doses are calculated assuming a release duration and exposure time of 30 days. The EAB dose is calculated over a 2-h period which yields the maximum dose.

Credited Operator Actions

The following actions taken by operators are credited in the analysis:

1. MSIV Alternative Leakage Treatment (ALT) Pathway - Lining up the MSIV ALT pathway by opening a valve to establish the pathway and closing boundary valves to direct MSIV leakage to the condenser for holdup and retention of activity in MSL piping and the condenser. The ALT pathway is discussed in section 10.24 (HNP-1) and subsection 9.5.10 (HNP-2).

2. Addition of pH Buffering Agent - Addition of sodium pentaborate to the suppression pool via operation of the standby liquid control (SLC) system to maintain suppression pool pH at 7 or higher for the duration of the accident, thereby precluding the re-evolution of iodine from the suppression pool.

3. Drywell Sprays - Initiation of drywell sprays based on radiation levels in the drywell to help remove airborne particulate in the drywell and reduce drywell temperature and pressure.

4. Turbine Building Fans - Initiation of one turbine building exhaust fan within 9 h of the start of the accident to remove activity from the turbine building. The use of turbine building fans to purge the area around the MCR is discussed in paragraph 15.3.1.3.

Methods

Offsite doses and doses to personnel in the MCR and TSC are calculated by modeling the transport of activity released from the core to the environment, while accounting for activity decay, dilution, holdup, and removal mechanisms. The analysis is performed in accordance with the guidance in the main body and Appendix A of RG 1.183 as documented in FSAR appendix A.

Activity transport models are developed for both the reactor building and the turbine building. There are three primary activity release pathways:

- Containment leakage - This includes leakage of airborne activity in the drywell and the torus air space. Initially any leakage is assumed to be directly to the environment at ground level. After reactor building drawdown to negative pressure, the leakage is assumed to be processed by the SGTS and released through the plant stack except for a small fraction that bypasses the SGTS.

- MSIV leakage - This leakage reaches the condenser via the steam lines. The condenser is then assumed to leak to the turbine building and eventually to the MCR and the environment.

- ESF leakage - This occurs in the reactor building after the drywell sprays have been initiated and water from the torus is recirculated back into the drywell.

To determine offsite doses, two models are developed. The first calculates doses from elevated releases from the reactor building via the SGTS. The second model is for ground level releases, which include reactor building activity bypassing the SGTS and MSIV leakage activity leaking from the condenser. The ground level releases are through the reactor building vent. Total offsite doses are a combination of doses from elevated releases and ground level releases.

In evaluating TSC doses, reactor building activity is released to the environment through the stack via the SGTS and the reactor building vent (for activity that bypasses the SGTS). MSIV leakage activity leaking from the condenser is released to the environment via the reactor building vent. Activity released to the environment reaches the TSC via outside air intake and unfiltered inleakage.

For MCR doses, reactor building activity is released to the environment through the stack via the SGTS. Reactor building bypass leakage is assumed to go into the condenser, where it leaks into the turbine building. MSIV leakage activity also collects in the turbine building via leakage from the condenser. Beginning at 9 h after the accident, turbine building air is exhausted at a rate of 15,000 ft^3/min. Activity released to the environment reached the MCR via an outside air intake at a rate of 250 ft^3/min. Turbine building activity also leaks directly into the MCR (unfiltered inleakage).

<u>Standby Liquid Control System Injection</u>

The dose analysis takes credit for the SLC system for the injection of a sufficient quantity of sodium pentaborate solution into the reactor vessel, and ultimately mixing in the suppression pool, to meet the requirement for maintaining pH at or above 7 and, thus, precluding the revolution of iodine from the suppression pool.

<u>Reduction in Containment and MSIV Leakage Rates</u>

Leakage may be reduced after the first 24 h, if supported by plant configuration and analyses, to a value not less than 50% of the Technical Specification leakage rate.

Some BWRs, including HNP, have containment atmosphere dilution (CAD) systems to control the hydrogen and oxygen levels inside the containment. The CAD system works by injecting nitrogen into the containment, which has the potential to increase pressure. The severe accident guidelines and emergency operating procedures for HNP call for the drywell and the torus to be vented while nitrogen is being injected such that the pressure does not increase. Therefore, without a pressure increase associated with the CAD system, the HNP containment

leakage rate would be expected to decrease in the same manner as a BWR without a CAD system or a PWR.

The containment and MSIV leakage rates are both based on the peak drywell pressure and temperature. The volumetric flowrates are calculated at these peak conditions as well as the later time steps, when the pressure and temperature have decreased. By comparing the flowrates at different time steps, the reduction in leakage rate can be calculated at 24 h or any other time step. Since the flowrate through the MSLs is driven by the pressure difference between the drywell upstream and the condenser downstream, it is reasonable to assume that the MSIV leakage rate will be reduced by the same magnitude as containment leakage.

It is assumed that the containment and MSIV leakage paths are sufficiently restrictive that the flows are unchoked and may be treated as incompressible. The containment leakage is into the reactor building while the MSIV leakage is into the turbine building via the condenser. For both leakages, the downstream pressure in the reactor building and turbine building is assumed to be atmospheric at 14.7 psia.

The use of sprays reduces the drywell pressure from a peak value of 65.5 psia in Unit 1 and a peak value of 62.0 psia in Unit 2.

The MSIV leakage rate is based on a peak pressure of 61.6 psia and a peak temperature of 340°F. The saturation steam pressure at 340°F exceeds 61.6 psia, meaning the steam is superheated. In applying the flow equation at 0 h, increasing the density causes the flowrate to decrease, which results in higher flow ratios at 24 and 72 h. Hence, to minimize the initial flowrate, the maximum possible air density is added to the superheated steam density. The air pressure used to calculate the air density is taken as the difference between 61.6 psia and the design drywell pressure of 62 psig or 76.7 psia.

The containment and MSIV leakage rates may be reduced to 60% of the initial values at 24 h and to 50% at 72 h.

<u>MCR Dose due to Airborne Activity in the Turbine Building</u>

In calculating doses within regions, the LocaDose code only considers activities within the region. Although the MCR has 2-ft-thick concrete walls, the radiation shine dose from the airborne activity within the turbine building could be significant because the MCR is located in the turbine building. The Shield-SG computer program is used to calculate the MCR dose due to turbine building activity.

A dose of 2.38E-03 rem TEDE is calculated for a conservatively low value of turbine building exhaust rate and, therefore, the highest turbine building activity. This external shine dose from turbine building activity is conservatively applied to the MCR dose evaluation.

<u>MCR Dose due to Other External Sources</u>

In addition to the dose contributions from the MCR air, ingress and egress through the turbine building, and turbine building air, the shine from other external sources is evaluated. Other external shine sources considered are secondary containment, the cloud outside the turbine

building, MSLs, condenser, and MCR filters. Analysis has determined that the shine dose from these sources is estimated to be 0.03 rem TEDE.

MCR Ingress/Egress Dose

Since the MCR is located in the turbine building, the MCR operator would walk through the turbine building when entering or leaving the MCR. A conservative maximum walking distance through the turbine building is estimated from turbine building dimensions. Using this distance, the transit time through the turbine building is estimated based on a walking speed of 3 mph. An additional time of 45 s for using stairwells and opening doors is added, and the total transit time is assumed to be 2 min.

The ingress/egress dose is calculated by determining the average turbine building dose rate during a time interval and multiplying by the exposure duration. Assuming two one-way trips per day, the doses from all trips over the 30-day duration of the accident are added to obtain the total ingress/egress dose.

15.3.3.4.2.2 Results and Consequences. Doses to MCR personnel, TSC personnel, and doses at the EAB and LPZ are shown below.

MCR Doses from LOCA

	Dose (rem TEDE)
MCR Air	4.32
Turbine Building Air	0.0024
Ingress/Egress through Turbine Building	0.57
Other External Shine Sources	0.03
Total	4.9
Regulatory Limit	5

TSC Doses from LOCA

	Dose (rem TEDE)
TSC Air	3.9
Regulatory Limit	5

Offsite Doses from LOCA

	Dose (rem TEDE)		
Release Pathway	EAB	LPZ	Regulatory Limit
Ground	0.307	0.644	
Elevated	0.033	0.110	
Total	0.34	0.75	25

15.3.3.5 Evaluation of Exclusion Area and LPZ Distance

Current radiological exposure analyses presented in this subsection demonstrate that the LOCA presents the most limiting challenge to the guideline dose values of 10 CFR 50.67. Since all the DBAs evaluated in this subsection give doses below the guideline dose values of 10 CFR 50.67, the exclusion area (1250 m) and LPZ (1250 m) distances are acceptable.

15.3.4 MSLBA (RADIOLOGICAL CONSEQUENCES) (EVENT 33)

This subsection provides the analysis of the radiological consequences for the MSLBA, which is a DBA evaluated for each new fuel design. The evaluation methodology for reloads is contained in the applicable version of ***NEDE-24011-P-A (GESTAR II)***. The paragraph 15.3.4.4.1 realistic evaluation provides the baseline radiological evaluation used in the assessment of each new fuel design, consistent with the evaluation process described in ***NEDE-24011-P-A***. The paragraph 15.3.4.4.2 conservative (NRC) licensing basis evaluation implements AST and conforms to RG 1.183 as documented in appendix A.

15.3.4.1 Identification of Causes

No identifiable events will result in an MSLBA. However, since such an accident provides an upper limit estimate to the resultant effects for this category of pipe breaks, the MSLBA is assumed to occur without the cause being identified.

Additional information on the capability of HNP-2 to accommodate a high-energy line break is provided in HNP-2-FSAR supplement 15A.

15.3.4.2 Starting Conditions and Assumptions

Prior to an MSLBA, the reactor is at a normal plant operating condition. For the realistic analysis, the initial condition is assumed to be the most probable operating condition, rated power. For the conservative (NRC) licensing basis evaluation, the plant is assumed to be in hot standby to maximize the inventory lost through the break prior to isolation.

15.3.4.3 Accident Description

Accidents that result in the release of radioactive material outside the secondary containment are the result of postulated breaches in piping outside the RCPB. A break spectrum analysis for the complete range of reactor conditions indicates that the DBA for breaks outside the secondary containment is a complete severance of one of the MSLs.

The sequence of events and the approximate elapsed times required to reach the events are as follows:

Event Sequence		Elapsed Time
1.	The event begins; the postulated instantaneous MSLB occurs.	0
2.	The high-flow signal initiates MSIV closure.	~ 0.5 s
3.	The reactor scrams.	< ~ 1.0 s
4.	The MSIVs are fully closed.	~ 5.5 s

15.3.4.4 Analysis of Effects and Consequences

15.3.4.4.1 Realistic (Conservative Engineering) Evaluation Methods

The MSLBA evaluation is considered a realistic, yet conservative, assessment of the consequences of a failure of one of the MSLs external to the secondary containment for the most probable plant operating condition (power operation).

The realistic evaluation was performed for the original rated conditions. The impact of power uprate from 2436 MWt to 2804 MWt on the radiological analyses for the realistic evaluation methods is not considered significant because the MSLBA will not cause any calculated fuel failures. As a result, the radiological exposure is dominated by the activity of the coolant released during the event. The design basis coolant activity was not changed for power uprate. Therefore, the fission products released during the event are not expected to change significantly. A small increase in coolant released during the event may occur due to the increase in operating pressure. However, this change is well within the conservatism included in the analysis process. The realistic evaluation methods are consistent with the DBA analysis results.

15.3.4.4.1.1 Methods, Assumptions, and Conditions. The following methods, assumptions, and conditions are used in the realistic analysis of the effects and consequences associated with the MSLBA:

Primary System Mass Loss

A postulated guillotine break of one of the four MSLs outside the secondary containment results in mass loss from both ends of the break. The flow from the break is realistically determined by considering not only the minimum flow areas, but also the system pipe and valve loss characteristics. The following assumptions and conditions are used in determining the mass loss from the primary system from the inception of the break to full closure of the MSIVs:

A. The reactor is operating at 105% of nuclear boiler rated steam flow conditions.

B. An instantaneous circumferential MSLB occurs.

C. System pressure is initially 965 psia, and the effects of RPV pressure decrease during the transient are considered.

D. The isolation valves start to close at 0.5 s on a high-flow signal and are fully closed at 5.5 s.

E. The homogeneous critical flow model is applicable.(13) The effects of pipe friction and valve losses are included.

F. Standby ac power is available.

This analysis differs from the NRC-guided analysis (paragraph 15.3.4.4.2) in that the transient effects associated with the most probable operating condition, equipment availability, pipe and valve losses, level rise, and liquid quality are all included in this analysis.

Radioactive Material Released

The following assumptions are used in the calculation of the quantity and types of radioactive material released from the RCPB:

A. The amount of steam discharged is calculated in the analysis of the nuclear system transient.

B. The concentrations of biologically significant radionuclides contained in the reactor coolant are as follows:

Isotope	Concentration (µCi/g)
I-131	0.018
I-132	0.16
I-133	0.12
I-134	0.31
I-135	0.17

Measurements made on current BWRs show the activity ratio between the main turbine condensate and reactor coolant is on the order of 0.5 to 2%. For the purpose of this evaluation, the conservative assumption that the activity/lb of steam = 2% of the activity/lb of reactor water is made.

C. The noble gas discharge rate, after a 30-min holdup, is assumed to be 0.1 Ci/s, which is an unusually high normal discharge rate. This assumption permits direct computation of the amount of noble gas activity leaving the RPV at the time of the

accident. The result is that 0.475 Ci of noble gas activity (with half-life > 1 min) leaves the RPV during each second the isolation valve is open.

D. Because of the short half-life of N-16, the radiological effects from this isotope are of no major concern and are not considered in the analysis.

15.3.4.4.1.2 **Results and Consequences.** The total integrated mass leaving the break is 52,300 lb, of which 36,100 lb are liquid and 16,200 lb are steam. Of the 16,200 lb of steam, 2700 lb resulted from flashing of the liquid. The evaluation for ROPI to 1060 psia is based on a total integrated mass of < 52,800 lb leaving the break with no significant impact on the results of the existing evaluation.

Fuel Damage

No cladding perforations result as a consequence of the MSLBA.

Radioactive Material Released from the Break

The activity released from the hypothetical MSLBA is a function of coolant activity, valve closure time, and mass of coolant release. A portion of the released coolant exists as steam prior to the blowdown, and as such does not contain the same concentration per unit of mass as does the steam generated as a consequence of the blowdown. Therefore, it is necessary to subtract the initial steam mass from the total mass released and assign to it only 2% of the iodine activity contained by an equivalent mass of primary coolant.

Radioactivity Released to the Environment

One hundred percent of the noble gases released from the break is released to the environment. Of the total iodine contained in the steam-coolant mixture released from the break, all iodine contained in the initial steam discharged from the vessel (which has only 2% iodine carryover) via the break and all iodine contained in the coolant that flashes to steam is airborne in the turbine building. Although only 2700 lb of the coolant actually flashes to steam that is included in the mass of the steam release, it is conservatively assumed an additional amount of liquid, which is 40% of 36,100 lb of the discharged liquid, also flashes to steam. A 50% plateout of iodine occurs in the turbine building before release to the environment. The isotopic activity released from the break to the environment is presented in table 15.3-7.

Radiological Effects

The resulting offsite radiological exposures for a ground-level release are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	1.2E-07	6.4E-05
LPZ (1250 m)	1.2E-07	6.4E-05

The meteorological conditions are presented in HNP-2-FSAR subsection 2.3.4.

15.3.4.4.1.3 Consideration of Uncertainties. The MSLBA was conservatively analyzed. As a result of this conservative approach, no uncertainties were evaluated.

15.3.4.4.2 Conservative (NRC) Licensing Basis Evaluation Methods

15.3.4.4.2.1 Methods, Assumptions, and Conditions. See tables 15.3-11 and 15.3-14 for the inputs for the MSLBA consequence analysis.

For the design basis MSLBA, the temperature and pressure transients resulting from this event are not severe enough to cause fuel damage. Therefore, radiological consequences are due to the activity in the reactor coolant at the time of the break. Offsite doses and doses to personnel in the MCR and TSC are calculated according to the guidance in the main body and Appendix D of RG 1.183. For doses to MCR personnel, the release is assumed to be contained within the turbine building. For offsite and TSC personnel doses, the release is assumed to leave the turbine building with no holdup. Offsite doses are calculated for two different primary coolant iodine concentrations. The first assumes a pre-accident spike and the second assumes an equilibrium iodine concentration value.

Dose equivalent (DE) I-131, as defined in the Technical Specifications, is that amount of I-131 (microcuries/gram) that alone would produce the same committed effective dose equivalent (CEDE) as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. Doses are calculated using the dose conversion factors from references 21 and 22.

The following assumptions are utilized in developing the dose model:

1. Before the accident, the reactor is assumed to be in the hot standby mode to maximize the inventory lost through the break prior to isolation. The mass released includes the steam originally in the line as well as from a portion of the saturated liquid which spills from the break and flashes to steam.

2. The steam that is released expands due to the lower atmospheric pressure and becomes superheated. The initial mass of the saturated liquid that is released equals the mass of saturated liquid and vapor at atmospheric pressure (14.7 psia) and 212°F . Enthalpy is constant through the phase change as part of the released saturated liquid flashes to vapor.

3. Releases are ground level releases through the reactor building vent.

4. In calculating the MCR dose, it is assumed that the activity released from the break is uniformy mixed with the turbine building free volume.

5. The release from the break is assumed to be an instantaneous puff.

6. MCR, TSC, and offsite doses are calculated assuming an exposure time of 30 days.

7. The EAB dose is calculated over the maximum 2-h period. For a puff release, this is the first 2 h.

15.3.4.4.2.2 **Results and Consequences.** Doses to MCR personnel, TSC personnel, and doses at the EAB and LPZ are shown below.

MCR Doses from MSLBA

	Dose (rem TEDE)
MCR Air	3.70
Ingress/Egress	0.22
Total	3.9
Regulatory Limit	5

TSC Doses from MSLBA

	Dose (rem TEDE)
TSC Air	0.43
Regulatory Limit	5

Offsite Doses from MSLBA

	DE-I131 Activity (µCi/g)	Dose (rem TEDE) EAB	Dose (rem TEDE) LPZ	Regulatory Limit
Pre-accident Spike	2.0	0.15	0.15	25
Equilibrium Iodine Activity	0.2	0.015	0.015	2.5

15.3.5 FUEL-HANDLING ACCIDENT (EVENT 34)

This subsection provides the analysis of the radiological consequences for the fuel-handling accident, which is a DBA evaluated for each new fuel design. The analysis provided in this subsection is for the initial core and fuel (8x8) design. The evaluation methodology for reloads is contained in the applicable version of ***NEDE-24011-P-A (GESTAR II)*** for GNF fuel and Section 5.5.4 of reference 19 for the four Westinghouse SVEA-96 Optima2 lead use assemblies loaded into HNP-1. The analysis for GNF fuel documented in this subsection provides the baseline radiological consequences evaluation used in the assessment of each new fuel design, consistent with the evaluation process described in ***NEDE-24011-P-A***. Changes in fuel and fuel grapple designs are evaluated relative to the baseline analysis to demonstrate their acceptability. The paragraph 15.3.5.4.2 conservative (NRC) licensing basis evaluation implements AST and conforms to RG 1.183 as documented in appendix A.

With the introduction of 10 x 10 fuel and 24-month cycle operation, an evaluation of the fuel handling accident was performed according to the NEDE-24011-P-A process. This evaluation (reference 15) concluded that the current FSAR analysis (based upon 8 x 8 fuel) remains bounding. The evaluation also examined a potential increase in radial peaking above the currently assumed value of 1.5 and the potential use of the newer GE NF-500 refueling mast instead of the standard triangular mast. The evaluation concluded that the current FSAR analysis would be applicable to cores with radial peaking factors up to 1.7 **OR** applicable for the use of the NF-500 mast, but not both.

15.3.5.1 Identification of Causes

The fuel-handling accident is assumed to occur as a consequence of a failure of the fuel assembly lifting mechanism resulting in the dropping of a raised fuel assembly onto the top of the core.

15.3.5.2 Starting Conditions and Assumptions

Accidents that result in the release of radioactive material directly to the refueling floor can occur when the drywell head is off. An evaluation of the various conditions that can exist when the drywell head is off reveals that the greatest potential for the release of radioactive material occurs when the drywell head, RPV head, dryers, and separators are removed. In this case, radioactive material released as a result of fuel damage is available for transport directly to the refueling floor.

15.3.5.3 Accident Description

The most severe fuel-handling accident from the radiological viewpoint is the dropping of a fuel assembly onto the top of the core. The sequence of events and the approximate times to reach the events are as follows:

	Event Sequence	Elapsed Time
1.	The fuel assembly is being handled by refueling equipment. The assembly drops onto the top of the core.	0
2.	Some fuel rods in both the dropped assembly and reactor core are damaged, resulting in the release of gaseous fission products to the reactor coolant and eventually to the refueling floor atmosphere.	< ~ 2 min
3.	The refueling floor ventilation exhaust radiation monitoring system alarms to alert plant personnel, isolates the ventilation system, and starts SGTS operation.	< ~ 5 min
4.	Operator actions begin.	

The instrumentation provided to mitigate the consequences of a fuel-handling accident forms part of the refueling floor ventilation exhaust radiation monitoring system.

The location of the HNP-2 detectors with respect to the point of postulated release of activity and with respect to the isolation dampers is shown on drawing nos. H-26237, H-26238, and H-26240. For HNP-2, the transit time from the detectors to the isolation dampers is a minimum of 3.2 s. The closure time of the isolation dampers, based upon actual tests conducted by the vendor, is a maximum of 2.2 s. The response time of the detector and its associated electronics is 0.1 s. Based upon these times, closure of the isolation dampers following a fuel-handling accident in either the reactor well or the spent-fuel pool occurs before the refueling floor environment is released to the exhaust plenum. For HNP-1, the isolation damper closure time and the detector response time are also less than the transit time from the detectors to the isolation dampers.

Following a fuel-handling accident, the refueling floor monitoring system automatically isolates the ventilation system, closes the primary containment purge isolation valves, and initiates the SGTS, which is discussed in HNP-2-FSAR subsection 6.2.4 and HNP-1-FSAR subsection 5.3.2. The paragraph 15.3.5.4.2 conservative (NRC) licensing basis evaluation provides dose results for both SGTS in operation and SGTS not in operation.

15.3.5.4 <u>Analysis of Effects and Consequences</u>

15.3.5.4.1 Realistic (Conservative Engineering) Evaluation Methods

The analytical methods and associated assumptions used to evaluate the consequences of the fuel-handling accident are considered to provide a realistic, yet conservative, assessment of the consequences.

The realistic evaluation methods are consistent with the DBA analysis results. The realistic evaluation was performed for the original rated conditions (2436 MWt). The impact of power uprate from 2436 MWt to 2804 MWt on the radiological analyses for the realistic evaluation methods is < 11.2% due to the change in fission products available [a function of assumed power level (2537 MWt versus 2818 MWt) and operating history prior to the accident] for release during the event. This change is well within the conservatism included in the analysis process.

15.3.5.4.1.1 __Methods, Assumptions, and Conditions__. The assumptions used in the analysis of the fuel-handling accident are listed below:

A. The fuel assembly is dropped from the maximum height allowed by the fuel-handling equipment.

B. The entire amount of potential energy referenced to the top of the core is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly in the water above the racks and requires the complete detachment of the assembly from the fuel hoisting equipment. This is only possible if the fuel assembly handle, the fuel grapple, or the grapple cable breaks.

C. None of the energy associated with the dropped fuel assembly is absorbed by the fuel material (uranium dioxide).

15.3.5.4.1.2 __Results and Consequences__. The results and consequences associated with the fuel-handling accident using the realistic evaluation methods are as follows:

__Fuel Damage__

Dropping a fuel assembly onto the reactor core from the maximum height allowed by the refueling equipment, < 30 ft, results in an impact velocity of 40 ft/s. The kinetic energy acquired by the falling fuel assembly is < 17,000 ft-lb and is dissipated in one or more impacts.

The first impact is expected to dissipate most of the energy and cause the largest number of cladding failures. To estimate the expected number of failed fuel rods in each impact, an energy approach is used. The fuel assembly is expected to impact the reactor core at a small angle from the vertical, possibly inducing a bending mode of failure on the fuel rods of the dropped assembly. Each fuel rod is assumed to resist the imposed bending load by a couple consisting of two equal, opposite concentrated forces. Therefore, fuel rods are expected to absorb little energy prior to failure as a result of bending.

Actual bending tests with concentrated point loads show that each fuel rod absorbs ~ 1 ft-lb prior to cladding failure. Each rod that fails as a result of gross compression distortion is expected to absorb ~ 250 ft-lb before cladding failure (based upon 1% uniform plastic deformation of the rods). The energy of the dropped assembly is conservatively assumed to be absorbed by only the cladding and other core structures. Because a fuel assembly consists of

72% fuel, 11% cladding, and 17% other structural material by weight, the assumption that no energy is absorbed by the fuel material results in considerable conservatism in the mass energy calculations that follow.

The energy absorption by the initial and the successive impacts is estimated by considering a plastic impact. Conservatism of momentum for a plastic impact shows that the fractional kinetic energy absorbed during impact is:

$$1 - \frac{M_1}{M_1 - M_2}$$

where: M_1 = the impacting mass.

M_2 = the struck mass.

Based upon the fuel geometry in the reactor core, four fuel assemblies are struck by the impacting assembly. The fractional energy loss on the first impact is ~ 80%.

The second impact is expected to be less direct. The broad side of the dropped assembly impacts approximately 24 more fuel assemblies, so that after the second impact, only 136 ft-lb (~ 1% of the original kinetic energy) are available for a third impact. Because a single fuel rod is capable of absorbing 250 ft-lb in compression before cladding failure, it is unlikely that any fuel rod will fail on a third impact.

If the dropped fuel assembly strikes only one or two fuel assemblies on the first impact, the energy absorption by the core support structure results in approximately the same energy dissipation on the first impact as in the case where four fuel assemblies are struck. The energy relationships on the second and third impacts remain approximately the same as in the original case. Thus, the calculated energy dissipation is as follows:

- First impact 80%
- Second impact 19%
- Third impact 1% (no cladding failures)

The first impact dissipates 0.80 x 17,000 or 13,600 ft-lb of energy. It is assumed 50% of this energy is absorbed by the dropped fuel assembly and the remaining 50% is absorbed by the struck fuel assemblies in the core. Because the fuel rods of the dropped fuel assembly are susceptible to the bending mode of failure and because 1 ft-lb of energy is sufficient to cause cladding failure as a result of bending, all 63 rods of the dropped fuel assembly are more susceptible to bending failure than the other 55 fuel rods. It is assumed the tie rods fail on the first impact. Thus, 4 x 8 = 32 tie rods (total in four assemblies) are assumed to fail. [Note: This discussion is applicable to the original 8x8 fuel design. For other fuel configurations and fuel grapple designs, the methods of ***NEDE-24011-P-A (GESTAR II)*** apply.]

Because the remaining fuel rods of the struck assemblies are held rigidly in place in the core, they are susceptible only to the compression mode of failure. To cause cladding failure of one fuel rod as a result of compression, 250 ft-lb of energy are required. To cause failure of all the remaining rods of the 4 struck assemblies, 250 x 56 x 4 or 56,000 ft-lb of energy would have to be absorbed in cladding alone. Thus, it is clear that not all the remaining fuel rods of the struck assemblies can fail on the first impact. The number of fuel rod failures caused by compression is computed as follows:

$$\frac{(0.5 \times 13{,}600)\left(\frac{11}{11+17}\right)}{250} = 11$$

Thus, during the first impact, fuel rod failures are as follows:

Dropped assembly	63	rods (bending)
Struck assemblies	32	tie rods (bending)
Struck assemblies	11	rods (compression)
	106	total failed rods

Because of the less severe nature of the second impact and the distorted shape of the dropped fuel assembly, it is assumed in only 2 of the 24 struck assemblies are the tie rods subjected to bending failure. Thus, 2 x 8 = 16 tie rods are assumed to fail. The number of fuel rod failures caused by compression on the second impact is computed as follows:

$$\frac{\left(\frac{0.19}{2}\right)\left(\frac{11}{11+17}\right)17{,}000}{250} = 3$$

Thus, during the second impact, the fuel rod failures are as follows:

Struck assemblies	16	tie rods (bending)
Struck assemblies	3	rods (compression)
	19	total failed rods

The total number of failed rods resulting from the accident is as follows:

First impact	106	rods
Second impact	19	rods
Third impact	0	rods
	125	total failed rods

Fission Product Released from the Fuel

Fission product release estimates for the fuel-handling accident are based upon the following assumptions:

A. The reactor fuel has an average irradiation time of 1095 days at 2537 MWt up to 24 h prior to the accident. This assumption results in an equilibrium fission product concentration at the time the reactor is shut down.

   Longer operating histories do not increase the concentration of the fission products of concern. The 24-h decay time allows time to shut down the reactor, depressurize the nuclear system, remove the RPV head, and remove the RPV upper internals. It is not expected that these operations can be accomplished in < 24 h.

B. An average of 1.7% of the noble gas activity and 0.34% of the halogen activity is in the fuel rod plenums and available for release. This assumption is based upon fission product release data from defective fuel experiments.[(5)]

C. Because of the negligible particulate activity available for release in the fuel plenums, none of the solid fission products are assumed to be released from the fuel.

D. It is assumed 125 fuel rods failed. This was the conclusion of the analysis of mechanical damage to the fuel. This is considered conservative. As a result, it is expected that < 125 rods would be damaged.

E. The fission product inventories in the fuel rods at the time of the accident are as follows:

Fission Product	Activity (Ci)
Noble gases	1.8×10^8
Halogens	2.3×10^8

   These activity contents are the result of an analysis of the fission product inventories in the core, assuming equilibrium conditions at design power followed by a 24-h decay period.

Using the above assumptions, the following amounts of fission product activity are released from the fuel to the water in the RPV as a result of the dropped fuel assembly:

Fission Product	Activity (Ci)
Noble gases	1.7×10^4
I-131	3.3×10^3

Fission Product	Activity (Ci)
I-132	4.5×10^{2}
I-133	8.9×10^{2}
I-134	9.6×10^{-6}
I-135	1.1×10^{2}

Fission Product Released to the Refueling Area Atmosphere

The following assumptions and initial conditions are used in calculating the fission products released to the refueling area:

A. The fission product activity released to the refueling area atmosphere will be in proportion to the nonremoval efficiency of the water. Because water has a negligible effect on a removal of the noble gases, the gases are assumed to be instantaneously released from the pool to the refueling area atmosphere.

B. The iodine activity airborne is in proportion to the partition factor and the ratio of the volume of air (V_a) to the volume of water (V_w) for which the respective values are applicable. It is assumed a partition factor of 100 and a V_a/V_w of 3 are applicable for this event. It should be noted that the volume assumed for V_a is not equal to the total volume of air in the refueling atmosphere, but is a conservative estimate of the volume of air that may form an equilibrium condition with the activity in the fuel pool.

C. The ventilation rate from the refueling area to the environment via the SGTS is 3.6 air changes/day based upon the SGTS flow rate of 3000 ft^3/min for HNP-1 and 4000 ft^3/min for HNP-2, which together serve the combined air volume of 2,840,000 ft^3 of the refueling area. Refueling area air volume is broken down into the component air volumes as follows:

• HNP-1 reactor building	1,275,000 ft^3
• HNP-1 refueling floor	725,000 ft^3
• HNP-2 refueling floor	840,000 ft^3

Based upon these assumptions, the activity airborne in the refueling area is shown in table 15.3-9.

Fission Product Released to the Environment

The following assumptions and initial conditions are used in evaluating the fission products released to the environs:

A. High-radiation levels in the refueling area ventilation system will isolate the normal ventilation system and actuate the SGTS. The release to the environment will be from the main stack via the SGTS filters at a leak rate of 3.6 air changes/day.

B. The fuel-handling accident does not result in the release of any liquid or vapor to the refueling area. Therefore, the normal building environmental condition existing prior to the accident will also exist after the accident, except for the addition of the released fission products. Relative humidity in the refueling area will be considerably below any levels that can be detrimental to the filter media in the SGTS.

C. The filter efficiency is conservatively used as 95% for iodines and 0% for noble gases.

Based upon these conditions, the fission products released to the environment are as shown in table 15.3-10.

Radiological Effects

Offsite radiological exposures were evaluated for the meteorological conditions presented in HNP-2-FSAR subsection 2.3.4 and the methods of reference 6. The results for a release height of 120 m are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	7.7E-06	2.9E-04
LPZ (1250 m)	4.3E-05	3.1E-03

15.3.5.4.1.3 <u>Consideration of Uncertainties</u>. This event was conservatively analyzed. Due to this conservative approach, no uncertainties were evaluated.

15.3.5.4.2 Conservative (NRC) Licensing Basis Evaluation Methods

15.3.5.4.2.1 <u>Methods, Assumptions, and Conditions</u>. See tables 15.3-11 and 15.3-15 for the inputs for the FHA consequence analysis.

Offsite doses and doses to personnel in the MCR and TSC are calculated according to the guidance in the main body and Appendix B of RG 1.183 as documented in FSAR appendix A.

Two cases of radioactivity release paths from the reactor building are evaluated. The first case assumes that the SGTS is in operation such that all releases are filtered and elevated after drawdown of the reactor building. In the second case, no credit for the SGTS is considered.

The following assumptions are utilized in the dose models:

1. The fuel handling accident is postulated to occur at the earliest possible time of fuel movement following shutdown from full power. The fuel decays for 24 h.

2. All the gap activity in the damaged rods is instantaneously released. Radionuclides considered are xenons, kryptons, halogens, cesiums, and rubidiums.

3. The minimum depth of water above the damaged fuel is 21 ft. Since this is less than the 23-ft depth assumed in the RG 1.183 derivation of the iodine decontamination factor, the reduced iodine decontamination factor is calculated as part of the analysis.

4. The retention of noble gases in the water in the spent fuel pool is negligible (i.e., decontamination factor of 1).

5. Particulate radionuclides are retained by the water in the spent fuel pool (i.e., infinite decontamination factor).

6. MCR and TSC doses are calculated for a 30-day period, since radioactivity that is brought into these rooms during the first 2 h of the accident will continue to expose occupants until it is removed by transfer or decay.

7. Offsite doses are calculated for a 2-h period, since the radioactive cloud moves past these locations during this time interval and no further exposure occurs.

15.3.5.4.2.2 Results and Consequences. Doses are calculated for the MCR, TSC, EAB, and LPZ. The results for the first case, SGTS in operation, and the second case, no SGTS in operation, are shown in the table below.

Doses from FHA

	Dose (rem TEDE)		
	Case 1: SGTS	Case 2: No SGTS	Limit
MCR	0.72	3.5	5.0
TSC	0.80	3.9	5.0
EAB	0.25	1.2	6.3
LPZ	0.25	1.2	6.3

15.3.6 FUEL ASSEMBLY LOADING ERROR (EVENT 35)

The fuel assembly loading error is a limiting event for reloads and, consistent with ***NEDE-24011-P-A (GESTAR II)***, is evaluated each operating cycle. The current reload report provides the current safety analysis results for the limiting events and is used to establish the applicable core operating limits documented in each unit's ***Core Operating Limits Report (COLR) (incorporated by reference into the FSAR)***. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements.

The two different possibilities for operation of a fuel assembly in an improper position are a mislocated fuel assembly and a misoriented fuel assembly. Both of these fuel assembly loading errors are classified as accidents, but for analysis purposes, the fuel cladding integrity safety limit is used as the event acceptance limit. This subsection presents the results of the analysis for the original rated conditions (2436 MWt).

15.3.6.1 Identification of Causes

15.3.6.1.1 Starting Conditions and Assumptions

For the original rated conditions, the fuel assembly loading error is based upon the assumption that a fuel assembly is loaded in an incorrect position, and the reactor is subsequently operated at rated plant conditions.

15.3.6.1.2 Accident Description

For the original rated conditions, the fuel assembly loading error event considers an assembly that is in an incorrect position subsequent to reactor startup and operation. For the plant design that uses three unique bundle types in the initial core, the fuel assembly loading error can occur in two ways:

- Loading a high-reactivity bundle into the highest-powered, medium-reactivity bundle location.

- Loading a low-reactivity bundle (a natural uranium bundle) adjacent to the highest-reading local power range monitor (LPRM).

The latter case is always the more severe of the two, since it is assumed the reading of the particular LPRM is true and can be applied to the other three symmetric pseudo-LPRM locations in the core. The implication is that the erroneous, low-reading LPRM location is brought to the thermal limits and the three pseudo-LPRM locations are exceeding the limits.

15.3.6.2 <u>Analysis of Effects and Consequences</u>

15.3.6.2.1 Methods, Assumptions, and Conditions

For original rated conditions, the analysis methods for calculation of three-dimensional nuclear characteristics and corresponding thermal limits are used. The calculations are based upon moving a peripheral natural uranium bundle into the interior location of a high-enrichment bundle at the highest-reading LPRM location. The calculations are performed at beginning-of-cycle (BOC) operation at rated conditions. The critical rod pattern and fuel bundle exchange locations for this accident are shown in figure 15.3-1.

15.3.6.2.2 Results and Consequences

The changes in linear heat generation rate (LHGR) and minimum critical power ratio (MCPR) are assumed to be directly proportional to the difference in LPRM readings for the actual LPRM location where the misloaded fuel assembly exists and the pseudo-LPRM locations in the other three quadrants. Results show that MCPR is reduced by 11.9% and MLHGR increases by 17.2%.

15.3.6.2.3 Consideration of Uncertainties

The uncertainties do not differ from the normal uncertainties associated with the calculation of gross power distribution.

15.3.7 RECIRCULATION PUMP SEIZURE (EVENT 36)

This subsection provides the analysis results for the recirculation pump seizure accident. This analysis was performed for the initial core for original rated conditions (2436 MWt) and demonstrates the event is nonlimiting. This conclusion is consistent with ***NEDE-24011-P-A (GESTAR II)***.

15.3.7.1 Identification of Causes

15.3.7.1.1 Starting Conditions and Assumptions

The recirculation pump seizure accident is assumed to occur as a consequence of an unspecified, instantaneous stoppage of one recirculation pump shaft while the reactor is operating at 105% of nuclear boiler rated steam flow power (2535 MWt). Also, the reactor is assumed to be operating at thermally limited conditions.

15.3.7.1.2 Accident Description

The case of recirculation pump seizure represents the extremely unlikely event of instantaneous stoppage of the pump motor shaft of one recirculation pump. This produces a very rapid decrease of core flows as a result of the large hydraulic resistance introduced by the stopped rotor.

The pump seizure event is a very mild accident in relation to other accidents, such as the LOCA. It is easily verified by consideration of the two events. In both accidents, the recirculation driving loop flow is lost extremely fast. In the case of a seizure, stoppage of the pump occurs. For a LOCA, the severance of the line has a similar, but more rapid and severe, influence.

Following a pump seizure, natural circulation flow continues, water level is maintained, and the core remains submerged, providing a continuous core cooling mechanism. However, for a LOCA, complete flow stoppage occurs, and water level decreases due to a loss of coolant, resulting in uncovering the reactor core and subsequent overheating of the fuel rod cladding. In addition, for the pump seizure, reactor pressure does not decrease; whereas, for the LOCA, complete depressurization occurs. Clearly, both the increased temperature of the cladding and the reduced reactor pressure combine to yield a much more severe stress and the potential for cladding perforation is greater for the LOCA than for the pump seizure. Therefore, it can be concluded that the potential effects of the hypothetical pump seizure accident are very conservatively bounded by the effects of a LOCA.

15.3.7.2 Analysis of Effects and Consequences

15.3.7.2.1 Methods, Assumptions, and Conditions

The nonlinear dynamic model described in reference 14 is used to simulate the recirculation pump seizure. Since the more negative void reactivity coefficient assumed for pressurization transients is nonconservative for the recirculation pump seizure, the accident is evaluated with the conservatively reduced void coefficient given in table 15.2-3.

15.3.7.2.2 Results and Consequences

Figure 15.3-2 shows that the transient core coolant flow drops rapidly, reaching its minimum at ~ 1.4 s. The level swells due to the rapid flow reduction and initiates a high-level trip of the main turbine and feedwater turbines with subsequent initiation of a scram. Both recirculation pump motors are also tripped at the time of the high-level turbine trip; however, a model constraint prevents simulating the two-pump trip. The level decreases to the low-level trip point where the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems initiate at 40.3 s. A delay time of ~ 30 s occurs prior to either RCIC or HPCI system water reaching the vessel; therefore, operation was not included in this run.

15.3.7.2.3 Consideration of Uncertainties

The assumption that the reactor is initially at limiting conditions forces the expected results, should this seizure occur, to be less severe than calculated.

15.3.8 FEEDWATER LINE BREAK (RADIOLOGICAL CONSEQUENCES) (EVENT 37)

This subsection provides the radiological analysis results for a feedwater system piping break accident outside containment. This analysis was performed for the initial core for original rated conditions (2436 MWt). The impact of power uprate from 2436 MWt to 2804 MWt on the radiological analyses is not considered significant, because no calculated failures result from the event. As a result, the activity of the coolant released during the event dominates the radiological exposure. The design basis coolant activity was not changed for power uprate. Therefore, the fission products released during the event are not expected to change significantly. Based upon this analysis, it was concluded that the feedwater line break accident is bounded by the MSLBA and is nonlimiting in the safety analysis process. Therefore, the feedwater line break accident is not reanalyzed each reload.

15.3.8.1 Identification of Causes

No identifiable event results in a feedwater line break accident. The break is postulated to occur without the cause being identified.

15.3.8.2 Starting Conditions and Assumptions

Prior to the feedwater line break accident, the reactor is operating at the original plant operating full-power condition (2436 MWt).

15.3.8.3 Accident Description

Accidents that result in the release of radioactive material outside the secondary containment are the result of postulated breaks in the RCPB. A break spectrum analysis for the complete range of reactor conditions indicates the DBA for breaks outside containment is a complete severance of one of the MSLs as described in subsection 15.3.4. The feedwater line break is less severe than the MSLB.

The following list depicts the sequence of events and the approximate elapsed times for the feedwater line break accident:

	Event Sequence	Elapsed Time
1.	The feedwater pipe circumferentially breaks between the last high-pressure heater and the outboard feedwater check valve.	0
2.	Feedwater flow into the RPV reaches zero; the feedwater check valves in the broken line isolate the reactor from the break.	~ 3.0 s
3.	Low RPV water level scrams the reactor; the main turbine trips from the load mismatch; the turbine bypass valves function normally.	~ 5 s
4.	The feedwater pipe break sufficiently reduces either the reactor feed pump suction pressure or condensate pump discharge pressure to start the standby condensate and/or condensate booster pumps; an increased ΔP across the condensate demineralizers automatically opens the bypass around the demineralizers.	~ 5.5 s
5.	The feedwater pump trips on low suction pressure.	~ 8 s
6.	Low RPV water level initiates RCIC/HPCI.	~ 60 s
7.	RPV water level reaches the lowest point before RCIC/HPCI restore level; level is still > level 1.	~ 90 s
8.	The steam flow through the bypass system is virtually zero. The RCPB may be manually isolated at any time.	~ 5 min
9.	Steam for the turbine-driven feed pumps was exhausted from either the main turbine cross-around piping or the steam lines between the MSIVs and the main turbine stop valves. The reactor feed pumps continue to windmill with flow from the condensate pumps.	< ~ 8 min
10.	Inventory of water in the main condenser hotwell is pumped out of the break by the condensate and/or condensate booster pumps.	< ~ 8 min
11.	Feedwater lines between the last feedwater heater and break complete draining out of the break.	~ 15 min

15.3.8.4 <u>Analysis of Effects and Consequences</u>

15.3.8.4.1 Realistic (Conservative Engineering) Evaluation Methods

The feedwater line break accident evaluation discussed in this paragraph is considered to be a realistic, yet conservative, engineering assessment of the consequences of a failure of the feedwater piping external to the containment for the most probable plant operating condition.

15.3.8.4.1.1 <u>Methods, Assumptions, and Conditions</u>. The methods, assumptions, and conditions associated with the feedwater line break using the realistic evaluation methods are as follows:

<u>Primary System Mass Loss</u>

A postulated guillotine break of the feedwater system piping outside the secondary containment results in a mass loss of 24,100 lb of feedwater blowdown from the break. This blowdown is at high temperature and pressure and, thus, is subject to some flashing to steam. The contribution of water from the condenser hotwell is ~ 189,000 gal, which would be < 200°F and 270 psig (nonflashing). The flow from the break is realistically determined using the following assumptions and conditions:

A. The reactor is operating at 100% feedwater flow.

B. A sudden circumferential break occurs in one of the feedwater lines between the last feedwater heater and the secondary containment.

C. System pressure is initially at 1060 psi.

D. The feedwater check valves operate immediately to isolate the break from the RPV. Decay heat-generated steam continues to flow through the bypass valves into the condenser until ~ 300 s.

E. The condensate and/or the condensate booster pumps are assumed to pump all of the water from the hotwell out of the feedwater line break.

F. The mass of water contained in the feedwater heaters, the mass of water that results from the complete drainage of the feedwater piping downstream of the last feedwater heater, and the trapped condensed steam in the turbine piping are considered negligible compared to the inventory in the hotwell.

G. The turbine bypass valves are assumed to function normally to maximize hotwell inventory. However, if the valves do not function as expected, the radiological consequences of the event will not be impacted, since the entire hotwell inventory is assumed to be pumped out of the break. The feedwater check valves and high-pressure makeup (HPCI/RCIC) will still adequately control RPV level.

Radioactive Material Released

The following assumptions are used in the calculation of the quantity and types of radioactive material released from the RCPB.

A. The concentrations of biologically significant radionuclides contained in the primary coolant are as follows:

Isotope	Concentration (μCi/g)
I-131	0.018
I-132	0.16
I-133	0.12
I-134	0.31
I-135	0.17

Measurements made on current-generation BWRs show the activity ratio between the main turbine condensate and the reactor coolant is on the order of 0.5% to 2%. For the purposes of this evaluation, the conservative assumption is made that the activity/lb of steam is equal to 2% of the activity/lb of reactor water.

B. Noble gas activity in the feedwater is negligible.

C. Because of the short half-life of N-16, the radiological effects from this isotope are negligible and are not considered in the analysis.

D. As the flow in the condensate feedwater system increases following the pipe break, the high differential pressure across the condensate demineralizers is assumed to automatically open the demineralizer bypass flow.

E. The normal operating iodine reduction factor by the condensate demineralizers is 1000. For conservatism, the reduction factor is assumed to be 10.

F. Of the 24,100 lb of feedwater blowdown, 10% is assumed to flash to steam. Of this 10% (2410 lb), 1000 lb are assumed to have bypassed the demineralizer, which has an efficiency of at least 90%. All iodine contained in this 1000 lb is assumed available for release. Only 10% of the iodine contained in the remaining 1410 lb is available for release to the environment.

15.3.8.4.1.2 Results and Consequences. The results and consequences associated with the feedwater line break accident using the realistic evaluation methods are as follows:

Fuel Damage

No cladding perforations result as a consequence of the feedwater line break accident.

Radioactive Material Released from the Break

The isotopic activity discharged from the break and carried off by steam is as follows:

Isotope		Activity (Ci)
I-131		1.9E-04
I-132		1.7E-03
I-133		1.2E-03
I-134		3.2E-03
I-135		1.8E-03
	TOTAL	8.1E-03

Fission Product Released to the Environment

It is conservatively assumed 50% of the airborne activity released from the break is removed by condensation and plateout prior to release to the environment. The iodine release to the environment is as follows:

Isotope		Activity (Ci)
I-131		9.3E-05
I-132		8.3E-04
I-133		6.2E-04
I-134		1.6E-03
I-135		8.8E-04
	TOTAL	4.0E-03

Radiological Effects

The radiological effects are based upon a puff release to the atmosphere using the meteorology presented in HNP-2-FSAR subsection 2.3.4 and the methods presented in reference 5. The whole-body dose results from the gamma radiation emitted by the iodines of interest. The offsite doses for a ground-level release are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	9.4E-09	6.5E-06
LPZ (1250 m)	9.4E-09	6.5E-06

15.3.8.4.1.3 Consideration of Uncertainties. The feedwater line break accident was conservatively analyzed, therefore, no uncertainties were evaluated.

15.3.8.4.1.4 Conservative (NRC) Licensing Basis Methods Evaluation. At the present time, there are no NRC guidelines upon which to base an evaluation. Therefore, no NRC-guided estimate of the consequences of a feedwater line break accident can be made.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

"GESTAR II - General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A.

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TABLE 15.3-1

CRDA (EVENT 31) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY AIRBORNE IN THE CONDENSER (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	2.36E 00	2.35E 00	2.34E 00	2.29E 00	2.16E 00	1.66E 00	1.73E-01
I-132	3.59E-01	2.67E-01	1.97E-01	3.19E-02	2.48E-04	7.74E-14	0.0
I-133	1.25E 00	1.21E 00	1.17E 00	9.56E-01	5.60E-01	5.05E-02	4.65E-11
I-134	2.84E-01	1.30E-01	5.89E-02	5.09E-04	1.60E-09	0.0	0.0
I-135	6.88E-01	6.20E-01	5.59E-01	2.97E-01	5.52E-02	2.81E-05	0.0
TOTAL	4.94E 00	4.57E 00	4.32E 00	3.57E 00	2.78E 00	1.71E 00	1.73E-01
KR-83M	4.53E 01	3.13E 01	2.15E 01	2.28E 00	5.68E-03	1.05E-14	0.0
KR-85M	2.37E 02	2.03E 02	1.74E 02	6.87E 01	5.75E 00	8.04E-04	0.0
KR-85	4.19E 02	4.18E 02	4.18E 02	4.18E 02	4.16E 02	4.10E 02	3.58E 02
KR-87	1.72E 02	1.01E 02	5.81E 01	2.18E 00	3.42E-04	0.0	0.0
KR-88	3.95E 02	3.09E 02	2.41E 02	5.45E 01	1.03E 00	1.78E-08	0.0
KR-89	1.08E-01	2.54E-07	4.82E-13	0.0	0.0	0.0	0.0
XE-131M	3.18E 01	3.17E 01	3.16E 01	3.12E 01	2.99E 01	2.47E 01	4.84E 00
XE-133M	1.35E 02	1.33E 02	1.31E 02	1.21E 02	9.83E 01	3.80E 01	1.04E-02
XE-133	6.55E 03	6.51E 03	6.47E 03	6.26E 03	5.71E 03	3.79E 03	1.10E 02
XE-135M	1.67E 01	1.15E 00	7.61E-02	6.29E-09	0.0	0.0	0.0
XE-135	1.57E 03	1.46E 03	1.35E 03	8.57E 02	2.55E 02	1.08E 00	0.0
XE-137	3.86E-01	9.10E-06	1.79E-10	0.0	0.0	0.0	0.0
XE-138	5.78E 01	3.24E 00	1.73E-01	3.99E-09	0.0	0.0	0.0
TOTAL	9.62E 03	9.20E 03	8.90E 03	7.81E 03	6.52E 03	4.27E 03	4.73E 02

TABLE 15.3-2

CRDA (EVENT 31) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY RELEASED TO THE ENVIRONMENT (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	2.54E-08	7.98E-05	2.85E-04	2.61E-03	9.96E-03	3.85E-02	1.24E-01
I-132	3.81E-09	1.01E-05	2.99E-05	1.14E-04	1.35E-04	1.36E-04	1.36E-04
I-133	1.32E-08	4.14E-05	1.45E-04	1.20E-03	3.64E-03	6.83E-03	7.14E-03
I-134	3.02E-09	5.90E-06	1.35E-05	2.38E-05	2.39E-05	2.39E-05	2.39E-05
I-135	7.30E-09	2.18E-05	7.31E-05	4.79E-04	9.52E-04	1.06E-03	1.06E-03
TOTAL	5.27E-08	1.59E-04	5.46E-04	4.43E-03	1.47E-02	4.66E-02	1.32E-01
KR-83M	4.80E-07	1.21E-03	3.46E-03	1.13E-02	1.25E-02	1.25E-02	1.25E-02
KR-85M	2.51E-06	7.28E-03	2.37E-02	1.33E-01	2.17E-01	2.24E-01	2.24E-01
KR-85	5.81E-06	1.42E-02	5.08E-02	4.72E-01	1.85E 00	8.06E 00	5.79E 01
KR-87	1.83E-06	4.15E-03	1.08E-02	2.57E-02	2.65E-02	2.65E-02	2.65E-02
KR-88	4.18E-06	1.14E-02	3.52E-02	1.54E-01	1.98E-01	1.99E-01	1.99E-01
KR-89	1.23E-09	5.74E-08	5.74E-08	5.74E-08	5.74E-08	5.74E-08	5.74E-08
XE-131M	3.48E-07	1.08E-03	3.85E-03	3.55E-02	1.36E-01	5.46E-01	2.13E 00
XE-133M	1.43E-06	4.54E-03	1.61E-02	1.43E-01	5.05E-01	1.46E 00	2.06E 00
XE-133	7.09E-05	2.21E-01	7.89E-01	7.19E 00	2.70E 01	9.74E 01	2.33E 02
XE-135M	1.80E-07	1.25E-04	1.56E-04	1.59E-04	1.59E-04	1.59E-04	1.59E-04
XE-135	1.66E-05	5.07E-02	1.73E-01	1.25E 00	2.88E 00	3.58E 00	3.58E 00
XE-137	4.35E-09	2.91E-07	2.91E-07	2.91E-07	2.91E-07	2.91E-07	2.91E-07
XE-138	6.22E-07	3.91E-04	4.73E-04	4.80E-04	4.80E-04	4.80E-04	4.80E-04
TOTAL	1.05E-04	3.16E-01	1.11E 00	9.41E 00	3.28E 01	1.12E 02	2.99E 02

TABLE 15.3-3

LOCA (EVENT 32) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY AIRBORNE IN THE PRIMARY CONTAINMENT (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	2.73E 01	2.72E 01	2.71E 01	2.64E 01	2.49E 01	1.88E 01	1.72E 00
I-132	1.37E 01	1.01E 01	7.49E 00	1.21E 00	9.38E-03	2.88E-12	0.0
I-133	9.34E 01	9.04E 01	8.74E 01	7.14E 01	4.17E 01	3.70E 00	3.00E-09
I-134	5.34E 00	2.45E 00	1.11E 00	9.57E-03	2.99E-08	0.0	0.0
I-135	2.68E 01	2.41E 01	2.17E 01	1.15E 01	2.14E 00	1.07E-03	0.0
TOTAL	1.66E 02	1.54E 02	1.45E 02	1.11E 02	6.87E 01	2.25E 01	1.72E 00
KR-83M	3.48E 02	2.41E 02	1.65E 02	1.74E 01	4.33E-02	7.86E-14	0.0
KR-85M	1.93E 02	1.66E 02	1.42E 02	5.60E 01	4.67E 00	6.39E-05	0.0
KR-85	3.20E 02	3.20E 02	3.20E 02	3.19E 02	3.16E 02	3.05E 02	2.22E 02
KR-87	1.70E 02	9.95E 01	5.75E 01	2.15E 00	3.36E-04	0.0	0.0
KR-88	3.40E 02	2.66E 02	2.08E 02	4.68E 01	8.83E-01	1.49E-08	0.0
KR-89	4.42E 01	1.04E-04	1.97E-10	0.0	0.0	0.0	0.0
XE-131M	2.40E 01	2.39E 01	2.39E 01	2.34E 01	2.24E 01	1.81E 01	2.96E 00
XE-133M	1.04E 02	1.03E 02	1.01E 02	9.34E 01	7.53E 01	2.85E 01	6.48E-03
XE-133	5.00E 03	4.97E 03	4.94E 03	4.77E 03	4.33E 03	2.82E 03	6.81E 01
XE-135M	1.53E 01	1.06E 00	6.96E-02	5.74E-09	0.0	0.0	0.0
XE-135	1.05E 03	9.73E 02	9.02E 02	5.71E 02	1.69E 02	6.99E-01	0.0
XE-137	5.84E 01	1.38E-03	2.71E-08	0.0	0.0	0.0	0.0
XE-138	1.86E 02	1.04E 01	5.55E-01	1.28E-04	0.0	0.0	0.0
TOTAL	7.85E 03	7.17E 03	6.86E 03	5.90E 03	4.92E 03	3.17E 03	2.93E 02

TABLE 15.3-4

LOCA (EVENT 32) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY AIRBORNE IN THE REACTOR BUILDING (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	2.27E-04	1.24E-02	2.26E-02	5.47E-02	6.54E-02	5.01E-02	4.61E-03
I-132	1.14E-04	4.62E-03	6.24E-03	2.50E-03	2.47E-05	7.67E-15	0.0
I-133	7.17E-04	4.12E-02	7.28E-02	1.48E-01	1.10E-01	9.84E-03	8.04E-12
I-134	4.45E-05	1.12E-03	9.25E-04	1.98E-05	7.86E-11	0.0	0.0
I-135	2.23E-04	1.10E-02	1.81E-02	2.39E-02	5.62E-03	2.85E-06	0.0
TOTAL	1.38E-03	7.03E-02	1.21E-01	2.29E-01	1.81E-01	5.99E-02	4.61E-03
KR-83M	2.89E-03	1.10E-01	1.38E-01	3.61E-02	1.14E-04	2.09E-16	0.0
KR-85M	1.61E-03	7.57E-02	1.19E-01	1.16E-01	1.23E-02	1.70E-07	0.0
KR-85	2.66E-03	1.46E-01	2.66E-01	6.60E-01	8.32E-01	8.11E-01	5.91E-01
KR-87	1.42E-03	4.53E-02	4.79E-02	4.45E-03	8.86E-07	0.0	0.0
KR-88	2.83E-03	1.21E-01	1.73E-01	9.69E-02	2.32E-03	3.97E-11	0.0
KR-89	3.67E-04	4.75E-08	1.65E-13	0.0	0.0	0.0	0.0
XE-131M	2.00E-04	1.09E-02	1.99E-02	4.85E-02	5.89E-02	4.83E-02	7.88E-03
XE-131M	8.65E-04	4.68E-02	8.44E-02	1.93E-01	1.98E-01	7.59E-02	1.72E-05
XE-133	4.16E-02	2.27E 00	4.12E 00	9.87E 00	1.14E 01	7.50E 00	1.81E-01
XE-135M	1.27E-04	4.81E-04	5.81E-05	1.19E-11	0.0	0.0	0.0
XE-135	8.73E-03	4.44E-01	7.52E-01	1.18E 00	4.45E-01	1.86E-03	0.0
XE-137	4.86E-04	6.28E-07	2.26E-11	0.0	0.0	0.0	0.0
XE-138	1.55E-03	4.74E-03	4.63E-04	2.65E-11	0.0	0.0	0.0
TOTAL	6.53E-02	3.27E 00	5.72E 00	1.22E 01	1.30E 01	8.43E 00	7.80E-01

TABLE 15.3-5

LOCA (EVENT 32) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY RELEASED TO THE ENVIRONMENT (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	1.90E-08	6.02E-05	2.26E-04	2.59E-03	1.21F-02	5.13E-02	1.63E-01
I-132	8.95E-09	2.49F-05	7.77E-05	3.47E-04	4.32E-04	4.33E-04	4.33E-04
I-133	6.12E-08	2.02E-04	7.46E-04	7.65E-03	2.80E-02	5.63E-02	5.91E-02
I-134	3.51E-09	7.22E-06	1.72E-05	3.26E-05	3.28E-05	3.28E-05	3.28E-05
I-135	1.75E-08	5.53E-05	1.95E-04	1.56E-03	3.57E-03	4.08E-03	4.08E-03
TOTAL	1.10E-07	3.50E-04	1.26E-03	1.22E-02	4.42E-02	1.12E-01	2.27E-01
KR-83M	4.55E-06	1.21E-02	3.63E-02	1.36E-01	1.56E-01	1.56E-01	1.56E-01
KR-85M	2.53E-06	7.75E-03	2.65E-02	1.80E-01	3.28E-01	3.43E-01	3.43E-01
KR-85	4.21E-06	1.42E-02	5.33E-02	6.18E-01	2.98E 00	1.42E 01	9.58E 01
KR-87	2.23E-06	5.35E-03	1.45E-02	3.86E-02	4.02E-02	4.02E-02	4.02E-02
KR-88	4.44E-06	1.28E-02	4.14E-02	2.14E-01	2.95E-01	2.97E-01	2.97E-01
KR-89	6.22E-07	2.94E-05	2.94E-05	2.94E-05	2.94E-05	2.94E-05	2.94E-05
XE-131M	3.19E-07	1.06E-03	3.99E-03	4.58E-02	2.16E-01	9.46E-01	3.56E 00
XE-133M	1.38E-06	4.56F-03	1.70E-02	1.88E-01	8.12E-01	2.55E 00	3.61E 00
XE-133	6.69E-05	2.02E-01	8.28E-01	9.39E 00	4.32E 01	1.70E 02	4.01E 02
XE-135M	2.03E-07	1.47E-04	1.86E-04	1.91E-04	1.91E-04	1.91E-04	1.91E-04
XE-135	1.37E-05	4.42E-02	1.59E-01	1.40E 00	3.81E 00	4.92E 00	4.92E 00
XE-137	8.12E-07	5.52E-05	5.52E-05	5.52E-05	5.52E-05	5.52E-05	5.52E-05
XE-138	2.47E-06	1.62E-03	1.98E-03	2.01E-03	2.01E-03	2.01E-03	2.01E-03
TOTAL	1.04E-04	3.24E-01	1.18E 00	1.22E 01	5.19E 01	1.94E 02	5.10E 02

TABLE 15.3-6

LOCA (EVENT 32) NRC ANALYSIS RADIOLOGICAL EFFECTS (rem)

This table has been deleted.

TABLE 15.3-7

MSLBA (EVENT 33) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY RELEASED TO THE ENVIRONMENT (Ci)

Isotope		Activity
I-131		7.1E-02
I-132		6.3E-01
I-133		4.8E-01
I-134		1.2E 00
I-135		6.7E-01
	TOTAL	3.1E 00
KR-83M		2.1E-02
KR-85M		3.5E-02
KR-85		1.4E-04
KR-87		1.1E-01
KR-88		1.1E-01
KR-89		4.7E-01
XE-131M		9.9E-05
XE-133M		1.7E-03
XE-133		4.7E-02
XE-135M		1.4E-01
XE-135		1.3E-01
XE-137		6.1E-01
XE-138		4.7E-01
	TOTAL	2.1E 00

TABLE 15.3-8

MSLBA (EVENT 33) NRC ANALYSIS
INITIAL CORE
RADIOLOGICAL EFFECTS

This table has been deleted.

TABLE 15.3-9

FUEL-HANDLING ACCIDENT (EVENT 34) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY AIRBORNE IN THE REFUELING AREA (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	8.61E 01	8.54E 01	8.47E 01	8.08E 01	7.11E 01	4.00E 01	2.80E-01
I-132	1.17E 01	8.66E 00	6.36E 00	1.00E 00	7.28E-03	1.66E-12	0.0
I-133	2.30E 01	2.21E 01	2.13E 01	1.70E 01	9.29E 00	6.13E-01	3.80E-11
I-134	2.46E-07	1.12E-07	5.07E-08	4.26E-10	1.25E-15	0.0	0.0
I-135	2.75E 00	2.47E 00	2.12E 00	1.15E 00	1.99E-01	7.41E-05	0.0
TOTAL	1.23E 02	1.19E 02	1.15E 02	9.99E 01	8.06E 01	4.07E 01	2.80E-01
KR-83M	3.76E-01	2.25E-01	1.33E-01	5.72E-03	1.30E-06	0.0	0.0
KR-85M	1.13E 01	8.41E 00	6.20E 00	9.95E-01	7.59E-03	2.16E-12	0.0
KR-85	8.10E 02	6.99E 02	6.01E 02	2.44E 02	2.22E 01	4.45E-04	0.0
KR-87	8.66E-04	4.36E-04	2.17E-04	3.31E-06	4.74E-11	0.0	0.0
KR-88	2.28E 00	1.54E 00	1.03E 00	9.51E-02	1.64E-04	5.75E-17	0.0
KR-89	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-131M	6.15E 01	5.30E 01	4.55E 01	1.82E 01	1.59E 00	2.68E-05	0.0
XE-133M	2.22E 02	1.89E 02	1.61E 02	6.04E 01	4.45E 00	3.51E-05	0.0
XE-133	1.21E 04	1.03E 04	8.86E 03	3.49E 03	2.90E 02	3.92E 03	0.0
XE-135M	3.10E 00	1.85E-01	1.05E-02	3.53E-10	0.0	0.0	0.0
XE-135	3.52E 03	2.82E 03	2.25E 03	5.81E 02	1.57E 01	1.35E 06	0.0
XE-137	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-138	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	1.67E 04	1.41E 04	1.19E 04	4.39E 03	3.34E 02	4.42E 03	0.0

TABLE 15.3-10

FUEL-HANDLING ACCIDENT (EVENT 34) REALISTIC ANALYSIS
INITIAL CORE
ACTIVITY RELEASED TO THE ENVIRONMENT (Ci)

Isotope	1 min	1 h	2 h	8 h	1 day	4 days	30 days
I-131	1.08E-02	6.43E-01	1.28E 00	5.00E 00	1.41E 01	4.34E 01	8.08E 01
I-132	1.47E-03	7.60E-02	1.32E-01	2.62E-01	2.87E-01	2.87E-01	2.87E-01
I-133	2.87E-03	1.69E-01	3.32E-01	1.19E 00	2.72E 00	4.45E 00	4.57E 00
I-134	3.09E-11	1.29E-09	1.87E-09	2.34E-09	2.35E-09	2.35E-09	2.35E-09
I-135	3.44E-04	1.96E-02	3.71E-02	1.10E-01	1.75E-01	1.89E-01	1.89E-01
TOTAL	1.54E-02	9.08E-01	1.78E 00	6.57E 00	1.73E 01	4.83E 01	8.59E 01
KR-83M	9.45E-04	4.43E-02	7.06E-02	1.07E-01	1.09E-01	1.09E-01	1.09E-01
KR-85M	2.84E-02	1.47E 00	2.56E 00	5.12E 00	5.61E 00	5.61E 00	5.61E 00
KR-85	2.03E 00	1.13E 02	2.10E 02	5.67E 02	7.89E 02	8.12E 02	8.12E 02
KR-87	2.18E-06	9.46E-05	1.42E-04	1.88E-04	1.88E-04	1.88E-04	1.88E-04
KR-88	5.71E-03	2.83E-01	4.74E-01	8.28E-01	8.64E-01	8.64E-01	8.64E-01
KR-89	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-131M	1.54E-01	8.58E 00	1.60E 01	4.28E 01	5.92E 01	6.07E 01	6.07E 01
XE-133M	5.55E-01	3.08E 01	5.70E 01	1.49E 02	2.01E 02	2.05E 02	2.05E 02
XE-133	3.02E 01	1.68E 03	3.12E 03	8.30E 03	1.14E 04	1.71E 04	1.17E 04
XE-135M	7.94E-03	1.60E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01
XE-135	8.81E 00	4.74E 02	8.53E 02	1.96E 03	2.34E 03	2.35E 03	2.35E 03
XE-137	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-138	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	4.18E 01	2.31E 03	4.26E 03	1.10E 04	1.48E 04	1.51E 04	1.51E 04

TABLE 15.3-11 (SHEET 1 OF 2)

COMMON INPUTS FOR DBA RADIOLOGICAL ANALYSES

Input/Assumption	Value
Reactor Power	2818 MWt (current licensed rated thermal power level times an uncertainty factor of 1.005)
Core Inventory	The equilibrium core inventory of fission products per unit power (Ci/MWt) has been generated using the ORIGEN2 computer program based on a 24-month fuel cycle. The inventory is limited to the radionuclide groups and elements specified in RG 1.183, Table 5. In addition, a 10% margin is incorporated into the core inventory to allow for future fuel changes or power uprates.
Atmospheric Dispersion Factors	MCR and TSC: Table 2.3-25 EAB and LPZ: Table 2.3-11
Volumes	
MCR Free Volume	9.35E4 ft^3
TSC Free Volume	1.56E4 ft^3
TB Free Volume	6.50E6 ft^3
Turbine/Condenser Volume (combined volume of low-pressure turbine and condenser)	1.72E5 ft^3
MCR/TSC Ventilation	
MCR Filtered Intake Rate	250 ft^3/min
MCR Recirculation	2,100 ft^3/min
MCR Filter Efficiency (Intake and Recirculation)	95% for all radionuclide except noble gases

TABLE 15.3-11 (SHEET 2 OF 2)

Input/Assumption	**Value**	
MCR Unfiltered Leakage	115 ft^3/min (for LOCA, CRDA, and MSLB)	
MCR Ingress/Egress	Two one-way trips per day, lasting 2 min (each way)	
TSC Filtered Intake Rate	500 ft^3/min	
TSC Recirculation	500 ft^3/min	
TSC Filter Efficiency (Intake and Recirculation)	90% for all radionuclides except noble gases	
TSC Unfiltered Inleakage	10,000 ft^3/min	
Breathing Rates and Occupancy Factors		
Breathing Rate (MCR, TSC, TB)	3.5E-04 m^3/s	
Breathing Rate (Offsite)	0-8 h: 8-24 h: 1-30 days:	3.5E-04 m^3/s 1.8E-04 m^3/s 2.3E-04 m^3/s
MCR and TSC Occupancy Factors	0-1 day: 1-4 days: 4-30 days:	100% 60% 40%
Turbine Building Ventilation		
Turbine Building Fans - Time to Start	9 h after initiation of the accident (for LOCA, CRDA, and MSLB)	
Turbine Building Fan Exhaust Rate	15,000 ft^3/min (for LOCA, CRDA, and MSLB)	

TABLE 15.3-12

INPUTS FOR ANALYSIS OF CONTROL ROD DROP ACCIDENT

Note: the inputs in this table are in addition to those of table 15.3-11.

Input/Assumption	**Value**	
Fuel Quantity	560 fuel bundles in core. Each GE14 (10 x 10) fuel bundle contains an average 87.3 fuel rods.	
Fuel Damage	1189 fuel rods experience cladding failure. 11 fuel rods experience melting.	
Core Radial Peaking Factor	1.5 (applied to all damaged fuel rods)	
Cladding Failure Release Fractions	Iodine	10%
	Br	5%
	Noble gases	10%
	Cs, Rb	12%
Melting Release Fractions	Iodine	50%
	Br	30%
	Noble gases	100%
	Cs, Rb	25%
	Sb, Se, Te	5%
	Ba, Sr	2%
	Noble Metals	0.25%
	Lanthanides	0.02%
	Ce, Np, Pu	0.05%
Fraction of the activity released from the reactor coolant within the pressure vessel that reaches the turbine and condenser	Noble gases	100%
	Iodine	10%
	Other	1%
Activity that reaches the turbine and condenser that is available for release to the environment	Noble gases	100%
	Iodine	10%
	Other	1%

TABLE 15.3-13

CORE RELEASE RATES FOR LOSS-OF-COOLANT ACCIDENT

		Release Fraction		Release Rate (Frac/h)	
Group	Elements	Gap	Early In-Vessel	Gap	Early In-Vessel
Halogens	I, Br	0.05	0.25	0.1	0.167
Noble Gases	Kr, Xe	0.05	0.95	0.1	0.633
Alkali Metals	Cs, Rb	0.05	0.20	0.1	0.133
Tellurium Metals	Sb, Se, Te	0	0.05	0	0.0333
Barium, Strontium	Ba, Sr	0	0.02	0	0.0133
Noble Metals	Co, Mo, Pd, Rh, Ru, Tc	0	0.0025	0	0.00167
Lanthanides	Am, Cm, Eu, La, Nb, Nd, Pm, Pr, Sm, Y, Zr	0	0.0002	0	0.000133
Cerium group	Ce, Np, Pu	0	0.0005	0	0.000333
Release Duration (h)		0.5	1.5		

Note: Release rate is obtained by dividing the release fraction by the release duration.

TABLE 15.3-14

INPUTS FOR ANALYSIS OF MAIN STEAM LINE BREAK ACCIDENT

Note: The inputs in this table are in addition to those of table 15.3-11.

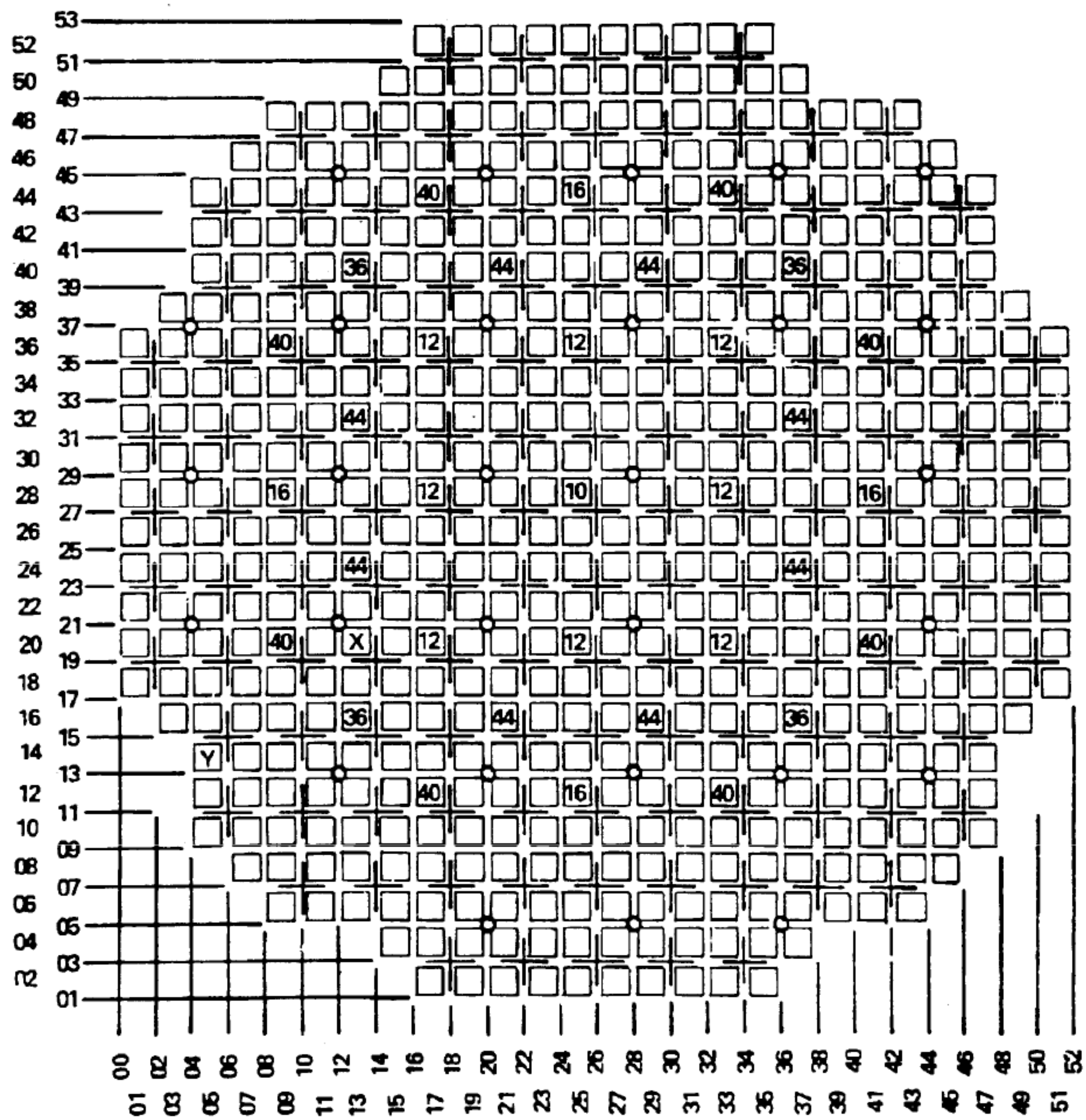
Input/Assumption	Value		
Primary Coolant Iodine Activity	Pre-accident Spike: Maximum Equilibrium:	2.0 μCi/g DE I-131 0.2 μCi/g DE I-131	
MSIV Closure Time	5.5 s		
Blowdown Mass Release	Steam Mass Release(lbm)	Steam plus Liquid Mixture Mass Release (lbm)	Total Mass Release (lbm)
	1.4E + 4	3.9E + 4	5.3E + 4
Blowdown Mixture Quality	7%		

TABLE 15.3-15

INPUTS FOR ANALYSIS OF FUEL HANDLING ACCIDENT

Note: The inputs in this table are in addition to those of table 15.3-11.

Input/Assumption	Value	
Iodine Species in Spent Fuel Pool	Elemental:	99.85%
	Organic:	0.15%
Fuel Quantity	560 fuel bundles in core. Each GE14 (10 x 10) fuel bundle contains an average 87.3 fuel rods.	
Fuel Rods Damaged	172	
Fission Product Release Fractions	I-131:	0.08
	Other halogens:	0.05
	Kr-85:	0.10
	Other noble gases:	0.05
	Alkali Metals:	0.12
Maximum Core Radial Peaking Factor	1.5 (applied to all damaged fuel rods)	
MCR Unfiltered Inleakage	10,000 ft^3/min	



HIGH ENRICHMENT BUNDLE MOVED FROM LOCATION "X" TO "Y"

LOW ENRICHMENT BUNDLE MOVED FROM LOCATION "Y" TO "X"

ACAD 2150301

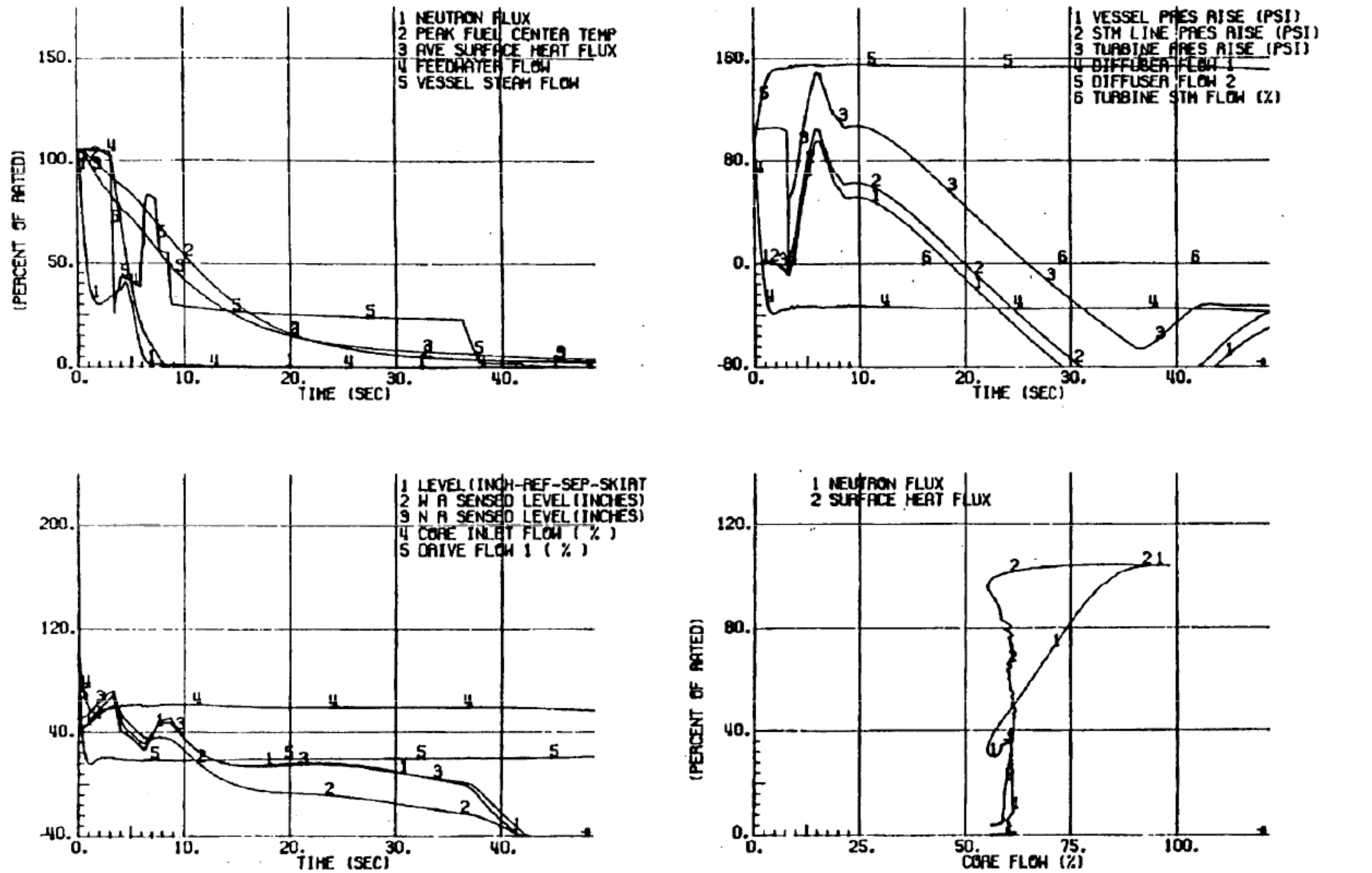
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CRITICAL ROD PATTERN AND FUEL BUNDLE EXCHANGE LOCATIONS FOR MISPLACED BUNDLE ACCIDENT (0.0 GWd/T)

FIGURE 15.3-1



ACAD 2150302

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

SEIZURE OF ONE RECIRCULATION PUMP
VOID COEFFICIENT = -12.0

FIGURE 15.3-2

15.4 ANALYSES OF SPECIAL EVENTS

Special events are evaluated to demonstrate plant capabilities required by the regulatory requirements and guidance, industry codes and standards, and licensing commitments. The specific special events considered are dependent upon the goals of the analysis. Special events evaluated in the safety analysis include:

- Stability (Event 41).
- Overpressure protection (Event 42).
- Shutdown without control rod insertion [standby liquid control system (SLCS) capability] (Event 43).
- Main control room (MCR) uninhabitability (Event 44).
- Anticipated transients without scram (ATWS) (Event 45).
- Generator load rejection with flux scram and no bypass or recirculation pump trip (RPT) (Event 46).
- Turbine trip with flux scram and no bypass or RPT (Event 47).
- Loss of one dc system (Event 48).
- Loss of instrument air (Event 49).
- Loss of service water system (Event 50).
- Fire (Event 51).
- Miscellaneous small releases outside containment (Event 52).
- Instrument line break (Event 53).
- Liquid radwaste tank failure (Event 54).
- Gaseous radwaste tank failure (Event 55).
- Station blackout (SBO) (Event 56).

The specific safety analysis results for special events presented in this section are the results for HNP-2. Because of the essentially identical design of the two units, the conclusions for HNP-2 apply also to HNP-1.

15.4.1 STABILITY (EVENT 41)

Stability is considered a potentially limiting special event for reloads and plant modifications that can reduce stability margins.

Stability is reevaluated each operating cycle to establish the change in critical power ratio (ΔCPR) associated with the setpoints for the oscillation power range monitor (OPRM), which is part of the power range neutron monitor (PRNM) upgrade. The ΔCPR is used as a part of the process for establishing the operating limit minimum critical power ratio (OLMCPR) for the reload. Table 15.1-1 identifies the reload reports consistent with Final Safety Analysis Report (FSAR) update requirements.

Stability was evaluated for power uprate to a rated thermal power (RTP) of 2804 MWt and for reactor operating pressure increase (ROPI) to 1060 psia.[9, 10]

This subsection describes the safety analysis requirements for stability and the power uprate evaluations.

Stability evaluations are performed to demonstrate compliance with General Design Criterion (GDC) 12 of Title 10 Code of Federal Regulations (CFR) Part 50, Appendix A. GDC 12 requires that the reactor core and associated coolant, and the control and protection systems be designed to assure power or flow oscillations that can result in conditions exceeding the specified acceptable fuel design limits (SAFDLs) either are not possible or can be readily detected and suppressed.

Three general types of stability are considered in the FSAR:

A. Stability of the entire reactor system in response to changes in system pressure, flow, and water level as determined by the coupled response of the overall plant dynamics, and the turbine and reactor control systems (total plant stability).

B. Stability of the reactor core in response to changes in core flow, subcooling, or pressure, including nuclear feedback effects from changes in core voids and fuel temperature (core stability).

C. Thermohydrodynamic stability of individual fuel channels at various power and flow conditions resulting from perturbations in flow or channel boundary conditions, independent of reactor system controls or nuclear feedback (channel stability).

Total plant stability is considered nonlimiting, because it was demonstrated as being acceptable during the plant startup test program in which the control systems are tuned to ensure acceptable plant performance.

Stability of the core and the fuel channels is considered potentially limiting, because under certain plant operating conditions, there is a potential to encounter instabilities that could challenge the safety limit MCPR (SLMCPR). Stability margin decreases in the low-flow and high-power regions of the power-to-flow map (figure 15.1-3). The OPRM is automatically armed

in regions where potential instabilities may occur. The OPRM initiates a scram on exceeding algorithms that are period, growth-rate, and amplitude based. The ΔCPR associated with OPRM setpoints was used as part of the process for establishing the OLMCPR for power uprate.

15.4.2 OVERPRESSURE PROTECTION (EVENT 42)

Overpressure protection is considered a potentially limiting special event for reloads and plant modifications that can increase the peak reactor pressure vessel (RPV) pressure during pressurization events.

Consistent with ***NEDE-24011-P-A, "GESTAR II - General Electric Standard Application for Reactor Fuel," (incorporated by reference into the FSAR)***, overpressure protection is reanalyzed each operating cycle as part of the process for demonstrating compliance with the ASME Boiler and Pressure Vessel Code. For the current reload, the analysis methodology is described in ***NEDE-24011-P-A (GESTAR II***), and the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements.

Overpressure protection was reanalyzed for power uprate to an RTP of 2763 MWt.(1) The results of the power uprate analysis for overpressure protection, which are applicable to HNP-1 and HNP-2, are provided in HNP-1-FSAR subsection 4.4 and HNP-2-FSAR subsection 5.2.2.

This subsection describes the safety analysis requirements for overpressure protection.

The safety relief valves (SRVs) are designed to prevent overpressurization of the RPV and associated cooling systems. Pressure relief is accomplished by opening the Code-qualified SRVs. The ASME Code permits pressurization events to exceed RPV and reactor coolant boundary (RCPB) design pressure for normal operation based upon the frequency of occurrence. The ASME Code requires the lowest qualified SRV setpoint to be at or below RPV design pressure. Based upon ASME Code requirements, a conservative approach to the overpressure protection analysis has been adopted. In this approach, the ASME Code is conservatively interpreted as requiring the most severe pressurization transient to be analyzed, while not allowing credit to be taken in the analysis for the direct scram input to the reactor protection system (RPS). Concurrently, the ASME Code limit for upset events (110% of the RPV design pressure) is conservatively used as the event acceptance limit. Based upon the safety analysis process, as confirmed by the power uprate and ROPI,(9,10) the most severe pressurization event is the closure of all main steam isolation valves (MSIVs), at their fastest design closure time, with a flux scram. (Note: The direct scram initiated by the MSIV position switches is conservatively ignored.)

15.4.3 SHUTDOWN WITHOUT CONTROL ROD INSERTION (SLCS CAPABILITY) (EVENT 43)

Shutdown without control rod insertion (SLCS capability) is considered a potentially limiting special event for reloads and plant modifications that can increase core reactivity.

Consistent with ***NEDE-24011-P-A (GESTAR II)***, the SLCS capability analysis is reanalyzed each operating cycle. For, the current reload, the analysis methodology is described in ***NEDE-24011-P-A (GESTAR II)***, and the cycle-specific analysis results are provided in the reload report. Table 15.1-1 identifies the reload reports consistent with FSAR update requirements.

The SLCS capability was reanalyzed for power uprate (2804 MWt) and ROPI to 1060 psia.[9,10]

This subsection describes the safety analysis requirements for shutdown without control rod insertion and establishes the SLCS capability considering power uprate and ROPI.

The objective of this analysis is to demonstrate the plant can be shut down independent of control rod insertion, as required by GDC 26 of 10 CFR 50, Appendix A. The SLCS is designed to insert sufficient negative reactivity to enable the reactor to reach a cold xenon-free shutdown condition from full-power operation without movement of the control rods. (Reference HNP-1-FSAR subsection 3.8.4 and HNP-2-FSAR paragraph 4.2.3.4.) The analysis of this event provides the required demonstration of SLCS capability.

In the SLCS capability analysis, the control rods are assumed to remain withdrawn in their full-power pattern for an equilibrium xenon concentration. The SLCS is manually initiated to provide negative reactivity by injecting sodium pentaborate into the core, thus, enabling the cold shutdown condition to be attained. Cold shutdown is accomplished when the reactor is subcritical at the most reactive temperature with no xenon present. For power uprate and ROPI to 1060 psia, it was determined that the required concentration of boron can be injected into the RPV to achieve cold shutdown without dependence upon the control rods.

15.4.4 MCR UNINHABITABILITY (EVENT 44)

The MCR is continuously occupied by qualified operating personnel. As discussed in HNP-2-FSAR section 6.4 (which applies also to HNP-1), the MCR is habitable under anticipated operational occurrences (AOOs), as well as design basis accidents (DBAs).

The capability of the plant to attain a cold shutdown condition independent of the MCR is described in supplement 15C. Reloads do not affect the plant's capability to attain a cold shutdown condition independent of the MCR. Therefore, MCR uninhabitability is not reevaluated for reloads.

Power uprate only impacts the radiological source terms. The radiological analysis of the DBAs for power uprate provided in section 15.3 demonstrates that radiological exposure limits for MCR operators established by GDC 19 are satisfied. The conclusions of the radiological analyses are not changed by reloads incorporating approved fuel designs. Therefore, this capability is considered nonlimiting with respect to reloads.

This subsection provides the results of the MCR evaluation for the original rated conditions (2436 MWt) and has only been updated to reflect changes relative to fire protection requirements, power uprate to an RTP of 2804 MWt, reactor pressure of 1060 psia, and reload considerations.

15.4.4.1 Identification of Causes

High Radiation

The design of the MCR shielding and the heating, ventilation, and air-conditioning (HVAC) system ensures MCR habitability throughout any design basis radiological accident. The HVAC system is designed to shift automatically to the pressurization mode to prevent infiltration of contaminated air into the MCR should any one of a number of high-radiation signals be received. (See HNP-2-FSAR section 6.4 for details on the initiating parameters.)

In the pressurization mode, the MCR is positively pressurized with respect to the surrounding turbine building by taking in outside air through one of the redundant MCR charcoal filter trains. The MCR normal air-handling units remain operable during accident conditions to provide air conditioning.

The operation of the MCR HVAC system is discussed in more detail in HNP-2-FSAR section 6.4 and subsection 9.4.1.

The radiological doses to MCR personnel as a result of the loss-of-coolant accident (LOCA) are discussed in paragraph 15.3.3.4.2. The LOCA is the limiting DBA with respect to MCR doses. The doses for the LOCA are within the limits of GDC 19.

Failure of the Main Control Room Environmental Control System

The main control room environmental control (MCREC) system, designed in accordance with Seismic Category I requirements and described in HNP-2-FSAR subsection 9.4.1, is composed of three independent, physically isolated, 50% capacity subsystems. The MCREC system is designed to retain full design capacity despite a single active failure.

Fires in the MCR

The MCR is designed and operated under requirements to minimize the likelihood of a fire originating in the MCR. Severe limitations are placed on combustible material in the MCR. Thermal and electric insulation was chosen to minimize flame spread, smoke, and noxious gas production. Analyses indicate that MCR personnel will not be adversely affected by the toxic fumes of fire-extinguishing agents and the products of combustion due to a fire. Even in the unlikely event of an Underwriters Laboratory Class A fire, MCR operators can quickly extinguish the fire, and MCR evacuation should not be necessary. The MCR habitability system provides for rapid smoke clearing through the ventilation systems. Self-contained breathing devices are available should they be required due to smoke conditions. Therefore, it is extremely improbable that a fire could spread or compromise MCR habitability.

The MCR fire protection system is described in detail in the ***Edwin I. Hatch Fire Hazards Analysis and Fire Protection Program (FHA) (incorporated by reference into the FSAR)***.

Fires External to the MCR

The MCR occupies one floor of the control building. The adjacent floors, both above and below, are isolated by fire barriers. The ventilation system for the MCR is separate from the ventilation system for the cable spreading room. Cable and other penetrations into the MCR incorporate smoke and fire stops. The fire protection and suppression systems for the adjacent areas are described in the ***FHA.***

A fire external to the MCR might introduce smoke and heat into the MCR through the MCREC system outside air intake. There is no smoke detector in the outside air intake duct. However, upon smoke reaching the MCR, the operator would become aware and would manually isolate the MCR. The MCR remains habitable in the isolation mode for ~ 14 people for at least 50 h, an interval limited by the buildup of carbon dioxide. Therefore, it is extremely improbable that a fire external to the MCR will require evacuation.

Pipe Rupture in the Fire Protection System

The carbon dioxide storage unit, located outside the cable spreading room in the control building at el 147 ft, is designed for a pressure of 363 psi and contains 26,000 lb of CO_2. The total energy released in an isentropic expansion of liquid CO_2 to atmospheric pressure is 3.15×10^8 ft-lb. The working pressure is 300 psi. The storage unit is manufactured and tested in compliance with the ASME Code for Unfired Pressure Vessels. Two SRVs are set at 357 psi. An audible alarm is set to sound at 325 psi. The storage unit is designed to comply with Part 1910 - Occupational Safety and Health Standards.

The storage unit is separated from any safety-related equipment by a walled enclosure, is constructed of steel with a steel outer container and insulation between, and has a minimum shell thickness of 31/32 in. and minimum head thickness of 13/16 in. The design temperature limits are -20°F to 650°F, with a normal operating temperature of 0°F. The unit is hydrostatically tested at 550 psi. Pressure is controlled by a refrigeration unit, and overpressurization is prevented by two SRVs. The possibility of an explosion is not seen since CO_2 is a stable compound. For these reasons, no mechanisms of vessel rupture are postulated, and only a break of the largest line (6 in.) leading from the unit is considered. The calculated overturning moment is 1.7×10^6 in.-lb. Since it would take an overturning moment in excess of 10^7 in.-lb to overturn the unit, it is concluded that a break of the largest line could neither move nor overturn the unit.

A pressure transient analysis was performed for the case of the 6-in. line rupture. The 6-in. line is a 7-ft standpipe that extends to near the bottom of the tank. Following the postulated break, two-phase flow results with a maximum estimated blowdown rate of 500 lb/s. At the pipe exit, it is conservatively estimated that 50% of the liquid CO_2 flashed to gas.

The CO_2 tank room has an estimated free volume of 21,000 ft^3. The limiting structural elements (concrete block walls) have a design basis of 50-lb/ft^2 differential pressure, although these walls are estimated to be capable of withstanding ~ 2 to 4 times the pressure differential. A wall with normally closed fire doors separates the CO_2 tank room from the cable spreading room. Assuming that the blowdown rate is constant until the tank empties, the transient analysis indicated a requirement of 13 ft^2 of vent area out of the CO_2 tank room to limit the differential

pressure to < 50 lb/ft^2. The required vent area in the ceiling of the tank room that leads to the HNP-1 turbine deck is provided. The effectively infinite volume of the turbine deck precludes a pressure problem. Furthermore, the separation of the CO_2 tank room from the MCR and the separation of the turbine deck from the MCR are such that no CO_2 will reach the MCR. The MCR air intake is located on the west wall of the turbine building, and the turbine building ventilation exhaust is through the reactor building vent stack east of the turbine building.

In the event of a fire in the cable spreading room and concurrent discharge of 97% liquid CO_2 at a rate of 44 lb/s (system design flow), the current ventilation system exhaust ducting will provide enough vent area to maintain the differential pressure < 50 lb/ft^2. The cable duct seals leading to the MCR are designed to withstand pressure substantially greater than the resultant pressure, and the cable spreading room has a separate ventilation system, thus precluding the entrance of CO_2 into the MCR.

<u>Hazardous Chemical Release</u>

No gaseous chlorine is stored on site. The plant has the capability to inject the following:

- Sodium hypochlorite, a corrosion inhibitor, and a silt dispersant into the service water systems to control organic biofouling, corrosion, and silt deposition.

- Sodium hypochlorite into the circulating water system to control organic biofouling in the pipelines and heat exchangers.

- Sodium bisulfite or ammonium bisulfite into the circulating water system at the HNP-1 and HNP-2 flume overflow weirs to remove chlorine residuals from the water overflowing to the river during the circulating water system chlorination cycle.

The chemical treatment system for the circulating water system is located in the area between the Unit 1D helper tower and the Unit 2 flume. Sodium hypochlorite is stored in a 10,000-gal tank placed in a concrete enclosure at this location. The concrete enclosure is sized to contain 110% of the tank's inventory. The diluted solutions of chemicals are piped to the circulating water flumes as shown on drawing no. H-43801. The dechlorinating chemical (sodium bisulfite or ammonium bisulfite) is stored in two tanks, one each at the HNP-1 and HNP-2 flume overflow weirs.

The maximum inventory of chemicals on hand at any one time is as follows:

- Sodium hypochlorite - 23,000 gal

- Corrosion inhibitor - 4000 gal

- Silt dispersant - 4000 gal

- Sodium bisulfite/ ammonium bisulfite - 6000 gal

In accordance with Department of Transportation and/or Interstate Commerce Commission (ICC) regulations, a licensed carrier transports the liquid sodium hypochlorite, corrosion inhibitor, silt dispersant, sodium bisulfite, and ammonium bisulfite to the site. Once the chemicals are received on site, plant personnel trained in the handling of these chemicals ensure the following practices are observed:

A. Administrative controls are in place to ensure chemical delivery trucks are escorted on site and the chemicals are sampled prior to unloading.

B. Precautions are taken to ensure the chemicals can only be stored in their respective tanks.

The water treatment system is designed to minimize potential fire sources. The water treatment containments (dikes) are constructed of concrete and the associated shelter is constructed of steel. The storage tanks are made of fiberglass reinforced plastic. The pump skids contain negligible combustible material. Additionally, sodium hypochlorite, sodium bromide, corrosion inhibitor, and dispersant vapors or liquids are nonexplosive and nonflammable.

The water treatment system is designed to minimize the potential for the release of chemicals beyond system boundaries. The sodium hypochlorite water treatment containments (dikes) are sized to contain 110% of the inventory of one tank. The containment (dike) surrounding the silt dispersant storage tank is sized to contain 100% of the inventory of the tank.

The dechlorinating chemical tanks, both at the HNP-1 and HNP-2 flume overflow weirs are maintained in reinforced concrete containments (dikes) which are sized to hold 100% of tank volume. The vaults limit the surface area of a spill such that control room habitability is not an issue.

Replenishment of the tanks at the flume overflow weirs is accomplished under administrative controls designed to minimize the release of sodium bisulfite or ammonium bisulfite beyond system boundaries. The replenishment process is monitored so the MCR can be notified should a spill outside the vault occur.

Fumes from a sodium hypochlorite spill cannot incapacitate the MCR operators. Vapors generated from an accidental spill of corrosion inhibitor, dispersant, sodium bisulfite, or ammonium bisulfite are less volatile than the vapors generated due to a spill of sodium hypochlorite. Therefore, the release of sodium hypochlorite bounds the release of dispersants or corrosion inhibitors. The materials of the lined piping/valves/components in the water treatment system are compatible with the chemicals being utilized. Should a leak in the water treatment system occur, corrosion would not affect any safety-related systems.

In the case of tank ruptures, release of chlorine vapors is negligible, and at no time does the MCR chlorine concentration exceed the toxicity limit of Regulatory Guide 1.78 (1974). Therefore, no hazard to the MCR operators can occur.

15.4.5 ATWS (EVENT 45)

The ATWS evaluations demonstrate compliance with 10 CFR 50.62. Generic analyses demonstrate that ATWS events can pose a significant challenge to the event acceptance limits. Plant and fuel design changes that can have a significant impact on the plant's response to ATWS events require evaluation.

Examples of changes that require ATWS evaluations are power uprate and new fuel designs that significantly change nuclear parameters; e.g., changes to the number of fuel rods or the amount of solid water in a fuel assembly.

This subsection summarizes the results of the generic ATWS evaluations and provides the results of the ATWS analyses for power uprate.

For postulated ATWS events, the following assumptions apply:

A. The plant is operating in a planned operating mode.

B. A transient (an AOO with a high frequency of occurrence) requiring a scram occurs.

C. The control rods fail to insert.

For a postulated failure-to-scram to occur, multiple failures in either the RPS or the control rod drive (CRD) system are required. Consequently, ATWS is a hypothetical event and is considered beyond the design basis for the plant. However, consistent with the requirements of 10 CFR 50.62, the following actions have been taken:

A. The following plant design modifications were made to either reduce the probability of an ATWS or mitigate its consequences:

   - Improvements in the design of the scram discharge volume (SDV).
   - Inclusion of an alternate rod insertion (ARI) system.
   - Incorporation of an ATWS-RPT.

B. The capability of the plant to withstand ATWS consequences was demonstrated.

The generic studies for ATWS covered the following nine potential initiating events:

- Turbine or generator trip with bypass.
- Closure of all MSIVs.
- Recirculation flow controller failure - increasing flow.

- Pressure regulator failure - open.
- Feedwater controller failure - maximum demand (FWCF).
- Loss of feedwater flow (LOFW).
- Loss of offsite power (LOSP).
- Inadvertent opening of an SRV.
- Trip of two recirculation pumps.

Based upon the generic studies, it was determined that, for power uprate, the following four ATWS events required reanalysis:

- Closure of all MSIVs.
- Pressure regulator failure - open.
- LOSP.
- Inadvertent opening of an SRV.

NEDE-24011-P-A (GESTAR II) concludes that ATWS consequences are relatively insensitive to typical reload fuel and core design changes. As a result, selected ATWS events were reanalyzed for power uprate and ROPI;[1, 9, 10] however, ATWS evaluations are not required for reloads unless a new fuel design is introduced. If a new fuel design is introduced, the evaluation process provided in **NEDE-24011-P-A** is followed.

For the power uprate analysis to an RTP of 2804 MWt and ROPI to 1060 psia, the methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key initial conditions and analysis assumptions are provided in table 15.4-1. The analysis results are summarized in table 15.4-2.

Reference 11 provides the evaluation of the impact on ATWS of the installation of adjustable speed drives (ASDs) to provide power to the recirculation pump motors. The ASDs replace the recirculation pump motor-generator (M-G) sets. While certain recirculation pump characteristics changed as a result of this plant modification, the ATWS evaluation performed for an RTP of 2804 MWt and ROPI to 1060 psia remains bounding.

15.4.6 GENERATOR LOAD REJECTION WITH FLUX SCRAM AND NO BYPASS OR RPT (EVENT 46)

To demonstrate the plant’s capability, a special event analysis of generator load rejection with a flux scram and no bypass or RPT was analyzed for the original rated conditions (2436 MWt).

For the original analysis of the generator load rejection with flux scram and no bypass event, it was postulated that a failure of all safety-related signals is generated in the nonsafety-related turbine building, resulting in the following:

- A reactor shutdown initiated on high neutron flux.

- The unavailability of the turbine bypass system.

- The failure of an RPT to be initiated on the load rejection signal.

The results of an evaluation performed for the load rejection transient, compounded by the following three assumed failures, is provided in the paragraph below:

- Failure of the direct trip scram.

- Failure of the RPT system.

- Failure of the bypass system.

The resulting transient shows similar results to the 251 NSSS GESSAR analysis previously found to have acceptable consequences. The results are summarized in table 15.4-3, which provides the maximum RPV pressure and MCPR values, and the times at which they occur. In addition, the number of rods that reach boiling transition and the peak cladding temperature are included. Figure 15.4-1 provides the curves of neutron flux, flowrates, and pressures typically provided for the events described in chapter 15. In addition, figure 15.4-2 provides the critical power ratio (CPR) variation throughout the critical portion of the transient.

The peak cladding temperature and the MCPR indicate a similar severity to the 251 NSSS GESSAR analysis, which did not result in calculated fuel failures. Based upon this result and the similarity of results with the evaluations in NEDE-25014,[(2)] it is concluded that no fuel failures will result from this event. Since this combined event is accepted as being of such a low probability to be considered a capability analysis that is beyond the design basis and no fuel failures are calculated to occur, the consequences of this event satisfy the event acceptance limit.

This event was reevaluated for power uprate to an RTP of 2763 MWt.[(1)] The analysis of the load rejection with no bypass and with direct scram and RPT demonstrates that an increase in RTP from the original value of 2436 MWt to the current value of 2763 MWt has very little impact on the thermal margins. For the case without direct scram and no RPT, a similar trend is expected. Thus, it was concluded the consequences of a generator load rejection with flux scram and no bypass or RPT at 2763 MWt, consistent with its very low probability, are acceptable for power uprate. The evaluations performed for thermal power optimization (2804 MWt) and ROPI to 1060 psia concluded that there is no significant change to the results of the existing evaluations.

Based upon the evaluations for the original rated conditions and power uprate, it was concluded the generator load rejection with flux scram and no bypass or RPT is a nonlimiting special event and is not reanalyzed each reload.

15.4.7 TURBINE TRIP WITH FLUX SCRAM AND NO BYPASS OR RPT (EVENT 47)

To demonstrate the plant's capability, a special event analysis of the turbine with a flux scram and no bypass or RPT was analyzed for the original rated conditions (2436 MWt).

General Electric performed a probability study to determine the probability that either a turbine control valve (TCV) fast closure or a turbine stop valve (TSV) fast closure will not result in a reactor trip. Based upon the fact that the probability of an unsuccessful trip path is on the order of 10^{-6}, it is General Electric's opinion that failure of the trip signal being successful is so low as to be deemed almost incredible. The probability analysis was submitted to the NRC in Amendment 14 to 251 NSSS GESSAR.

Even though the probability of a turbine trip occurring and the reactor trip not being successful is of such low probability to be almost incredible, an analysis was performed to show the inherent capability of the reactor system under this faulted condition. For purposes of this analysis, it was assumed the reactor scrams on the neutron flux signal, which is the next scram signal to occur. It was also assumed the RPT signal does not function. The results of the analysis are:

	No. Bypass
• Initial CPR	1.23
• MCPR	0.8625
• Expected rods subject to boiling transition (%)	7.00
• Peak neutron flux (% of nuclear boiler rated)	1162
• Peak heat flux (% of nuclear boiler rated)	136
• Peak core pressure (psig)	1236
• Peak dome pressure (psig)	1226

For an HNP-1 equilibrium cycle core, which closely resembles the HNP-2 initial core, the following analysis for the load rejection/turbine trip case without bypass and using direct scram was made. The results are a ΔMCPR of 0.43 without RPT and a ΔMCPR of 0.28 with RPT.

This event was reevaluated for power uprate to an RTP of 2763 MWt.[(1)] The analysis of the turbine trip with no bypass and with direct scram and RPT demonstrates that an increase in RTP from the original value of 2436 MWt to the current value of 2763 MWt has very little impact

on the thermal margins. For the case without direct scram and no RPT, a similar trend is expected. Thus, it was concluded the consequences of a turbine trip with flux scram and no bypass or RPT at 2763 MWt, consistent with its very low probability, are acceptable for power uprate.

The evaluations performed for thermal power optimization (2804 MWt) and ROPI to 1060 psia concluded that there is no significant change to the results of the existing evaluations.

Based upon the results of the evaluation for ROPI, it was concluded the turbine trip with flux scram and no bypass or RPT is the limiting pressurization transient for HNP-2 Cycle 17 in terms of minimum critical power ratio (MCPR) and the reload specific analysis continue to confirm the acceptability of this transient.

15.4.8 LOSS OF ONE dc SYSTEM (EVENT 48)

To demonstrate the plant's capability, an analysis of the loss of one of the redundant dc power supply systems was performed for the initial plant design. This evaluation demonstrates the plant’s capability to accommodate the loss of a single independent dc power supply division and mitigate the consequences of the AOOs and accidents considered in the safety analysis.

The plant’s capability to accommodate the loss of a single independent dc power supply division and mitigate the consequences of the AOOs and accidents considered in the safety analysis was evaluated and found to be acceptable.

Because the potential transient effects are covered by other event analyses, evaluation of this event for reloads is not required.

The failure of a dc power supply system can cause a turbine trip. The consequences of a turbine trip with no bypass (TTNBP) are evaluated in paragraph 15.2.3.3.

Both HNP-1 and HNP-2 have the following two Class 1E dc power systems:

- A 125-250-V-dc power system.
- A 125-V-dc diesel auxiliary power system.

15.4.8.1 <u>Identification of Causes</u>

The possible causes for the loss of the two Class 1E dc power systems listed above are as follows:

- Loss of power to or failure of the battery chargers.
- Loss of batteries.

- Fault on buses or outgoing feeders.

15.4.8.2 <u>125-250-V-dc Power System</u>

Loss of this entire engineered safety feature (ESF) dc system is not credible, since it is divided into two independent load groups (Division I and Division II). As shown in HNP-1-FSAR figure 8.3-4 and drawing no. H-13370, this system has independent buses, batteries, and battery chargers. The only connection between the two load groups is the automatic depressurization system (ADS).

For the ADS, the logic channel of each system is normally connected to a 125-V-dc Division I source. In the event Division I dc power fails, the logic channels are transferred to a Division II source by actuation of a voltage-sensing relay. Since the logic channels are supplied from divisional distribution panels, the divisions are separated by breakers. Therefore, the worst condition that can be hypothesized is complete failure of one of the two divisional 125-250-V-dc power sources.

15.4.8.2.1 Results and Consequences

The results of the complete failure of one division means that all equipment depending upon that division is inoperable because of a lack of power.

Some loads, such as the high-pressure coolant injection (HPCI) system and the reactor core isolation cooling (RCIC) system motor-operated valves (MOVs), are a part of systems that are functionally not required to meet the single-failure criterion (RCIC MOVs supplied from Division II). Some loads, such as dc emergency lighting, are split so that failure of one group is tolerable. Other loads, such as circuit breaker control circuits, are segregated into load groups so that all categories of equipment, including ac and dc apparatus, fall into corresponding divisions. For example, the circuit breakers associated with Division I are served by circuits from the Division I dc subsystem. Operation of the circuit breakers in this load group is affected only by failures in power on the Division I dc bus.

15.4.8.2.2 Consideration of Uncertainties

Batteries are highly reliable equipment and very infrequently subject to uncertainties of operation. In any case, strict segregation into two load groups and functional redundancies ensure compliance with the single-failure criterion.

15.4.8.3 <u>125-V-dc Diesel Auxiliary Power System</u>

The three 125-V-dc diesel auxiliary power systems, one for each diesel generator (DG), are completely independent. Each of these three systems has its own distribution cabinet, battery, and battery charger. No connections exist between any of the three 125-V-dc diesel auxiliary power systems; however, the dc controls for DG 1B may be aligned to either an HNP-1 or an

HNP-2 source depending upon the alignment of DG 1B. The worst condition considered is the complete failure of one 125-V-dc diesel auxiliary power system.

15.4.8.3.1 Results and Consequences

The results of the complete failure of one 125-V-dc diesel auxiliary power system means that all equipment depending upon that system, including the DG, will not be available. This situation is tolerable, since two out of three DGs can meet the accident conditions on HNP-2, and four out of five DGs can meet accident conditions on one unit while supplying the safety shutdown loads of the other unit. (See HNP-2-FSAR table 8.3-4.)

15.4.9 LOSS OF INSTRUMENT AIR (EVENT 49)

To demonstrate the plant's capability, an analysis of the loss of the instrument air system was performed for the initial plant design. This evaluation demonstrates the plant's capability to accommodate the loss of the instrument air system.

Because the potential transient effects are covered by other event analyses, evaluation of the loss of instrument air event for reloads is not required.

The loss of instrument air may result in:

- Control system failures in the feedwater system.
- Decreasing condenser vacuum due to the isolation of the steam supply to the steam jet air ejectors (SJAEs).
- Control rod insertion.

Control system failures in the feedwater system are bounded by the LFWH event (paragraph 15.2.1.1), the FWCF event (paragraph 15.2.7.1), and the LOFW event (paragraph 15.2.8.4). Decreasing condenser vacuum is bounded by the loss of condenser vacuum as described in paragraph 15.2.3.4. Control rod insertion is less severe than a normal scram. The following evaluation was performed for the initial plant design.

15.4.9.1 <u>Identification of Causes</u>

The compressed air system (HNP-1-FSAR section 10.11 and HNP-2-FSAR section 9.3) supplies the instrument air requirements. The system is designed so that the failure of a single active component (compressor, receiver, aftercooler, filter, cooling water pump, or fan) will not render the system inoperable. The loss of instrument air can only occur as the result of the following:

- A major line break in the compressed air system.

- The mechanical or electrical failure of the normal instrument air supply.
- A major dryer failure.

The loss of all instrument air is extremely unlikely.

In the event of an LOSP, the air compressors stop, and for a short time thereafter, the air receivers supply the necessary instrument air.

15.4.9.2 Analysis of Effects and Consequences

Loss of the instrument air system neither initiates shutdown of the reactor nor precludes its shutdown, since backup systems are available to maintain the necessary equipment operable. All equipment using instrument air is designed to fail to a position that is consistent with the safe shutdown of the plant. Air-operated equipment that must be available in the event of a failure of the instrument air system is provided with Seismic Category I accumulators sized to allow their respective valves to be cycled a minimum of five times.

15.4.10 LOSS OF SERVICE WATER SYSTEM (EVENT 50)

This subsection provides the evaluation results of the loss of one division of the redundant plant service water (PSW) system. This evaluation, which was performed for the initial plant design, demonstrates the plant's capability to accommodate a single failure in the PSW system.

The capability of the PSW system was evaluated for power uprate to an RTP of 2804 MWt and ROPI to 1060 psia and found to be acceptable.[1, 9, 10]

The loss of the PSW system does not directly initiate any plant event; therefore, the event does not require reevaluation for reloads.

15.4.10.1 Identification of Causes

Regardless of the cause, one division of the PSW system and one division of the corresponding residual heat removal (RHR) system required for the safe shutdown of the reactor are assumed to be lost.

15.4.10.1.1 Starting Conditions and Assumptions

The loss of service water system event was analyzed using the following assumptions:

A. Prior to the event, the reactor and turbine are operating normally at rated power.

B. The DBA LOCA occurs, namely, the circumferential sudden break of a reactor recirculation loop pipe.

C. A complete loss of normal offsite power occurs simultaneously with the recirculation pipe break.

D. The DGs start normally.

E. The emergency core cooling system (ECCS) starts and operates normally.

F. The residual heat removal service water (RHRSW) system is manually started 10 min following the DBA. The PSW system is started automatically within 1 min following the DBA.

15.4.10.1.2 Event Description

With the PSW system supplying cooling to the RHR pump seal coolers and the RHR and core spray (CS) pump room coolers, and with the RHRSW system supplying water to the RHR heat exchanger, either Division I or Division II of the PSW system is assumed to fail with the simultaneous failure of the corresponding division of the RHRSW system.

15.4.10.2 <u>Analysis of Effects and Consequences</u>

15.4.10.2.1 Methods, Assumptions, and Conditions

In analyzing the failure of one division of the service water systems, the other division of each service water system is assumed to be operable, consistent with the single-failure criteria for redundant systems. The failure of one division of each service water system results in the isolation of the respective RHR system.

15.4.10.2.2 Results and Consequences

The failure of one division of each service water system has no effect on the remaining operable RHR loop. Since either division of each service water system is capable of satisfying the safety-related requirements, the failure of either division does not worsen the consequences of the LOCA.

15.4.10.2.3 Consideration of Uncertainties

Since the conservative assumption used is that one complete RHR loop is rendered incapable of meeting its performance objective by losing its respective service water system, no other uncertainties are involved.

15.4.11 FIRE (EVENT 51)

This section originally provided the results of the evaluation of major and minor internal fires, which was performed for the initial plant design. Since this evaluation was performed, the plant has demonstrated conformance with 10 CFR 50.48, "Fire Protection." The plant fire protection capability is described in the ***FHA***.

The capability of the safe shutdown systems for fire protection was evaluated for power uprate to an RTP of 2804 MWt and ROPI to 1060 psia and found to be acceptable.[1, 9, 10]

The reload fuel and core designs do not significantly affect the capability of the safe shutdown systems for fire protection. Therefore, the fire special event does not require reanalysis for reloads.

15.4.12 MISCELLANEOUS SMALL RELEASES OUTSIDE CONTAINMENT (EVENT 52)

This subsection provides the results of the evaluation of miscellaneous small releases outside containment, which was performed for the initial plant design to demonstrate this plant capability. Power uprate to an RTP of 2804 MWt and ROPI to 1060 psia do not significantly affect this plant capability.

Miscellaneous small releases outside containment do not directly initiate any plant event, nor do they significantly affect the reload fuel and core designs. Therefore, this event does not require reanalysis for reloads.

Releases that can occur from piping failures outside containment include the following:

- Feedwater line break (HNP-2-FSAR subsection 15.3.8).
- Main steam line break (HNP-2-FSAR subsection 15.3.4).
- Instrument line break (HNP-2-FSAR subsection 15.4.13).

The analysis of these events provides doses that can occur for such a classification of piping failure events.

Other releases that can occur outside containment include small spills and leaks of radioactive material inside structures housing process equipment.

Conservative values for leakage were assumed and evaluated as discussed in HNP-2-FSAR sections 11.2 and 11.3. The offsite dose that results from any small spill that can occur outside containment will be negligible in comparison to the dose resulting from other events involving the release of radioactive material outside containment.

15.4.13 INSTRUMENT LINE BREAK (EVENT 53)

This subsection provides the analysis results for breaks in instrument lines or small lines from the RCPB that penetrate the primary containment (instrument line break). This analysis was performed for the original rated conditions (2436 MWt). Based upon this analysis, it was concluded the instrument line break is a nonlimiting special event and does not require reanalysis for reloads, because it is bounded by other events.

Because no fuel failures are predicted to occur as a result of an instrument line break, only the activity in the reactor coolant or from preexisting fuel defects is released during the event.

The Technical Specifications limit reactor coolant activity. The reactor coolant activity assumed in the analysis is greater than the Technical Specifications limit.

The increase in RTP to 2804 MWt and ROPI to 1060 psia do not affect reactor coolant activity. Therefore, the power uprate to an RTP of 2436 MWt does not represent a significant increase in the event consequences.

15.4.13.1 <u>Identification of Causes</u>

No specific event or circumstance that results in the failure of an instrument line has been identified. However, for the purpose of evaluating the consequences of a small-line rupture, the failure of an instrument line is assumed to occur. A sampling line break (in lieu of the control rod drive hydraulic system (CRDHS) return header, the insert and withdraw line, and the radwaste sump pump discharge line) was selected as a worst-case instrument line break based upon the following considerations:

A. CRDHS return header - This piping is provided with inside and outside containment check valves and a third air-operated check valve.

B. Insert and withdraw line - This piping is connected to a hydraulic drive assembly, which by virtue of its configuration, significantly limits fluid flow through the broken pipe.

15.4.13.2 <u>Event Description</u>

The reactor is operating at full power when a circumferential rupture of an instrument line connected to the primary coolant system is postulated to occur outside the drywell but inside the excess flow check valves. This failure results in the release of primary system coolant to the secondary containment until the reactor is depressurized. This event could conceivably occur in the drywell. However, the associated effects would not be as significant as the effects from a failure in the secondary containment. The sequence of events and the approximate elapsed times for this event are as follows:

	Event Sequence	Elapsed Time
1.	The event begins; the instrument line fails external to the drywell but inside the excess flow check valves	0
2.	The break is identified.	~ ≤ 10 min
3.	Operator actions begin.	~ ≤ 12 min

15.4.13.3 Analysis of Nonradiological Effects and Consequences

The analytical techniques used to evaluate the consequences of the instrument line break event are consistent with well-established heat transfer and mass blowdown calculational models. The instrument line is assumed to fail external to the drywell and inside the secondary containment, resulting in the release of primary coolant to the secondary containment.

Mass Loss into the Containment

As a consequence of the instrument line break, the reactor is scrammed, and the RPV is cooled and depressurized over a 4-h period. The following assumptions and conditions are the basis for the mass loss during the 4-h period:

A. Shutdown and depressurization are initiated at 12 min after the break occurs.

B. Normal depressurization and cooldown of the RPV occur.

C. The line contains a 1/4-in. flow-restricting orifice inside the drywell.

D. The homogeneous critical blowdown flow model is applicable, and flow is critical at the orifice.[3]

E. According to Moody,[3] the blowdown flowrate is the maximum for a two-phase mixture (8000 lb-water/s-ft^2 at 1000 psia). This blowdown is continuous for a period of 12 min. After 12 min, it is assumed the operator has initiated reactor shutdown, and RPV pressure decreases linearly to atmospheric at 4 h following the break. After 12 min, blowdown flow decreases linearly from its maximum to zero at 4 h following the break.

On the basis of the above assumptions, the total integrated mass of steam and water released into the secondary containment by way of the break during the blowdown for 4 h is ~ 20,607 lb.

Figure 15.4-3 shows the RPV pressure during a normal shutdown following the assumed instrument line break. Figure 15.4-4 shows the flowrate from the break into the containment and the rate of flashing, assuming no friction losses associated with the saturated liquid flowing into the instrument line occur. The blowdown rate was computed from the RPV pressure, assuming saturated liquid flowing into the instrument line, conservation of mass and energy,

and no losses in the line. Figures 15.4-5 and 15.4-6 show the temperature and pressure in the secondary containment following the instrument line break.

The results of the analysis show that no appreciable increase in temperature or pressure in the secondary containment occurs. Building leakage is proportional to the square root of the differential pressure (4000 ft^3/min at 1/4-in. H_2O).

Secondary Containment Pressure and Temperature Response

The model used to calculate the pressure and temperature response consisted of a volume, assumed to be the total free volume of the secondary containment below the refueling floor, into which reactor coolant is blown down from rated reactor temperature and pressure. The standby gas treatment system (SGTS) and leakage remove mass and energy from the volume.

For analysis purposes, the operator is assumed to start the SGTS 12 min after the leak occurs. This is conservative in that, if the normal building ventilation system is considered to be operating, the removal rate is greater.

Mass and energy balance equations for the air and vapor in the secondary containment were solved iteratively in the manner prescribed in IDO-17220 (CONTEMPT computer program)[(4)] to determine the temperature. The pressure response was calculated from the mass inventory, temperature, and volume.

Specifically, the following assumptions were used for the pressure and temperature analysis:

A. The instrument line has a 1/4-in. restricting orifice.

B. Secondary containment conditions at the time of the break are:

- Pressure (psia) 14.7
- Net free volume (ft^3) 1.275×10^6
- Mass of air (lb) 8.6×10^4
- Mass of vapor at 50% RH (lb) 2100
- Temperature (inside) (°F) 105
- Temperature (outside) (°F) 90

C. Building leakage is proportional to the square root of the pressure differential (4000 ft^2/min at 1/4-in. H_2O).

D. No building heat transfer occurs.

E. No friction losses in the instrument line occur.

F. The SGTS flowrate is constant at 4000 ft^3/min.

On the basis of the above assumptions, it was determined that the pressure in the secondary containment and its subcompartments remained at atmospheric, and the building temperature increased to a maximum of < 122°F with 100% relative humidity.

Results

The results of the analysis outlined above indicate that the structural integrity of the building is ensured. The building can easily withstand 94-lb/ft^2 internal pressure without yielding or cracking. The blowout roof vents that open at 55 lb/ft^2 (10.6 in. H_20) and discharge to the atmosphere will remain closed.

The resultant temperature of < 122°F and a relative humidity of 100% will not adversely affect SGTS functional ability or performance. The SGTS moisture-separator will remove any entrained moisture in the air entering the train. Following the moisture-separator, the electric heating coil is designed to reduce the relative humidity of entering air at 120°F and 100% relative humidity to 70%. At this humidity level, data do not indicate any significant adverse effect on the iodine removal efficiency of the charcoal. The resultant temperature of < 122°F is well below the ignition temperature of the charcoal.

A separate analysis was performed to verify that no appreciable pressure buildups will occur in any subcompartments housing instrument lines. The subcompartment containing instrument lines with the lowest ratio of vent area to free volume is the torus chamber room located at el 87 ft, with a free volume of ~ 293,000 ft^3 and a vent area of ~ 398 ft^2.

The analysis was performed using the CONTEMPT computer code with the assumption that leakage was from the subcompartment to an effectively infinite volume.[4] The results indicate that the vent area is large enough so that no pressure differential between the subcompartment and the remainder of the secondary containment will exist.

15.4.13.4 Analysis of Radiological Effects and Consequences

The radiological exposure calculations provided in this section are for the initial core for the original rated conditions (2436 MWt).

The impact of power uprate from an RTP of 2436 MWt to 2763 MWt is not considered significant, because no calculated fuel failures occur as the result of this event. As a result, the activity of the coolant released during the event dominates the radiological exposure. The Technical Specifications control coolant activity. The increase in RTP to 2763 MWt does not affect reactor coolant activity. Therefore, the fission products released during the event are not expected to change significantly. A small increase in coolant released during the event may occur due to the increase in operating pressure. However, this change is well within the conservatism included in the analysis process. As a result, these radiological evaluations are considered bounding for the instrument line break.

Radiological exposures are based upon the assumption that the activity released to the secondary containment is proportional to the mass loss. In addition to the activity contained in the coolant prior to blowdown, additional activity may be released as a consequence of a reactor scram and an RPV depressurization. This additional release is taken into consideration in evaluating radiological exposures and is based upon the originally proposed Technical Specifications for primary coolant concentrations.

It is possible for the coolant concentration to be higher than the design value of 0.018 μCi/g of I-131. Based upon the data presented by Brutschy, et al., there is only a 4% chance the concentration of I-131 will be as high as 4.0 μCi/g after a complete depressurization.(5) Thus, based upon an extrapolation using a lognormal distribution, a value as high as 10 μCi/g following shutdown has an approximate 1% probability of occurrence. If four complete shutdowns/year are assumed, each with a 2-h window for maximum spiking activity, the probability of reaching the originally proposed Technical Specifications iodine concentration limit is 0.01 x 4 x 2/8760, or < 1 in 100,000/reactor year. Despite this minuscule probability, the coolant concentration is assumed to be at the maximum level of 10 μCi/g. This concentration is conservative when compared to the Technical Specifications limits.

The total flowrate from the break is 2.85 lb/s from a line with a 1/4-in. orifice. To obtain the highest iodine release, it is assumed the line is connected to the RPV at a point where saturated water exists. This leads to a flashing rate of 1.1 lb/s into the secondary containment. It is further assumed the secondary containment is not isolated for 10 min, and complete mixing of the flashed coolant takes place with a reduction factor of only 2 due to plateout and washout. These assumptions result in ~ 1.9 Ci of I-131 airborne in the secondary containment at the end of the 10-min period.

The release to the environment, assuming a 4000-ft^3/min purge rate, is 0.038 Ci of I-131. With an X/Q value of 3.1 x 10^{-5} s/m^3, the inhalation dose is only 6.1 x 10^{-4} rem, far below the 300-rem guideline value of 10 CFR 100. After isolation, the dose contribution is negligible, because the leak rate drops to ~ 6 ft^3/min, and the iodine is filtered through a 99% efficient SGTS.

Noble gas concentrations are based upon the noble gas release rates from the RPV, without assuming any decay that results in a total off-gas release rate of 100,000 μCi/s after a 30-min decay and nuclear boiler steam flowrate of 10,459,500 lb/h. Activity is considered to be released to the secondary containment during the blowdown period, with no credit taken for source dilution effects as a consequence of clean coolant injection.

Fuel Damage

The consequences of an instrument line break do not result in any fuel perforation or fuel damage. Therefore, the radiological consequences are limited to the release of the activity contained in the primary coolant, which flashes to steam.

Fission Product Released from the Fuel

As a consequence of a reactor scram and an RPV depressurization, it is expected that additional iodine and noble gas activity will be released from the fuel rods that may have

experienced cladding damage during normal operation. The noble gases, being only slightly soluble in the reactor coolant, will, for the most part, be released to the RPV vapor dome. However, the released iodine and noble gas are assumed to remain in the coolant and are discharged from the vessel in proportion to the mass of coolant released. This additional source is considered in the subsequent subsections.

Secondary Containment Activity

The activity airborne within the secondary containment is a function of primary coolant activity, blowdown rate, condensation rate, and fraction of liquid that flashes to steam.

Analysis

Prior to the time the secondary containment was drawn down to negative pressure, the activity released to the environment is based upon the normal building ventilation rate. During this time, the release is treated as a ground-level release. For subsequent time periods, the activity released to the environment is based upon the SGTS exhaust rate. The release is filtered by charcoal adsorbers and vented from the plant stack as an elevated release.

Assumptions

A. The reactor has operated for 1000 days prior to the event at a power level of 2550 MWt (100% power = 2436 MWt).

B. The operator detects the leak and begins shutdown at 12 min. After 12 min, the leak decreases linearly to zero at 4 h.

C. Blowdown from the break is treated in the same manner as for the pressure temperature analysis.

D. The total integrated mass of fluid released into the secondary containment by way of the break during blowdown is 20,607 lb.

E. Iodine inventory released to the secondary containment atmosphere during the event is based upon an iodine concentration of 10 μCi/g of dose equivalent I-131, a blowdown mass of 20,607 lb, and a hot-leakage iodine partition factor of 0.1.

F. Noble gas inventory released to the secondary containment atmosphere during the event is consistent with the noble gas concentrations that are based upon noble gas release rates from the RPV without assuming any decay resulting in a total off-gas release rate of 100,000 μCi/s after 30-min decay, a nuclear boiler steam flowrate of 10,459,000 lb/h, and a blowdown mass of 20,607 lb.

G. The charcoal filter efficiency of the SGTS filters is assumed to be 95% for removal of all forms of iodine.

H. Credit for the SGTS filters for removal of iodines is taken after 12 min following the initiation of the break. Release through the SGTS filters is considered an elevated release through the plant stack vent.

I. The atmospheric dispersion factors at the exclusion area boundary (1250 m) are as follows:

	Ground-Level Release	Elevated (Stack) Release
0 - 12 min	4.1×10^{-4} s/m^3	---
12 min - 2 h	---	1.7×10^{-6} s/m^3
2 - 4 h	---	9.4×10^{-7} s/m^3

J. No credit is taken for cloud depletion by ground deposition and radioactive decay during transit to the site boundary or the outer boundary of the low population zone (LPZ).

K. The total-body gamma dose is based upon models described in Regulatory Guide 1.3, June 1974.

L. The thyroid dose is based upon a breathing rate of 3.47×10^{-4} m^3/s and thyroid dose conversion factors found in reference 6.

Results

The potential radiological consequences resulting from the occurrence of a postulated instrument line break were conservatively analyzed using assumptions and models described in previous sections.

The total-body gamma doses due to immersion from direct radiation and the thyroid dose due to inhalation were analyzed for the 0- to 2-h period at the exclusion area boundary and for the duration of the event at the LPZ outer boundary. The analysis results are as follows:

	Whole-Body Dose (rem)	Thyroid Dose (rem)
Exclusion area(1250 m)	6.91×10^{-5}	1.87×10^{-1}
LPZ (1250 m)	6.94×10^{-5}	1.873×10^{-1}

The resultant doses are well within the guideline dose values of 10 CFR 100.

15.4.14 LIQUID RADWASTE TANK FAILURE (RADIOLOGICAL CONSEQUENCES) (EVENT 54)

This subsection provides the radiological analysis results for a liquid radwaste tank failure. This analysis was provided for the original rated conditions (2436 MWt).

The impact of power uprate from an RTP of 2436 MWt to 2804 MWt and ROPI to 1060 psia on the radiological analyses is not considered significant, because radiological exposure is a function of the design basis reactor coolant activity in the tank. The increase in RTP to 2804 MWt and ROPI to 1060 psia do not affect the design basis reactor coolant activity. Therefore, power uprate does not involve a significant change to the event consequences. In addition, any small change in tank activity due to operational changes is well within the conservatism included in the analysis process.

Based upon this evaluation, it was concluded that a liquid radwaste tank failure is a nonlimiting special event and does not require reanalysis for reloads.

15.4.14.1 Identification of Causes

Although not analyzed for the requirements of Seismic Category I equipment, the liquid radwaste tanks are constructed in accordance with sound engineering principles. Therefore, simultaneous failure of all the tanks is not considered credible, although conservatively analyzed below.

15.4.14.2 Starting Conditions and Assumptions

This event postulates the failure of the liquid radwaste tanks located in the radwaste building. The liquid radwaste tanks hold the radioactive liquid wastes from the floor drains, equipment drains, and chemical wastes generated during plant operation. The radioisotope inventories in these tanks are provided in HNP-2-FSAR table 11.2-2.

15.4.14.3 Event Description

An event that causes the simultaneous rupture of the liquid radwaste tanks is highly improbable. In most cases, the tanks are individually located in highly shielded areas. Therefore, the probability of a missile striking and rupturing all the tanks is remote. The only event that might cause failure of all the radwaste tanks is an earthquake sufficient in magnitude to exceed design capabilities. Thus, the failure of all radwaste tanks is assumed to occur. The sequence of events and the approximate elapsed times assumed to occur are as follows:

Event Sequence		Elapsed Time
1.	The event begins; a failure occurs.	0
2.	Area radiation alarms alert plant personnel.	~ 1 min
3.	Operator actions begin (not essential).	~ 5 min

15.4.14.4 Analysis of Effects and Consequences

15.4.14.4.1 Realistic (Conservative Engineering) Evaluation Methods

The analytical methods and associated assumptions used to evaluate the consequences of the liquid radwaste tank failure are considered to provide a realistic, yet conservative, assessment of the consequences.

15.4.14.4.1.1 Methods, Assumptions, and Conditions. The liquid radwaste tank failure is evaluated in accordance with the following assumptions and conditions:

A. The rupture of a liquid radwaste tank in the radwaste area results in the release of the contents of the tank.

B. One percent of the total iodine inventory released from the tank becomes airborne and available for release at ground level without filtration to the environment.

C. The release (through ventilation or leakage) takes place over a 2-h period.

15.4.14.4.1.2 Results and Consequences. The results and consequences for a liquid radwaste tank failure are provided below:

Iodine Released from the Tanks

The iodine isotopic activity concentrations in the tanks are given in HNP-2-FSAR table 11.2-2. These values are based upon the full tank capacity. Total maximum expected inventories used in this analysis are given below:

Isotope	Activity (Ci)
I-131	3.4×10^{-1}
I-132	3.1
I-133	2.3
I-134	6.1
I-135	3.4

The airborne activity released from the tanks is conservatively assumed to be 1% of the values shown above. The airborne activity is assumed to be released directly to the atmosphere before the operator initiates isolation.

Radiological Effects

Radiological effects are based upon a puff release to the atmosphere using the meteorological conditions presented in HNP-2-FSAR subsection 2.3.4 and the methods presented in reference 7. The whole-body dose results from the gamma radiation emitted by the iodine. The radiological effects of a puff release at the height of 0 m are as follows:

	Whole-Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1250 m)	2.7×10^{-6}	2.8×10^{-4}
LPZ (1250 m)	2.7×10^{-6}	2.8×10^{-4}

15.4.14.4.1.3 Consideration of Uncertainties. The liquid radwaste tank failure was conservatively analyzed. As a result of this conservative approach, no uncertainties were evaluated.

15.4.14.4.2 Conservative (NRC) Licensing Basis Evaluation Methods

At the present time, the NRC has not issued any guidelines for evaluating the liquid radwaste tank failure. Therefore, no NRC-guided estimate of the consequences of this event can be made.

15.4.15 GASEOUS RADWASTE TANK FAILURE (EVENT 55)

This subsection provides the radiological analysis results for postulated failures of the gaseous radwaste system. In the analysis performed for the original rated conditions (2436 MWt), three different failures were analyzed:

- Failure of the off-gas system.
- Failure of an SJAE line.
- Malfunction of the turbine gland-sealing system.

The impact of power uprate 2804 MWt and ROPI to 1060 psia on the radiological analyses is not considered significant, because radiological exposure is based upon the design basis off-gas activity that is not expected to change due to power uprate and ROPI to 1060 psia. Any small change in off-gas activity due to plant operating conditions is well within the conservatism included in the analysis process.

Based upon this evaluation, it was concluded that failure of the off-gas system is a nonlimiting special event and does not require reanalysis for reloads.

15.4.15.1 Off-gas System Failure

15.4.15.1.1 Identification of Causes

An evaluation of events that can cause a gross failure in the off-gas system resulted in the identification of two potential events:

- A seismic event more severe than the one for which the off-gas system is designed.
- A failure of the electric preheater controls system and subsequent heating of the off-gas pipe to a temperature above maximum allowable.

The potential for pipe failure due to overheating caused by a failure of the electric preheater control system is not considered credible. The control components of the preheater section are designed with redundancy and diversity to limit the pipe wall temperature to less than the maximum allowable. No single failure can result in heating of the pipe to temperatures above 800 ºF. The off-gas electric preheater system meets the design basis criteria established for the original heat exchanger system.

15.4.15.1.2 Starting Conditions and Assumptions

The equipment and piping are designed to contain any explosion having a reasonable probability of occurrence. Therefore, an explosion is not considered a possible failure mode. The equipment vaults are not accessible during normal operation. Therefore, an operator-induced failure is not considered reasonable. The only credible event that could result in the release of significant activity to the environment is an earthquake.

15.4.15.1.3 Event Description

Even though the off-gas system is designed to uniform building code seismic requirements, an event more severe than the design requirements is arbitrarily assumed to occur, resulting in the failure of the off-gas system. The sequence of events following this failure and the approximate elapsed times are as follows:

	Event Sequence	Elapsed Time
1.	The event begins; the system fails.	0
2.	Noble gases are released.	0
3.	Area radiation alarms alert plant personnel.	~ < 1 min
4.	Operator actions begin (not essential).	~ < 1 min

15.4.15.1.4 Analysis of Effects and Consequences

15.4.15.1.4.1 <u>Realistic (Conservative Engineering) Evaluation Methods</u>. The analytical methods and associated assumptions used in evaluating the consequences of an off-gas system failure are considered to provide a realistic, yet conservative, assessment of the consequences.

15.4.15.1.4.1.1 Methods, Assumptions, and Conditions. The reactor is assumed to be operating at rated power conditions for a period of time sufficient to cause an equilibrium inventory to be accumulated in the off-gas system. The activity in the off-gas system is based upon the following conditions:

- 40-sf^3/min air inleakage.
- 100,000-μCi/s noble gas after a 30-min delay.
- 12 charcoal beds.
- Removal of daughter products by the following equipment:
  - Off-gas condenser - 100% washed out.
  - Water separator - 100% washed out.
  - Holdup pipe - 20% washed out.
  - Dryer - 100% retained.
  - Carbon beds - 100% retained.

- Post-filter - 100% retained.

Adsorber Vessels

Charcoal serves as a noble gas adsorber and iodine filter in the off-gas system.

The charcoal absorber tanks are 4 ft in diameter and 21-ft tall, have dished heads, are designed for 350 psig, and are connected in a single vault.

The only credible failure that can result in the loss of carbon from the vessels is the failure of the concrete structure surrounding the vessel. A circumferential failure of the vessel can result from concrete falling onto the vessel in either of two ways:

A. Bending load - The vessel is supported in the center and loaded on each end. This can result in a tear around 50% of the circumference.

B. Shearing load - The vessel is supported and loaded near the same point from above.

In either case, not more than 10 to 15% of the carbon will be displaced from the vessel. Iodine is strongly bonded to the charcoal, and exposure to the air is not expected to remove the iodine. However, 10% of the iodine activity contained in the adsorber vessels is conservatively assumed to be released to the vault containing the off-gas equipment. The first vessel will contain essentially all adsorbed iodine.

Measurements made at KRB[a] indicate that off-gas is ~ 30% richer in Kr than air. Therefore, if the carbon is exposed to air, it will eventually reach equilibrium with the noble gases in the air. However, the first few inches of carbon will blanket the underlying carbon from the air. An assumed 100% loss of noble gas activity from the failed vessels is conservative because of the small fraction of carbon exposed to the air.

Holdup Pipe

A pipe rupture and a depressurization of the pipe are considered. Normally, the pipe operates at < 7 psig and depressurizes to 14.7 psia. The possible loss is conservatively taken as 20% of the particulates. The model used assumes plateout or washout of 20% of the particulate daughters for the calculation of the holdup pipe inventory.

15.4.15.1.4.1.2 Results and Consequences. The results and consequences of an off-gas system failure are provided below:

Fuel Damage

No cladding perforations result from an off-gas system failure.

a. Kernkraftwerk FWE Bayermwerk, 237 MWe BWR, Gundremmingen, West Germany.

Fission Product Released from the Fuel

No fission product released from the fuel results from a gaseous tank rupture.

Component Activity

HNP-2-FSAR tables 11.3-1 and 11.3-2 contain a list of the isotopic inventories assumed to be contained in the various components of the off-gas system.

Fission Product Released to the Environment

HNP-2-FSAR tables 11.3-1 and 11.3-2 provide a list of the isotopic inventories in the off-gas system equipment. Table 15.4-4 provides the primary activity released to the environment for each component considered.

Radiological Effects

Radiological effects are based upon a puff release to the atmosphere at a height of 0 m using the meteorological conditions presented in HNP-2-FSAR subsection 2.3.4 and the methods presented in reference 7. The reanalyzed realistic analysis results for the exclusion area and the LPZ boundaries are provided in table 15.4-4.

15.4.15.1.4.1.3 Consideration of Uncertainties. The gaseous radwaste tank failure was conservatively analyzed. Due to this approach, no uncertainties were evaluated.

15.4.15.1.4.2 Conservative (NRC) Licensing Basis Evaluation Methods. At the present time, the NRC has not issued any guidelines for evaluating the failure of the off-gas system. Therefore, no NRC-guided estimate of the consequences of this event can be made.

15.4.15.2 Failure of SJAE Lines (Radiological Consequences)

15.4.15.2.1 Identification of Causes

An evaluation of events that can cause a failure of the SJAE lines indicates that a seismic event more serious than the system is designed to withstand is the only event that can rupture the lines. The lines are designed to withstand the effects of a hydrogen explosion.

15.4.15.2.2 Starting Conditions and Assumptions

The incident is assumed to occur while the reactor is operating at 2535 MWt, a power level equivalent to 105% steam flow for the original rated conditions. Also, the off-gas and reactor

coolant iodine are conservatively assumed to be consistent with a 30-min noble gas release rate of 0.1 Ci/s.

15.4.15.2.3 Event Description

The lines leading from the SJAEs to the off-gas system are assumed to fail, resulting in activity normally processed by the off-gas system being discharged directly to the turbine building and subsequently through the ventilation system to the environment. This failure results in a loss of flow to the off-gas system signal.

15.4.15.2.4 Analysis of Effects and Consequences

15.4.15.2.4.1 Realistic (Conservative Engineering) Evaluation Methods. The analytical methods and associated assumptions used in evaluating the consequences of a failure of the SJAE lines are considered to provide a realistic, yet conservative, assessment of the consequences.

15.4.15.2.4.1.1 Methods, Assumptions, and Conditions. The reactor is assumed to be operating at a steam flow of 1.1 x 10^7 lb/h, with the noble gas and iodine activity at their design basis level. The reactor water concentrations for iodine are as follows:

Isotope	Concentration (μCi/g)
I-131	0.018
I-132	0.160
I-133	0.120
I-134	0.310
I-135	0.170

The iodine activity per pound of steam is assumed to be 2% of the iodine activity per pound of reactor coolant. An additional iodine decontamination factor of 140 exists between the condenser water and the off-gas piping.

No credit is taken for plateout in the building prior to release to the environment. The design basis noble gas release rate is 0.1 Ci/s at 30 min; however, the mix for the failure of the SJAE lines is only ~ 0.2-min old at the time of release. Therefore, the noble gas release rate at the break location is 0.7 Ci/s. It is assumed the operator will start shutting down the plant within 10 min of the line break.

15.4.15.2.4.1.2 Results and Consequences. The results and consequences of a failure of the SJAE lines are provided below:

<u>Fuel Damage</u>

No cladding perforations result from the failure of the SJAE lines.

<u>Fission Product Released from the Fuel</u>

No fission product released from the fuel results from the failure of the SJAE lines.

<u>Fission Product Released to the Environment</u>

The total activity released during the 10-min period is shown in table 15.4-5.

<u>Radiological Effects</u>

The radiological effects are based upon the meteorology presented in HNP-2-FSAR subsection 2.3.4 and the methods presented in reference 7. The radiological effects of a puff release at a height of 30 m are as follows:

	Whole-Body Dose (rem)	Inhalation Dose (rem)
Exclusion area (1250 m)	3.6E-03	1.3E-03
LPZ (1250 m)	3.6E-03	1.3E-03

15.4.15.2.4.1.3 Consideration of Uncertainties. Failure of the SJAE lines was conservatively analyzed; therefore, no uncertainties were evaluated.

15.4.15.2.4.2 <u>Conservative (NRC) Licensing Basis Evaluation Methods</u>. At the present time, the NRC has not issued any guidelines for evaluating the failure of the SJAE lines. Therefore, no NRC-guided estimate of the consequences of this event can be made.

15.4.15.3 <u>Malfunction of Turbine Gland-Sealing System (Radiological Consequences)</u>

15.4.15.3.1 Identification of Causes

Failure of various components of the turbine gland-sealing system can lead to system malfunction.

15.4.15.3.2 Starting Conditions and Assumptions

A. The power plant is operating at full power, the site auxiliary steam boiler is not operating, and the high-pressure turbine packing leakoff to the steam-seal header is providing gland-sealing steam.

B. The plant is operating in the startup process, with zero load on the main generator. The site auxiliary steam boiler is providing gland-sealing steam to the main turbine and reactor feed pump turbines.

15.4.15.3.3 Event Description

15.4.15.3.3.1 Loss of Sealing Steam. Instrumentation on the steam-seal header detects low sealing-steam header pressure, and an alarm indicating the low-pressure condition is annunciated in the MCR. A complete loss of sealing steam can only occur as discussed in the two cases below:

Case 1 Assuming starting conditions as described in item A above:

A complete loss of sealing steam can only be caused by a rupture of the 3.5-psig steam-seal header. This results in a high-pressure turbine gland-steam leakoff to the turbine building accompanied by the automatic opening of the steam-seal feed valve, thus, contributing additional nuclear steam to the turbine building environment. In view of the fact this system disorder is annunciated in the MCR, the above condition should not persist for a period no greater than 10 min before operator action to terminate the event is initiated.

Case 2 Assuming starting conditions as described in item B above:

A complete loss of sealing steam can be caused by either a failure of the site auxiliary steam boiler system to supply sufficient quantities of steam or a failure of the various control valves to maintain steam-seal header pressure.

In either of the above two cases, the result for the low-pressure turbines' shaft packing is essentially the same. That is, air is drawn into the turbine casing along the turbine shaft, resulting in cool-air quenching of the hot turbine shaft, which causes excessive shaft vibration.

In case 1, the turbine high-pressure packing releases steam to the turbine building environment. No adverse effects due to radiation are expected, since the plant analysis of the main steam line break accident (MSLBA) in the turbine building reveals that any high-energy or moderate-energy line failure outside the primary containment will not result in radiation exposures to MCR personnel or the general public exceeding allowable limits.

In case 2, the high-pressure turbine packings are under a negative pressure; consequently, the packings will also draw cool air into the turbine casing, as in the case of the low-pressure turbine packings.

15.4.15.3.3.2 <u>Loss of Vacuum in the Gland-Seal Condenser</u>. During normal operation, one of two gland-seal condenser blowers removes noncondensables from the gland-seal condenser. In the event one blower malfunctions, the backup blower automatically assumes the gas-removal requirements. Assuming the loss of both blowers, the vacuum in the gland-seal condenser is lost. The pressure in the steam-seal exhaust header increases to a pressure greater than atmospheric, causing sealing steam to leak into the turbine building through the turbine glands.

15.4.15.3.4 Analysis of Effects and Consequences

15.4.15.3.4.1 <u>Realistic (Conservative Engineering) Evaluation Methods</u>. The analytical methods and associated assumptions used in evaluating the consequences of a malfunction of the turbine gland-sealing system are considered to provide a realistic, yet conservative, assessment of the consequences.

15.4.15.3.4.1.1 Conditions and Assumptions. In the event sealing steam is lost, the action of cool air being drawn into the sealing glands and the resultant shaft vibration will cause tripping of the turbine-generator by the excessive shaft vibration trip. This tripping mechanism is independent of operator action and, consequently, produces a rapid and safe shutdown of the turbine-generator.

15.4.15.3.4.1.2 Results and Consequences. The results and consequences of the malfunction of the turbine gland-sealing system are provided below:

<u>Fuel Damage</u>

No cladding perforations result from a malfunction of the turbine gland-sealing system.

<u>Fission Product Released from the Fuel</u>

No fission product released from the fuel results from a malfunction of the turbine gland-sealing system.

<u>Fission Product Released to the Environment</u>

Failure of the gland-sealing system results in the release of radioactive steam to the turbine building. Due to the above hypothesized events, the amount of steam released to the turbine building is small because of the close clearances in the turbine shaft sealing glands. Any

release will be well below the release used for the failure of the SJAE lines (paragraph 15.4.15.2), as well as far below that of the MSLBA discussed in subsection 15.3.4.

Radiological Effects

The radiological effects are inconsequential, since any release will be well below the releases used for the failure of the SJAE lines (paragraph 15.4.15.2).

15.4.16 SBO (EVENT 56)

The SBO evaluations are provided to demonstrate compliance with 10 CFR 50.63. SBO is defined in 10 CFR 50.2 as the complete loss of ac power to the essential and nonessential electrical buses concurrent with a turbine trip and the unavailability of the redundant onsite emergency ac power systems. However, SBO does not include the loss of available ac power to buses fed by station service batteries through inverters or alternate ac sources (as defined in 10 CFR 50.2), nor does it assume a concurrent failure or DBA. Analyses have demonstrated that SBO can pose a significant challenge to the event acceptance limits; however, it is not significantly impacted by the reload fuel and core designs. As a result, SBO was reanalyzed for power uprate to an RTP of 2804 MWt and ROPI to 1060 psia. SBO analysis is not required for reloads.

This subsection provides the results of the SBO analysis to demonstrate compliance with the SBO coping capability requirements of 10 CFR 50.63. The reactor system and containment pressure/temperature responses were reanalyzed to determine the effects of increased decay heat due to extended power uprate. The reactor system and containment reanalysis confirmed that the current HNP coping duration for SBO of 4 h is acceptable.

The SBO reactor system and containment reanalysis for extended power uprate, thermal power optimization, and ROPI to 1060 psia were performed using the latest NRC approved GE evaluation models.[1, 9, 10] Several SBO cases were analyzed with various assumptions as described below. The key initial conditions and analysis assumptions are provided in table 15.4-6, with the analysis results summarized in table 15.4-7.

Case 1: Swing DG 1B loading below required loading limit, and suppression pool cooling could be initiated within 1 h.

Case 2: No suppression pool cooling within the 4 h coping period and no RPV depressurization.

Case 3: No suppression pool cooling within the 4 h coping period with RPV depressurization when required to prevent exceeding the suppression pool heat capacity temperature limit (HCTL).

The HNP coping duration for SBO is 4 h. However, suppression pool cooling, which uses swing DG 1B, can be initiated in 1 h when diesel-loading margins are met and if the operator deems necessary.

The results of the reactor system and containment pressure/temperature SBO reactor containment reanalysis show the resulting peak pool temperatures with either the 1-h or the 4-h suppression pool cooling initiation is acceptable for containment and ECCS performance.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

"GESTAR II - General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A.

Edwin I. Hatch Fire Hazards Analysis and Fire Protection Program.

REFERENCES

1. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 & 2," NEDC-32749, July 1997.

2. Scatena, G. J., "Reclassification of Turbine and Generator Trips Without Bypass," NEDE-25014.

3. Moody, F. J., "Maximum Two-Phase Vessel Blowdown From Pipes," ASME Paper No. 65-WA/HT-1, March 15, 1965.

4. Richardson, L. C. et al., "CONTEMPT - A Computer Program for Predicting the Containment Pressure - Temperature Response to a Loss-of-Coolant Accident," IDO-17220, Phillips Petroleum Company, June 1967.

5. Brutscky, F. J., et al., "Behavior of Iodine in Reactor Water During Plant Shutdown and Startup," NEDO-10585, August 1972.

6. International Commission on Radiological Protection, Report of Committee II on Permissible Dose for Internal Radiation, 1959.

7. Horton, N. R.; Williams, W. A.; Holtzclaw, D. W., "Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor," APED-5756, March 1969.

8. "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32523P, March 1996; and NEDO-32523, Class I (Non-Proprietary), and Supplements, April 1996.

9. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

10. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

11. “Edwin I. Hatch Nuclear Plants, Units 1 & 2 Adjustable Speed Drives Implementation Project – Transient and LOCA Support,” 0000-0055-5361-R0, Revision 0, GE Hitachi Nuclear Energy, October 2008.

TABLE 15.4-1

KEY INITIAL CONDITIONS AND ASSUMPTIONS FOR ATWS ANALYSIS

Rated thermal power (MWt)	2804
RPV steam flow (Mlb/h)	12.17
Core flow (Mlb/h)	71.5% of rated
Feedwater temperature (°F)	425.7
RPV dome pressure (psia)	1060
ATWS-RPT trip (psia)	1190
SRV setpoints (psia)	1119.7 to 1181.7
SRV capacity (% of rated steam flow)	76
RHR heat exchanger effectiveness/loop (Btu/s-°F)	Temperature Dependent
SLCS flowrate (gal/min)	41.2
Boron-10 enrichment (%)	60
Initial suppression pool mass (Mlb)	5.358
Initial suppression pool temperature (°F)	100
Service water temperature (°°F)	97
RHR start time (s)	660
Nuclear parameters	BOC & EOC
Dynamic void coefficient (¢/%)	-15.70 (BOC) -11.0 (EOC)

<u>LEGEND</u>:

BOC - beginning of cycle
EOC - end of cycle

TABLE 15.4-2

SUMMARY OF ANALYSIS RESULTS FOR ATWS[c]

Initiating Event	Exposure	Peak Neutron Flux (%)	Peak Heat Flux (%)	Peak Dome Press (psig)	Peak RPV Press (psig)	Peak Pool Temp (°F)	Peak Clad Temp (°F)
Pressure regulator failure - open	BOC	400[b]	148[b]	1479[b]	1498[b]	187	1499
Pressure regulator failure - open	EOC	583	157	1437	1456	192	1402
Closure of all MSIVs	BOC	311	140	1425	1444	202	1243
Closure of all MSIVs	EOC	329	142	1460[b]	1479[b]	217[b]	(a)
Loss of offsite power	EOC	187	100	1250	1273	199	687
Inadvertent opening of an SRV	EOC	113	101	1175	1197	177	(a)

a. Not limiting.
b. Updated based on the results of ATWS analyses provided by references 9 and 10.
c. RHRSW temperature increase to 97ºF has no impact on the reported values for ATWS event except for insignificant changes to peak pool temperature; however, the 217ºF peak temperature remains bounding.

TABLE 15.4-3

SUMMARY OF ANALYSIS RESULTS FOR TURBINE AND GENERATOR TRIPS WITHOUT BYPASS (NO DIRECT SCRAM, NO RPT) ANALYSIS

Maximum RPV pressure (psig)	1245
Time of maximum pressure (s)	2.8
MCPR	0.89
Time of MCPR (s)	1.7
Rods in boiling transition (%)	6.7
Peak cladding temperature (°F)	< 1420
Peak value of fuel average temperature (°F)	1544

TABLE 15.4-4

RADIOLOGICAL EFFECTS OF OFFGAS (RECHAR) SYSTEM FAILURE

(Exclusion Area and LPZ Boundaries - Both 1250 m)
Realistic (Conservative Engineering) Evaluation

Component Failed	Primary Component Activity Released	Resultant Dose
1st charcoal bed	Iodine (10%)	1.4 mrem thyroid
12th charcoal bed	Noble gas (100%)	1.9 mrem whole-body
Prefilter housing	Particulate (1%)	5.0 mrem whole-body
Holdup pipe	Particulate (20%)	3.2 mrem whole-body

TABLE 15.4-5

FAILURE OF SJAE LINES
ACTIVITY RELEASED TO ENVIRONMENT

Realistic (Conservative Engineering) Analysis

Isotope		Activity (Ci)
I-131		2.1E-03
I-132		1.9E-02
I-133		1.4E-02
I-134		3.6E-02
I-135		2.0E-02
	TOTAL	9.1E-02
KR-83M		3.6E 00
KR-85M		5.9E 00
KR-85		2.3E-02
KR-87		1.8E 01
KR-88		1.9E 01
KR-89		7.9E 01
XE-131M		1.7E-02
XE-133M		2.8E-01
XE-133		7.9E 00
XE-135M		2.3E 01
XE-135		2.1E 01
XE-137		1.0E 02
XE-138		7.9E 01
	TOTAL	3.6E 02

TABLE 15.4-6

KEY INITIAL CONDITIONS AND ASSUMPTIONS FOR SBO ANALYSIS

Rated thermal power (MWt) (100% of rated)	2804
Core flow (% of rated)	100
Scram and reactor isolation	Initiated at start of event
Feedwater flow	Ramped to zero in 5 s
SRV low-low set logic	Operable[a]
Decay heat	ANS 5.1-1979
RCIC and HPCI initiation level	Level 2
RCIC startup time (s)	45
RCIC flowrate (gal/min)	360
HPCI startup time (s)	75
HPCI flowrate (gal/min)	4250
Initial containment pressure (psig)	0.88
Initial suppression pool pressure (psig)	0.88
Initial suppression pool mass (Mlb)	5.358
Initial suppression pool volume (ft^3)	86,652
Initial suppression pool temperature (°F)	100
Service water temperature (°F)	97
Initiation of suppression pool cooling (base case)	At 4 h
RHR flow (suppression pool cooling mode) (gal/min)	7700
RHR heat exchanger effectiveness (Btu/s-°F)	Temperature dependent[b]

a. Maximizes mass and energy transfer to suppression pool.

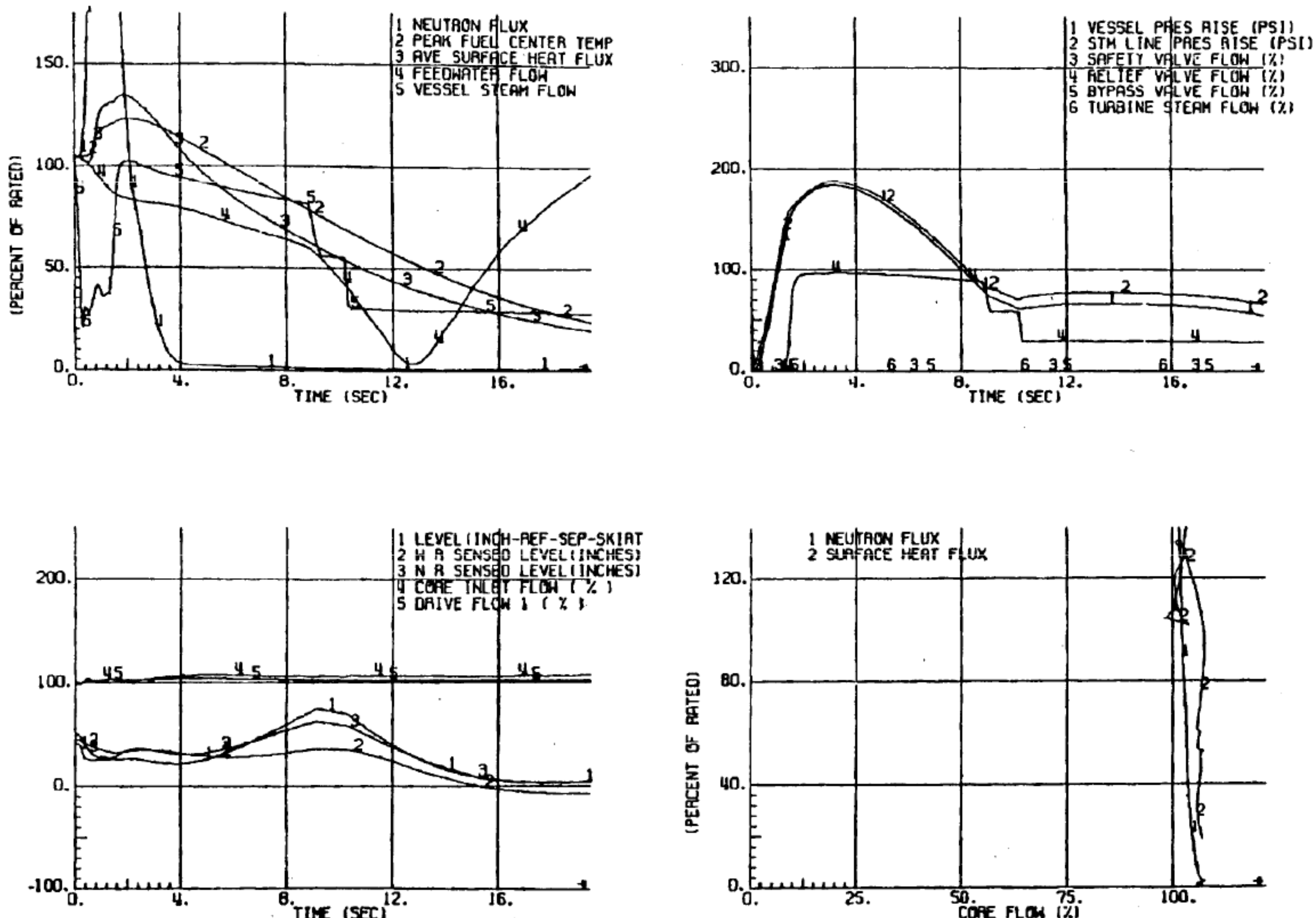
b. Reference GEH 0000-0126-6532-R1, Revision 1,"Ultimate Heat Sink Temperature Increase to 97°F Impact on DBA-LOCA Analysis and DW Equipment Qualification Analysis," June 2011.

TABLE 15.4-7

SUMMARY OF ANALYSIS RESULTS FOR SBO

Parameter	Case 1 Suppression Pool Cooling Initiated at 1 h	Case 2 Suppression Pool Cooling Initiated at 4 h[a]	Case 3 Suppression Pool Cooling Initiated at 4 h[b]
Peak drywell pressure (psig)	26.4	28.3	30.9
Peak drywell temperature (°F)	263	265	268
Peak wetwell airspace pressure (psig)	25.4	27.4	29.9
Peak suppression pool temperature (°F)	170	186	208

a. No depressurization.
b. Depressurization at 3.5 h to remain within suppression pool HCTL.



ACAD 2150401

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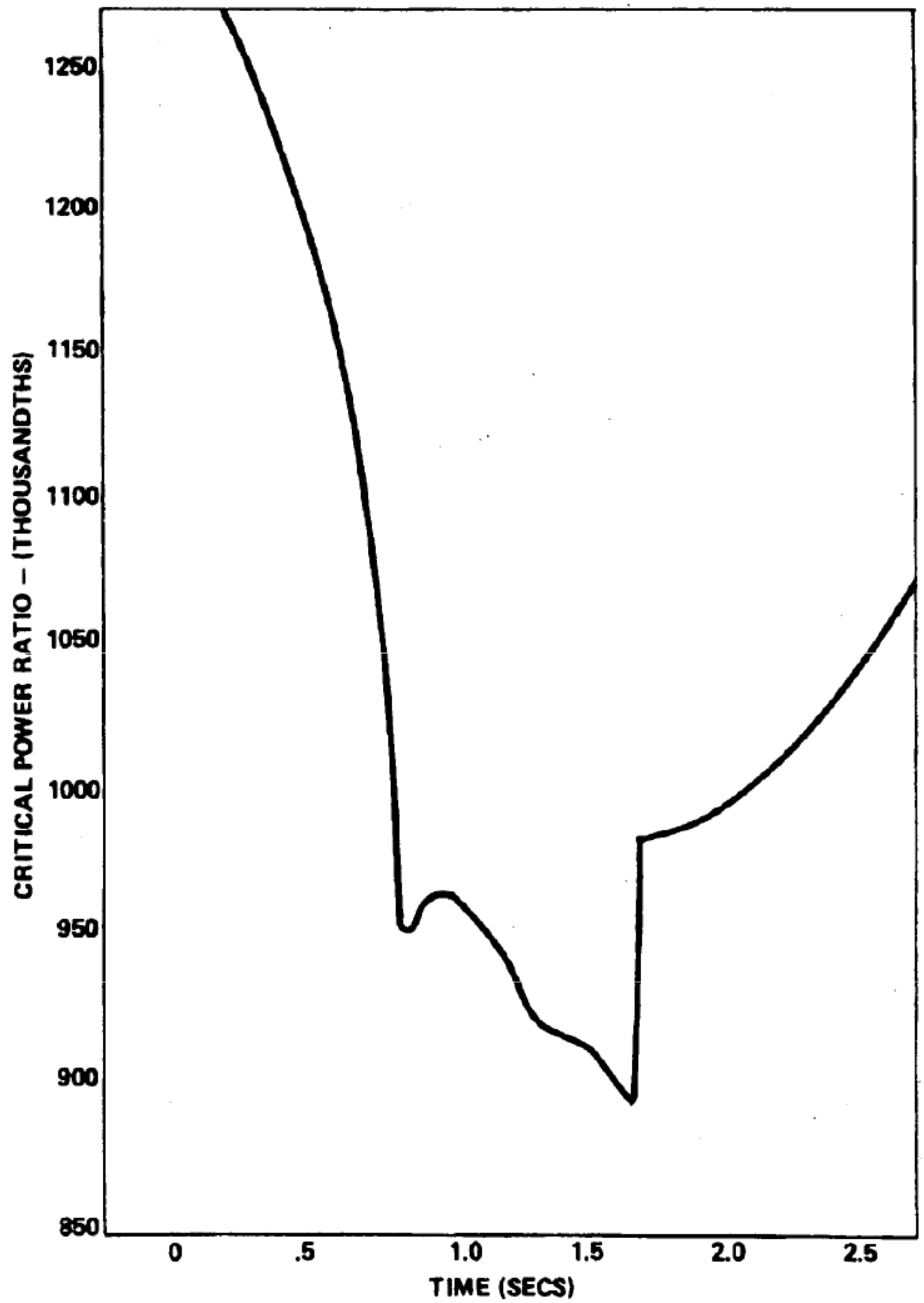
UNIT 1 AND UNIT 2

LOAD REJECTION WITH NO BYPASS, RPT, OR DIRECT SCRAM

FIGURE 15.4-1



ACAD 2150402

REV 19 7/01

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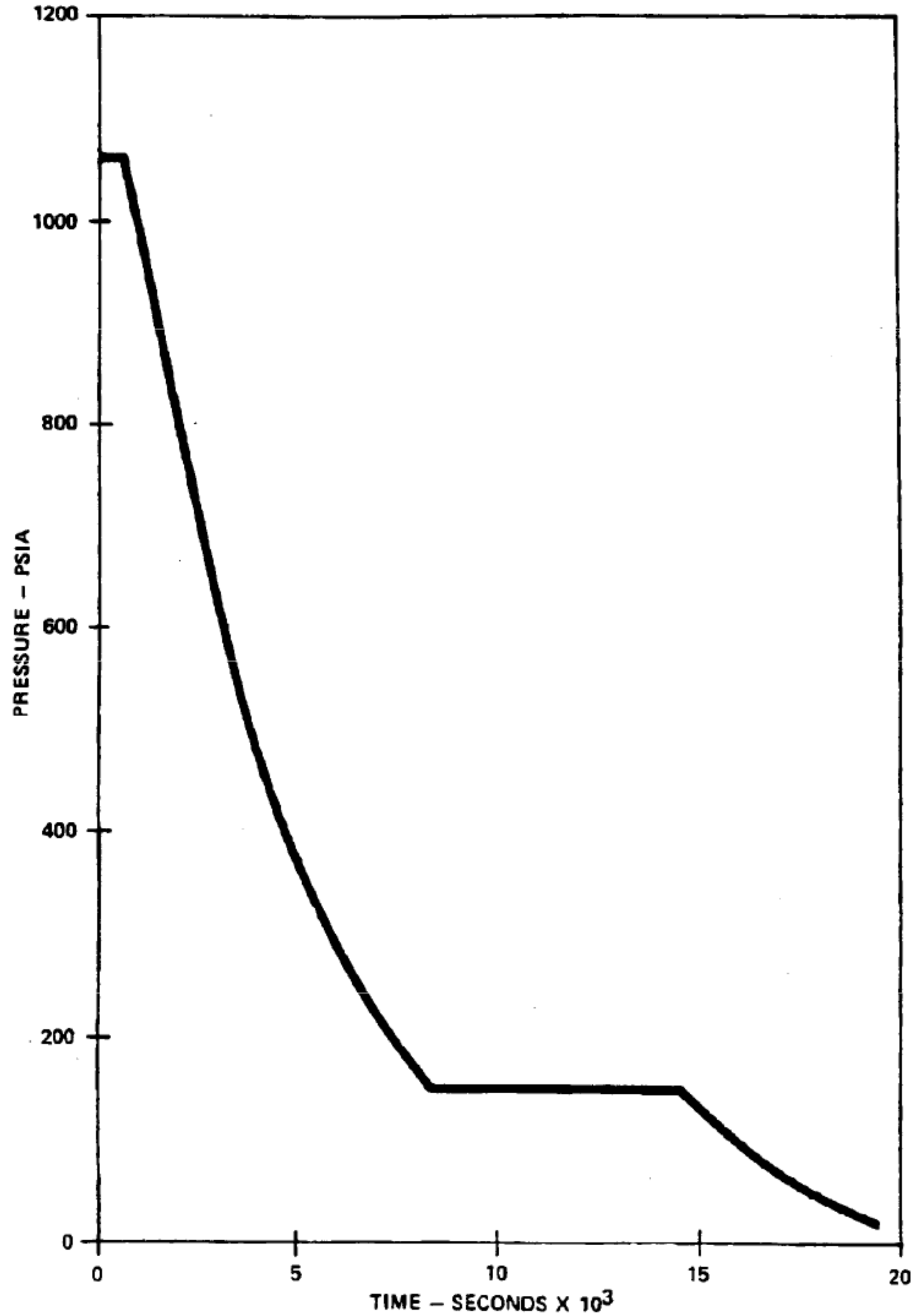
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CPR VERSUS TIME FOR LOAD REJECTION WITH NO BYPASS, RPT, OR DIRECT SCRAM

FIGURE 15.4-2



ACAD 2150403

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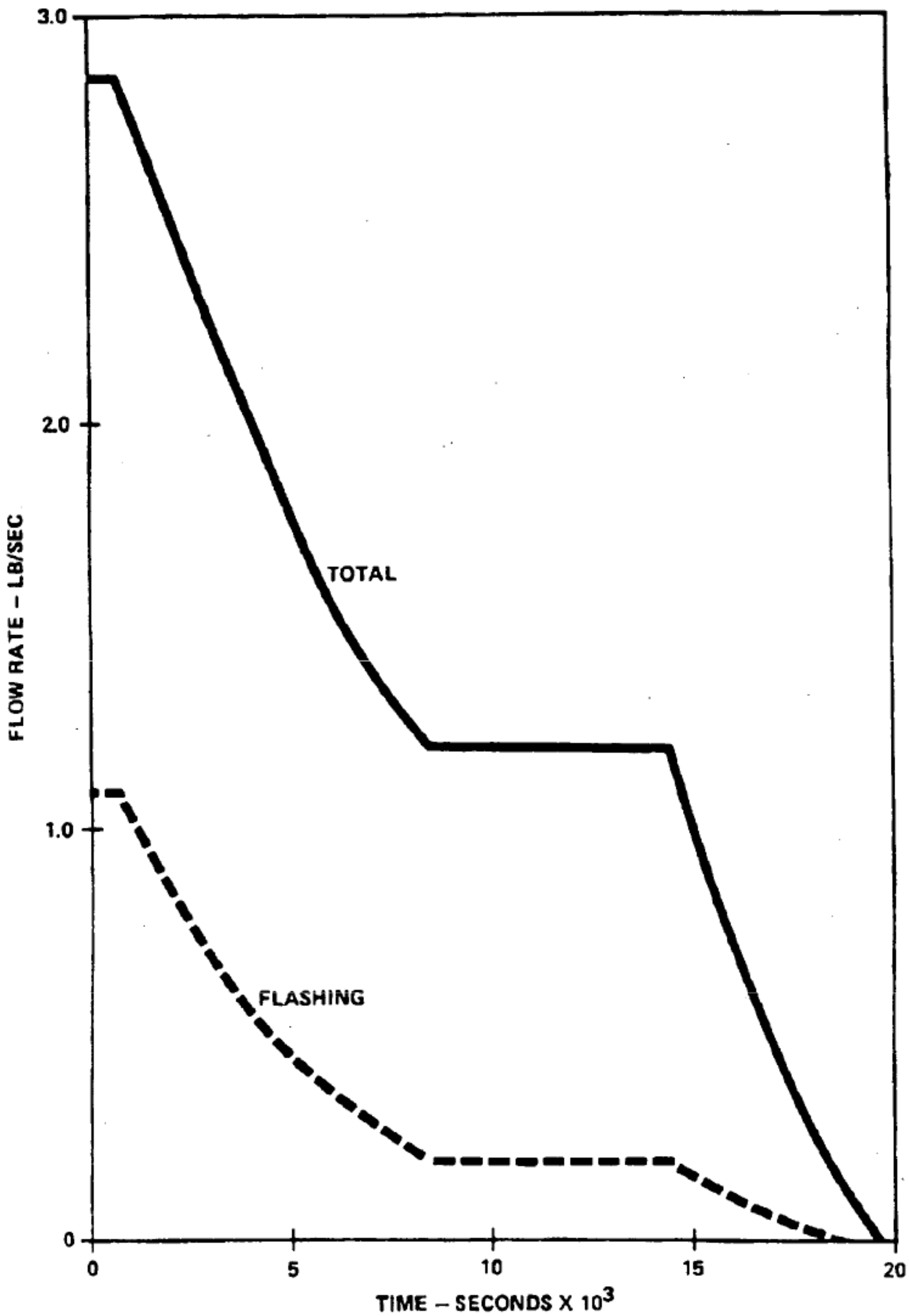
RPV PRESSURE IN NORMAL SHUTDOWN

FIGURE 15.4-3



ACAD 2150404

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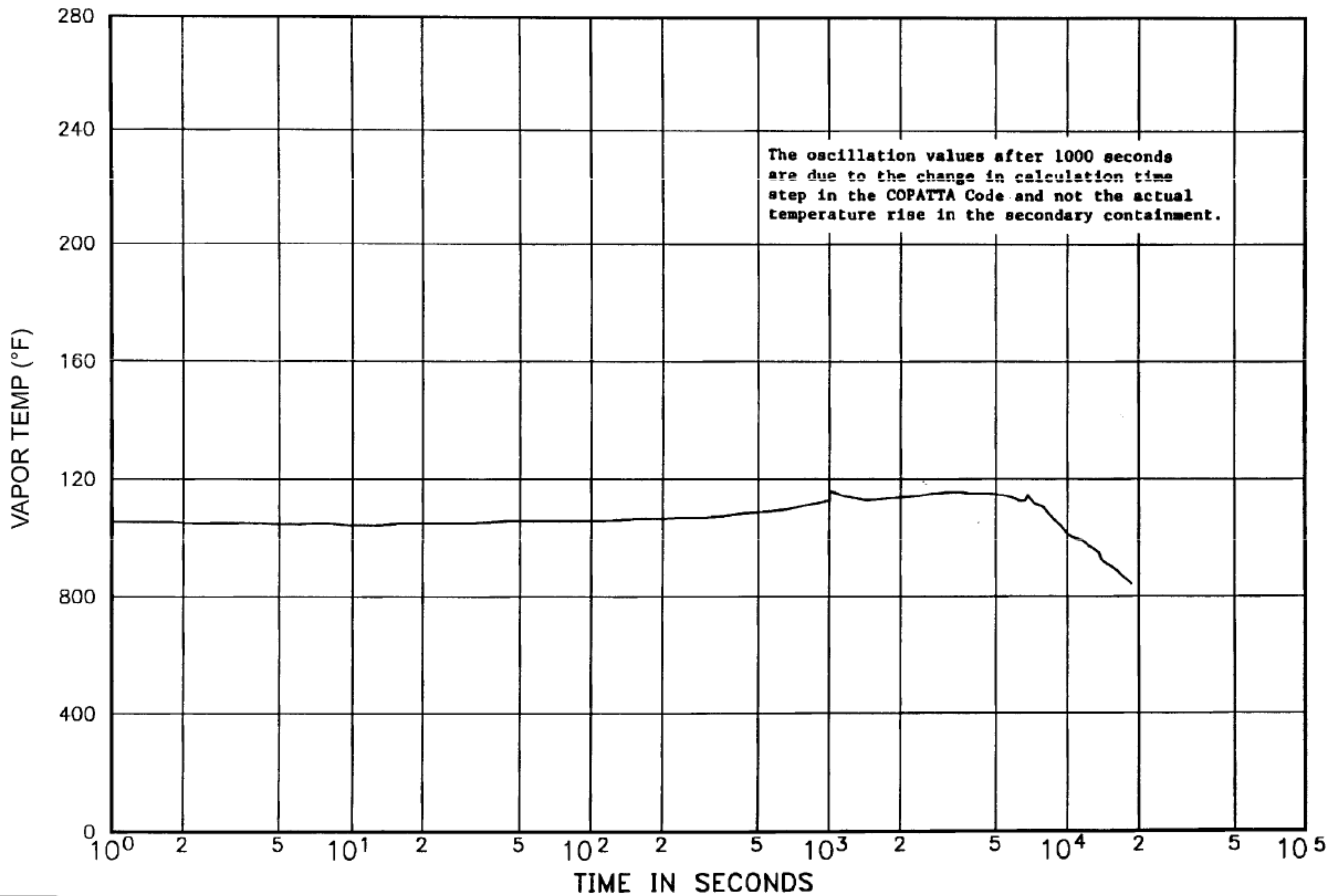
MASS FLOWRATE FROM INSTRUMENT LINE
WITH 1/4-in. ORIFICE
(SATURATED WATER)

FIGURE 15.4-4



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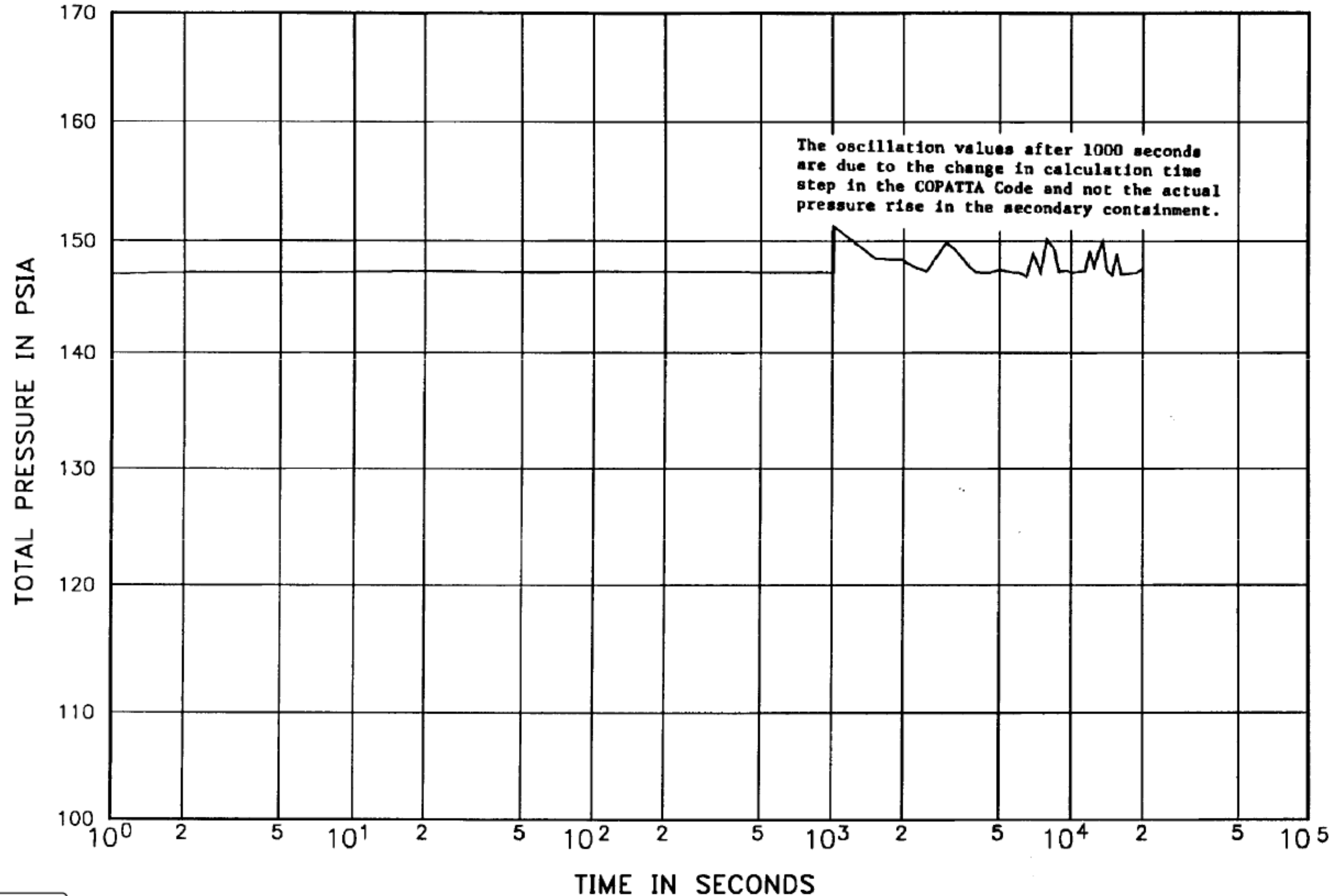
VAPOR TEMPERATURE VERSUS TIME
INSTRUMENT LINE BREAK

FIGURE 15.4-5



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REV 19 7/01

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UNIT 1 AND UNIT 2

PRESSURE VERSUS TIME
INSTRUMENT LINE BREAK

FIGURE 15.4-6

SUPPLEMENT 15A

DESIGN AGAINST HIGH-ENERGY PIPE BREAKS OUTSIDE THE PRIMARY CONTAINMENT

15A.1 PURPOSE

The purpose of this report is to summarize the capability of the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) to withstand the effects of a high-energy line break outside the primary containment, to bring the reactor to a safe shutdown, and to maintain the reactor in a safe shutdown condition.

15A.2 INTRODUCTION

The analysis of the potential effects of a high-energy piping system failure and the ability to initiate and maintain a safe shutdown was performed in accordance with the 21 U.S. Atomic Energy Commission (AEC) criteria presented in the attachment to the AEC letter of December 22, 1972, entitled "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment" as modified by the errata sheet sent under AEC cover letter to the applicant dated January 12, 1973. Portions of the attachment are repeated and all criteria are addressed specifically in this report.

Based on the analyses described and with the design changes discussed within this report, the reactor can be placed and maintained in safe shutdown condition and the plant can withstand the effects of high-energy line breaks outside containment. As a result of IEB 79-14 which required an evaluation of as-built safety-related piping systems, major portions of the piping referenced in this section were reanalyzed. The piping systems modified or reanalyzed as a result of IEB 79-14 were reviewed to assure that any cracks or breaks postulated would not affect safety-grade equipment or structures such that the reactor could not be brought to and maintained in a safe shutdown condition.

As a result of additional requested information by the Nuclear Regulatory Commission (NRC), additional criteria were evaluated, and the results are presented in supplement 15A.A.

15A.3 GENERAL DESIGN EVALUATION

Prior to discussing the detailed evaluation of high-energy fluid system failures, some general comments are provided in subsections 15A.3.1 and 15A.3.2, with respect to the capability of HNP-2 to withstand the adverse effects of the postulated accident.

15A.3.1 EVALUATION WITH RESPECT TO AEC CRITERIA

Each of the 21 AEC criteria is addressed in tabular form below. Most of these criteria form the bases for the detailed system analyses discussed in section 15A.5. A general design

evaluation, in conjunction with references to other portions of the FSAR, is provided to satisfy fully the intent of some of the criteria.

AEC Criterion No.	FSAR Section Applicable	Remarks (R) or General Design Evaluation (E)
1	15A.4.1.1	(R) Systems for which pipe whip protection is required are identified.[a]
2	15A.4.1	(R) Systems for which jet impingement and environmental effects must be analyzed are identified.
	15A.4.2.1, 15A.4.2.2	(R) Criteria for postulating failure locations are stated.
3	15A.4.2.1	(R) Pipe break orientation criteria are stated.
4	15A.5	(R) In lieu of performing dynamic analyses, it was assumed that, where a pipe causes a pipe to move and strike an essential component, that component is lost unless the component is a pipe of equal or greater diameter and heavier wall thickness.[a] Target components are identified in section 15A.5.
5(a)	15A.5.1.1	(R) Pipe anchors and restraints are designed for pipe rupture loads for steam and feedwater lines.
5(b)	15A.5	(R) Protective measures against direct effects are discussed by individual system.
5(c)	N/A	N/A
5(d)	N/A	N/A
5(e)	N/A	N/A
5(e)	15A.5.1.1	(R) Criteria for design of anchors and restraints are stated.

a. Refers to the AFC criteria attached to the December 22, 1972, letter to the applicant.

AEC Criterion No.	FSAR Section Applicable	Remarks (R) or General Design Evaluation (E)
6	15A.5	(E) Seismic Category I reinforced concrete structures and members are evaluated by ultimate strength design methods of American Concrete Institute 318-63, Part IV-B, using the strain and stress assumptions of Section 1503. Loads and load factors for this case are as follows: Maximum transient pressure 1.5 Dead load 1.0 Live load 0 or 1.0 (to maximize effects) The following combination was also considered: Maximum transient pressure 1.25 Dead load 1.0 Live load 1.0 Earthquake 1.25 The combination from above which provided the greatest load was used in design. Tornado and normal thermal loads were not included. Seismic Category I structural steel members were evaluated by conventional working stress methods of the American Institute of Steel Construction (AISC) specifications using a 50% increase in allowable stresses, which provides sufficient margin against yielding.
7	15A.4.4.1, 15A.5	(E) The structural design load resulting from pipe break consists primarily of differential pressures acting on the various walls and slabs. Peak values were computed in all areas, and the weakest member in each area was checked for adequate capacity. Concurrent loadings (such as dead, live, and equipment) were considered. Loads due to thermal stress were not considered since the high-temperature conditions were of short duration and it is not likely that thermal loads result in structural failure.

AEC Criterion No.	FSAR Section Applicable	Remarks (R) or General Design Evaluation (E)
8	15A.3.1, criterion 7	(E) Reversal of the normal stress pattern was considered. Also, as indicated in Criterion 6, the concurrent live load is conservatively assumed to be either 0 or 100% to maximize effects of possible stress reversals.
9	3.8, 15A.5, 15A.6	(E) Vent openings added as modifications are discussed in sections 15A.5 and 15A.6. The net section in each of the modified slabs or walls are adequate to satisfy all criteria listed in section 3.8.
10	15A.5	(E) The failure of any structure or structural element is precluded, either by determining the acceptability of existing design or by modifying the existing design to withstand the effects of pipe breaks.
11	15A.5, 15A.4.2.3	(R) The basic approach to maintaining required redundancy is to assume that the line being considered fails; any equipment damaged from the postulated line break's direct or environmental effects, so as not to be functional, is considered part of the accident; after the accident, a single active failure is assumed to occur in the worst place with regard to shutdown capability; after these assumptions, the ability to safely shut down the reactor is maintained.
12	15.4, 15A.3.2	(R) Habitability of the main control (MCR) room is addressed for a main steam line break (MSLB).
		(E) The entire control complex, located in the control building, is not adversely affected by any high-energy line failure.
	15.4	(R) MCR protection from the design basis accidents is discussed.
13(a)	Table 15A-3	(R) A table of equipment required for safe shutdown is provided.
	NA	(R) Time after postulated accident and duration required for the operation of shutdown equipment is provided in HNP-2 plant procedures.

AEC Criterion No.	FSAR Section Applicable	Remarks (R) or General Design Evaluation (E)
13(b)	15A.3.2, item E	(R) Qualification tests for cable, field splices, and connection, including radiation tolerance, meet the requirements of Institute of Electrical and Electronic Engineers (IEEE) 383-1974.
	15A.3.2, item F	(R) Qualification tests for valve operators are described.
	15A.5	(R) Environmental conditions are summarized.
13(c)	15A.4.3, 15A.5	(R) Barriers provided to protect electrical equipment from pipe whip and jet forces are discussed in section 15A.5.
13(d)	Criterion 12	(R) No adverse environment in the control complex is expected.
13(e)	15A.2, 15A.5	(R) Onsite emergency ac power sources are located in a separate protective structure (diesel generator building).
14	N/A	N/A
15	15A.5	(R) Any adverse effects of steam or water flooding are addressed by individual line break .
	3.8.4	(R) Design against flooding of safety-related equipment in the reactor building is discussed.
	10.4	(R) Flooding effects and design features for the turbine building are discussed.
16	3.2, chapter 17	(E) Further quality control or inspection is not required.
17	15A.5.3	(R) Leakage detection systems are adequate to meet criteria.

AEC Criterion No.	FSAR Section Applicable	Remarks (R) or General Design Evaluation (E)
18	NA	(R) The shutdown procedure followed without loss of offsite ac power is described in HNP-2 plant procedures.
	NA	(R) The shutdown procedure followed with loss of offsite ac power is described in HNP-2 plant procedures.
	Table 15A-3	(R) A table of equipment required for safe shutdown is provided.
	15A.5	(R) Shutdown procedure, including effects of single active failure followed for each individual break, is provided.
19	3.2	(E) Description of seismic and quality classification of safety-related high-energy lines is provided.
	15A.3.2	(E) Item I provides seismic classification for main steam lines.
20	15A.4.4	(R) Summary of approach, assumptions, and computer model is documented.
	Table 15A-2	(R) Blowdown energy and time interval for each line break are tabulated.
	15A.5	(R) Results of each analysis are given by individual system.
21	15A.5	(E) The structural capabilities of the primary and secondary containment structures were evaluated for direct effects of the postulated breaks and the effects of external and differential pressure. Special vendor qualification was obtained to assure adequate margin in the results as applicable to the primary containment.

15A.3.2 INHERENT PLANT SAFETY FEATURES WITH RESPECT TO DESIGN AGAINST HIGH-ENERGY PIPE FAILURES

The following is a list of inherent safety features of HNP-2 which enable the plant to withstand the effects of high-energy piping system failures. These safety features are stated generally and references are provided which discuss the design features in more detail.

A. All safeguard equipment is located within Seismic Category I structures with redundant features being physically separated by distance and in most cases by Seismic Category I walls (section 3.8 and chapter 6).

B. The control complex, including the battery rooms, cable spreading room, switchgear rooms, and MCR, is located in a separate Seismic Category I structure. As shown in figure 15A-2, 5-ft-thick Seismic Category I concrete walls separate the control complex from the compartment containing the main steam and feedwater lines.

C. The diesel generators and their associated equipment and emergency power sources are located in a separate Seismic Category I structure physically removed from the turbine and reactor buildings. No postulated high-energy pipe failure can cause pipe whip, jet impingement, or environmental damage to the onsite emergency ac power supply.

D. There is no equipment or instrumentation located in any area of the turbine building proper through which any high-energy lines run which would obviate the ability to shut down the reactor safely. The cable chase area below el 147 ft of the turbine building is analyzed to Seismic Category I criteria. There is a 5-ft-thick barrier between the main steam and feedwater piping located above el 147 ft and the cable chase area. This structural element precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building on the cables. For the installation of the analog transmitter trip system (ATTS), cables in conduit were routed near the main steam and feedwater lines in the turbine building to reach the cable spreading room. These cables are protected from the effects of postulated breaks by a steel barrier which surrounds the conduit. Therefore, postulated failure of a high-energy pipe occurring in the turbine building does not prevent safe shutdown of the reactor.

E. All cabling used for equipment required for safe shutdown is environmentally qualified for the application to the requirements of 10 CFR 50.49. The environmental and radiation qualifications of the cables meet the requirements of IEEE 383-1974. The criteria for cable routing are provided in section 8.3.

F. All the valve motor operators (required for safe shutdown) used outside the primary containment are similar to those used inside the primary containment and are environmentally qualified to 10 CFR 50.49. The performance of the valve operators used within and outside the primary containment under high-temperature saturated-steam conditions is documented in the HNP-2 Environmental Qualification Central File.

G. In general, no safeguard instrument panels are located in close proximity to high-energy piping nor are there direct line-of-sight paths of communication between high-energy pipes and safeguard panels. Therefore, there are no direct effects of pipe whip and jet impingement on such panels due to the postulated high-energy pipe failures. Panels, which are located near high-energy lines, include those in the HPCI and reactor core isolation cooling (RCIC) rooms. For a break in either room, the only required function of the HPCI or RCIC system is the isolation of the broken pipe. Evaluation of the jet impingement and pipe whip effects upon such panels has assured that the isolation function is not affected.

   Some panels are located near the control rod drive (CRD) piping, which is high pressure, although not high temperature. Analysis of the whip and jet potential from these postulated breaks has shown it to be below the damage threshold of the panels.

H. The ventilation supply to the control room is on the west side of the control building at el 180 ft, i.e., the side away from the reactor building. As such, there is no possibility of steam from a postulated high-energy pipe break being drawn into the control room. The MCR is automatically isolated by the main steam line high-flow signal indicative of an MSLB. Also, radiation monitors are provided in the control room intake to provide automatic isolation of the MCR upon receipt of a high-radiation signal.

   None of the postulated high-energy line failures can cause pipe whip, jet impingement, external overpressurization, or environmental damage to the control complex or radiation hazard to the operators.

I. As described in section 3.2, the main steam lines are designed to Seismic Category I criteria out to the turbine stop valves in the turbine building.

J. Relief vents exist in the roofs of the reactor building (600 ft^2) and turbine building (3000 ft^2) that are designed to relieve at 55 lb/ft^2 (~ 0.4 psid) for a tornado. These vents, however, perform the function of venting from internal pressure without damage to the structure.

15A.4 METHODS OF ANALYSIS AND ASSUMPTIONS

15A.4.1 IDENTIFICATION OF HIGH-ENERGY FLUID SYSTEMS

The criteria for identification of high-energy fluid systems outside the primary containment are schematically summarized in table 15A-1.

High-energy lines identified in 15A.4.1.1 are evaluated for direct effects of pipe whip and jet impingement and for all adverse environmental effects (pressure, temperature, radiation, and flooding). Moderate-energy lines identified in 15A.4.1.1 are evaluated for the direct effects of jet impingement and for adverse environmental effects.

15A.4.1.1 High-Energy Lines Identified

For postulating pipe breaks per AEC criteria and pipe cracks at the most adverse locations, the following high-energy lines have been identified:

High-Energy Line	Service Temperature (°F)	Service Pressure (psig)	Pipe Diameter (in.)	Pipe Schedule
Main steam	551.7	1045	24	80
Feedwater	425.7	1086	18	120
HPCI steam	551.7	1045	10	80
RCIC steam	551.7	1045	4	80
Reactor water cleanup (RWC)	534.5	1211/1050	4/6[a]	80
Residual heat removal (RHR)[b] discharge	280[c]/117[d]	340/190	24	30

15A.4.1.2 Moderate-Energy Lines Identified

For postulating critical size cracks, the following moderate-energy lines were identified:

Moderate-Energy Line	Service Temperature (°F)	Service Pressure (psig)	Pipe Diameter (in.)	Pipe Schedule or Thickness (in.)
Nonflashing				
CRD return	150	1029[f]	3	80
Residual heat removal service water (RHRSW)	95	415	18	0.5
Flashing				
Auxiliary steam	450	175	10	40
RHR suction[e]	328/125[d]	170[c]/20	20	30

a. These values apply to piping upstream of the RWC pump.
b. Breaks and cracks are not postulated to occur in these lines due to infrequent and short-term periods (~ 1.5 h during cooldown) during which the AEC temperature and/or pressure criteria are exceeded.
c. At onset of RHR shutdown cooling operation.
d. At end of RHR shutdown cooling operation.
e. Cracks are not postulated to occur in this line due to infrequent and short-term periods (~ 1.5 during cooldown) during which the AEC temperature criterion is exceeded.
f. The CRD return has been evaluated as a high-energy line in section 15AA.

15A.4.2 HIGH-ENERGY PIPING SYSTEM FAILURE ASSUMPTIONS

15A.4.2.1 High-Energy Line Breaks

A. In accordance with AEC Criterion 3, piping systems identified in paragraph 15A.4.1.1 are assumed to break as follows:

- Circumferential breaks are perpendicular to the pipe axis, and the break area is equivalent to the internal cross-sectional area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially and cause pipe movement in the direction of jet reaction. Circumferential breaks are to be considered in pipes exceeding 1-in. nominal pipe size.

- Longitudinal breaks are parallel to the pipe axis. The break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in a direction normal to the pipe axis. Longitudinal breaks are to be considered in pipes of 4-in. nominal pipe size and larger.

- At each postulated break location, a circumferential break is assumed to occur in pipes larger than 1 in., and a longitudinal break is assumed to occur in pipes 4 in. and larger except where detailed stress analysis at a particular postulated break location demonstrates that either:

  - The maximum stress is in the longitudinal direction and is a factor of 1.5 higher than the circumferential stress at that point on the cross-section, in which case only a circumferential break is postulated at that location.

  - The maximum stress is in the circumferential direction and is a factor of 1.5 higher than the longitudinal stress at that point on the cross- section, in which case only a longitudinal break is postulated at that location and is oriented around the circumference at the point of maximum stress.

- Longitudinal breaks are not postulated at terminal ends if the pipe does not have a longitudinal weld.

- Longitudinal breaks are not postulated at intermediate locations where the criterion for a minimum number of break locations must be satisfied.

B. In accordance with AEC Criterion 2, circumferential and/or longitudinal breaks have been assumed to occur at the following locations in each piping run or branch run:

- Terminal ends.

- Any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated

basis under the loadings associated with seismic events and operational plant conditions exceed 0.8 (S_h + S_A).[a] If there are no locations where these stresses are exceeded, then a minimum of two intermediate circumferential breaks have been postulated and selected on the basis of highest stress.

The requirements of the pipe break criteria in a post 79-14 context were reviewed utilizing the guidelines presented in the Standard Review Plan (SRP), section 3.6.2, Revision 1, which was in effect at the time of the review. The guidelines presented in SRP section 3.6.2, Revision 1, state that as a result of piping reanalysis, the highest stress locations may be shifted; however, the initially determined intermediate break locations need not be changed unless one of the following conditions existed:

(i) Maximum stress ranges or cumulative usage factors exceed the threshold levels identified in Branch Technical Position (BTP) MEB 3-1, paragraph B.1.c.(1).(b) or B.1.c.(1).(c).

(ii) A change is required in pipe parameters such as major differences in pipe size, wall thickness, and routing.

(iii) Breaks at the new highest stress locations are significantly apart from the original locations and result in consequences to safety-related systems requiring additional safety protection.

To determine whether intermediate break locations required reanalysis, the guidance provided in items (i) and (ii) above were utilized. Item (iii) would have resulted in a complete reevaluation, unless the break locations had not changed at all, which would have required a massive engineering effort. In addition, IEB 79-14 requirements were primarily invoked to reconcile the as-built systems with the design. It was not the intent of the Bulletin to repostulate the breaks and design the plant for a set of new break locations. Furthermore, the entire concept of postulating two intermediate breaks even if the stresses in the pipe are below the threshold levels is totally arbitrary.

It is evident and recognized in BTP MEB 3-1, section A, that pipe breaks are, at best, only a remote possibility, whether at postulated locations or otherwise. In addition, the inservice inspection requirements in effect provide reasonable assurance of the system integrity on a continued basis. Thus, the locations of postulated high-energy piping failures, as presented below, are not revised for each stress calculation revision. A safety impact review and break location changes will be done only for the following cases:

a. S_h is the stress calculated by the rules of NC-3600 for Class 2 and 3 components, respectively, of the American Society of Mechanical Engineers (ASME) Code, Section III, Winter 1972 Addenda.
S_A is the allowable stress range for expansion stress calculated by the rules of NC-3600 of the ASME Code, Section III, or the USA Standard Code for Pressure Piping, American National Standards Institute B31.1.0-1967.

A. The revised pipe stress or cumulative usage factor exceeds the threshold levels.

B. There is a major change in the pipe diameter or routing.

C. Terminal ends have changed.

The 0.1 cumulative usage factor (CUF) criterion in BTP MEB 3-1 represents a screening criterion so that a sufficient number of postulated break locations is developed. The screening criterion of 0.1 CUF is not tied to the plant operating license term as applied to the HNP-2 stress calculations.

15A.4.2.2 <u>High-Energy and Moderate-Energy Line Cracks</u>

In accordance with AEC Criterion 2 (as modified by the errata sheet referred to in section 15A.2), high-energy and moderate-energy lines identified in paragraphs 15A.4.1.1 and 15A.4.1.2 are assumed to develop critical size cracks, which are taken to be one-half the pipe diameter in length and one-half the wall thickness in width. These cracks are assumed to occur at any location along the length and at any point around the circumference of the pipe, where the stress exceeds 0.4 (1.2 S_h + S_A).

15A.4.2.3 <u>Other Failure Assumptions</u>

In addition to the assumptions for postulating breaks or cracks, other failure assumptions include:

A. The postulated break or crack was assumed to occur during normal operating conditions at rated power.

B. No other accident was assumed to occur concurrently with the pipe failure outside the containment.

C. A single failure of an active component was assumed to occur in the analysis of the accident and the analysis of the ability to shut down the reactor safely.

D. A loss of offsite ac power was assumed to occur only for line breaks which would result in an immediate reactor trip. The possibility of reactor trip for each line break is discussed under "Analysis of Shutdown Capability" for each line in section 15A.5.

15A.4.2.4 <u>Piping Penetrating Containment</u>

All high-energy piping between containment is ASME Section III, Class 1.

Pipe breaks are not postulated in portions of high-energy piping extending from the containment penetration to the first inside and/or outside isolation valve provided the following requirements are met:

A. The following design stress and fatigue limits are not exceeded:

For ASME Code, Section III, Class 1 Piping

- The stress range S_n does not exceed 2.4 S_m, or
- The stress range S_n as calculated by equation 10 in Paragraph NB-3653 exceeds 2.4 S_m but is $<$ 3.0 S_m and the cumulative usage factor is $<$ 0.1, or
- The stress range S_n exceeds 3.0 S_m but the stresses computed by equations 12 and 13 of subparagraph NB-3653 are $<$ 2.4 S_m and the usage factor is $<$ 0.1.

B. All analyses to date have and it is the intent of the applicant to meet the criteria in A; however, if the criteria is exceeded in some systems, the 100% volumetric examinations completed during each inservice inspection interval (IWA-2400, ASME Code, Section XI) of all circumferential and longitudinal pipe welds within the boundary of these portions of piping to the maximum extent practicable without imposing design changes provide the sufficient assurance of the integrity of this piping.

C. The pipe is anchored or restrained at the containment penetration so that forces and moments associated with failure of piping beyond the outboard isolation valve are not transmitted through the pipe to the containment penetration or the inboard isolation valve; and the forces and moments associated with failure of piping beyond the inboard isolation valve are not transmitted through the pipe to the containment penetration or the outboard isolation valve.

D. The extent of piping run between containment isolation valves is reduced to the minimum length practical.

E. The design at points of pipe fixity, e.g., pipe anchors or welded connections at containment penetrations, do not require welding directly to the outer surface of the piping (e.g., flued integrally forged pipe fittings are acceptable designs) except where such welds are 100% volumetrically examinable in service to the maximum extent practicable without imposing design changes.

A review of HNP-2 design and layout of the high-energy fluid system piping between the first isolation valve outside the containment and the first pipe whip restraint inside the containment has revealed that HNP-2 is amenable to the performance of augmented inservice inspection as defined by the Augmented Inservice Inspection of High-Energy Fluid System Piping, an NRC Publication.

Stress analyses were performed for ASME Class 1 piping between containment isolation valves. The results of the analyses indicate that there are no Class 1 pipes between containment isolation valves that have calculated stress levels and fatigue usage factors in excess of the limits specified in paragraph 3.6.2.2 and subsection 15A.4.2.

All pipe whip restraints whose dynamic loadings include gap effects are designed statically according to the provisions of paragraphs 3.6.3.1 a and b. A dynamic load factor (K_2) of 2.0 is used. Design adequacy is then determined by using the energy balance methods specified in BN-TOP-2.[(1)]

The anchors and restraints at the flued heads which normally contact the pipe are designed in accordance with ASME Section III, Appendix F and the AISC, and use the ultimate strength of the pipe for design loads. Normal operating loads are also considered in accordance with ASME Section III, but these loadings are minor compared to the rupture loads.

15A.4.3 JET IMPINGEMENT AND PIPE WHIP ANALYSIS

A thorough examination of each high-energy line identified in paragraph 15A.4.1.1. above, to determine the direct effects of pipe whip and jet impingement, was made by detailed drawing analysis. Certain safety-related cables and electrical components were identified to require protection from jet impingement on the basis of maintaining redundancy, and it was conservatively decided to provide protective barriers for the pipes. Where provided, barriers are designed in accordance with the analytical methods described in BN-TOP-2[(1)] and BC-TOP-9A.[(2)] The locations where such protective means are provided are identified in the detailed system analyses which follow in section 15A.5.

The drywell pneumatic system and nitrogen system are not specifically protected from pipe break effects outside the drywell, except at the drywell penetrations. Credit is taken for local operator action to restore within 2 h this pneumatic supply if damaged by a pipe break outside the drywell.

15A.4.4 COMPARTMENT PRESSURE-TEMPERATURE ANALYSIS

15A.4.4.1 <u>General Approach and Assumptions</u>

In accordance with AEC Criterion 20, a complete pressure-temperature transient analysis was performed for each compartment containing a postulated failure of a high-energy or moderate-energy line. Details of these analyses are discussed by individual system in section 5A.5; however, the general approach and assumptions applicable to all such analyses are as follows:

A. The pressure-temperature transient analysis was performed for the compartment in which the high-energy and/or moderate-energy (flashing) line failure was postulated (compartment 1) as well as for the other affected compartments which have direct or indirect communication with the original compartment.

B. The blowdown and energy releases from the broken lines are given in table 15A-2. To obtain maximum break area, a pipe is considered to be instantaneously and completely severed. Two-phase-mixture carryover time has been calculated by General Electric, using the LAMB code. A mixture quality of 7% was assumed for the mixture portion of the blowdown. Moody frictionless blowdown was assumed for major process lines, and the flow was considered critical at the point of minimum flow area.

C. The blowdown was assumed to last for the time interval corresponding to the maximum allowable closing times of the isolation valves, plus an additional signal delay time. The blowdown interval for each line break is provided in table 15A-1.

D. The short-term temperature-pressure transient analysis was calculated using the Bechtel code COPDA. The code and analysis are described in paragraph 15A.4.4.2. The temperature and pressure in different compartments, as well as the differential pressures across specific walls, are listed by system in section 15A.5. The short-term pressure transient analysis does not include any heat transfer. Long-term temperature transients in the compartment were obtained from the Bechtel code COPATTA. The code and analysis are discussed in paragraph 15A.4.4.3. Credit was taken for walls and slabs and major equipment as heat sinks in the long-term analyses. All other potential heat sinks were neglected.

E. The capability of the compartments and structures to withstand the resultant pressures was evaluated. In addition, the performance capability of components necessary for safe shutdown was evaluated to determine the effect of the resultant environment.

F. In cases where the pressure or temperature or both exceeded acceptable values on structures, structural elements, or the design requirements of critical equipment, an analysis was performed to determine the vent area required to reduce the pressures and temperatures to acceptable values. This additional vent area was then incorporated in the design, and the final analysis was to verify the acceptability of the design change. In evaluating the capability of structures or structural elements to withstand the resultant pressures, a value of 90% of ultimate stress was used.

15A.4.4.2 The Mathematical Model

The COPDA computer program was used to perform the short-term compartment pressure transient analysis. This program is capable of handling up to 100 control volumes with a maximum of 5 flow paths out of any compartment. The calculational methods used in COPDA are described in detail in the following paragraph.

15A.4.4.2.1 Initial Compartment Conditions

The masses of air and water as steam in the compartments are determined using the initial input conditions of temperature, pressure, relative humidity, and compartment volumes. The specific humidity of saturated air at the compartment temperature is read from a correlation table of temperature and water vapor in saturated air. The compartment specific humidity is obtained by:

$$SH = (RH)(SSH)$$

where:

SH = specific humidity of compartment air (lb steam/lb air).

RH = relative humidity of compartment air.

SSH = specific humidity of saturated air at compartment temperature (lb steam/lb air).

The vapor pressure of the water is determined by:

$$PW = \frac{(SH)(PT)}{0.623 + SH}$$

where:

PW = vapor pressure of water at compartment temperature (psia).

PT = total compartment pressure (psia).

The air pressure in the compartment is determined by:

$$PA = PT - PW$$

The mass of air in the compartment is evaluated using the perfect gas law equation:

$$MA = \frac{(144)(PA)(V)}{(R/n)(T)}$$

where:

V = volume of compartment (ft^3).

R = gas constant (1545.3).

T = compartment temperature (°R)

n = molecular weight of air (28.97 lb/lb mole).

PA = partial pressure of the air (lb/in.^{2}).

The mass of water vapor in the compartment, MS, is:

$$MS = (MA)(SH)$$

The masses of air and water vapor in the remaining compartments are determined in the same manner.

The internal energy of the air, UA (I), in each compartment is calculated using 460 R as a base:

$$UA(I) = [CV][MA(I)][TP]$$

where:

CV = specific heat of air at constant volume (0.171 Btu/lb- °F).

TP = compartment temperature (°F).

The internal energy of the water vapor in each compartment is calculated by the equation:

$$US(I) = [MS(I)][UG]$$

where:

UG = internal energy of the steam evaluated from the saturated steam tables at the compartment temperature.

15A.4.4.2.2 Conservation of Mass and Energy in Compartments

The inventory of the total mass and energy in the compartments is maintained from the inlet and exit flows during the time increment:

$$MA(I) = MA'(I) + \sum^{N}|MAI| - \sum^{N}|MAO|$$

$$MW(I) = MW'(I) + \sum^{N}|MWI| - \sum^{N}|MWO|$$

$$MS(I) = MS'(I) + \sum^{N}|MSI| - \sum^{N}|MSO|$$

$$MV(I) = MW(I) + MS(I)$$

$$MT(I) = MV(I) + MA(I)$$

$$UA(I) = UA(I) + \sum^{N} \left| UAI \right| - \sum^{N} \left| UAO \right|$$

$$UW(I) = UW(I) + \sum^{N} \left(HI \left| MSI \right| \right) - \sum^{N} \left(HO \left| MWO \right| \right)$$

$$US(I) = US(I) + \sum^{N} \left(HGI \left| MSI \right| \right) - \sum^{N} \left(HGO \left| MSO \right| \right)$$

$$UV(I) \quad = \quad UW(I) + US(I)$$

$$UT(I) \quad = \quad UV(I) + UA(I)$$

where:

Primed (′) values refer to end of previous time step, all other values refer to current time step.

MW(I) = mass of water in compartment (I), (lb).

MV(I) = mass of water and steam in compartment (I), (lb).

MT(I) = total mass in compartment (I), (lb).

MAI = mass of air entering compartment (lb).

MAO = mass of air leaving compartment (lb).

MWI = mass of water entering compartment (lb).

MWO = mass of water leaving compartment (lb).

MSI = mass of steam entering compartment (lb).

MSO = mass of steam leaving compartment (lb).

UAI = enthalpy of air entering compartment (Btu).

UAO = enthalpy of air leaving compartment (Btu).

HI = enthalpy of water entering compartment (I), (Btu/lb).

HO = enthalpy of water leaving compartment (I), (Btu/lb).

HGI = enthalpy of steam entering compartment (I), (Btu/lb).

HGO = enthalpy of steam leaving compartment (I), (Btu/lb).

UA(I) = energy in air in compartment (I), (Btu).

UW(I) = energy in water in compartment (I), (Btu).

US(I) = energy in steam in compartment (I), (Btu).

UV(I) = energy in vapor in compartment, (I), (Btu).

UT(I) = total energy in compartment, (I), (Btu).

15A.4.4.2.3 Compartment Pressure Calculations

The compartment pressure is calculated using the total mass and energy in the compartment after the flow from the upstream compartments and/or the blowdown was added to the compartment inventory of mass and energy. A convergence procedure is used to arrive at the equilibrium thermodynamics conditions in the compartment using temperature as the trial argument. The equilibrium thermodynamic state is considered determined when the trial temperature provides properties such that the ratio of the difference between the trial energy balance and the energy inventory is < 0.001. The state properties of the steam and water mixture at the trial temperature are obtained from the saturation tables. The mass of steam is then determined by:

$$MS = [(V) - (MW_1)(VL)] / VG$$

where:

V = volume of compartment (ft^3).

VL = specific volume of water (ft^3/lb).

VG = specific volume of steam (ft^3/lb).

MW_1 = mass-water from previous iteration (lb).

The mass of water (MW) is determined by:

$$MW = MV - MS$$

A trial energy balance is calculated:

$$ETRIAL = (MS)(US) - (MW)(UL) + 0.171(MA)(TP)$$

The procedure is repeated varying the value of TP until the relation:

$$(UT - ETRIAL) / UT \leq 0.001$$

is satisfied.

If, after establishing the thermodynamic equilibrium conditions, MW ≤ 0, the compartment is considered to be superheated. The equilibrium conditions are recalculated by setting the steam mass equal to the vapor mass and calculating the steam pressure at the search temperature by:

$$PS = 0.5961(MS)(T)/V$$

PS = pressure of steam (psia).

T = compartment search temperature (°R).

V = compartment volume (ft^3).

The internal energy of the steam at the pressure and temperature is obtained from the superheat tables and a trial energy balance calculated by:

$$ETRIAL = (MS)(US) + 0.171(MA)(TP)$$

The procedure is repeated varying the value of TP until the relation:

$$(UT - ETRIAL)/UT \le 0.001$$

is satisfied.

The total pressure in the compartment is the sum of the steam pressure and the air pressure with the latter being calculated by:

$$PA = 0.37MA\,(TP + 459.688)/V$$

where:

$$0.37 = R/(\text{mole weight})(144) = 1545.3/(28.97)(144)$$

15A.4.4.2.4 Flow Calculation

Two flow equations are provided for calculating the flow between compartments. The Moody equation is used for the analysis of reactor cavity pressures resulting from the decompression of the primary coolant system and for other compartments where the blowdown results in single component two-phase flow fairly early in the transient. A compressible fluid flow equation is used for the analysis of compartment pressures for the MSLBs and for other compartments where the blowdown results in two component two-phase flow for all of the transient or that portion of the transient through the maximum peak pressure.

In the application of the Moody equation for calculating the flow from compartment 1 to component 2, the flow is assumed to be critical if the pressure in compartment 2 is < 0.55 times

the pressure in compartment 1. If the flow is critical, the throat pressure is set equal to 0.55 times compartment 1 pressure.

For subcritical flow the form of the Moody equation is:

$$G = \left[\frac{2 * g_c * J * (HO - H2)}{\left(\frac{X * VG}{K} + (1 - X) * VF \right)^2 * (X * K^2 + 1 - X)} \right]^{1/2}$$

Where: HO is the stagnation enthalpy of the fluid in compartment 1 and the remaining state terms are evaluated at compartment 2 pressure. For isentropic flow, the formula is evaluated by the equations in compartment 1:

$$HO = UV(I) / MV(I) + PS(I) * 144 * V(I) / (MV(I) * 778)$$

$$X = (HO - HF) / (HG - HF)$$

$$SO = SF + X * SFG$$

and then in compartment 2:

$$X = (SO - SF) / (SG - SF)$$

$$H2 = HF + X * HFG$$

$$K = (VG/VL)^{1/3} * 1.224 * (P1 - P2) / P2$$

The state properties for compartment 1 and 2 are obtained from the saturation tables at the pressures in the compartments. For critical flow the forms of the Moody equation is:

$$G = \frac{2 * g_c * J * (HO - HT)^{1/2}}{\left[(1 - X) * VF^{2/3} + X * VG^{2/3}\right]^{3/2}}$$

where for compartment 1:

$$HO = UV(I) / MV(I) + PS(I) * 144 * V(I) / (MV(I) * 778)$$

$$X = (HO - HF) / (HG - HF)$$

$$SO = SF + X * SFG$$

and for the throat:

$$PT = PT(I) * 0.55$$

$$X = (SO - SF)/(SG - SF)$$

$$HT = HF + X * HFG$$

The state properties for compartment 1 and the throat are obtained from the saturation tables at the respective pressures in the compartment and throat.

For both the subcritical and critical flow conditions, the calculated value of the flow is decreased to 60% of the flow. In the application of the compressible fluid flow equation, if the ratio of the pressure in compartment 2 to the pressure in compartment 1 is less than RC as obtained by:

$$RC = \left[\frac{2}{1+K}\right]^{\frac{K}{K-1}}$$

the flow is considered to be critical. The form of the flow equation is:

$$G = \left[(g_c * K * P1) * RH01 * \left[\frac{2}{K+1}\right]^{\frac{K+1}{K-1}}\right]^{1/2}$$

The isentropic exponent K for the air, steam, and water mixture is calculated by:

$$K = KGF * \frac{PS(I)}{PT(I)} + KA * \frac{PA(I)}{PT(I)}$$

where:

KA = isentropic value of K for air of 1.4.

KGF = isentropic value of K for steam-water mixture.

RH01 = MT(I)/VOL(I) (lb/ft^3).

P1 = compartment 1 pressure (psia).

If the flow is subcritical, the form of the flow equation is:

$$G = \left[2 * g_c * P1 * RH01 * \frac{K}{K-1}\left(R^{\frac{2}{K}} - R^{\frac{K+1}{K}}\right)\right]^{1/2}$$

where the terms are as previously defined and R = P2/P1.

The mass flow for both the compressible fluid flow equation and the Moody equation is calculated by:

$$MF = G * A * C$$

$$MAF = MF * MA(I) / MT(I)$$

$$MWF = MF * MW(I) / MT(I)$$

$$MSF = MF * MS(I) / MT(I)$$

The energy transferred by the flow is:

$$UAF = MAF * (CP * TC(I) + 31.54)$$

$$UWF = MWF * HL$$

$$USF = MSF * HG$$

where:

A	=	area of flow path (ft^2).
G	=	mass flow (lb/ft^2 s).
C	=	coefficient calculated external to code.
CP	=	specific heat of air at constant pressure.
HL	=	enthalpy of water at compartment temperature.
HG	=	enthalpy of steam at compartment temperature.

The flow coefficient "C" was calculated using the same methods as outlined in the COPRA computer program which has been previously submitted for AEC review in NS-731-TN, "Containment Pressure Analysis," Power and Industrial Division, Bechtel Corporation, San Francisco, California, December 1968.

15A.4.4.3 <u>COPATTA</u>

15A.4.4.3.1 COPATTA Computer Program Description

The long term temperature transient analyses were performed using the COPATTA computer program. The COPATTA code is Bechtel's program to analyze the effects of a loss-of-coolant

accident on the reactor building. COPATTA was derived from the original CONTEMPT[3] code. The present COPATTA program is written in Fortran IV and uses the GE635 computer.

To determine the long term temperature response the COPATTA analysis was begun after the compartment peak pressures had been attained. The initial conditions used were taken from the results of the compartment analysis at the time corresponding to the startup time for COPATTA. The code then calculated the heat transferred from the atmosphere to the structures, thus determining the compartment temperature as a function of time.

15A.4.4.3.2 COPATTA Model

The COPATTA code as used in the case of the el 130-ft floor in the reactor building is based on thermodynamic equilibrium modeling of a two region compartment. The two-region compartment model predicts pressure and temperature histories of the compartment atmosphere and temperature histories of the compartment sump, the compartment structure, and various heat sinks within the structure.

The two regions which are incorporated in the COPATTA model are the compartment atmosphere and the compartment sump. The compartment atmosphere is a vapor region, and the compartment sump is a liquid region. The code calculates pressure-temperature transients for each of the regions by use of a finite difference, stepwise iteration between thermodynamic states. Iterations are based on the conservation of energy, mass, and their related functions.

Energy is transferred between the liquid and vapor regions by boiling with evaporation neglected. A convective heat transfer coefficient of zero is used as a conservative representation of the convective heat transfer. Each of the regions is assumed homogeneous with temperature differences allowable between the regions. Any moisture condensed in the vapor region during each step is immediately added to the sump (liquid) region. All noncondensible gases are included in the vapor region of the model.

15A.4.4.3.3 Thermodynamic Assumptions

The basic COPATTA program calculates conditions in two separate regions of the compartment, a water region in the sump and an atmosphere region. In a thermodynamic sense, the two regions are open systems since the program permits mass flow across the boundaries of each of the regions. The expression of the first law of thermodynamics for such open systems is:

$$\frac{\partial U}{\partial t} = \sum_{j} \frac{dQ}{dt} + \sum_{i} h \frac{dm_i}{dt}$$

where:

U = the internal energy of the system (Btu).

Q = heat energy addition to the system (Btu).

h = enthalpy of the mass entering the system (Btu/lbm).

m = mass entering the system (lbm).

t = time (h).

Integration of the above equation for each region, from the start of the transient to any later time, provides the thermodynamic properties with which the static point conditions of pressure and temperature can be determined. Numerical integration of the thermodynamic equations for each of the regions and the calculation of properties within the regions are based on the following assumptions:

A. At the breakpoint, the discharge flow separates into a steam phase which is added to the compartment atmosphere (vapor) region and a water phase which is added to the compartment sump (liquid) region. The water phase is at the saturation temperature corresponding to the total compartment pressure, while the steam phase is at the partial pressure of the steam in the compartment.

B. The compartment atmosphere pressure is also the sump pressure.

C. The steam-air mixture and the water phase are each assumed homogeneously mixed with uniform properties. Specifically, thermal equilibrium between the air and steam is assumed. A temperature difference may exist between the atmosphere region and the liquid region.

D. All of the steam condensed from the atmosphere during any time interval is added to the sump immediately at the end of the interval.

E. Mass and energy are transferred from the liquid region (sump) to the compartment atmosphere by boiling if the calculation indicates that the compartment pressure is less than the saturation pressure corresponding to the liquid temperature. Pipe breaks affecting component performance capability may be in the same room with the component of concern or in adjacent rooms. See table 3.11-1 for equipment qualification parameters.

F. The sump region contains no water at the beginning of the transient.

G. Condensation of steam due to a vapor pressure gradient between the steam in the compartment atmosphere and the water in the sump is neglected.

H. Condensation of the steam on structural heat sinks occurs at the saturation temperature corresponding to the total pressure in the compartment. Thus, during

atmospheric superheat conditions, the condensing boundary layer is at saturation conditions.

15A.4.4.3.4 Atmosphere and Sump Regions

Initially, the compartment system is entirely composed of water vapor and air occupying the free volume of the compartment. The water vapor and air partial pressures, masses, and internal energies are determined from the initial temperature, total pressure, and relative humidity. During the first advancement, a step input of mass and energy can be added to the compartment atmosphere.

The transient pressure and temperature calculations are made by considering the mass, volume, and energy equations for the water, steam, and air in the compartment atmosphere and sump regions. These equations give:

$$M = m_w + m_s + m_a$$

$$V = m_w v_w + m_s v_s + m_a v_a$$

$$U = m_w u_v + m_s u_s + m_a u_a$$

where:

M = total mass of water (w), steam (s), and air (a) (lb/min).

m = individual constituent mass (lbm).

V = total system free volume (ft^3).

v = individual constituent specific volume (ft^3/lbm).

U = total internal energy of water, steam, and air (Btu).

u = individual constituent specific internal energy (Btu/lbm).

The above equations are solved iteratively for each time advancement until a specified convergence criterion is satisfied. The respective water (w) and steam(s) properties used in the equations are evaluated based on the steam table values for water or steam at their respective temperatures T_w and T_s. Air (a) properties are evaluated at the air temperature, T_a. By assumption, the steam temperature and the air temperature are equal to the vapor region temperature, T_v. The specific volume of air, v_a, is calculated from the Ideal Gas Law; the air specific internal energy, u_a, is calculated from

$$u_a = C_v(T_v - T_o)$$

where:

C_v = 0.171 Btu/lbm - °F, the specific heat of air.

T_o = the initial containment atmosphere temperature (°F).

Once the mass, volume, and energy equations are solved for the converged values of T_w and T_v, the compartment pressure is calculated.

The total compartment pressure is computed from the sum of the partial pressures of steam and air at the compartment atmosphere temperature, T_v. The steam partial pressure is taken from the steam table values, and the air partial pressure is computed from the Ideal Gas Law relationship.

15A.4.4.3.5 Heat Transfer Considerations

Heat transfer takes place between the compartment atmosphere and the exposed surfaces inside the compartment. The heat sinks used in this analysis were the concrete walls and slabs (totaling 56,774 ft^2 for the el 130-ft floor). All miscellaneous equipment and structural steel within the compartment were conservatively calculated to be 2500 ft^2 carbon steel and 1900 ft^2 stainless steel. The rate of heat transfer between the compartment regions and these conducting masses is determined by the surface area, the surface temperature, the heat transfer coefficient, the physical arrangement of the conducting masses, and the thermal properties of these masses. All of the above parameters are considered by the COPATTA computer program during the transient analyses as described in this section.

15A.4.4.3.6 Heat Conduction Calculations

The COPATTA program makes provision for the simulation of up to 20 heat conducting masses in the analytical model. These heat conducting masses are described by a one-dimensional, multiregion heat conduction equation given by:

$$\rho C \frac{dT}{dt} = \nabla \cdot (K \nabla T) + S$$

where:

T = temperature (°F)

t = time (h)

K = thermal conductivity (Btu/h -ft - °F)

ρC = volumetric heat capacity (Btu/ft^3- °F)

S = volumetric heat generation rate (Btu/h-ft^3)

The spatial gradient operation, ∇, is applied in any of three coordinate systems in order to perform heat transfer calculations for rectangular, cylindrical, or spherical geometries.

The input for the heat conduction calculation includes provisions for specifying the geometry, the surface area, the number, and coordinates for different material regions, the mesh point spacing, and the material type for each heat conducting mass. The mesh point spacing used in this analysis was 0.1 in. for the first 6 in. and 0.5 in. for the remainder.

Boundary conditions ranging from perfectly insulated (adiabatic) to zero resistance are applied to each of the heat conducting mass external surfaces, as appropriate. These boundary conditions may indicate exposure to a constant temperature, a time dependent temperature, the compartment atmosphere or sump temperature, or some combination of the above. Heat transfer coefficient control is similar, ranging from values of zero through values dependent on the steam/air ratio in the compartment atmosphere or the condensing steam value which is dependent upon a turbulence parameter inside the compartment.

During the post-blowdown period of the transient which is the period of interest in this case, a steady-state condition develops due to decreasing turbulence in the compartment. Heat transfer under these conditions is dependent upon the steam-air steady-state mixture. Experimental work by Uchida, et al[(4)] shows that during free convection cooling periods, the condensing heat transfer coefficient is dependent on the ratio of non-condensable gas to steam masses. Application of the Uchida data during the long term cooling period (based on the reduction of turbulence in the compartment), specifies the condensing heat transfer coefficient during the transient.

The heat transfer coefficient between the water regions of the sump and the heat sinks is assumed to be 1000.0 Btu/h ft^2-°F. This heat transfer coefficient is specified at the liquid-vapor interface between the compartment sump and atmosphere regions. These conservative values assure higher temperature conditions within the compartment.

15A.5 DETAILED SYSTEM ANALYSES

The following considerations were applied to the detailed system analysis in addition to those discussed by individual high-energy line failure:

A. Safe shutdown includes meeting the following criteria: radioactive dose limits of 10 CFR 100, mechanical and thermal limits for catastrophic failure of the fuel barrier, nuclear and containment system stresses allowed for accidents by applicable codes, and radiation exposure limits for MCR personnel specified in General Design Criterion 19 of 10 CFR 50, Appendix A.

B. The normal shutdown procedure and the shutdown procedure with loss-of-offsite power (LOSP) assumed, as described in HNP-2 plant procedures, include the use of both RHR loops for shutdown cooling operation. If one loop of the RHR system were disabled due to a pipe break, leaving only one RHR loop available for shutdown cooling operation, the plant could still be brought to a cold shutdown condition, although more time would be required. This condition is based on the assumption that the suppression pool temperature limit of 170°F does not have to be maintained, since no other accident is postulated to occur concurrently with the high-energy line break. Each loop of the RHR system is capable of operation with

a single active failure, with the exception of the valves in the suction line and the discharge valves from the recirculation line.

C. Blowdown data are provided in table 15A-2. Equipment required and/or preferred for use in bringing the reactor to a safe shutdown is specified in table 15A-3 and discussed in HNP-2 plant procedures.

D. The primary containment structural integrity was evaluated following each postulated failure. In each pressure calculation, the external pressure in the drywell air gap and against each appurtenance, e.g., personnel lock, and the torus was calculated. Generally, factors of safety, with respect to the initiation of buckling, of two or greater, were verified by the containment vendor. In all calculations, other structural elements were found to be more limiting with respect to ultimate failure than the primary containment with respect to the initiation of buckling.

E. No hatches or block walls were allowed to fail in such a manner as to create missiles.

F. For each pressure/temperature analysis discussed below, the loads on structural elements (floor, slabs, etc.) given are the most limiting ones for the case analyses.

G. HNP-2 ac and dc motor control centers (MCCs) are located in the reactor building at el 130 ft. In the event of a high-energy steamline break, these MCCs are subjected to abnormal environmental conditions.

The solid doors into the main steam pipe chase from el 130 ft were removed and replaced with chain-link security doors to enhance ventilation in the steam chase. The temperature and pressure response from the HNP-1 analysis (214°F and 100% relative humidity) were applied to the HNP-2 el 130 ft floor to account for the open doorways. The HNP-2 door opening area from the chase to the el 130 ft floor is only 56 ft^2 (total), while the HNP-1 opening is 442 ft^2. Thus, the application of the HNP-1 temperature to the HNP-2 el 130 ft floor is clearly conservative. The radiation effects analysis is not affected by this because the radiation levels are bounded by the large-break LOCA rather than the MSLB.

The HNP-1 ac and dc MCCs are qualified for the environment on el 130 ft. Documentation supporting environmental qualification of these MCCs can be found in the Unit 1 EQ Central File, QDP 6 (ac) and QDP 7 (dc).

The HNP-2 ac and dc MCCs are qualified for the environment on el 130 ft. Documentation supporting environmental qualification of these MCCs can be found in the Unit 2 EQ Central File, QDP 6 (ac) and QDP 23 (dc).

Break locations for high-energy and moderate-energy piping outside the containment are provided in HNP-2 stress calculations which were reviewed and revised (if necessary) as part of the overall pipe stress reanalysis effort performed for NRC Inspection and Enforcement Bulletin (IEB) 79-14. These HNP-2 stress

calculations also provide stress intensities and usage factors for the various data points analyzed on the high-energy and moderate-energy piping. However, the stress intensities and usage factors are not reviewed for each stress calculation revision. These values will only be updated if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

The locations of pipe whip restraints for systems containing high-energy piping are identified on plant drawings controlled by the HNP configuration control management program.

15A.5.1 MAIN STEAM LINE BREAK

As shown in figures 15A-3 and 15A-4, four main steam lines are routed from the primary containment through the main steam pipe chase at el 130 ft in the reactor building to the turbine building. Pipe failure in the main steam system outside the primary containment is discussed in chapter 15. The design of the main steam lines, isolation valves, and flow restrictors is discussed in chapters 5 and 10.

The main steam lines automatically isolate in the event of a postulated failure. A break is sensed by high steam line flow, high temperature in the pipe chase, or low reactor water level. Descriptions of these automatic isolation systems appear in section 7.3.

15A.5.1.1 MSLB in Main Steam Pipe Chase

In the main steam pipe chase, located at el 130 ft of the reactor building, west of the drywell, each of the 4 main steam lines is anchored immediately downstream of the outboard isolation valve. In addition, there is a four-direction (including rotation) restraint at the primary containment penetration. Tie rods are provided between the anchor and the restraint to prevent separation of the pipe at the break postulated to occur downstream of the outboard isolation valve between the anchor and the restraint. The entire anchor and restraint system is designed to withstand pipe rupture loads as defined below. The purpose of this restraint system is to protect the primary containment penetration from pipe rupture in this area and to isolate the outboard isolation valve from pipe break, thermal expansion loads, and earthquake effects in the piping downstream of the anchor (figures 15A-3 and 15A-4).

The design of anchors and restraints for pipe rupture loads is based on the following criteria:

A. Design Loads

The design loads for the pipe anchors and restraints and support steel design is determined by the following formula:

$$F = K_1 K_2 \, PA \text{ lb}$$

where:

K_1 = thrust multiplication factor for the change in momentum due to a two-phase flow. A value of 1.26 is used.

K_2 = dynamic load factor to account for the effects of rapidly applied load. This factor is calculated in accordance with the methods described in BN-TOP-2.[(1)]

P = operating pressure of the fluid (psig).

A = pipe internal area (in.^{2}).

B. Design Stress

Restraints and supporting steel are designed in accordance with the AISC Code, Seventh Edition, using a 50% increase in code allowable stresses and using forces as described in A.

In considering the direct effects of an MSLB, it is necessary to determine whether such a break could cause a subsequent break in another main steam line or a feedwater line and thereby increase the blowdown. The locations of main steam and feedwater lines relative to each other are illustrated in figures 15A-3 and 15A-4. In evaluating the possibility of subsequent breaks as a direct effect of an MSLB, the following argument is presented:

A. Any break at the terminal end on the upstream side of the anchor does not result in pipe movement because of the anchor-restraint system described above.

B. A longitudinal break at the terminal end on the downstream side of the anchor does not result in pipe movement since the anchor prevents movement. In accordance with paragraph 15A.4.2.1, longitudinal breaks are not postulated at these locations.

C. Circumferential breaks are postulated at the intermediate break locations since the stress criteria set forth in paragraph 15A.4.2.1 are not exceeded. Because of the piping geometry in this area, as shown in figures 15A-3 and 15A-4, a circumferential break at any of the postulated break locations in the pipe chase room does not cause the pipe to move toward the other steam lines or the feedwater lines.

According to the AEC criteria, terminal break locations are postulated on both sides of the anchor and at the turbine connections.

A stress summary and the postulated break locations are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values will be updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

The targets considered in this room are the HPCI injection line and the main steam isolation valves (MSIVs). The HPCI injection line rises through the floor of the pipe chase directly under one of the feedwater lines and connects to the bottom of the feedwater line, downstream of the

outer feedwater isolation check valve. The feedwater line from the containment penetration to the check valve is considered as part of the target. The anchors and restraints on the main steam lines in this area prevent these lines from moving toward this target. A fluid jet from any of the postulated breaks is either not directed toward this target or is prevented from damaging the target by physical separation by the intervening anchor frames which span the width of the room. The MSIVs are protected from pipe movement and jet effects by these same features.

The environmental effects resulting from an MSLB in the pipe chase do not prevent the proper operation of the MSIVs.

Essential cables in the main steam pipe chase, which are part of the ATTS, are routed so that pipe whip or fluid jets from postulated breaks are not directed toward the conduit.

Details of the main steam and feedwater frames and stiffeners are shown on figures 15A-3 and 15A-9.

There is no jet impingement on the torus via the pipe chase floor opening from any postulated break location.

The pressure-temperature transient analysis for an MSLB in the pipe chase was performed in accordance with the procedure described in subsection 15A.4.4 and with the blowdown data provided in figure 15A-1 and table 15A-2. The flow model is shown in figure 15A-10. Modifications in HNP-2 are designed to permit pressure relief to the turbine building. The additional vent area includes 304 ft^2 directly to the turbine building from the pipe chase, 300 ft^2 from the pipe chase via the vent room directly above the pipe chase at el 164 ft, through 300 ft^2 of vent area from the vent room directly to the turbine building, and on pipe chase floor el 130 ft, a 210-ft^2 grated vent area with 95 ft^2 of it covered by blowoff panel. The blowoff through 300 ft^2 of vent area from the vent room directly to the via the vent room directly above the pipe chase at el 164 ft, panel covering the grating on the pipe chase floor allows an effective vent area of 80 ft^2 from pipe chase to torus and 280 ft^2 from torus to pipe chase. All vents to the turbine building have blowoff panels designed to pop off and provide clear openings. These modifications are incorporated in the design and are a part of the plant construction.

The solid doors into the main steam pipe chase from el 130 ft were removed and replaced with chain-link security doors to enhance ventilation in the steam chase. The addition of these two 28-ft^2 openings from the steam chase to the el 130-ft floor is not modeled in the pressure temperature transient analysis. The absence of these openings in the model causes the model to conservatively over predict the temperature and pressure in the pipe chase and torus while underestimating the temperature and pressure on the el 130-ft floor. The underestimation of temperature and pressure on el 130-ft floor is addressed by qualifying all equipment in the affected area to the HNP-1 temperature and pressure response curves. HNP-1 has a 442-ft^2 opening from the steam chase to the el 130-ft floor.

The initial conditions and final results of the pressure analysis, with the proposed modification, are summarized as follows:

Initial conditions

Temperature (°F)	105	all compartments
Pressure (psia)	14.7	
Relative humidity (%)	50	

Room volumes (ft^3):	
Pipe chase	30,000
Vent room	5000
Floor el 130 ft	2.5×10^5
Drywell air gap	3700
Torus chamber room	2.92×10^5
Direct vent areas (ft^2) from pipe chase to:	
Floor el 130 ft	0
Vent room	300
Turbine building	304
Drywell air gap	0
Torus chamber room	80

Results

Maximum pressure (psia) in.:	
Pipe chase	17.75
Floor el 130 ft	14.76
Vent room	15.6
Drywell air gap	14.77
Torus chamber room	16.96
Maximum differential pressure (psid):	
Occurs on the ceiling of the torus room 4.5 s after the break	2.22
Maximum temperature (°F)	
Floor el 130 ft	105
In pipe chase	295

The above pressure-temperature calculation was performed using ten separate compartments.

An analysis of postulated cracks in the main steam pipe chase resulted in no potential problems with respect to jet impingement on piping, structural elements, or electrical cable. The other environmental effects are much less severe than the postulated break. A leak is detected by the temperature sensors located in the pipe chase, which initiates isolation of the main steam lines.

15A.5.1.2 MSLB in Turbine Building

All main steam piping within the turbine building is physically separated from structures, systems, and components important to reactor safety by both distance and structural barriers. More information regarding this is provided, subsection 15A.3.2.D. Location of the main steam lines in the turbine building with respect to the control complex in the control building is shown on figure 15A-2.

Postulated break locations in the turbine building are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values will be updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

The pressure-temperature transient analysis was performed for an MSLB in the turbine building using eight separate compartments. As indicated by the results summarized below, no pressure or temperature problems were identified in the turbine building.

<u>Initial conditions</u>		
Temperature (°F)	105	all compartments
Pressure (psia)	14.7	all compartments
Relative humidity (%)	50	all compartments
Room volumes (ft^3):		
Condenser room el 130 ft containing steam lines	6.0×10^5	
Floor above el 164 ft	3.3×10^6	
Vent areas (ft^2) from condenser room at el 130 ft to:		
Floor above el 164 ft	1116	
Condenser room below el 130 ft	3613	
<u>Results</u>		
Maximum pressure (psia) in:		
Condenser room at el 130 ft	15.4	
Floor above el 164 ft	14.9	
All compartments below el 130 ft	15.4	
Maximum temperature (°F) in:		
Condenser room at el 130 ft	246	
Floor above el 164 ft	124	
All other areas	< 120	

As was the case for the pipe chase, postulated cracks do not result in any adverse effects on safety-related components.

15A.5.1.3 Analysis of Shutdown Capability

The ability to shut down the reactor safely following a postulated main steam line failure was analyzed. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table 15A-3. The required equipment is operable with the required redundant components available.

For an MSLB outside the primary containment, the reactor is automatically scrammed by turbine control valve fast closure, assuming an LOSP shuts of the MSIVs, or by steam flow, high temperature in the vicinity of the pipe chase, or low-low reactor water level. The reactor pressure vessel (RPV) isolation is completed by the closure of the MSIVs. After isolation of the RPV, pressure increases until the setpoint of the safety relief valves is reached. Pressure is then automatically relieved by the discharge of steam to the pressure suppression pool.

RPV water level is maintained by automatic operation of the HPCI system and/or operation of the RCIC system. Assuming that the hypothesized single active component failure disables the HPCI system, RPV water level is maintained by operation of the RCIC system.

Subsequent to the initial blowdown and not necessarily before a 10-min interval, the operator manually initiates the condensing mode of the RHR system. The additional operations required to bring the reactor to a safe shutdown condition are described in HNP-2 plant procedures. An assumed LOSP is considered to be effective at the time of the initial pipe break.

The RHRSW system and plant service water (PSW) system are not affected by the postulated MSLB. Therefore, adequate component and room cooling for the equipment identified in table 15A-3 would be available.

15A.5.2 FEEDWATER LINE BREAK

As shown in figures 15A-3 and 15A-4, two feedwater lines are routed from the primary containment through the main steam pipe chase to the turbine building. Since the routing of these lines follows the routing of the main steam lines, several analogies can be drawn with respect to analyses performed on the main steam lines. The blowdown energy released from a feedwater line break is approximately a factor of 6 less than an MSLB. The pipe whip and jet impingement loads are also less limiting than for an MSLB.

The pressure at the discharge of the feed pumps during normal conditions is ~ 1310 psig and about 1086 psig at the reactor inlet nozzle, and the temperature is ~ 425.7°F, thus, the feedwater system is considered a high-energy system. Backflow from the RPV to the break is prevented by closure of the feedwater check valves (one inside the containment and two air-assisted check valves outside the containment) coincident with flow reversal. Thus, flow through the break would be from the feed pumps only. It is assumed that water from both feed pumps would discharge through the break. As soon as the postulated break occurs, the discharge pressure of the pumps decreases and the flow increases until pump runout occurs. It is conservatively assumed that the steam-driven feed pumps would continue running until the steam supply is terminated by closure of the MSIVs due to low RPV water level. This assumption implies that offsite ac power is not lost for this accident. If offsite ac power is lost,

the electric motor-driven condensate booster pumps would shut down which would cause the feed pumps to trip due to low suction pressure.

Postulated critical size cracks were evaluated with no potential jet impingement problems identified anywhere along the feedwater lines. Other environmental effects are considerably less significant than those for the main steam lines.

15A.5.2.1 Feedwater Line Break in Main Steam Pipe Chase

The feedwater lines in this room are divided into seismic and nonseismic portions by an anchor. Each of these two pipes is anchored and restrained in the same manner as described in subsection 15A.5.1 for the main steam lines. The anchors and restraints are designed for pipe rupture loads. A break at the terminal end of either of these lines on either side of the anchor would be upstream of the isolation check valves. The feedwater line to which the HPCI injection line connects is prevented from moving by the restraint at the containment penetration if it should break on the downstream side of the anchor. A break on the upstream side of the anchor would not direct the broken pipe toward the HPCI line. A fluid jet from either of these breaks would not be directed toward the HPCI line, or it would be intercepted by the anchor frame shown on figure 15A-3. The HPCI injection line would, therefore, not be damaged by a feedwater line break.

The MSIVs would not be damaged by the postulated terminal end breaks. The fluid jet from a break on the downstream side of the anchor is not directed toward the MSIVs. The pipe is prevented from separating at this location by the anchor-restraint system. The break on the upstream side of the anchor does not direct the broken pipe toward the valves. The fluid jet from the broken pipe is prevented from reaching the valves by intervening anchor frames as illustrated on figures 15A-3 and 15A-9.

The configuration of the nonseismic portion of the feedwater lines in the main steam pipe chase is indicated in HNP-2 stress calculations. Breaks are postulated to occur at any welded fitting and can be either longitudinal or circumferential. Blowdown from the reactor vessel is prevented by the check valves, and blowdown from the feedwater heaters is limited by the flow measuring elements. Due to the insufficient level of stored energy, there is no physical potential for significant pipe whip motion.

The jet impingement targets consist of air lines and accumulators, steam drain lines, steam leak detectors, the RCIC steam supply outboard isolation valve, the outboard MSIVs, various electrical conduits, and an air cooler. Of these targets, the only required function and/or pressure boundary which is threatened by jet forces is a conduit containing cables for RPV instrumentation signals. Jet barriers were installed to protect this conduit.

A conservative analysis of a feedwater line break in the main steam pipe chase, assuming no LOSP, was performed to evaluate the effects of reactor building flooding. An estimated inventory of 200,000 gal was used as discussed in the footnotes to table 15.A-2. The 80-ft^2 vent in the floor drains the water into the torus chamber area below which is designed for flooding.

15A.5.2.2 Feedwater Line Break in Turbine Building

The configuration of the feedwater system piping in the turbine building is indicated in HNP-2 stress calculations. All feedwater piping within the turbine building is physically separated from structures, systems, and components important to reactor safety and is also separated from these systems and components by Seismic Category 1 radiation shield walls, most of which are 5-ft 0-in. thick. No feedwater line failure in the turbine building prevents the safe shutdown of the plant.

Break locations are postulated at all welded fittings indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values are updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

Flooding in the turbine building as the result of a feedwater line break was evaluated, and it was determined that a break in the circulating water system would be more severe from the flooding point of view. The results of the following analysis from the circulating water system are presented in subsection 10.4.5.

In summary, flooding from a feedwater line break in the turbine building will not adversely affect the ability to shut down the reactor.

15A.5.2.3 Analysis of Shutdown Capability

The structures, systems, and components required for the safe shutdown of the plant following a postulated feedwater pipe break are presented in table 15A-3. Section 15.2 presents a parametric analysis of the transient conditions following loss of feedwater flow.

As stated previously, it is more conservative for this accident to assume that offsite ac power is not lost than to assume it is lost. If offsite power were lost coincident with the feedwater pipe failure, the reactor would be scrammed by the fast closure of the turbine control valves, low reactor water level, or closure of the MSIVs. If offsite power were not lost, the scram would be initiated by low reactor water level or MSIV closure. RPV isolation would be initiated by low reactor water level and completed by MSIV closure which would be initiated by high mainsteam pipe chase temperature, low steamline pressure, or manual action.

After the reactor is scrammed and the RPV isolated, the sequence of events is similar to that given above for the MSLB accident (MSLBA). The analysis of equipment availability following an MSLBA is applicable to a feedwater pipe break accident as well.

15A.5.3 HPCI STEAM LINE BREAK

As shown on figure 15A-6, the HPCI steam line leaves the primary containment just above el 130 ft and is routed through the pipe penetration room on the east side of the drywell. It penetrates the floor of the pipe penetration room and is routed through the torus room to the HPCI room south of the reactor building proper. Postulated break locations and the table of

stresses are provided in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values are updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

An anchor designed for pipe rupture loads is provided at the penetration flued head. Whip restraints are provided at locations shown on plant drawings. Whip restraints are provided to protect the PSW, RHRSW, RHR transfer piping, and torus from the effects of pipe whip and jet spray following a break at any of the postulated breakpoint locations.

Jet impingement from breaks in this line has been evaluated at all locations. No targets of concern were identified which would be potentially damaged.

A steam leak in the torus room from a HPCI steam line would be detected by ambient differential temperature switches in the ventilation system supply and exhaust. This temperature-detection system has the required redundancy to accept any single active failure and still perform its function.

Postulated critical cracks located anywhere along the steam line have no adverse effects on components required for safe shutdown. Environmental effects in the HPCI room and torus room are less severe than those for a break in these areas. Temperature sensors were added to permit detection of a crack that would blow down < 300% flow in the pipe penetration room.

Upon receipt of a high-temperature signal from the sensors, the HPCI steam line isolation valves close. The setpoint is set low enough to detect a break in the steam line but high enough to avoid spurious isolation. In addition, the radiation monitors in the reactor building ventilation system exhaust duct and the area radiation monitors (ARMs) would provide backup information to the operators in the event of a break.

Break isolation is automatically initiated by high steam flow (> 300% flow) and/or low pressure in the HPCI steam line.

15A.5.3.1 Pressure-Temperature Analysis

The pressure-temperature transient analysis was performed for the pipe penetration room, the torus room, and the HPCI turbine/pump room. The pressure-temperature analysis for the HPCI turbine/pump room included the impact of a HPCI steam line break on the equipment located in the south-east corner room due to the permanently secured open submarine door between the HPCI room and south-east corner room. The flow models are shown on figures 15A-11 and 15A-12. The results and conditions of these studies are summarized below:

A. HPCI room

Initial conditions

Temperature (°F)	105
Pressure (psia)	14.7
Relative humidity (%)	50
Volume (ft^3)	52,015

Vent area to atmosphere (ft^2)	81
Vent area to SE corner room (ft^2)	21.6 (door + duct opening of ~ 0.6 ft^2)

Results

Maximum pressure in HPCI room (psia)	21.3
Maximum pressure in SE corner room (psia)	16.0
Maximum temperature in HPCI room (°F)	231
Maximum temperature in SE corner room (°F)	215

Discussion

The vent area to the atmosphere is provided by the concrete hatch in the roof, which lifts under its own weight, conservatively estimated to be 4.5 psi. The ultimate (90%) structural capacity of the room is 13.9 psig, and the resultant maximum pressure in the room is 6.6 psig as indicated above.

A time-history dynamic analysis was performed on the roof hatch to evaluate the effects of allowing it to lift. The results of the analysis indicate the hatch would not cause damage that would preclude a safe shutdown. It is probable that damage could occur to the HPCI room roof; however, use of the system would be lost with the break.

B. Torus room

Initial conditions

Temperature (°F)	107
Pressure (psia)	14.7
Relative humidity (%)	50
Volume (ft^3)	2.92×10^5

Vent area to:

Pipe penetration room (ft^2)	218
Drywell air gap (ft^2)	6.7
Main steam pipe chase (ft^2)	180
Floor el 130 ft (ft^2)	18

Results

Maximum pressure in torus room (psia)	17.0
Maximum ΔP on torus room ceiling (psi)	2.27
Maximum temperature in torus room (°F)	218
Maximum temperature at el 130 ft (°F)	162

Discussion

The above results were determined with some plant modifications which include blocking the vent area to the RHR (east) corner rooms by sealing around pipe penetrations in order to maintain a safe environment in these rooms. A 258-ft^2 grated opening was provided at the 130-ft pipe penetration room floor to give an effective vent area of 218 ft^2. A 210-ft^2 grating with a 115-ft^2 blowoff panel superimposed on it was provided at the 130-ft floor of the pipe chase room. The blowoff panel is hinged to the west wall and blows in the direction of the pipe chase. The blowoff panel would not damage any MSIVs or critical components. As indicated in the results of this analysis, the maximum pressure in the torus compartment is well below the external pressure that would initiate suppression chamber buckling (> 8 psi).

The postulated full break of the HPCI steam line in the torus room yields a peak calculated temperature of 162°F on the el 130-ft floor. Thus, this postulated break represents the worst long-term temperature transient.

C. Pipe penetration room at floor el 130 ft

Initial Conditions

Temperature (°F)	105
Pressure (psia)	14.7
Relative humidity (%)	50
Volume (ft^3)	7550
Vent area to torus room (ft^2)	218

Results

Maximum pressure in pipe penetration room (psia)	17.9
Maximum ΔP across torus room ceiling (psi)	2.3
Maximum pressure in drywell air gap (psia)	14.9

Discussion

In order to obtain the acceptable results given above, it was necessary to provide a 258-ft^2 grated opening at the pipe penetration room floor and an airtight door to isolate the pipe penetration room from the rest of the el 130-ft floor. The maximum pressure against the containment personnel lock located at this room is approximately a factor of 2 below the pressure to initiate buckling. The concrete block wall directly opposite the containment personnel lock is reinforced with removable steel plates to prevent the pressure from blowing out the wall and creating missiles.

The postulated full break of the HPCI steam line in the pipe penetration room is not expected to yield a temperature higher than 162°F on the el 130-ft floor, which is the long-term temperature effect from a HPCI steam line break in the torus room.

15A.5.3.2 Analysis of Shutdown Capability

The ability exists to safely shut down the reactor following a postulated HPCI steam line failure. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table 15A-3. All of the required equipment is operable with the required redundant components available.

For a postulated break in the HPCI steam line, no scram results, the isolation valves close, and a normal shutdown of the plant follows. The shutdown process is described in HNP-2 plant procedures.

Break isolation is accomplished by automatic isolation of the HPCI steam line initiated by high-steam flow and/or low pressure in the HPCI steam line. High torus room temperature also automatically isolates the system.

15A.5.4 RCIC STEAM LINE BREAK

The RCIC steam line penetrates the primary containment into the main steam pipe chase and then penetrates the pipe chase floor at el 130 ft into the torus room below. It is then routed to the northwest corner room to the RCIC turbine.

A stress summary and the postulated breakpoint locations are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values will be updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

Pipe whip restraints are provided to protect the outboard isolation valve from postulated pipe break loads downstream of the isolation valve.

The PSW return header is assumed to be damaged as a consequence of a postulated break in the torus chamber room. The loss of the return header does not affect the PSW supply to the emergency core cooling system (ECCS) corner rooms. Flooding of the torus chamber room is not a concern and is discussed in paragraph 9.3.3.2.2.

Critical cracks postulated to occur anywhere along this line would not result in damage to safety-related equipment or components and would not impair the capability to safely shut down the reactor. Leaks would be detected by temperature instrumentation located in all compartments containing this line.

15A.5.4.1 Pressure-Temperature Analysis

The postulated failure of the RCIC steam line in the main steam pipe chase would have negligible effects compared to the failure of a main steam line. Similarly, a failure in the torus room would have less significant effects than a HPCI steam line failure in the same compartment. Critical cracks postulated to occur in these compartments would also be negligible compared to those for the larger lines. The initial conditions and results of the analysis performed for the RCIC northwest corner room are summarized as follows:

Initial conditions	
Temperature conditions	
Temperature (°F)	105
Pressure (psia)	14.7
Relative humidity (%)	50
Room volumes (ft^3):	
RCIC corner room	2.6×10^4
Reactor building above el 130 ft below refueling floor	8.8×10^5
Reactor building above refueling floor	3.7×10^5
Vent areas (ft^2) to:	
Reactor building el 130 ft	42
Reactor building to refueling floor	380
Results	
Maximum pressure (psia) in:	
RCIC corner room	15.8

The results indicate that the RCIC steam line break is not significant compared to the HPCI steam line break in the torus room and compared to either the MSLB or HPCI steam line break at the el 130-ft floor in the pipe penetration room. The break in the corner room renders that room and the RCIC unavailable for service, but does not lead to a pressure or temperature problem in any other compartment.

15A.5.4.2 Analysis of Shutdown Capability

The ability exists to safely shut down the reactor following a postulated RCIC steam line failure. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table 15A-3. All of the required equipment is operable with the required redundant components available.

Failure of the RCIC steam line has minor effects on the nuclear boiler system; i.e., reactor scram, reactor vessel isolation, or initiation of ECCS are extremely unlikely. The RCIC steam

line would be automatically isolated by high steam flow, low pressure, or high RCIC room temperature signal. Consequently, the reactor shutdown would be as described in HNP-2 plant procedures.

It is possible that a break in the RCIC steam line in the main steam pipe chase might initiate closure of the MSIVs from their associated high-temperature sensor. In this event, a reactor scram would result and an LOSP is assumed. The shutdown procedure for this case follows that provided in HNP-2 plant procedures.

15A.5.5 RWC LINE BREAK

The RWC system is described in subsection 5.5.8.

The high-energy portions of the system that are outside the primary containment are:

- From the primary containment to the inlet nozzle of the regenerative heat exchanger in the system supply line.
- From the discharge of the regenerative heat exchanger to the connection into the feedwater system in the return line.

A stress summary and the postulated break locations are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values are updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

One postulated break in the cleanup system incapacitates both the RWC and RCIC systems. Air-operated, containment isolation check valves in the feedwater system immediately downstream of the return line would preserve the integrity of the reactor coolant pressure boundary (RCPB).

Whip restraints are provided to protect the outboard isolation valve from postulated breaks in the area from pipe whip and jet impingement and environmental conditions.

A whip restraint is provided on the downcomer in the pipe chase room to protect the safety-related conduits in the vicinity from pipe whip and jet impingement forces. As indicated in HNP-2 stress calculations, there are no postulated break locations on floor el 130 ft outside the pipe chase room.

The routing of electrical cable trays on floor el 158 ft were reviewed, and as such the power and control cables for the RWC outboard isolation valve were removed and rerouted in a conduit.

Automatic isolation of the RWC system is accomplished by high equipment room temperature, high equipment room differential temperature, high flow, and high W flow signals. Descriptions of these isolation signals are provided in section 7.3. Blowdown data and isolation valve closing time for the cleanup system are given in table 15A-2.

It was determined that a failure in the 4-in. cleanup line at any location in the main steam pipe chase would not cause damage, either by pipe whip or jet impingement, from either a break or a crack, to the larger (14 in.) HPCI injection line. Intervening pipes and structures also prevent damage to the MSIVs.

A postulated break at the connection to the HPCI injection line in the pipe chase incapacitates both the RWC and HPCI systems. Air-assisted containment isolation check valves in the feedwater system, immediately downstream of the return line, would preserve the integrity of the RCPB.

Jet impingement from a postulated break at any welded fitting near el 166 ft - 5 1/4 in. in the reactor building could possibly cause damage from pipe movement to the RPV level and pressure sensing lines for the Division II side of the reactor protection system. The sensing lines are 3/8-in. outside diameter tubes mounted in a tray and are equipped with excess flow check valves to minimize leakage from a crack or break. Since the Division I RPV level and sensing lines would be unaffected by an RWC line failure, and are physically separated by distance and intervening structures, these lines are available to monitor the shutdown of the reactor. All active components associated with each division of these sensing lines are redundant; therefore, a single active failure does not affect the monitoring functions.

15A.5.5.1 Pressure-Temperature Analysis

A break of the RWC line in the main steam pipe chase in the reactor building would result in pressures and temperatures less than those resulting from an MSLB. A pressure-temperature transient analysis was performed for the pump room compartment. The flow model is shown in figure 15A-13. The initial conditions and results of the analyses performed at el 158 ft are summarized below:

Initial Conditions		
Temperature (°F)	105	all compartments
Pressure (psia)	14.7	all compartments
Relative humidity (%)	50	all compartments
Room volumes (ft^3):		
RWC pump room	11,200	
RWC heat exchanger room	22,000	
Cleanup phase separator room	9,500	
Reactor building below refueling floor, i.e., el 228 ft	7.8×10^5	
Refueling floor	1.25×10^6	
Maximum pressure (psia) in:		
Pump room	16.05	
Heat exchanger room	16.24	
Rest of el 158 ft	15	
el 185 ft	15	

Maximum temperature (°F) in:	
Pump room	218
Heat exchanger room	217
Rest of el 158 ft	210
el 185 ft	205
Maximum differential pressure (psid):	
Between pump room and el 185 ft	1.16

Differential pressures on roof, floors, and walls are acceptable.

The above analysis takes credit for 252 ft of hinged blowoff panels between the refueling floor (el 228 ft) and the rest of reactor building.

15A.5.5.2 Analysis of Shutdown Capability

The ability exists to safely shut down the reactor following a postulated RWC piping system failure. The structures, systems, and components that must be available to ensure meeting the criteria for safe shutdown are presented in table 15A-3. Required equipment is operable with the required redundant components available.

A postulated rupture of the RWC system piping probably does not cause a severe enough transient on the nuclear boiler system to result directly in a reactor scram, reactor vessel isolation (other than isolation of the RWC system), or automatic initiation of the ECCS. However, if the transient is such that any of those functions are required, they automatically are initiated by the appropriate setpoint being reached. The effect on the nuclear boiler system for this postulated break is similar to that resulting from the RCIC steam or injection line break; consequently, the shutdown options would be as described for that event.

15A.5.6 MODERATE-ENERGY LINE CRACKS

Moderate-energy lines were identified in paragraph 15A.4.1.2; criteria for the selection of postulated critical size cracks for these lines and their locations were discussed in paragraph 15A.4.2.2. The results of the analyses performed for moderate-energy lines are discussed by system in the following paragraphs. The shutdown capability discussed in HNP-2 plant procedures is not impaired by postulated cracks in any of the lines discussed.

15A.5.6.1 CRD Return Line Cracks

The CRD hydraulic system return line (pump discharge) was originally classified as a moderate-energy (nonflashing) line; however, as discussed in supplement 15A.A, this line was later reclassified as a high-energy line for which breaks were postulated.

A jet impingement barrier (steel plate assembly) was installed to protect the pilot valve (2C11-F009), which operates the inboard scram discharge volume vent and drain valve, thus precluding damage caused by jet impingement due to a crack in the CRD system piping.

15A.5.6.2 Auxiliary Steam Line Cracks

The auxiliary steam line is a moderate-energy (flashing) line used for various purposes in the reactor building. There is no flow in the line unless called upon for service; however, the line is pressurized during the cold winter months when it is used for plant heating.

Since a critical crack in this line would lead to steam emission only, jet impingement, pressure, and temperature are the environmental concerns. The piping is routed such that only a very small length at el 130 ft along the west wall of the reactor building is pressurized for plant heating. There is no jet impingement on safety-related cables or other equipment from a critical size crack in this line.

Steam pressurization analysis was performed for a critical size crack in this line at el 130 ft in the reactor building.

Initial Conditions

Temperature (°F)	105	all compartments
Pressure (psia)	14.7	
Relative humidity (%)	50	

The Bechtel computer code COPATTA, was used using walls, ceilings, and major equipment as heat sinks. The maximum resultant temperature was 149°F ~ 5 min after the crack occurred. An auxiliary steam line is used for various purposes in the HNP-2 turbine building. This line is the same size (10 in.) as that used in the reactor building. An analysis of this line for environmental effects in the turbine building has resulted in no problems being identified. The amount and duration of blowdown is not sufficient to create a pressurization or temperature problem.

15A.5.6.3 RHRSW Line Cracks

The RHRSW system is a moderate-energy line (nonflashing) used to provide cooling water to the RHR heat exchangers in the east corner rooms in the reactor building. No jet impingement or flooding problems were identified for this line in the reactor building. A critical size crack in this system in one of the RHR corner rooms or the torus room would be detected by the instrument sump in that room. A crack in either of the RHR corner rooms or in the torus room would not affect the redundant RHR loop in the other corner room.

The configuration of RHR and PSW piping in the river intake structure, as shown on drawing no. H-21102, indicates that very little physical separation could be obtained due to the size of the pump room. In order to provide protection from jet impingement to the

RHRSW pump motors and associated equipment, stiffened steel barriers mounted on a structural steel frame are provided.

Flooding of the RHRSW pump area in the intake structure is not a concern since grating is provided in the floor as shown on drawing no. H-12192, and water spillage does not accumulate due to gravity runoff.

A postulated critical size crack in the RHRSW line does not affect the capability to shut down the reactor, nor does such a crack require a shutdown procedure beyond that described above for normal shutdown with one RHR loop. The shutdown procedure is as described in HNP-2 plant procedures, with the additional qualification discussed in section 15A.5.B.

15A.5.6.4 Sampling Lines

Due to the fact that all sampling lines are < 1 in. in diameter, therefore, breaks in these lines are not considered in accordance with paragraph 15A.4.2.1. Some of the sample lines are high-energy lines and some are moderate-energy lines; therefore, critical size cracks were considered in the analysis in accordance with paragraph 15A.4.2.2.

The only sample lines that contain high-energy or moderate-energy fluid under normal plant conditions are:

A. RWC system sample line from the regenerative heat exchanger outlet: Normally, there is no flow in this line; however, it is pressurized to ~ 1201 psig from the sample point to the isolation valve in the sample station, and the water being sampled is > 130°F.

B. Reactor water sample line from recirculating pump discharge: Normally, this sample line is pressurized to about 1250 psig at ~ 550°F. The sample line has inboard and outboard containment isolation valves which automatically close after receiving an isolation signal.

C. Feedwater (2 sample lines) from the feedwater pipes upstream of the outboard check valves: Normally, these lines have continuous sample flow and are pressurized to ~ 1175 psig at 425.7°F.

Two of these sample lines (items A and B in the above listing) are routed in the same vicinity at el 158 ft in the reactor building. The piping used for these sample lines is 1/4-in. outside diameter stainless steel tubing with a wall thickness of 0.065 in. These lines are routed in Seismic Category I tubing trays, which reduces the possibility of physical damage to the sample lines. All sample lines in the reactor building are designed to Seismic Category I standards.

The two feedwater sample lines originate in the main steam line tunnel above el 147 ft in the turbine building and are routed north, dropped to the base el 112 ft, and then routed south to the sample station. No safety-related equipment is located in the vicinity of these lines. These lines are 3/8-in. outside diameter stainless-steel tubing with 0.065-in. wall thickness and are also routed in tubing trays.

A critical size crack in any of these sample lines does not result in any direct effects on structures, systems, or components required for shutdown. Jet impingement, pressure, and temperature effects are negligible due to the small size of the sample lines and the fact that they are completely enclosed in a protective channel.

Sample lines identified in B can be isolated by closing the RWC system supply line isolation valve. The feedwater sample lines can be isolated remotely by shutting down the reactor feedpumps (after shutting down the reactor and closing the MSIVs).

The indications available to the operator that a RWC or reactor water sample line failure has occurred are:

A. A temperature switch in the RWC equipment rooms indicates high ambient temperature and the RWC equipment room ventilation air inlet and outlet high differential temperature switch indicates leaks in either the RWC or reactor water sample lines which are routed in these areas. A discussion of these indications is provided in section 7.3.

B. Reactor building ventilation exhaust high radiation alarm: Section 7.6 and subsection 9.4.2 describe the operation of this system. A sample line failure results in higher than normal radiation levels in the reactor building ventilation exhaust which may initiate an alarm in the MCR and automatically initiates isolation of the secondary containment.

C. ARM alarm: There is an ARM in the vicinity of the sample station on the el 158-ft floor. In the event of a postulated sample line failure the general area radiation levels may rise and result in an alarm in the MCR.

A postulated failure of the feedwater sample lines in the main steam tunnel may result in a high temperature indication in the turbine building leak detection system.

15A.5.7 RADIOLOGICAL CONSIDERATIONS

The principal radiological concerns for a postulated high-energy or moderate-energy line failure outside primary containment are the extent of exposures to an individual located at the site boundary and an operator located in the MCR. A consideration of the radiological consequences associated with the time delay in isolating breaks is relevant only to the HPCI and RCIC systems. Calculations were made for these systems based on the time delays mentioned and assuming flow from the break to be 300% of rated flow for the system. Above this flow no time delay would exist because of isolation from the flow sensors (instantaneous). When related to the radiological effects of an MSLB, the following results were calculated:

- RCIC steam line - 0.30% of MSLB dose.
- HPCI steam line - 1% of MSLB dose.

As a result, the site boundary doses from the HPCI and RCIC steam line breaks are negligible compared to the dose from an MSLB. The MSLBA outside primary containment is a design basis accident (DBA) and the radiological consequences are discussed in section 15.3.

A failure in the feedwater line is not of concern with respect to radioactive releases, and a failure of a RWC line would be negligible when compared to the MSLB due to rapid isolation, much less discharge volume and less favorable transport mechanisms.

Previous analyses demonstrate that the LOCA is the limiting event for radiological exposures to operators in the MCR. Therefore, for power uprate and reactor operating pressure increase conditions (2804 MWt), only the LOCA was analyzed for MCR radiological exposures. An evaluation of exposure to MCR personnel is discussed in section 15.3. The relationship of exposure to control room personnel from the other high-energy line breaks to that of the MSLB is similar to the relationship for site boundary doses.

None of the moderate-energy lines contain significant radioactivity and no failure in these lines can cause discharge of reactor coolant. It is concluded that any high-energy or moderate-energy line failure outside the primary containment will not result in radiation exposures that exceed allowable limits to control room personnel or the general public.

15A.6 SUMMARY OF PLANT MODIFICATIONS

Although discussed by system in section 15A.5, this section provides a summary of plant modifications from the initial design to mitigate the effects of postulated high-energy and moderate-energy line failures outside the primary containment.

15A.6.1 MODIFICATIONS AS A RESULT OF PRESSURE-TEMPERATURE

As a result of detailed pressure-temperature transient analyses, some compartments were found to be overpressurized. For these compartments, additional vent area was provided in the form of clear (unobstructed) vent openings, grated vent openings, or blowout panels. The selection of the locations for such vents was based on a combination of factors such as efficiency in solving the pressurization problem, evaluation with respect to structural loadings and bearings, effect on plant personnel accessibility, and effect on construction man-hours and difficulty, as well as economic considerations. Locations where such modifications are provided are summarized as follows:

A. For MSLB in pipe chase, reactor building

  1. A blowout panel (304 ft^2) is provided between the main steam pipe chase and turbine building, above el 147 ft. This vent area is sketched on figure 15A-15.

  2. Open vents (total 300 ft^2) are provided between the vent room above the pipe chase and turbine building, above el 164 ft. These vents are sketched on figure 15A-14.

3. Blowout panels (total 300 ft^2) are provided between the vent room above the pipe chase and turbine building, above el 164 ft. These vents are sketched on figure 15A-14.

4. A 210-ft^2 grating with a 115-ft^2 blowoff panel superimposed on it is provided at the el 130-ft floor in the main steam pipe chase room. This gives an effective vent area of 80 ft^2 to the torus in case of an MSLB and 180 ft^2 in case of a HPCI line break in the torus.

5. Vent restrictors as shown on figure 15A-17 are provided on main steam and feedwater penetrations so as to preclude steam entering the drywell air gap.

B. For a HPCI steam line break in the pipe penetration room, reactor building:

1. A 258-ft^2 grated opening is provided on the pipe penetration room floor to give an effective vent area of 218 ft^2 between this room and the torus room. These vents are shown on figure 15A-16.

2. The block wall opposite the containment personnel lock is reinforced with removable steel plates to enable it to take the internal pressure without collapsing.

3. Temperature sensors are provided to enable detection of a failure in the HPCI steam line that would deliver $<$ 300% blowdown flow.

4. Vent restrictors as shown on figure 15A-17 are provided on RHR and HPCI penetrations so as to preclude steam entering the drywell air gap from the pipe penetration room.

5. An airtight door is provided between the pipe penetration room and reactor building el 130-ft floor.

C. For a HPCI steam line break in the torus room, reactor building basement:

1. All vent areas around piping and ducting penetrations leading into the RHR (east) corner rooms are sealed to preclude the adverse environment from entering these rooms and affecting the operation of the RHR system.

2. Grated blowout panels (total 210 ft^2) are provided in the floor of the main steam pipe chase at el 130 ft. These vents are sketched on figures 15A-3 and 15A-4.

15A.6.2 BARRIERS PROVIDED TO PROTECT AGAINST JET IMPINGEMENT

Various locations were determined to have potential jet impingement problems. Where identified, barriers were provided to protect the targets. The location of the barriers is detailed as follows:

Line Failure	Target Protected	Location
• Main steam or feedwater in turbine building	Essential conduit	Turbine building floor el 147 ft
• RHRSW line cracks	RHRSW pumps, motors, and associated equipment	River intake structure
• CRD system piping crack	Inboard scram discharge volume vent and drain valve, pilot valve (2C11-F009)	Reactor building floor el 130 ft
• Feedwater	Essential conduit	Main steam pipe chase
• Main steam or SJAE steam supply in turbine building	Essential conduit	Turbine building floor el 147 ft

15A.7 CONCLUSIONS

The analysis of postulated high-energy and moderate-energy line failures outside the primary containment has been completed. The following conclusions were drawn:

A. With plant modifications for additional vent area no structure or structural element fails due to pressurization or direct effects from a failure. The resultant environmental atmosphere in any room containing equipment required for safe shutdown of the reactor is such that the ability of the equipment to perform its required function is not precluded.

B. The physical capability for safe shutdown of the reactor is maintained for any postulated failure of high-energy or moderate-energy lines. The ability to safely shutdown the reactor also includes the assurance that radioactive releases do not exceed 10 CFR 100 values, mechanical and thermal limits for catastrophic failure of the fuel barrier are not exceeded, nuclear and containment system stresses allowed for accidents by applicable codes are not exceeded, and 10 CFR 50, Appendix A limits for control room personnel are not exceeded.

Although the HNP-2 is designed and constructed to quality standards that makes the failure of high-energy or moderate-energy lines highly unlikely, the analysis presented in this report indicates that with the plant modifications, the plant can withstand the effects of the postulated failures.

REFERENCES

1. "Design for Pipe Break Effects," BN-TOP-2, Revision 2, Bechtel Corporation, San Francisco, California, May 1972.

2. "Design of Structures for Missile Impact," BC-TOP-9A, Revision 2, Bechtel Corporation, San Francisco, California, September 1974.

3. Richardson, L. C., et al, "CONTEMPT - A Computer Program for Predicting the Containment Pressure - Temperature Response to a Loss-of-Coolant-Accident," 17220, Phillips Petroleum Company, June 1967.

4. Uchida, H., et al, "Evaluation of Post-Incident Cooling Systems of Light-Water Power Reactors," Third International Conference on the Peaceful Uses of Atomic Energy, New York, p. 93, 1965.

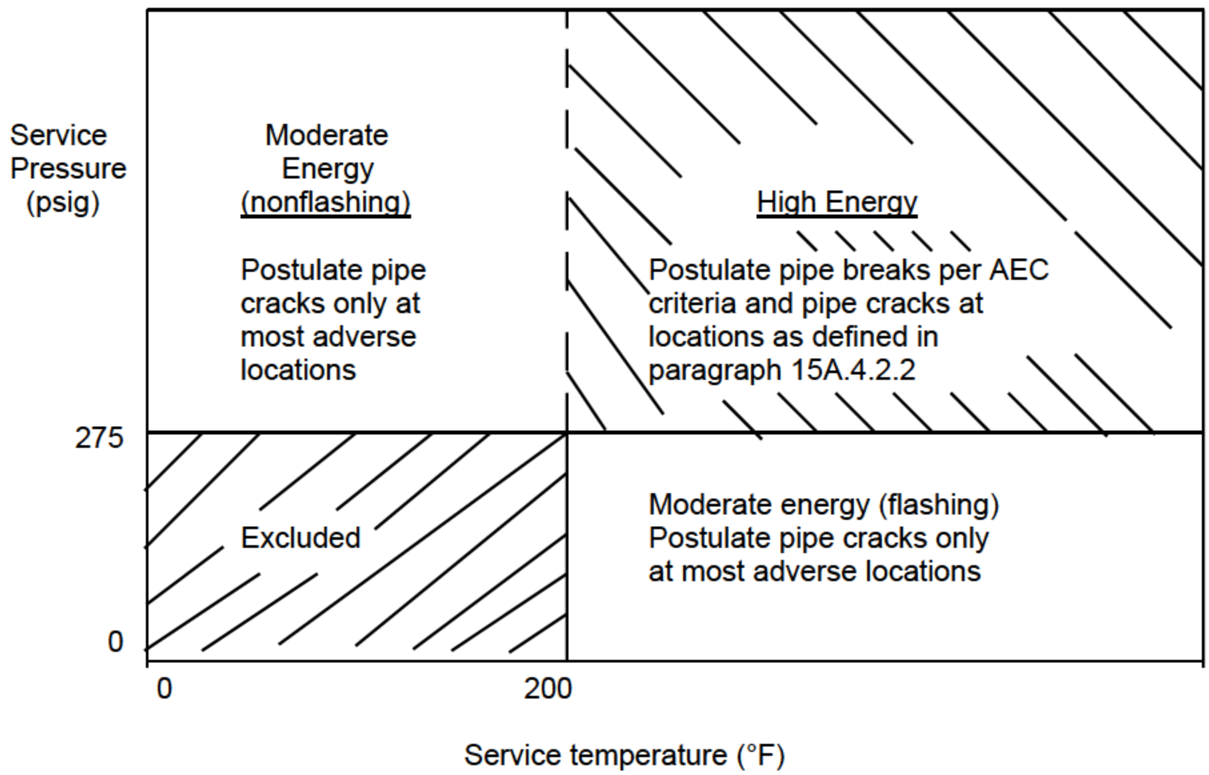
5. Not used.

6. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

7. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 15A-1

MODERATE- AND HIGH-ENERGY LINES



NOTE:
The high-energy and moderate-energy lines identified per the AEC criteria are listed as applicable to the schematic diagram.

TABLE 15A-2

BLOWDOWN DATA FOR HIGH-ENERGY LINE BREAKS

		Blowdown[a]		Blowdown Time Interval[b]		
High-Energy Line	Time After Break (s)	Mass Flow (lb/s)	Energy (Btu/lb)	Valve Closing Time (s)	Signal Delay Time (s)	Total Interval (s)
Main steam[d]	0	5300	1191.5	5.0	0.5	5.5
	2.75	4500	1191.5			
	2.76	19,600	589.3			
	4.0	19,500	589.5			
	5.5	0	589.5			
HPCI steam	Constant	3629	785.7	57.0	13.0	70.0
RCIC steam	Constant	336	1189.9	25.0	13.0	38.0
RWC[g]	Constant	1448	550.0	30.0	13.0	43.0
Feedwater[c]	Constant	3012[e]	402.5			[f]

a. Where applicable, a mixture quality of 7% is assumed for the mixture portion of the blowdown.

b. Valve closing times are the maximum allowable as specified in the Technical Requirements Manual. Signal delay times for isolation valves other than the MSIVs are conservatively taken as 13 s even though some isolation valves are dc operated and would have delays of only ≤ 3 s. The 13-s signal delay is based on the time for diesels to reach rated capacity. This is generally conservative, since for some of these systems, no LOSP is assumed or expected for a line break.

c. Feedwater line break in main steam pipe chase (18-in. diameter, schedule 120 line).

d. See figure 15A-1.

e. Duration of this blowdown rate is probably < 8 s. Following the break the MSIVs close, cutting off steam supply for running the reactor feed pumps. The pumps run out; since the MSIVs close in 6.0 s, the pumps run out at ~ 8 s following the break.

f. Note e above discusses the blowdown interval that would occur with an LOSP; however, the worst case for flooding effects would occur without an LOSP. For this case, the condensate and condensate booster pumps would continue to pump out the hotwell inventory until the condensate booster pumps automatically tripped (< 10 min) on low suction due to insufficient NPSH being supplied from the condensate pumps. The contr bution of water from the condenser hotwell is < 200,000 gal, which is at < 200°F and 270 psig (nonflashing).

g. The high-energy line break mass and energy release data were originally supplied by GE under GE letter SJ-73-39, dated January 26, 1973. GE letters GE-HATCH-TPO-022, dated May 17, 2002, and GE-HATCH-TPO-026, dated May 28, 2002, indicated that the mass and energy release data for the RWC lines were based on saturated liquid conditions and are nonconservative, since the RWC lines contain subcooled liquid. The mass and energy release data have been reevaluated and it has been concluded that the results of the original analysis are still bounding.

TABLE 15A-3 (SHEET 1 OF 3)

EQUIPMENT REQUIRED AND/OR PREFERRED FOR USE IN REACTOR SHUTDOWN FOLLOWING A HIGH-ENERGY LINE BREAK OUTSIDE PRIMARY CONTAINMENT

	High-Energy Line Break[a]					
Description of Equipment Required/Preferred	Main Steam	Feedwater	HPCI Steam	RCIC Steam	RWC	Notes
RPV (scram signals)	X	X	X	X	X	(b)
RPV and primary containment isolation control system	X	X	X	X	X	(c)
MCR environmental system	X	X	X	X	X	(d)
Pressure relief equipment						
Safety relief valves	X	X	X	X	X	(e)
Pressure suppression pool (passive)	X	X	X	X	X	
Flow restrictors (passive)	X					(f)
Core cooling preferences						
Incident detection circuitry (RPV low level only)	X	X	X	X	X	(g)
One of the following combinations required for core cooling and makeup:						
HPCI or RCIC	X	X			X	
One low pressure coolant injection or core spray loop			X	X		
RHR shutdown cooling mode	X	X	X	X	X	
RHR suppression pool cooling mode (one loop)	X	X	X	X	X	(h)
RHRSW to one RHR heat exchanger	X	X	X	X	X	(h)

TABLE 15A-3 (SHEET 2 OF 3)

Description of Equipment Required/Preferred	High-Energy Line Break[a] Main Steam	Feedwater	HPCI Steam	RCIC Steam	RWC	Notes
Electrical power systems						
Emergency ac power (2 of 3 diesel generators)	X	X	X	X	X	
Onsite dc power (125/250-V-dc power system)	X	X	X	X	X	
4160-V emergency buses (2 of 3 emergency buses)	X	X	X	X	X	
600-V emergency buses (1 of 2 buses)	X	X	X	X	X	
Motor control centers for above equipment	X	X	X	X	X	
Service water requirements						(j)
Diesel generator jacket cooling	X	X	X	X	X	
RHR pump cooling	X	X	X	X	X	
RHR room cooling	X	X	X	X	X	
HPCI room cooling	X	X		X	X	
RCIC room cooling	X	X	X		X	
Instrumentation for post-accident monitoring						
Reactor pressure indication	X	X	X	X	X	
Reactor water level indication	X	X	X	X	X	
Suppression pool temperature indication	X	X	X	X	X	
Suppression pool water level indication	X	X	X	X	X	

TABLE 15A-3 (SHEET 3 OF 3)

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a. An x indicates a requirement and/or preference for that particular line break.

b. Scram trip signals, settings, and operability requirements are provided in the Technical Specifications. A detailed discussion of these may be found in section 7.2 of the FSAR. Generally, low reactor water level will initiate a scram for most high-energy line breaks.

c. Instrumentation required to initiate reactor vessel and primary containment isolation with corresponding trip settings is listed in the Technical Specifications. A detailed discussion of these is given in section 7.3 of the FSAR. Instrumentation required to isolate core cooling systems is listed in the Technical Specifications.

d. This system, as described in section 6.4, assures continued habitability of the MCR following any high-energy line break.

e. There are 11 safety/relief valves as described in section 5.2. These valves are located inside the primary containment.

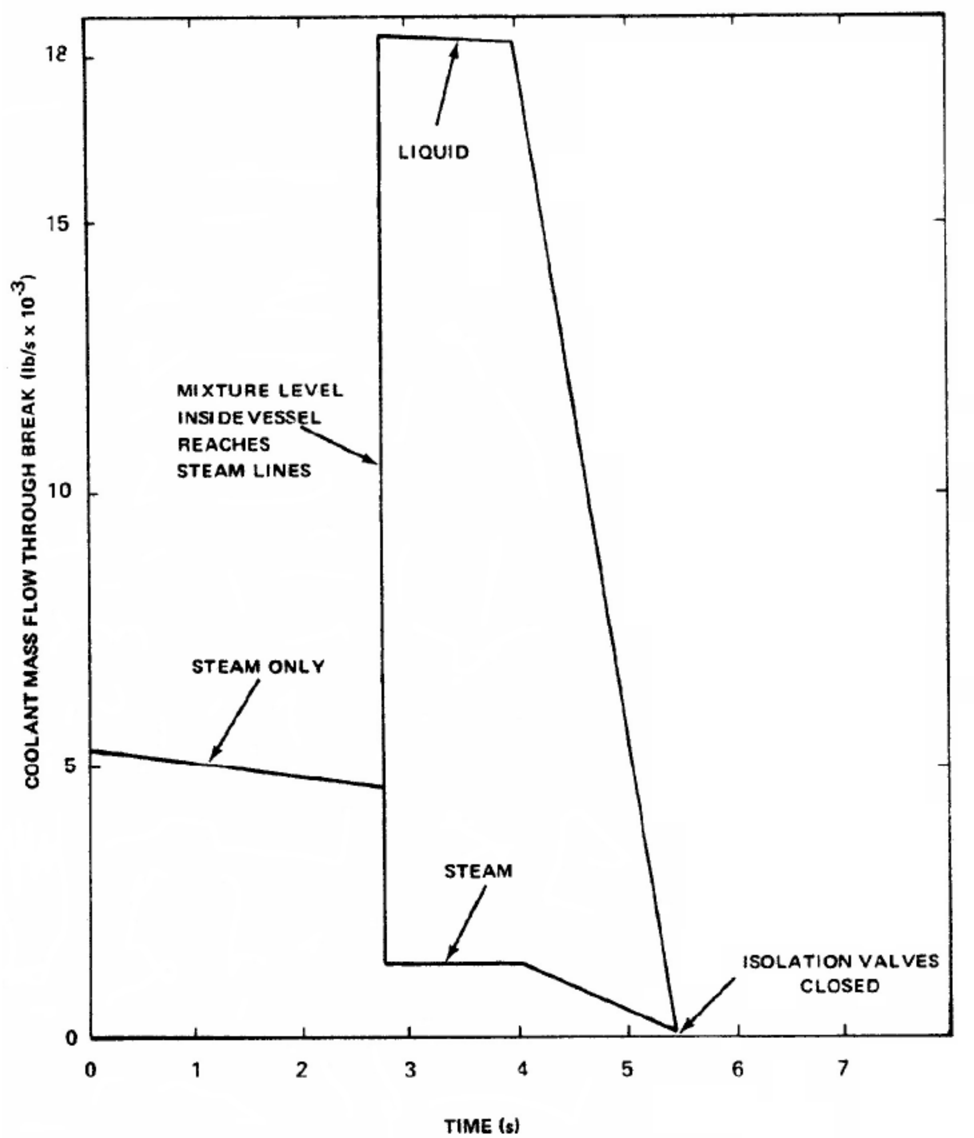
f. Flow restrictors for the main steam lines as described in section 5.5 are required to reduce the blowdown from an MSLB. These restrictors are located inside the primary containment.

g. Instrumentation and trip settings required for initiation of core cooling systems are specified in the Technical Specifications. Descriptions of ECCS are found in section 6.3 of the FSAR.

h. See discussion in section 15A-5, item b of this supplement.

i. Due to the flexibility of design with respect to core standby cooling systems, reactor coolant injection systems, and the various modes of the RHR system, it is more appropriate to list equipment preferred for use in plant shutdown. There are several automatic actions that serve to back up the preferred action, e.g., HPCI and RCIC perform similar functions. There are also options available to the operator such as utilizing both RHR loops, if available. These systems and functions are described in chapters 5 and 6.

j. Room or pump cooling is required only if the applicable system is available and called upon for service.



The original analyses are based on a total integrated mass of 52,300 lb leaving the break, of which 36,100 lb are liquid and 16,200 lb are steam. Of the 16,200 lb of steam, 2700 lb resulted from flashing of the liquid. The evaluation for ROPI is based on the total integrated mass of < 52,800 lb leaving the break with no significant impact on the results of the existing evaluation.

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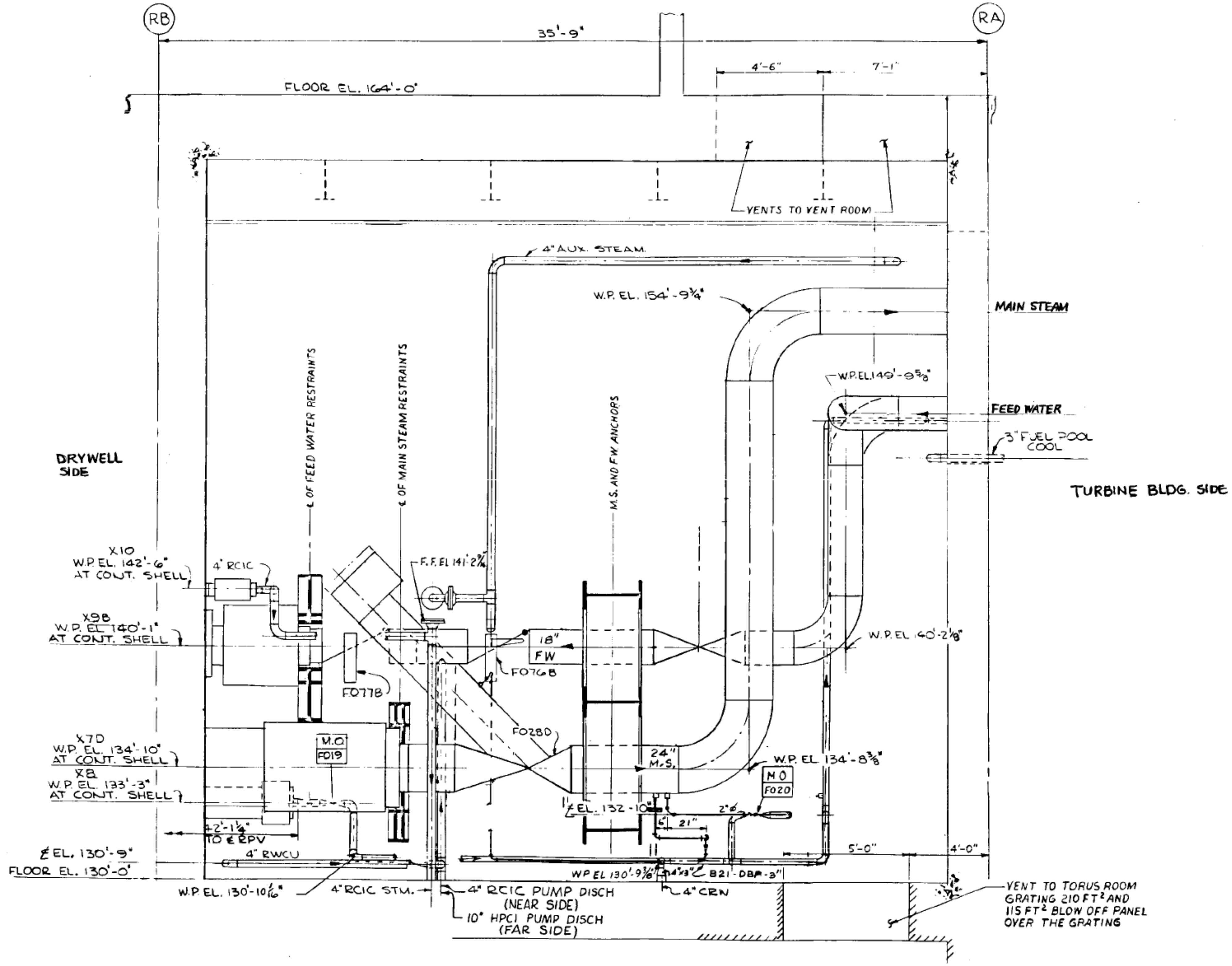
MSLBA-MASS OF COOLANT LOSS THROUGH BREAK WITH 5-s MSIV CLOSING TIME

FIGURE 15A-1



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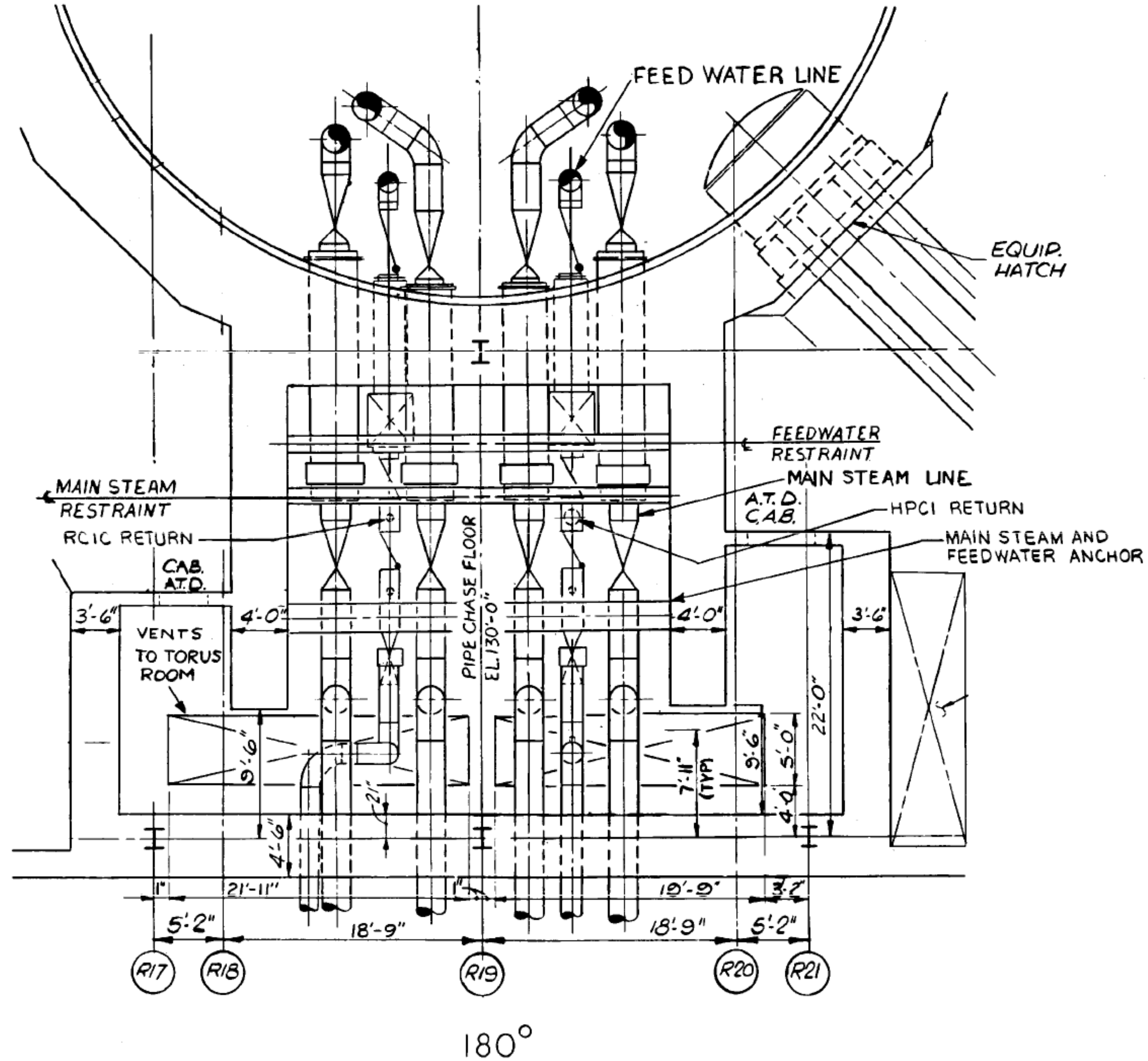
UNIT 2

MAIN STEAM AND FEEDWATER LINES IN MAIN STEAM PIPE CHASE, REACTOR BUILDING, ELEVATION VIEW LOOKING SOUTH

FIGURE 15A-3



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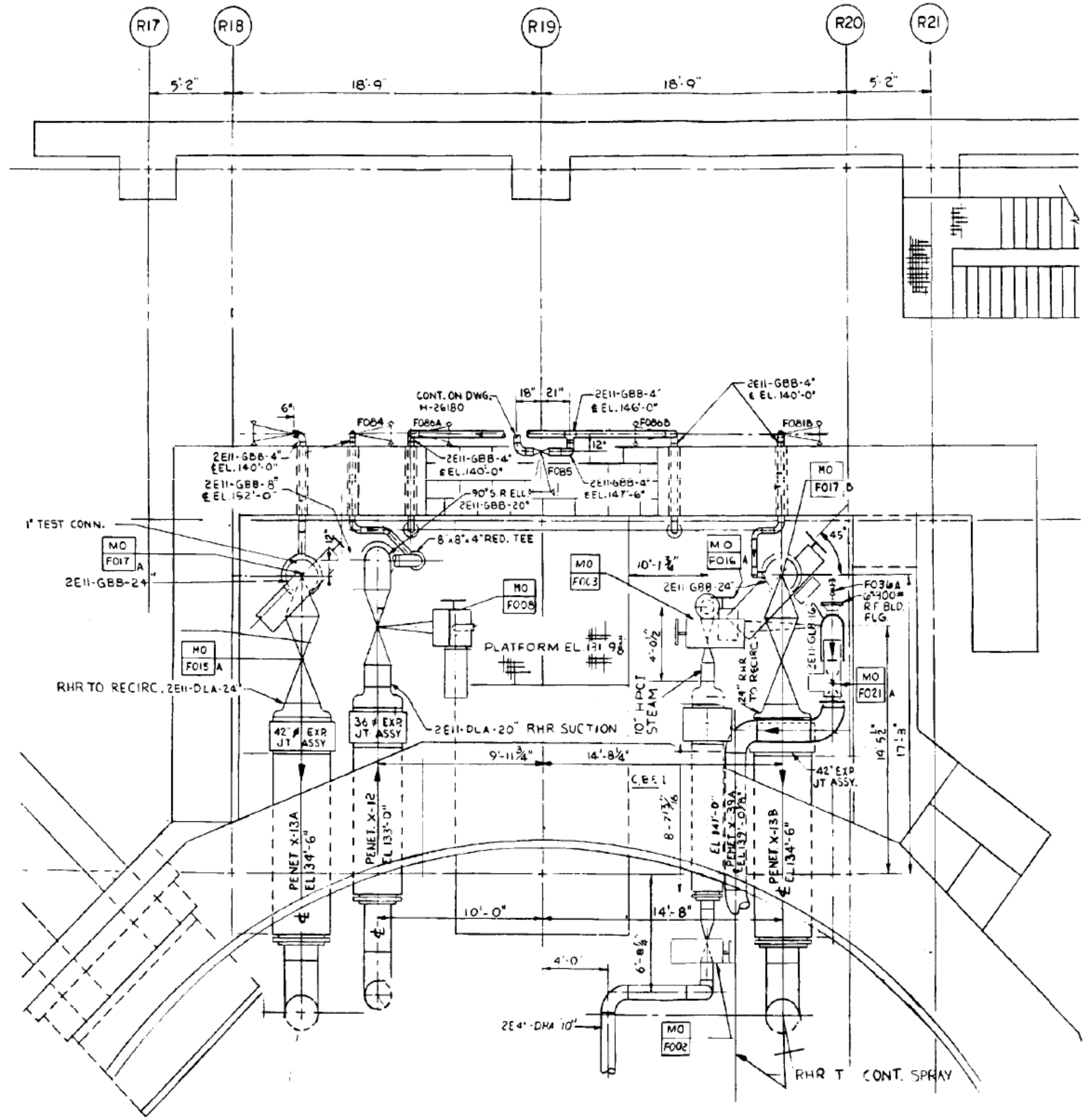
MAIN STEAM AND FEEDWATER LINES, MAIN STEAM PIPE CHASE REACTOR BUILDING – PLAN VIEW

FIGURE 15A-4



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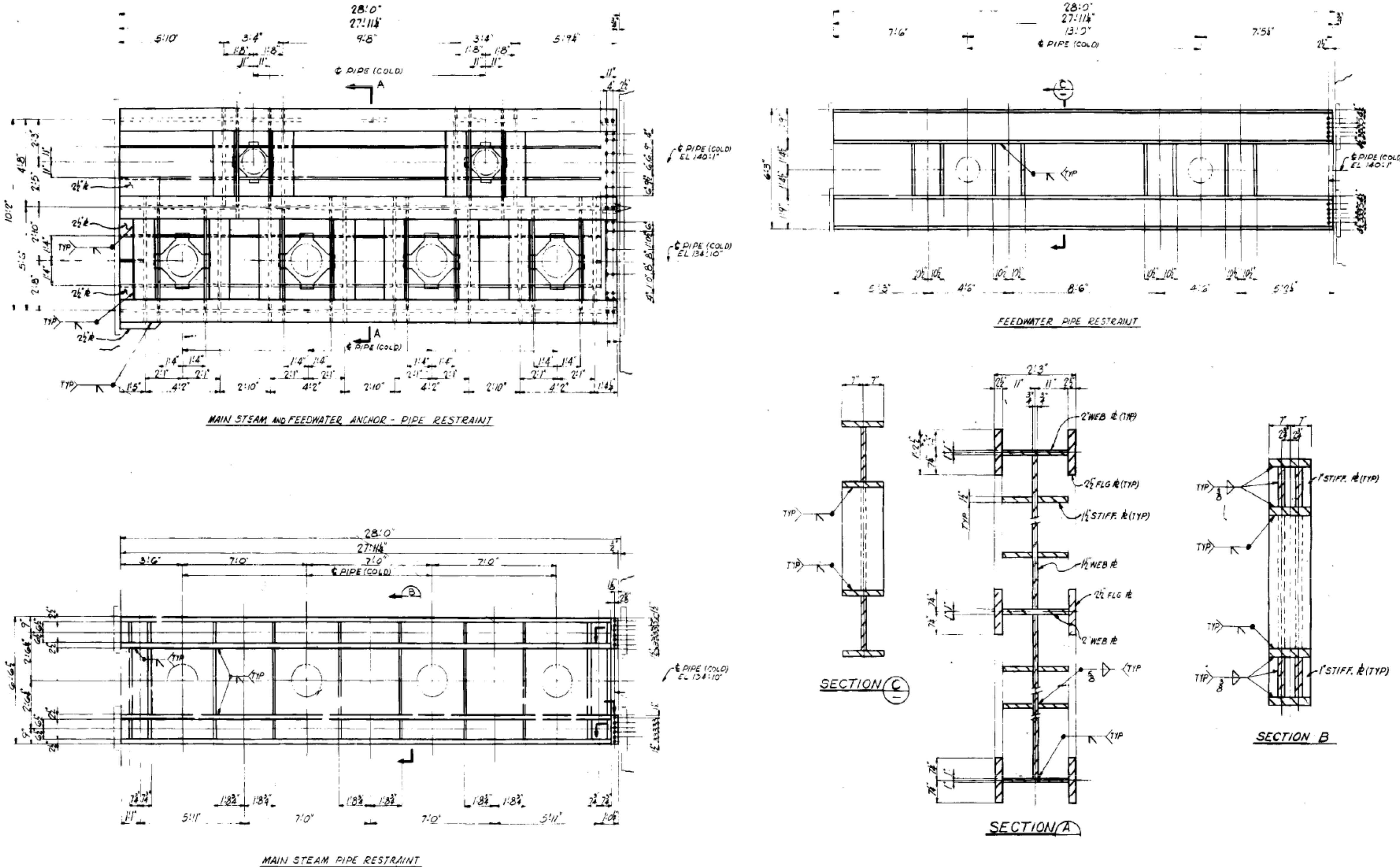
HPCI STEAM AND RHR LINES, PIPE PENETRATION ROOM, REACTOR BUILDING el 130 ft – PLAN VIEW

FIGURE 15A-6



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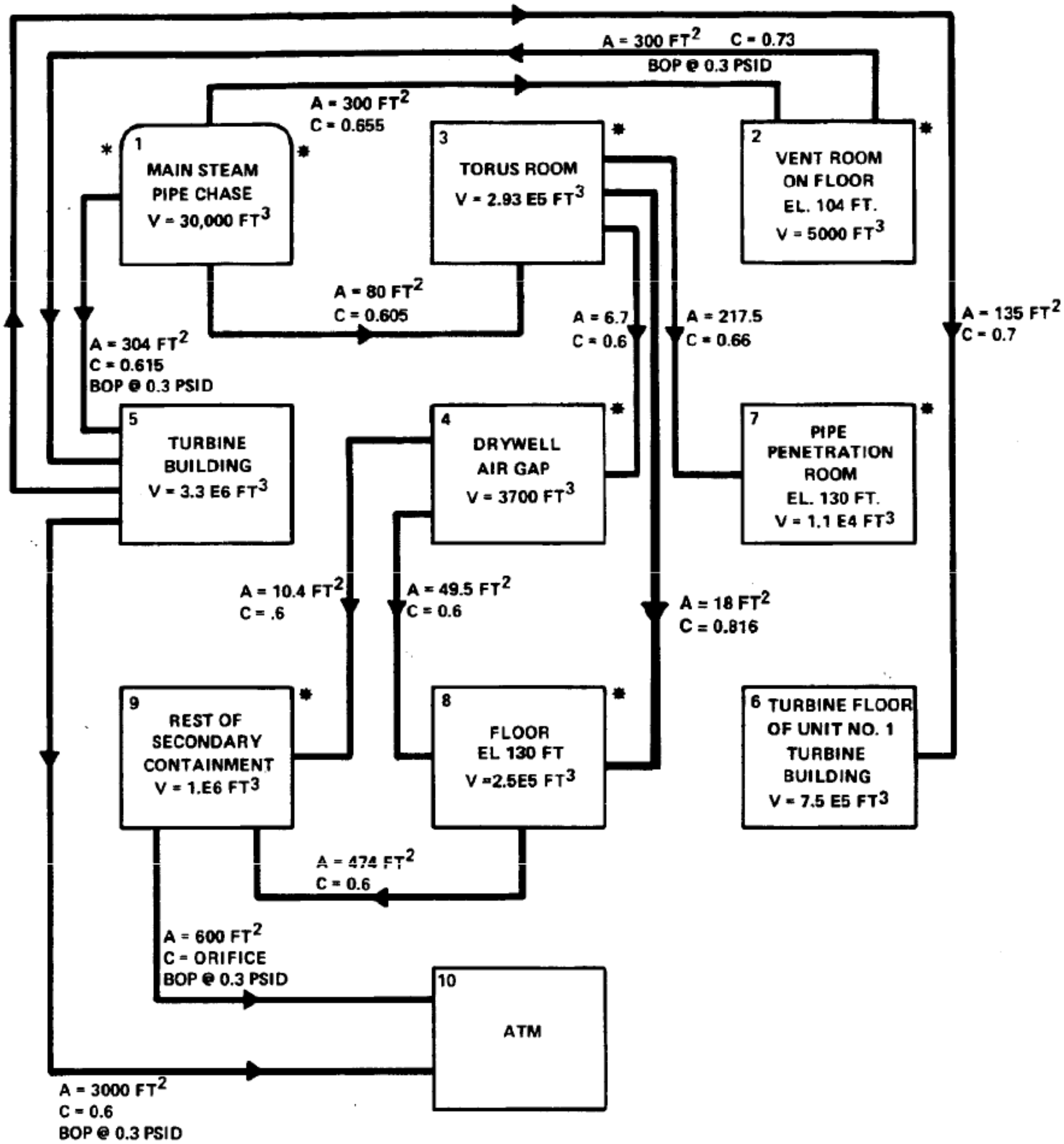
MAIN STEAM AND FEEDWATER
ANCHOR FRAME DETAILS
MAIN STEAM PIPE CHASE

FIGURE 15A-9



* BREAK COMPARTMENT
∗ REACTOR BUILDING

A = VENT AREA
C = FLOW COEFFICIENT
V = VOLUME
BOP = BLOW-OFF PANEL

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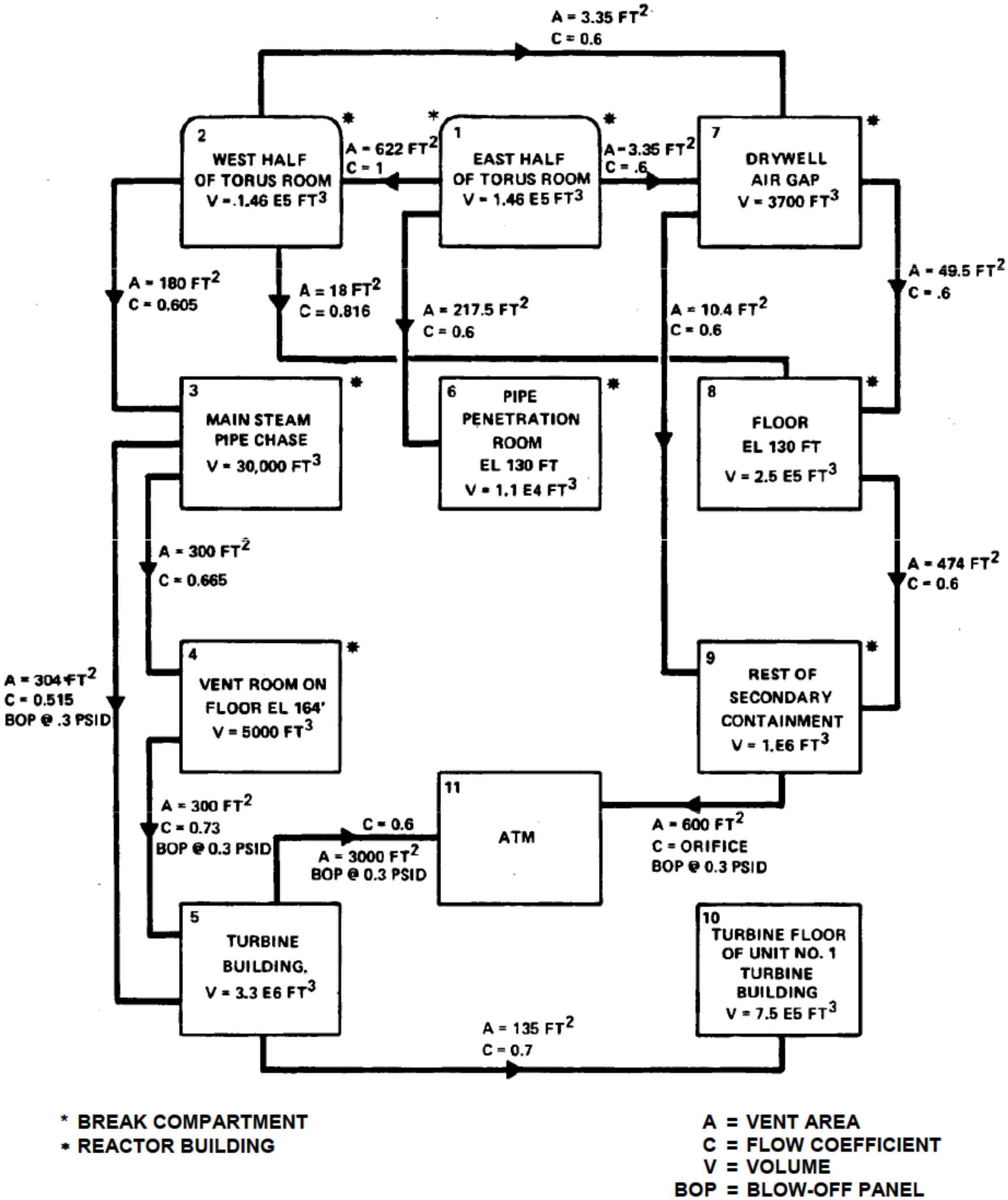
FLOW MODEL – MSLB
IN PIPE CHASE ROOM

FIGURE 15A-10



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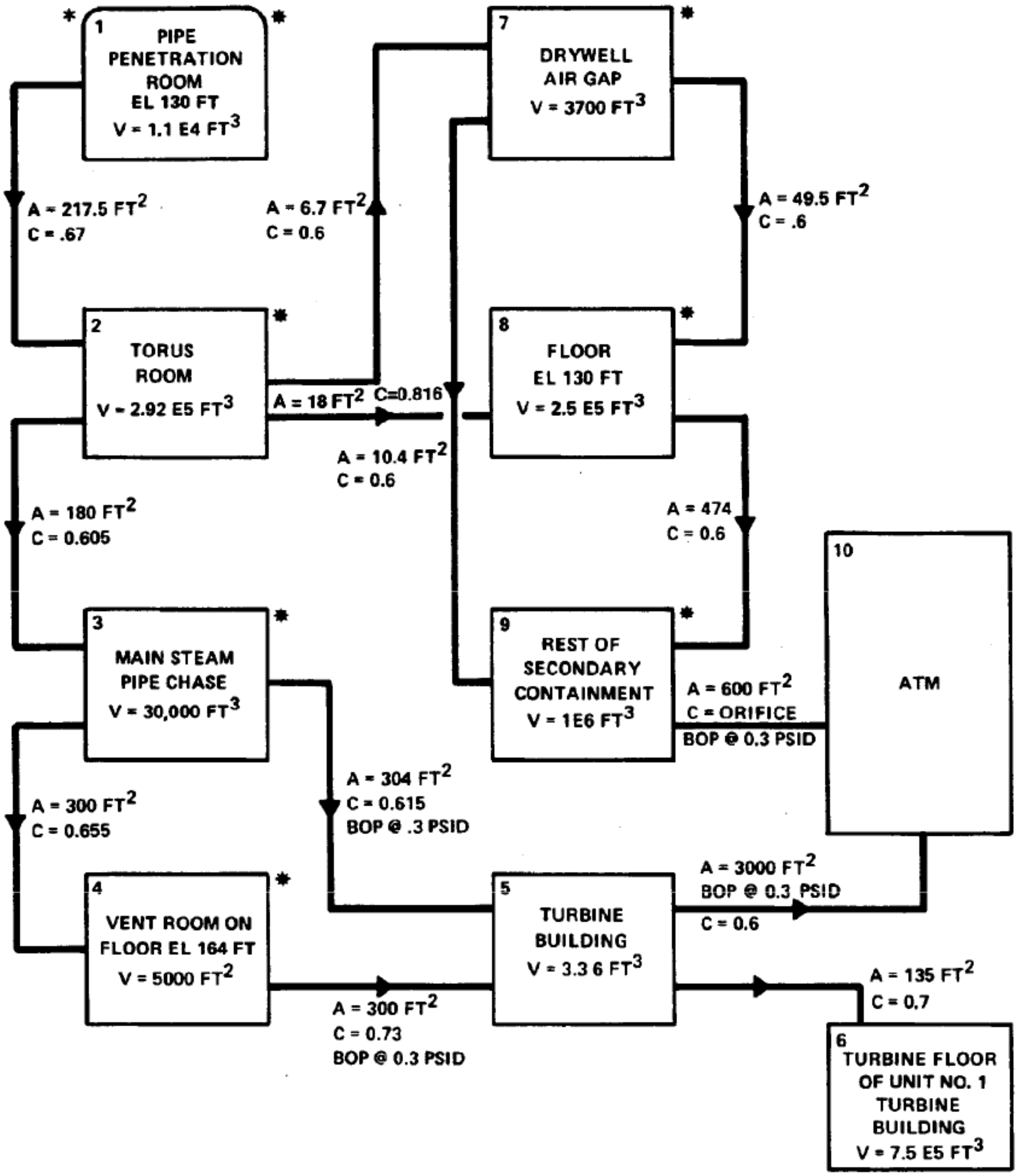
FLOW MODEL – HPCI STEAM LINE
BREAK IN TORUS ROOM

FIGURE 15A-11



* BREAK COMPARTMENT
* REACTOR BUILDING

A = VENT AREA
C = FLOW COEFFICIENT
V = VOLUME
BOP = BLOW-OFF PANEL

ACAD 215A12

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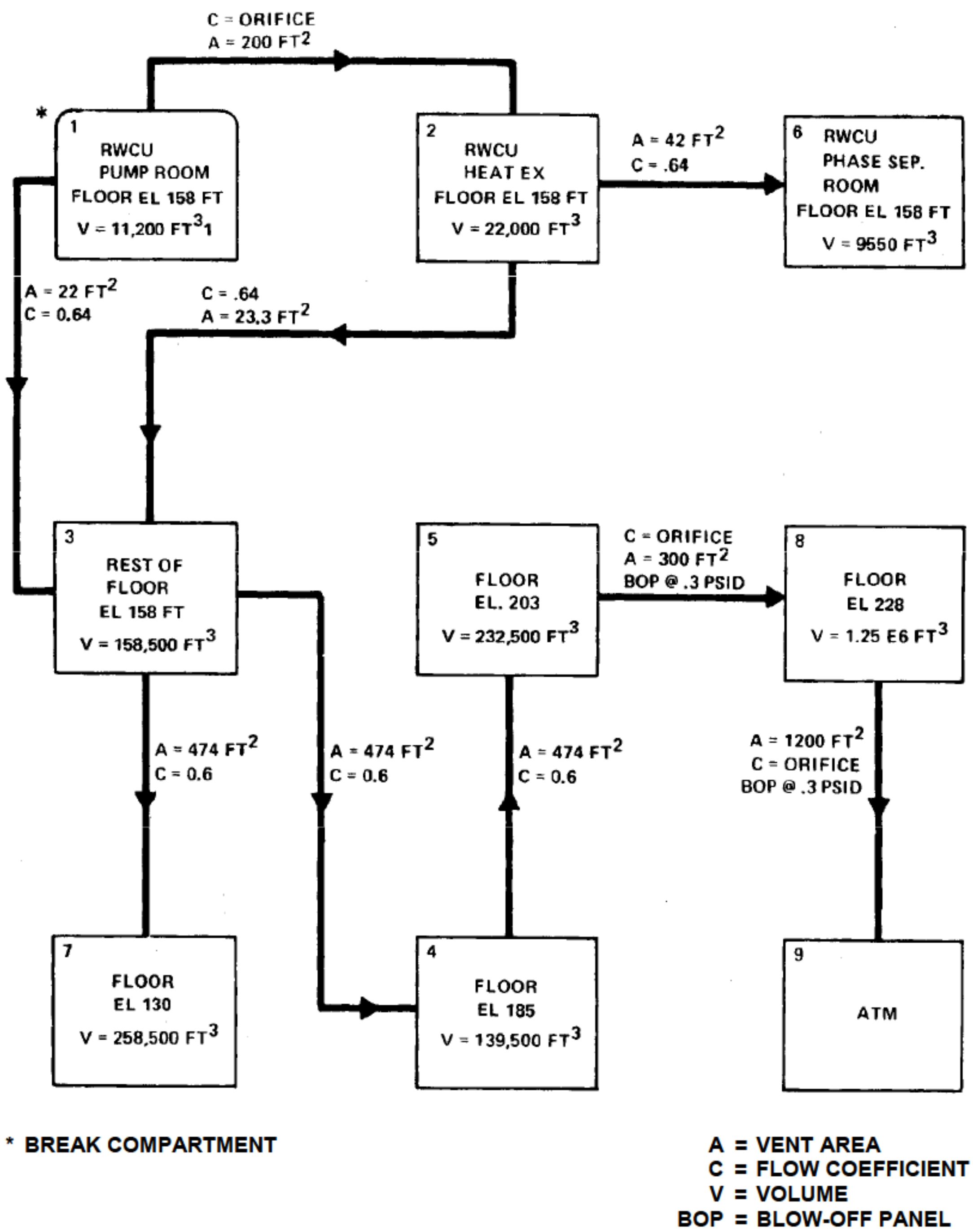
FLOW MODEL – HPCI STEAM LINE BREAK IN PIPE PENETRATION ROOM

FIGURE 15A-12



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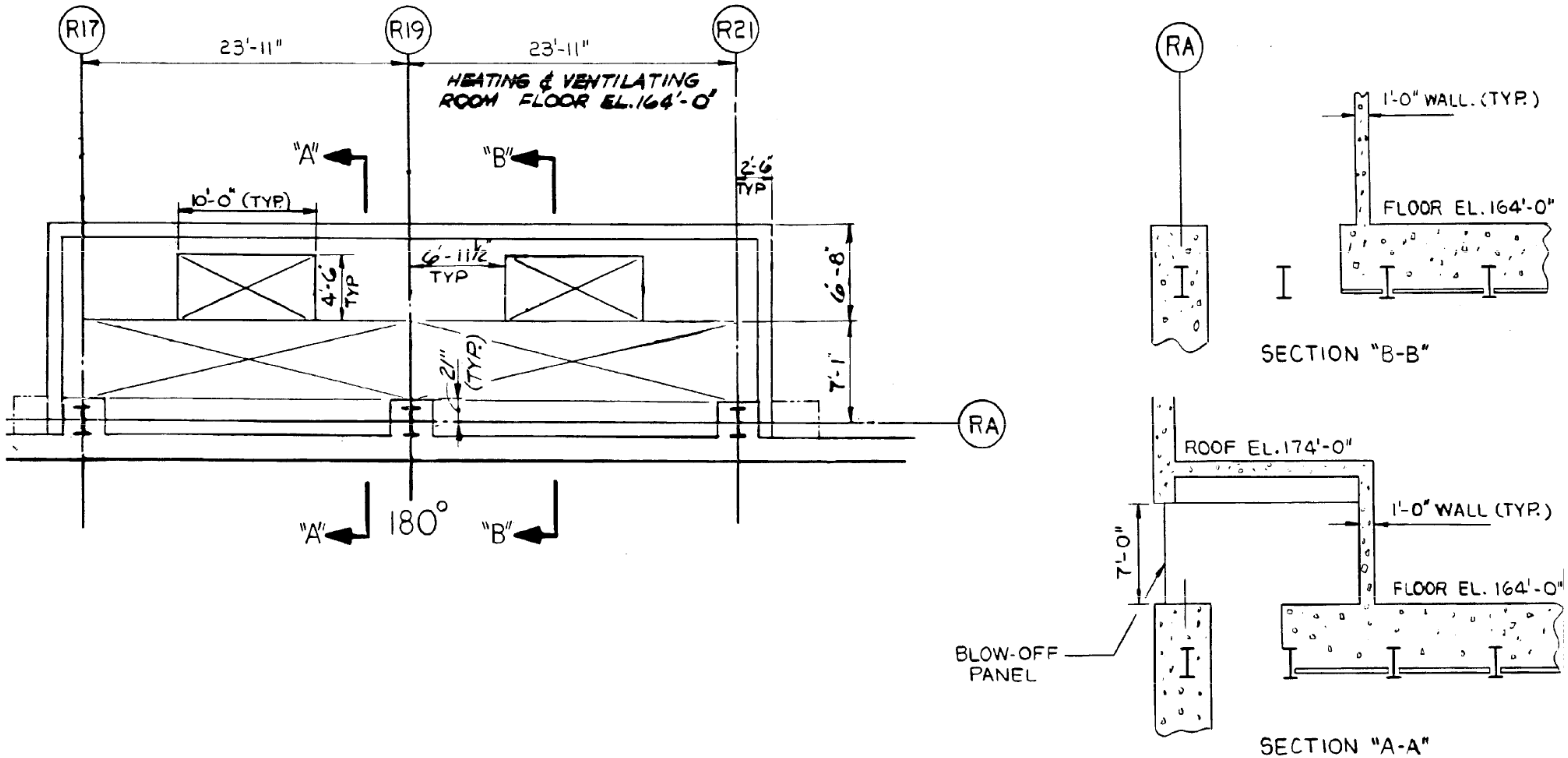
FLOW MODEL – RWC LINE BREAK IN PUMP ROOM – REACTOR BUILDING

FIGURE 15A-13



ACAD 215A14

REV 19 7/01

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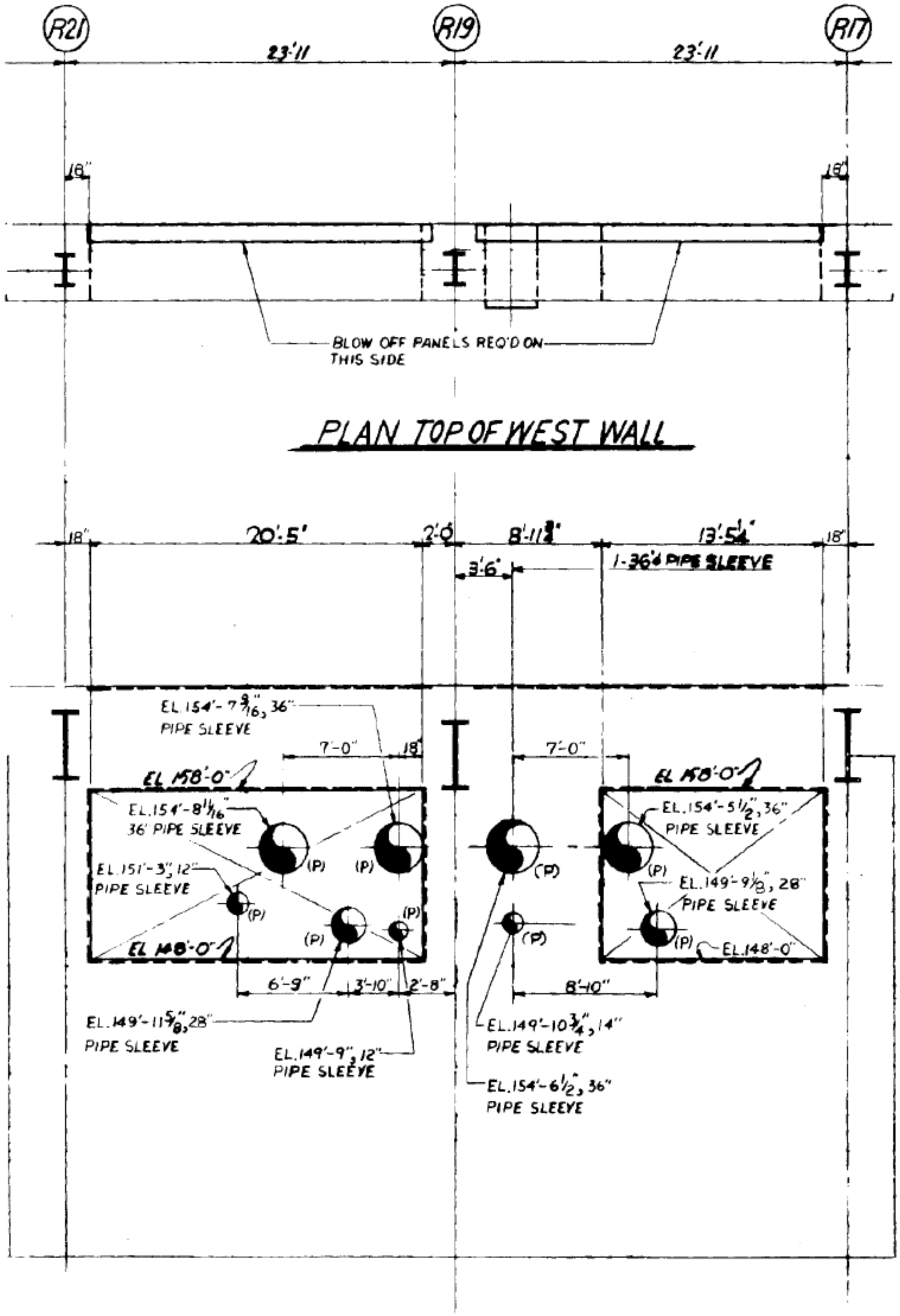
UNIT 2

VENT ROOM el 164 ft AND VENT AREA ADDITION FROM MAIN STEAM PIPE CHASE TO VENT ROOM TO TURBINE BUILDING – REACTOR BUILDING

FIGURE 15A-14



ACAD 215A15

REV 19 7/01

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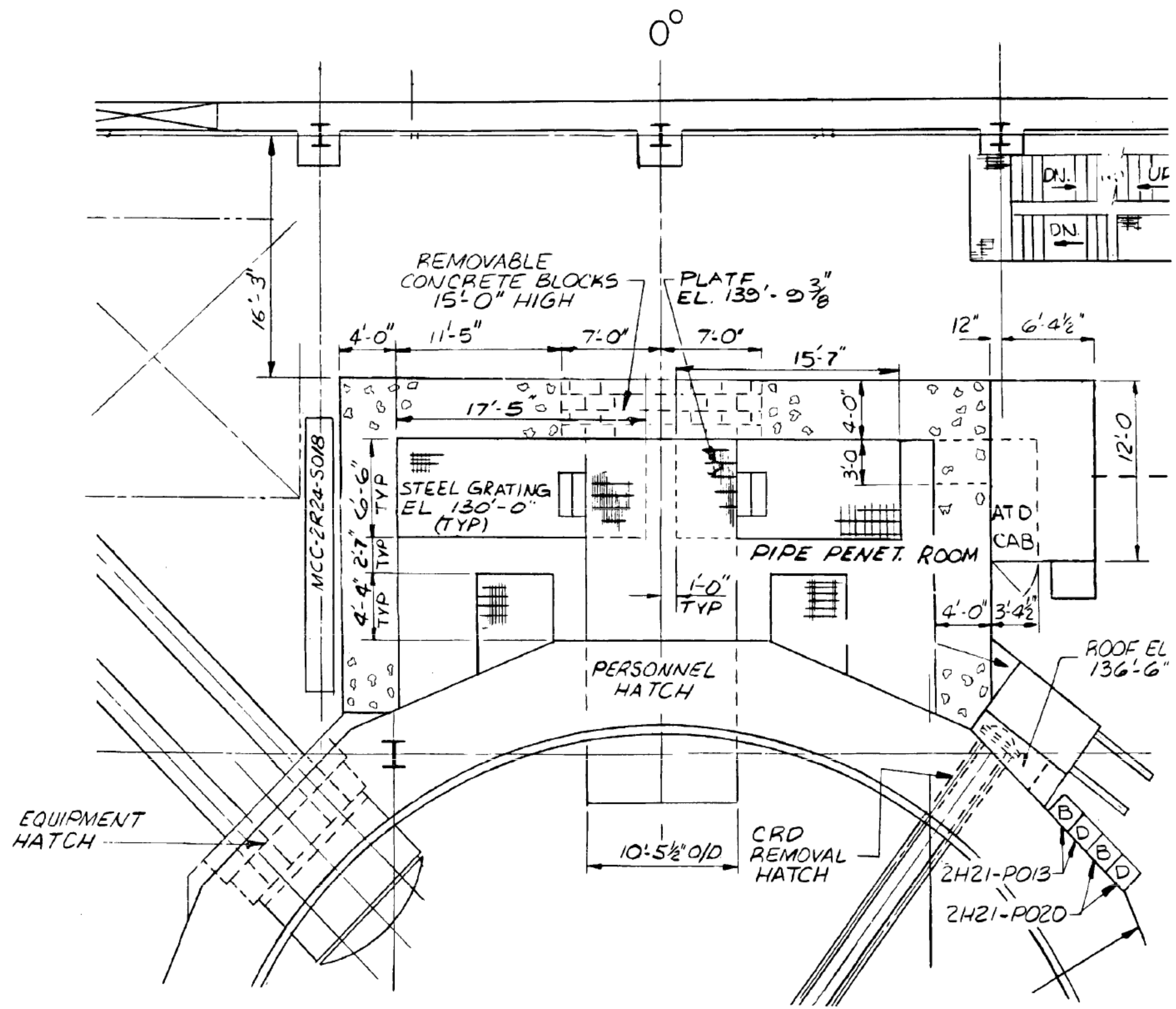
UNIT 2

VENT AREA ADDITION TO TURBINE BUILDING FROM MAIN STEAM PIPE CHASE, REACTOR BUILDING

FIGURE 15A-15



ACAD 215A16

REV 19 7/01

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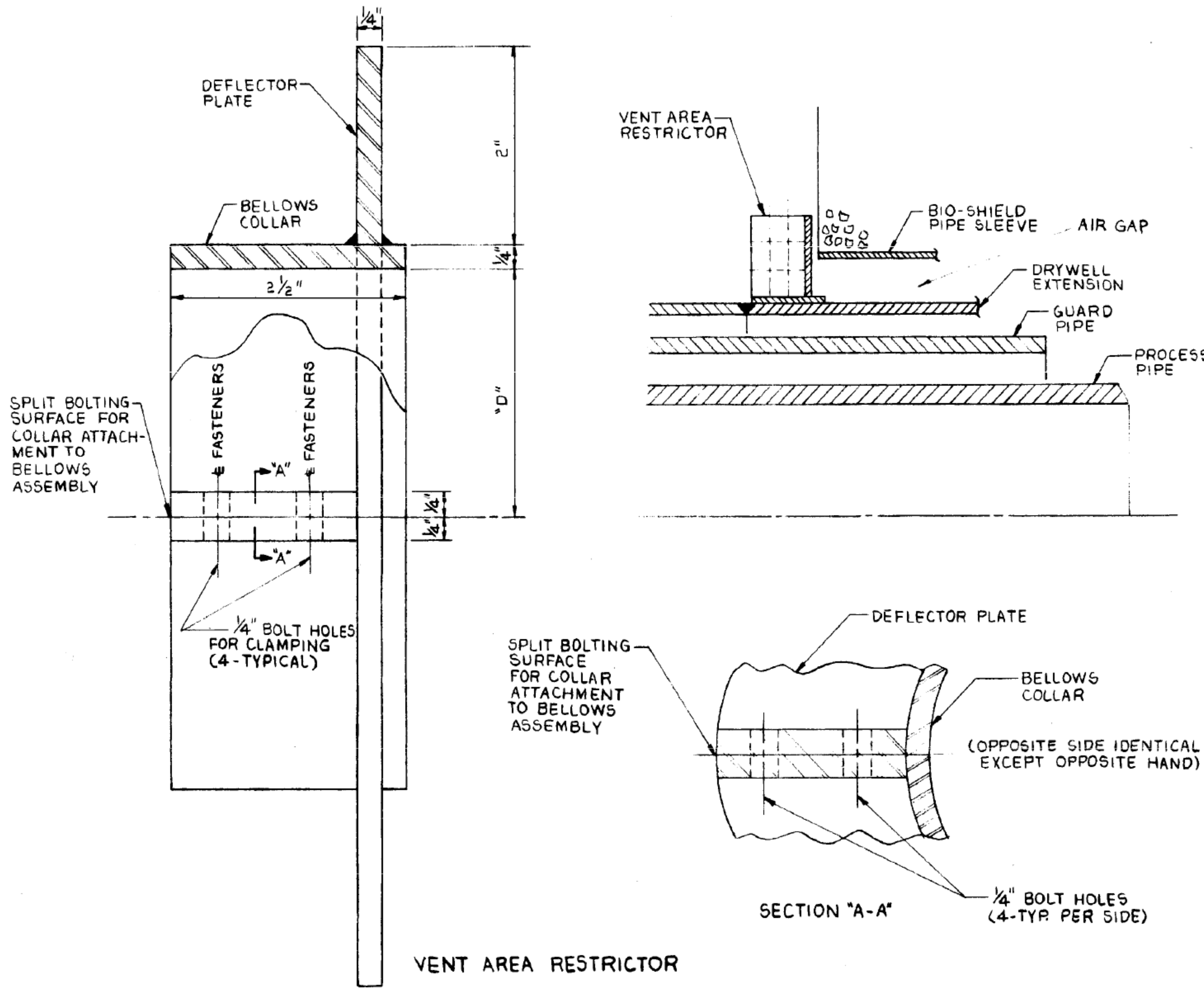
VENT AREA FROM PIPE PENETRATION ROOM, REACTOR BUILDING FLOOR el 130 ft TO TORUS ROOM

FIGURE 15A-16



NOTES:

ALL DIMENSIONS ARE NOMINAL ± 1/8" EXCEPT DIMENSION "D".

"D" EQUALS DRYWELL BELLOWS ASSEMBLY O.D., + 1/8" – 0.

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VENT AREA RESTRICTORS AROUND DRYWELL PENETRATIONS

FIGURE 15A-17

SUPPLEMENT 15A.A

RESPONSE TO NRC QUESTION A&PCSB-1

15A.A.1 BACKGROUND

The Nuclear Regulatory Commission (NRC) criteria for design and protection from high-energy breaks outside containment for Hatch Nuclear Plant-Unit 2 (HNP-2) was issued to the applicant with their letter of December 22, 1972. Subsequent meetings were held with the NRC to obtain clarification of the criteria which resulted in the NRC's approval of the criteria for classification of high-and moderate-energy lines as presented in table 15A-1. HNP-2 was designed and constructed in accordance with the criteria and analysis of appendix 15A. The evaluation of high-energy line breaks outside containment was filed with the NRC as a separate report, prior to submission of the Final Safety Analysis Report (FSAR) in March of 1975. This report was incorporated into the FSAR as supplement 15A and was resubmitted with the FSAR in July 1975.

The NRC review of the report on high-energy line breaks outside containment resulted in a request for a change in criteria as depicted in question A&PCSB-1. The impact of this new criteria was that most lines that were originally analyzed as moderate-energy lines were required to be analyzed as high-energy lines and the remaining lines that had previously been exempted from analysis based on low temperature and low pressure were required to be analyzed as moderate-energy lines.

The additional lines that the new criteria required to be analyzed for cracks as moderate-energy lines are listed in section 15A.A.4. All of these lines, with the exception of the residual heat removal service water system (which has been analyzed for cracking) are low-temperature and low-pressure lines which do not get exposed to high cyclic thermal stresses. Therefore, protection from cracks in these lines does not provide a significant increase in the degree of protection provided for the health and safety of the public and, therefore, should not be required.

At a meeting with the NRC on October 2, 1975, it was agreed that if a line operated in the high-energy range for < 1% of the plant operating time, it need not be evaluated for breaks. The lines exempted from this analysis are:

- Standby liquid control system.
- High-pressure coolant injection (HPCI) turbine exhaust and test lines.
- Core spray lines.
- Auxiliary steam line.

These lines would be evaluated for cracks only at locations where the stress exceeds 0.8 ($S_A + S_H$).

15A.A.2 ADDITIONAL HIGH-ENERGY LINES ANALYZED

	Service Temperature (°F)	Service Pressure (psig)	Pipe Diameter and Schedule
Reactor core isolation cooling (RCIC) injection	140	1230[a]	4 in./S80
RCIC turbine exhaust	240	10	10 in./S40
Reactor water cleanup (RWC) (remainder of piping in the pipe nest room and filter-demineralizer room)	120	1168[a]	3 in. and 4 in./ S80
Control rod drive (CRD) return	150	1039[a]	3 in./S80
Condensate system from booster pump to reactor feedwater pump	122-367	380	18 in., 24 in., and 26 in./S40
From reactor feedwater pump to 4th-stage heater	369	1210[a]	18 in., 24 in., and 26 in./S40
Steam jet air ejector (SJAE) lines off-gas	300	6	6 in./S40

15A.A.2.1 RCIC INJECTION LINE

The 4-in. RCIC injection line leaves the RCIC corner room and runs along the west wall of the reactor building in the torus chamber room. The line then turns east for ~ 20 ft and runs vertically up through the pipe chase floor into the north feedwater line. On the eastward run, a 4-in. branch line is provided for system testing.

A stress summary and postulated breakpoint locations are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values will be updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

a. These cases were evaluated for the small increases in service pressure and temperature associated with operation at 2804 MWt and reactor operating pressure increase. The increase in stress and cumulative fatigue usage was negligible.

Two separate pipe runs are considered: one from the anchor at the RCIC corner room wall to the feedwater line and a second from the feedwater connection to the anchor on the test line.

The postulated break in the pipe chase at data point 5 is at the connection to the feedwater system. The RWC return line to the feedwater system ties into the RCIC injection line upstream of the break. Therefore, a postulated break in this area disables both the RCIC and RWC systems.

A postulated break at data point 115E could cause the downstream end of the pipe to strike the torus. The event has been evaluated and does not cause loss of torus integrity.

Breaks postulated at other points do not cause any problem as a result of pipe whip or jet impingement.

The environmental effects of a RCIC injection line break in the pipe chase and torus room are less limiting than a main steam line break (MSLB) and HPCI line break, respectively.

The shutdown capability is the same as that discussed in paragraph 15A.5.4.2.

15A.A.2.2 RCIC TURBINE STEAM EXHAUST LINE

The RCIC turbine steam exhaust line was evaluated as a high-energy line and postulated breakpoint locations are indicated in HNP-2 stress calculations. Stress intensities and usage factors are not revised for each stress calculation revision. The values will be updated only if the stress calculation revisions define new break locations as described in paragraph 15A.4.2.1.B.

This line need not be evaluated for breaks or cracks because of the low stress levels $< 0.4\ (1.2\ S_h + S_A)$ and low system operating pressure (< 10 psig) together with the minimal expected system operating time of the line.

15A.A.2.3 RWC SYSTEM PIPING IN THE PIPE NEST ROOM AND FILTER-DEMINERALIZER ROOM

The RWC piping rises from the 158-ft floor to the pipe nest room at the el 185-ft floor and then to the filter-demineralizer room at el 203 ft.

All the high-energy piping is enclosed in the pipe nest room and the filter-demineralizer room.

Any break in these rooms does not cause any detrimental effects as a result of pipe whip and jet spray other than disabling the RWC system. Flooding in these rooms is not a concern as the floor drains drain to the southwest corner room sump, and the level switches annunciate in the control room. Annunciation of a break in the RWC piping in the filter demineralizer room is initiated by high room temperatures or high ventilation system differential temperatures.

Isolation of the RWC system is initiated by high differential flow in the system.

The shutdown capability is the same as that described in paragraph 15A.5.5.2.

15A.A.2.4 CRD RETURN LINE TO REACTOR PRESSURE VESSEL

The routing of this line is described in paragraph 15A.5.6.1. The CRD return line and the RWC return line were dynamically analyzed as one model and may, therefore, be considered a single piping run. No intermediate break locations need to be postulated in the CRD run since stress levels there are below the threshold level and lower than those in the RWC run. A circumferential break was postulated at data point 145 since it is a terminal end.

The shutdown capability is the same as that described in paragraph 15A.5.6.1.

15A.A.2.5 CONDENSATE SYSTEM

The condensate system is classified as a high-energy system from the condensate booster pump discharge through the feedwater heaters and reactor feed pumps to the fourth-stage heaters.

All the equipment is located in the turbine building. There is no safety-related equipment in the turbine building.

The pressure-temperature effects from a condensate line break are enveloped by the effects of a MSLB in the turbine building as discussed in paragraph 15A.5.1.2. The flooding effects are enveloped by the effects of a circulating water line break in the turbine building.

The analysis of the shutdown capability for a condensate system line break is the same as that for a feedwater line break and as discussed in paragraph 15A.5.2.3.

15A.A.2.6 SJAE OFF-GAS LINES

The SJAE operating conditions are 6 psig/300°F, and the effluent is discharged to the off-gas system.

The SJAEs are located close to the west wall of the turbine building at el 112 ft. The off-gas system preheaters and recombiners are located around the southwest corner of the turbine building el 112-ft floor.

A postulated failure of the air ejector off-gas line is detected by radiation instrumentation in the off-gas system equipment room. High-radiation-level alarms annunciate in the main control room. A normal shutdown of the reactor is initiated by the operator.

The pressure-temperature effects following an SJAE off-gas line failure are less severe than those following an MSLB in the turbine building. The radiological effects following an SJAE off-gas line break are discussed in subsection 15.4.15.

15A.A.3 (Deleted)

15A.A.4 ADDITIONAL MODERATE-ENERGY LINES NEEDED TO BE ANALYZED

	Service Temperature (°F)	Service Pressure (psig)
Plant service water (PSW) in reactor building	95	140
PSW in diesel generator room	95	140
PSW to control room coolers	95	140
Reactor building closed cooling water piping in reactor building	105	132
Fuel pool cooling system	150	87
Plant hot water heating system	195	100
Fire protection system	95	125
Condensate storage and transfer system	100	170
Circulating water system	110	27
Demineralized water transfer system	100	150
Residual heat removal service water (RHRSW) system[a]	95	415

All additional moderate-energy lines are being further reviewed for effects of critical-size cracks in response to IEB79-14. The location of the crack is at points determined by the criteria given in paragraph 15A.4.2.2.[a]

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a. The total system operating time during a cooldown event is 15 days. During this time, the RHRSW system operates in the high-energy range (< 275 psig) for ~ 1.5 h. Since the period of operation at high energy is < 2% of the total system operating time, the system is evaluated as a moderate-energy line, and is analyzed in subsection 15A.5.6.

SUPPLEMENT 15C

NUCLEAR SAFETY OPERATIONAL ANALYSIS AND SETPOINT METHODOLOGY (HNP-1 AND HNP-2)

15C.1 ANALYTICAL APPROACH

This supplement provides the results of the combined nuclear safety operational analysis (NSOA) for HNP-1 and HNP-2 which has been integrated with the setpoint methodology. The two units have virtually identical system designs, similar thermal-hydraulic and transient behavior characteristics, and utilize the same setpoint methodology. Therefore, the NSOA results and setpoint methodology are considered applicable to HNP-1 and HNP-2.

15C.1.1 NSOA AND SETPOINT METHODOLOGY OBJECTIVES

The objective of the NSOA is to identify, for each event in the safety analysis (chapter 15), the system level requirements that ensure the plant can be brought to a stable condition. Specifically, the NSOA considers the entire duration of each event from the spectrum of possible initial conditions and aftermath until either some mode of planned operation is resumed or the plant is in a stable condition with continuity of core cooling.

Figure 15C-1 provides a high level illustration of the process by which NSOA results are developed, including the relationship to the design and safety analysis processes.

The NSOA process uses operational criteria and required actions to identify the required systems, automatic instrument trips, monitored parameters (associated with required operator actions), and auxiliary systems to bring the plant to a stable condition for each event. The system-level requirements identified as required in the NSOA reflect the licensing basis of the plant and constitute the minimum required actions to bring the plant to a stable condition. In actual plant operation, additional procedural guidance and plant equipment are available to prevent or further mitigate these events. Finally, the NSOA focuses primarily on active plant features used to bring the plant to a stable condition; passive plant features are implicitly considered but not explicitly documented in the event evaluations and diagrams.

The objective of the setpoint methodology is to translate the safety analysis and NSOA requirements into plant operational requirements. In this context, setpoints are instrument limits, specified in terms of measurable process variables, at which system automatic or operator actions must take place to preserve the assumptions of the plant safety analysis or be controlled to satisfy licensing commitments. The setpoint methodology includes the calculational methods and practices, a hierarchy of setpoint classifications, the treatment of uncertainties, and the methodology used in the development of controlling values for analytical limits, allowable values, and nominal trip setpoints. The setpoint methodology is described in section 15C.5

15C.1.2 NSOA RELATIONSHIP TO SAFETY ANALYSIS

The safety analysis is performed to demonstrate compliance with appropriate event acceptance limits (subsection 15.1.5) for limiting event paths. Review of the event acceptance limits illustrates the safety analysis focus on event consequences. The event acceptance limits are either fission product barrier design basis limits or radiological dose limits derived from applicable regulatory requirements.

As such, the event paths analyzed as "limiting" in the safety analysis generally correspond to one, or a conservative representation of one, of the event paths for each event in the NSOA.

This safety analysis limiting-event path is selected to pose the most significant challenge to the applicable event acceptance limits and, therefore, typically concentrates on the short-term response to the event.

Thus, the safety analysis is consequences oriented, focusing on the limiting short-term response to the event, and the NSOA is event/system oriented, focusing on the system-level required actions necessary over the entire duration of the event (long-term response) to bring the plant to a stable configuration.

15C.2 <u>NSOA METHOD OF ANALYSIS</u>

15C.2.1 OPERATIONAL CRITERIA

The operational criteria are identified in table 15C-1.

The operational criteria establish the requirements for:

- Satisfying the applicable required actions to bring the plant to a stable condition consistent with the plant licensing basis.

- Applying the single failure criteria (subsection 15.1.6).

- Satisfying requirements unique to certain events.

Operational criteria are based upon the applicable regulatory requirements and guidance, industry codes and standards, plant-specific licensing commitments, nuclear steam supply system (NSSS) requirements, and fuel supplier design requirements.

15C.2.2 ANALYSIS ASSUMPTIONS/INITIAL CONDITIONS

15C.2.2.1 Operating States

Four boiling water reactor (BWR) operating states encompassing the entire operating envelop in which the plant can exist are defined in table 15C-2. The main objective in selecting operating states is to divide the plant operating spectrum into sets of initial conditions. This facilitates consideration of various events in each state. The events associated with each operating state are provided in table 15C-3.

Operating states are differentiated by a significant change in operational characteristics. The selection of not shutdown versus shutdown is based upon differences in reactivity control requirements. Requirements to shut down the reactor, under certain circumstances, are replaced by refueling interlock requirements. The selection of vented versus not vented is based upon differences in core cooling requirements. When the reactor pressure vessel (RPV) is vented, there is no requirement for the high pressure makeup systems (i.e., reactor core isolation cooling [RCIC] and high pressure coolant injection [HPCI]), because the reactor cannot become significantly pressurized. Also, with the RPV vented, the loss-of-coolant accident (LOCA) is not considered credible.

Each operating state includes an allowable range of values for important plant parameters. Within each state, these parameters are considered over their entire range.

For each event, the operating states in which the event can occur are determined. An event is considered applicable within an operating state if it can be initiated from the operating envelope and operating modes that characterize the operating state.

15C.2.2.2 Operating Modes

The operating states encompass all operating modes associated with planned operation and their respective operating envelopes. The plant operating modes associated with each operating state are identified in table 15C-2.

Together, the BWR operating states and the operating modes associated with planned operations define the operating envelope from which anticipated operational occurrences (AOOs), accidents, and special events are initiated. BWR operating states define the physical condition (e.g., pressure, temperature) of the reactor. Operating modes define what the plant is doing. The separation of the physical conditions from the operation being performed is deliberate and facilitates careful consideration of all possible initial conditions from which events may be postulated to occur.

15C.2.2.3 Planned Operation

Planned operation refers to normal plant operation under planned conditions within the allowable operating envelope in the absence of significant abnormalities. Following an event

(AOO, accident, or special event), planned operation is not considered to have resumed until the plant operating state is identical to a planned operating mode that could have been attained had the event not occurred. As defined, planned operation can be considered as a chronological sequence:

> Refueling outage ⌈ achieving criticality ⌈ heatup ⌈ power operation ⌈ achieving shutdown ⌈ cooldown ⌈ refueling outage

15C.2.2.4 <u>Key Bounding Parameters for Planned Operation</u>

For planned operation, the key bounding parameters, which assure the initial conditions assumed in the safety analysis are observed, and their implementing documents are provided in table 15C-4.

Maintaining planned operation within the bounds of the initial conditions assumed in the safety analysis assures conformance to the appropriate event acceptance limits (subsection 15.1.5). The implementing documents for the key bounding parameters (table 15C-4) indicate the method of controlling the parameter (e.g., Technical Specifications, ***Core Operating Limits Report (COLR) (incorporated by reference into the FSAR)***, and plant procedures) during plant operation.

15C.2.3 REQUIRED ACTIONS

Required actions are used in the NSOA process to ensure conformance with the NSOA operational criteria and to ensure the plant is brought to a stable condition consistent with the plant licensing basis. The end result of the plant systems performing their design function, in a timely manner, constitutes the required action.

Consistent with the safety analysis limiting-event path generally corresponding to one, or a conservative representation of one, of the event paths for each event in the NSOA, the required actions are also related to the safety analysis event acceptance limits (subsection 15.1.5). Table 15C-5 documents the correlation.

15C.2.4 EVENT ANALYSIS RULES

The event analysis rules are consistent with applicable regulatory requirements and guidance, plant-specific licensing commitments, and applicable industry codes and standards.
Table 15C-6 provides the event analysis rules used in performing the NSOA, along with explanations of the individual rules.

15C.3 <u>NSOA RESULTS</u>

15C.3.1 EVENT EVALUATIONS AND DIAGRAMS

The individual event evaluations in conjunction with their respective event diagrams document the detailed results of the NSOA. The event diagram format is shown in figure 15C-2. The event evaluations are provided in section 15C.4 and the associated event diagrams are shown in figures 15C-4 through 15C-51.

An event diagram for each event evaluated identifies the applicable operating states (for the overall event evaluation and, where applicable, for event paths that only apply to specific operating states), the required actions, the relationship of system operation and operator actions to the required actions, and the required functional redundancy. In addition, event diagrams identify each signal that initiates automatic system operation or alerts the operator to the need for action.

15C.3.2 AUXILIARY SYSTEM EVALUATION AND DIAGRAMS

Auxiliary systems are systems required for the proper functioning of front-line or other auxiliary systems. These systems are shown on auxiliary system diagrams. The auxiliary system diagram format is shown in figure 15C-3. The specific auxiliary system diagrams are shown in figures 15C-52 and 15C-53.

Using the information on the auxiliary system diagrams together with the event diagram, the complete system requirements for each event can be determined. Each system identified on an auxiliary system diagram is necessary to provide a required system function to support a front-line or another auxiliary system. Each auxiliary system is associated with all events for which it is required through the front-line system(s) it ultimately supports.

It should be noted that, in figure 15C-53, offsite ac power is shown as an auxiliary support system to illustrate the safety analysis requirements for the standby ac power system and the offsite ac power system. Based upon safety analysis requirements, the offsite ac power system is assumed to be available for all events, unless it is either lost as part of the event definition or assumed not to be available as part of the safety analysis requirements. The offsite ac power system is assumed to be unavailable for the following events:

- Lost as part of event definition.
    - Loss of residual heat removal (RHR) shutdown cooling (event 4).
    - Loss of auxiliary power (event 23).
    - Anticipated transient without scram (ATWS) (loss of auxiliary power only) (event 55).
    - Station blackout (SBO) (event 56).
- Not available as part of safety analysis requirements.

- LOCA (event 32).
- Main steam line break accident (MSLBA) (event 33).
- Feedwater line break (event 38).
- Fire (event 51).

The standby ac power system has the capability to provide ac power for all of the required front-line and auxiliary systems.

15C.3.3 SUMMARY MATRICES

A system, instrument trip, or operator action is considered "required" if identified on an event diagram as necessary to satisfy a required action or the operational criteria. Required auxiliary systems for each event are identified via the auxiliary system diagrams.

Based upon the event evaluations and diagrams, matrices are provided in tables 15C-7 through 15C-10 to identify the required systems, automatic instrument trips, monitored parameters (associated with required operator actions), and auxiliary systems for the events evaluated in the NSOA and the safety analysis.

15C.4 EVENT EVALUATIONS

15C.4.1 ANTICIPATED OPERATIONAL OCCURRENCES

15C.4.1.1 Decrease in Reactor Coolant Temperature

15C.4.1.1.1 Loss of Feedwater Heating (LFWH) (Event 1)

The event description and the safety analysis for the LFWH event are provided in paragraph 15.2.1.1. The event evaluation is documented in figure 15C-4.

A rapid decrease in feedwater temperature when the feedwater flow is mixed with the recirculation flow gradually increases core inlet subcooling, causing a relatively slow power increase and shift in power distribution toward the bottom of the core. The increase in power slightly increases steam flow, resulting in a small increase in RPV pressure due to the larger steam line pressure drops, assuming the pressure regulator acts to maintain constant turbine inlet pressure. A scram on high average power range monitor (APRM) simulated thermal power may occur depending upon the magnitude of the loss of feedwater heating and the resulting power increase. A conservative representation of the largest and most rapid loss of feedwater

heating resulting from a single active component failure in the manual flow control mode is analyzed.

An inherent assumption in the safety analysis process is that the pressure regulation system and the turbine bypass system can accommodate the additional steam produced as a result of the power increase without significantly increasing RPV pressure.

LFWH is considered only in operating state D (figure 15C-4), because significant feedwater heating occurs only during power operation with the main turbine in operation.

Depending upon the magnitude of the power increase, the neutron monitoring system (NMS) APRMs may initiate a high simulated thermal power trip.

A. If a simulated thermal power trip does not occur, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

B. If a simulated thermal power trip occurs, the NMS input into the reactor protection system (RPS) initiates a scram.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions.

RPV isolation is not required for event mitigation.

15C.4.1.1.2 Inadvertent Start of the HPCI Pump (Event 2)

The event description and the safety analysis for the inadvertent start of the HPCI pump are provided in paragraph 15.2.1.2. The event evaluation is documented in figure 15C-5.

The inadvertent starting of the HPCI pump results in an addition of colder water to the RPV from the condensate storage tank (CST) through the feedwater system. Increased feedwater flow at a colder temperature mixes with recirculation flow, resulting in an increase in core inlet subcooling (reduced core inlet temperature) and RPV water level. The increase in core inlet subcooling causes a relatively slow power increase and a shift in power distribution toward the bottom of the core. The power increase continues until either the feedwater control system responds to the increase in level by controlling water level or an NMS high neutron flux trip occurs.

A. If an NMS high neutron flux trip does not occur, the reactor will stabilize in a new steady-state operating condition, with feedwater available, at a higher power level until action is taken to secure the HPCI pump and return the plant to a planned operating condition.

B. If an NMS high neutron flux trip occurs, a scram is initiated.

A high RPV water level trip initiates turbine stop valve (TSV) closure (turbine trip), a trip of the HPCI system, and a trip of the feedwater system to terminate the increase in RPV inventory. The TSV closure initiates a turbine bypass valve opening signal. Depending upon the initial power level and the timing of the turbine trip, the safety relief valves (SRVs) can open to supplement the turbine bypass valves in relieving excess pressure.

An inherent assumption in the safety analysis process is that the pressure regulation system and the turbine bypass system can accommodate the additional steam produced as a result of the power increase (if a scram on NMS high neutron flux does not occur) without significantly increasing RPV pressure.

The inadvertent start of the HPCI pump is possible in operating states C and D (figure 15C-5).

In operating state D, the shutdown required action is dependent upon the magnitude of the NMS neutron flux increase.

A. If an NMS neutron flux trip does not occur, the reactor will stabilize in a new steady-state operating condition.

B. If the NMS neutron flux setpoint is reached, either the IRMs in the STARTUP mode, the APRMs (setdown) in the STARTUP mode, or the APRMs (in the RUN mode) initiate an NMS neutron flux trip signal to the RPS to initiate a scram. The scram results in a high RPV water level, which causes a feedwater system trip, TSV closure, and a HPCI system trip.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the continuing water boiloff following the feedwater system and HPCI system trips, a low RPV water level trip initiates the RCIC and HPCI systems to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.1.1.3 Shutdown Cooling (RHR) Malfunction - Decreasing Temperature (Event 3)

The event description and the safety analysis for the shutdown cooling (RHR) malfunction - decreasing temperature are provided in paragraph 15.2.1.3. The event evaluation is documented in figure 15C-6.

With the plant operating in the RHR shutdown cooling mode, a malfunction can reduce moderator temperature. A decrease in moderator temperature causes a slow insertion of positive reactivity into the core. If the reactor is either critical or near critical, a very slow increase in power level can result. If the operator does not act to control power level, an NMS high neutron intermediate-range monitor (IRM) flux scram will terminate the event.

The shutdown cooling malfunction - decreasing temperature event can occur in operating states A, B, and C (figure 15C-6), with RPV pressure less than the shutdown cooling pressure permissive.

If the reactor returns to critical, an NMS IRM high neutron flux signal to the RPS initiates a scram to terminate the power increase.

Because the shutdown cooling system remains in operation throughout the event, no unique requirement for pressure relief or core cooling arises. The normal operating system fulfills these required actions.

RPV isolation is not required for event mitigation.

15C.4.1.2 <u>Increase in Reactor Coolant Temperature</u>

15C.4.1.2.1 Loss of RHR Shutdown Cooling (Event 4)

The event description and the safety analysis for the loss of shutdown cooling are provided in paragraph 15.2.2.1. The event evaluation is documented in figure 15C-7.

The shutdown cooling mode of the RHR system is designed to remove decay heat, at low RPV pressure with the reactor shutdown, at a sufficient rate to maintain cold shutdown conditions. Typically, evaluation of the failure of the RHR shutdown cooling mode demonstrates alternative decay heat removal capability. The majority of components in the shutdown cooling system are redundant; thus, the loss of any single pump or heat exchanger does not significantly affect the continuity of core cooling, although coolant temperature can increase until a new steady-state condition is reached. However, closure of a shutdown cooling suction valve and the inability to reopen it can result in the total loss of shutdown cooling. For the total loss of shutdown cooling, RPV water temperature slowly increases until action is taken to control the temperature increase and reestablish decay heat removal using an alternate decay heat removal path.

In addition, to demonstrate the plant's capability to comply with GDC 34, an evaluation of the unavailability of the RHR shutdown cooling mode following a loss-of-offsite power (LOSP) from normal operating conditions was performed. For this evaluation, credit is taken only for safety-related equipment. Even though these assumptions change the event frequency, the event is conservatively evaluated as an AOO. The initial part of the event is identical to the loss of auxiliary power (paragraph 15C.4.1.8.3). Once the event is stabilized, action is taken to control the temperature increase and reestablish decay heat removal using the alternate decay heat removal path. The evaluation results provided in paragraph 15.2.2.2 demonstrate acceptability of the alternate decay heat removal path.

A loss of shutdown cooling can occur in all operating states (figure 15C-7).

The required actions are dependent upon whether or not the plant is initially operating in the shutdown cooling mode and whether or not a loss of ac power is assumed.

A. If the plant is operating in the shutdown cooling mode in operating state C and either a partial or total loss of shutdown cooling occurs, the plant continues in planned operation until a high pressure input into the primary containment and RPV (PC & RPV) isolation control system initiates closure of the shutdown cooling isolation valves. The LOSP path bounds the required action for this path. In operating states A and B, RPV isolation is not required. The extended core cooling path provides the shutdown cooling capability for all states.

B. If the plant is not operating in the shutdown cooling mode, the required actions are dependent upon whether or not an LOSP occurs.

   1. If ac power is available, the plant can continue in planned operation until the cause of the loss of shutdown cooling is repaired.

   2. If an LOSP occurs, the required actions are dependent upon whether or not a high RPV water level trip due to a recirculation pump trip (RPT), or a loss of condenser vacuum due to a loss of the circulating water pumps occurs.

In operating state B, and in operating state D if a scram is not initiated earlier, ultimately the coastdown of the RPS motor-generator (M-G) sets resulting from the loss of ac power (fail-safe design) initiates a scram.

In operating state D:

A. If a high RPV water level trip that initiates a turbine trip occurs, and the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an end-of-cycle RPT (EOC-RPT).

B. If initial power level is less than the pressure permissive, the TSV position switch scram and the EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

   1. If the NMS high neutron flux setpoint is reached, the NMS input into the RPS initiates a scram.

   2. If the NMS high neutron flux setpoint is not reached, a scram on high RPV pressure is initiated if the high RPV pressure scram setpoint is reached.

An alternate shutdown path can occur if a low condenser vacuum trip initiates main steam isolation valve (MSIV) closure. The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed

if the reactor is not in the RUN mode and the TSVs are < 90% open. In operating state D, MSIV closure in the RUN mode initiates a scram.

In operating states C and D, the SRVs self actuate to limit the RPV pressure increase if the SRV high pressure setpoint is reached.

The core cooling required action is dependent upon whether or not the normal cooling systems are available.

A. If the normal cooling systems are available, the plant continues in planned operation.

B. If the normal cooling systems are not available, a low RPV water level trip automatically initiates the RCIC and HPCI systems to restore and maintain water level, satisfying initial core cooling requirements.

Further action with respect to core cooling is not required if an emergency operating procedure (EOP) entry condition is not reached. Due to SRV, HPCI, and RCIC operation, the suppression pool temperature EOP entry condition may be reached. Consistent with EOP requirements, the suppression pool cooling mode of the RHR system is manually initiated. Depending upon initial plant conditions, suppression pool temperature and level may continue to increase and reach either the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure), or the SRV tailpipe limit (which is based upon RPV pressure and suppression pool level). If either limit is reached, manual initiation of the automatic depressurization system (ADS) is required after confirmation of the availability of the low pressure emergency core cooling system (ECCS) subsystems.

Based upon the RPV water level indication following depressurization and once the RPV pressure permissive is satisfied, either the core spray (CS) system, in combination with RHR in suppression pool cooling mode, or RHR alternate shutdown cooling is initiated to restore and maintain level. In both of these approaches a flow path is established through an open SRV back to the suppression pool. RHR alternate shutdown cooling is defined in plant procedures as follows. Suction is taken from the suppression pool, the water is cooled via an RHR heat exchanger (residual heat removal service water (RHRSW) system supplies cooling water to the RHR heat exchangers), and the water is supplied to the RPV via the LPCI injection valve lineup. These actions complete the extended core cooling required action.

It should be noted that the extended core cooling path for the loss of RHR shutdown cooling event bounds the extended core cooling path for other events involving turbine trips, generator load rejections, and loss of feedwater or main heat sink. This includes events in which the feedwater system initially provides core cooling but is manually tripped as the result of suppression pool high water level.

15C.4.1.3 Increase in Reactor Pressure

15C.4.1.3.1 Generator Load Rejection With No Bypass (LRNBP) (Event 5)

The event description and the safety analysis for the LRNBP are provided in paragraph 15.2.3.1. The event evaluation is documented in figure 15C-8.

A generator load rejection initiates a turbine control valve (TCV) fast closure, which causes a sudden reduction in steam flow, resulting in an increase in RPV pressure. The assumed unavailability of the turbine bypass valves increases the severity of the RPV pressure increase, which causes a reduction in core voids and a subsequent increase in neutron flux and surface heat flux. A scram and an EOC-RPT occur on a TCV fast closure signal. The opening of the SRVs limits the RPV pressure increase. The feedwater control system maintains RPV water level.

An LRNBP event can only occur in operating state D, with the main turbine operating (figure 15C-8).

The shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, a TCV fast closure initiates a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TCV fast closure scram and EOC-RPT are bypassed.

C For initial power levels less than the first-stage pressure permissive, the RPS initiates a scram on either high RPV pressure or an NMS high APRM neutron flux signal.

The SRVs self actuate to limit the RPV pressure increase resulting from TCV closure and the assumed unavailability of the turbine bypass valves.

The feedwater system provides initial core cooling. However, the continuing operation of the SRVs can result in an increase in suppression pool temperature such that an EOP entry condition is reached. The loss of RHR shutdown cooling (event 4) bounds the required action required for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.1.3.2 Generator Load Rejection with Bypass (LRBP) (Event 6)

The event description and the safety analysis for the LRBP are provided in paragraph 15.2.3.2. The event evaluation is documented in figure 15C-9.

A generator load rejection initiates a TCV fast closure, which causes a sudden reduction in steam flow, resulting in an increase in RPV pressure. TCV fast closure initiates the opening of the turbine bypass valves, reducing the severity of the pressure increase, which causes a reduction in core voids and a subsequent increase in neutron flux and surface heat flux. A

scram and an EOC-RPT occur on a TCV fast closure signal. The combination of opening the turbine bypass valves and the SRVs limits the RPV pressure increase. The feedwater control system maintains RPV water level.

An LRBP event can only occur in operating state D (figure 15C-9), with the main turbine operating.

The shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, a TCV fast closure initiates a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TCV fast closure scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

   1. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

   2. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

   3. If NMS high neutron flux and the high RPV pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TCV fast closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for core cooling arises. The normal operating systems fulfill this required action.

RPV isolation is not required for event mitigation.

15C.4.1.3.3 Turbine Trip With No Bypass (TTNBP) (Event 7)

The event description and the safety analysis for the TTNBP event are provided in paragraph 15.2.3.3. The event evaluation is documented in figure 15C-10.

A turbine trip initiates a rapid closure of the TSVs, causing a sudden reduction in steam flow, resulting in an increase in RPV pressure. The assumed unavailability of the turbine bypass valves increases the severity of the RPV pressure increase, which results in a reduction in core voids and a subsequent increase in the NMS neutron flux and the surface heat flux. The TSV position switches initiate a scram and an EOC-RPT. The opening of the SRVs limits the RPV pressure increase. The feedwater control system maintains RPV water level.

A TTNBP event can only occur in operating state, with the main turbine operating D (figure 15C-10).

The shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

B. If initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed.

C. For initial power levels less than the first-stage pressure permissive, the RPS initiates a scram on either high RPV pressure or an NMS high APRM neutron flux signal.

The SRVs self actuate to limit the RPV pressure increase resulting from the TSV closure and the assumed unavailability of the turbine bypass valves.

The feedwater system provides initial core cooling. However, the continuing operation of the SRVs can result in an increase in suppression pool temperature such that an EOP entry condition is reached. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.1.3.4 Loss of Condenser Vacuum (Event 8)

The event description and the safety analysis for the loss of condenser vacuum are provided in paragraph 15.2.3.4. The event evaluation is documented in figure 15C-11.

The loss of condenser vacuum, as the vacuum decreases (gauge pressure becomes less negative), sequentially trips the turbine (TSV closure and bypass valve opening), initiates MSIV closure, and closes the turbine bypass valves (initially opened as a result of the turbine trip). Because of the timing of the loss of condenser vacuum, the short-term event is very similar to the turbine trip with bypass (TTBP) event (paragraph 15C.4.1.3.5). The long-term event is very similar to the TTNBP event (paragraph 15C.4.1.3.3). The initial plant response and consequences are attributable to turbine bypass system availability. Closure of the MSIVs and turbine bypass valves later in the event affects the longer-term plant response and consequences.

A loss of condenser vacuum can occur only in operating states C and D (figure 15C-11).

In operating state D, the shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, a low condenser vacuum trip sequentially trips the turbine, resulting in a TSV closure, which initiates a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

    1. If the NMS high neutron flux setpoint is reached, either the IRMs in the STARTUP mode, the APRMs (setdown) in the STARTUP mode, or the APRMs (in the RUN mode) initiate an NMS neutron flux trip signal to the RPS to initiate a scram.

    2. If the NMS high neutron flux and the RPV high pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

    3. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

If a low condenser vacuum trip occurs, MSIV closure isolates the RPV. The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed if the reactor is not in the RUN mode and the TSVs are < 90% open. In operating state D, an alternate shutdown path is established by closing the MSIVs in the RUN mode to initiate a scram.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

If the MSIVs are closed as a result of the loss of condenser vacuum, the steam supply to the turbine-driven feedwater pumps is lost. The continuing water boiloff attributable to the RPV decay heat results in a low RPV water level trip setpoint for the initiation of the RCIC and HPCI systems to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

If the MSIVs are not closed, the normal operating systems provide core cooling.

15C.4.1.3.5 Turbine Trip With Bypass (TTBP) (Event 9)

The event description and the safety analysis for the TTBP event are provided in paragraph 15.2.3.5. The event evaluation is documented in figure 15C-12.

A turbine trip initiates a rapid closure of the TSVs, causing a sudden reduction in steam flow, resulting in an increase in RPV pressure, which causes a reduction in core voids and a subsequent increase in the NMS neutron flux and the surface heat flux. The TSV position switches, which are part of the RPS, initiate a scram and an EOC-RPT. The combination of opening the turbine bypass valves and the SRVs limits the RPV pressure increase. The feedwater control system maintains RPV water level.

A TTBP event can only occur in operating state D (figure 15C-12), with the main turbine operating.

The shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

   1. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

   2. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

   3. If the NMS high neutron flux and the high RPV pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for core cooling arises. The normal operating systems fulfill this required action.

RPV isolation is not required for event mitigation.

15C.4.1.3.6 Closure of All MSIVs (MSIVD) (Event 10)

The event description and the safety analysis for the MSIVD event are provided in paragraph 15.2.3.6. The event evaluation is documented in figure 15C-13.

The MSIVD event causes a rapid reduction in steam flow, resulting in an increase in RPV pressure. The RPV pressure increase results in a reduction in core voids and a subsequent increase in neutron flux and, depending upon the timing of scram, an increase in surface heat flux.

The MSIVD event can only occur in operating states C and D (figure 15C-13). In operating states A and B, the MSLs are continuously isolated. Isolation of all MSLs is most severe in operating state D during power operation.

In operating state D, the shutdown required action is dependent upon the position of the mode selector switch.

A. If the mode selector switch is in the RUN mode, the MSIV position switches initiate a scram.

B. If the mode selector switch is in the STARTUP mode, and the NMS high neutron flux setpoint is reached, either the IRMs or the APRMs (setdown) initiate an NMS neutron flux trip signal to the RPS to initiate a scram.

C. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

D. If the NMS high neutron flux and the RPV high pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached, except when the event is initiated from very low power levels.

A. If the SRV high pressure setpoint is not reached, heat losses from the system may be sufficient to limit any pressure increase.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the pressure increase.

As a result of MSIV closure, the steam supply to the turbine-driven feedwater pumps is lost. The continuing water boiloff attributable to RPV decay heat results in a low RPV water level trip for the initiation of the RCIC and HPCI systems, which are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

If a low RPV water level trip does not occur, the normal operating systems provide core cooling. The MSLs are isolated as part of the event definition, and isolation of other systems is not required.

15C.4.1.3.7 Closure of One MSIV (Event 11)

The event description and the safety analysis for the closure of one MSIV are provided in paragraph 15.2.3.7. The event evaluation is documented in figure 15C-14.

Closure of a single MSIV causes a slight reduction in steam flow, resulting in a small increase in RPV pressure, which causes an increase in neutron flux attributable to the reduction in moderator voids. The plant is designed so that closure of a single MSIV does not initiate a scram from the MSIV position scram logic. This situation occurs, because the MSIV position scram trip logic is designed to accommodate single-valve operation and testability during normal reactor power operation at limited power levels. However, if the flux increase is great enough, the NMS initiates a scram on NMS high neutron flux. During this event, the pressure regulation system controls RPV pressure, and the feedwater control system maintains water level.

Closure of one MSIV can occur only in operating states C and D (figure 15C-14). In operating states A and B, the main steam lines (MSLs) are continuously isolated.

Depending upon the magnitude of the flux increase, an APRM-initiated neutron flux trip can occur.

A. If a flux trip occurs, the NMS flux trip input into the RPS initiates a scram.

B. If an NMS flux trip does not occur, the reactor will stabilize in a new steady-state operating condition until necessary action is taken to return the reactor to a planned operating condition.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for core cooling or pressure relief arises.

RPV isolation is not required for event mitigation.

15C.4.1.3.8 Pressure Regulator Failure - Closed (Event 12)

The event description and the safety analysis for the pressure regulator failure - closed are provided in paragraph 15.2.3.8. The event evaluation is documented in figure 15C-15.

In the plant design, two identical pressure regulators are provided for pressure control. For failure modes in the controlling pressure regulator to the closed position, the backup pressure regulator assumes control of the TCVs.

During normal operation, both pressure regulators are assumed to be available.

A pressure regulator failure - closed event can only occur in operating state D, with the main turbine operating (figure 15C-15).

No unique required actions are necessary, because no protective system intervention is required due to the effectiveness of the backup pressure regulator. This stabilized condition will continue until action is taken to return the reactor to a planned operating condition. As a result, shutdown and RPV isolation are not required, and the normal operating systems, including feedwater control, recirculation flow control, backup pressure regulation, and turbine bypass, accomplish the pressure relief and core cooling functions.

RPV isolation is not required for event mitigation.

15C.4.1.4 Decrease in Reactor Coolant Flowrate

15C.4.1.4.1 Trip of One Recirculation Pump (Event 13)

The event description and the safety analysis for the trip of one recirculation pump are provided in paragraph 15.2.4.1. The event evaluation is documented in figure 15C-16.

The trip of one recirculation pump causes a decrease in core flow and a subsequent decrease in power level because of the increase in core voids. RPV water level increases due to the recirculation flow reduction and subsequent increase in voids, but is not expected to reach the RPV high water level trip.

Following the trip of one recirculation pump, the reactor is expected to stabilize in a new steady-state operating condition at a lower power and flow condition (single-loop operation). It should be noted that, if a high RPV water level trip occurs, the event is similar to the trip of both recirculation pumps.

The trip of one recirculation pump is considered in operating states C and D, but is significant only in operating state D (figure 15C-16), with the reactor critical and operating at a significant power level.

No unique required actions are necessary for this event, because no protective system intervention is required. The reactor will continue in single-loop operation until action is taken to

return the reactor to a planned operating condition. As a result, reactor shutdown and RPV isolation are not required, and the normal operating systems, including feedwater control, pressure regulation, and turbine bypass, accomplish core cooling and pressure relief functions. (If the plant is initially operating in single-pump operation, see paragraph 15C.4.1.4.2 below for long-term requirements.)

15C.4.1.4.2 Trip of Two Recirculation Pumps (Event 14)

The event description and the safety analysis for the trip of two recirculation pumps are provided in paragraph 15.2.4.2. The event evaluation is documented in figure 15C-17.

Tripping the recirculation pumps causes a rapid decrease in core flow and a subsequent decrease in power level because of the increase in core voids. RPV water level swells as the result of the void generation, and may reach the RPV high water level trip setpoint. A high RPV water level trip initiates a turbine trip (TSV closure) and a trip of the feedwater system to terminate the increase in RPV water level. TSV closure also initiates a scram and turbine bypass valve opening signal, which opens the turbine bypass valves. Following the turbine trip, the NMS neutron flux increase is limited by the increase in core voids due to the lower core flow, Doppler feedback, and scram. Opening the SRVs and the turbine bypass valves limits the RPV pressure increase. Operation of the HPCI and RCIC systems maintains RPV water level.

The trip of two recirculation pumps is considered in operating states C and D, but is significant only in operating state D (figure 15C-17), with the reactor critical and operating at a significant power level.

In operating state D, the required actions are dependent upon whether or not a high RPV water level trip occurs.

A. If a high RPV water level trip does not occur, the reactor will stabilize in a new steady-state operating condition. The feedwater control, pressure regulation, and turbine bypass systems remain in operation throughout the event, and no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions. If either one or both of the pumps cannot be restarted, the Technical Specifications require a reactor shutdown.

B. If a high RPV water level trip occurs, a turbine trip and a feedwater system trip are initiated, and the shutdown required action is dependent upon the initial power level.

    1. If the initial power level is greater than the turbine first-stage pressure permissive, a TSV closure initiates a scram and an EOC-RPT.

    2. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

a. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

b. If the NMS high neutron flux setpoint is not reached, but the high pressure scram setpoint is reached, the RPS pressure switches initiate a scram on high RPV pressure.

c. If the NMS high neutron flux and the high RPV pressure scram setpoints are not reached, the Technical Specifications require a reactor shutdown.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the continuing water boiloff following the feedwater system trip, a low RPV water level trip initiates the RCIC and HPCI systems to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.1.4.3 Recirculation Flow Control Failure - Decreasing Flow (Event 15)

The event description and the safety analysis for the recirculation flow control failure - decreasing flow are provided in paragraph 15.2.4.3. The event evaluation is documented in figure 15C-18.

A recirculation flow control failure - decreasing flow causes a decrease in power level because of the increase in core voids. RPV water level increases as the result of void generation, but is not expected to reach the RPV high water level trip. Following a recirculation flow control failure - decreasing flow, the reactor is expected to stabilize in a new steady-state operating condition at a lower power and flow condition until action is taken to return the reactor to a planned operating condition. It should be noted that, if a high RPV water level trip occurs, the event would be similar to, but less severe than, the trip of both recirculation pumps.

The recirculation flow control failure - decreasing flow event is considered only in operating state D (figure 15C-18), because the feedwater flow interlock limits the recirculation pump speed to a minimum below a preestablished value of feedwater flow that is attainable only in power operation.

No unique required actions are necessary for this event, because no protective system intervention is required. As a result, reactor shutdown and RPV isolation are not required, and the normal operating systems, including feedwater control, pressure regulation, and turbine bypass, accomplish core cooling and pressure relief functions.

15C.4.1.5 Increase in Reactor Coolant Flowrate

15C.4.1.5.1 Recirculation Flow Controller Failure - Increasing Flow (Event 16)

The event description and the safety analysis for the recirculation flow control failure - increasing flow are provided in paragraph 15.2.5.1. The event evaluation is documented in figure 15C-19.

An increase in recirculation flow causes an increase in core flow, which in turn, results in an increase in core power and shifts the power distribution toward the top of the core. The rate and magnitude of the power increase are dependent upon the rate and magnitude of the recirculation flow increase. Recirculation system flow controls limit the magnitude of the flow increase.

Two types of recirculation flow controller failure - increasing flow events are considered:

- The most rapid flow increase in either a single loop or both loops resulting in scram intervention on NMS high neutron flux.
- A slow recirculation flow increase that does not result in a scram.

For the rapid flow increase case, the relatively fast increase in neutron flux is terminated by a scram, which limits the energy input to the fuel, and the effect of the fuel time constant is to limit the change in surface heat flux.

An inherent assumption the safety analysis process is that there is sufficient capability in the pressure regulation or turbine bypass system to accommodate the additional steam produced as a result of the power increase without a significant increase in RPV pressure.

A recirculation flow control failure causing an increase in recirculation flow applies only in operating state D (figure 15C-19), because the feedwater flow interlock limits the recirculation pump speed to a minimum below a preestablished value of feedwater flow that is attainable only in power operation. The event evaluation is documented in figure 15C-19 for this event.

Depending upon the magnitude of the flow and subsequent power increase, an APRM-initiated neutron flux trip may initiate a scram. If a flux trip does not occur, the reactor will stabilize in a new steady-state operating condition until action is taken to restore the reactor to a planned operating condition.

Because the feedwater control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions.

RPV isolation is not required for event mitigation.

15C.4.1.5.2 Startup of Idle Recirculation Pump (Event 17)

The event description and the safety analysis for the startup of an idle recirculation pump are provided in paragraph 15.2.5.2. The event evaluation is documented in figure 15C-20.

The startup of an idle recirculation pump is intended to represent the spectrum of AOOs that can result from the inadvertent starting of a recirculation loop within the temperature limitation of the Technical Specifications. The startup of a cold recirculation loop increases core flow and causes a decrease in core inlet subcooling. The net effect of the startup of a cold recirculation loop event is an increase in power, a power distribution shift, and a decrease in sensed water level. Following the initial transient, the reactor stabilizes in a new steady-state operating condition.

The startup of an idle recirculation pump is considered in operating states C and D, but is significant only in operating state D (figure 15C-20), with the reactor critical and operating at a significant power level.
Depending upon the magnitude of the flow and subsequent power increase, an APRM-initiated neutron flux trip may occur. If a flux trip occurs, the NMS initiates a scram. If a flux trip does not occur, the reactor will stabilize in a new steady-state operating condition until action is taken to restore the reactor to a planned operating condition.

Because the feedwater control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions.

RPV isolation is not required for event mitigation.

15C.4.1.6 <u>Reactivity and Power Distribution Anomalies</u>

15C.4.1.6.1 Control Rod Withdrawal Error (All Power Levels) (Event 18)

The event description and the safety analysis for the control rod withdrawal error are provided in paragraph 15.2.6.1. The event evaluation is documented in figure 15C-21.

The rod withdrawal error (RWE) results in positive reactivity insertion. Both the core average power and the local power in the vicinity of the control rod increase. The core average and local power increases continue until the rod block monitor (RBM) acts to inhibit further withdrawal, a scram occurs, or the control rod reaches its fully withdrawn position. The normal operating

systems control any change to the reactor operating parameters. The two different conditions considered are the RWE at high power and the RWE in the STARTUP Mode.

Because an RWE results in an insertion of positive reactivity, it can occur under any operating condition and must be considered in all operating states (figure 15C-21).

No unique action is required in operating states A and C, because the core is more than one rod subcritical, and the complete withdrawal of the maximum-worth control rod is not sufficient to reach criticality. In operating states B and D, the required actions are dependent upon the initial power level.

In operating state B or D, in the STARTUP mode, the withdrawal of a high-worth control rod may cause a flux increase sufficient to initiate a scram on NMS high neutron flux from either the IRMs or the APRMs (setdown). If neither an IRM nor an APRM NMS high neutron flux trip occurs, the reactor will stabilize in a new steady-state operating condition until action is taken to restore the reactor to a planned operating condition.

In operating state D, with the initial power level above the low-power setpoint of the RBM, the sequence of events is dependent upon whether or not an NMS high neutron flux trip is encountered.

A. If a flux trip is encountered, the RBM initiates a control rod withdrawal block to terminate control rod withdrawal.
B. If a flux trip does not occur, the reactor will stabilize in a new steady-state operating condition.

In either case, steady-state operation continues until action is taken to restore the reactor to a planned operating condition.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions.

RPV isolation is not required for event mitigation.

15C.4.1.6.2 Control Rod Removal Error During Refueling (Event 19)

The event description and the safety analysis for the control rod removal error during refueling are provided in paragraph 15.2.6.2. The event evaluation is documented in figure 15C-22.

The nuclear characteristics of the core assure the reactor is subcritical in its most reactive condition with the most reactive control rod fully withdrawn during the refueling process. When the mode switch is in REFUEL, no more than one control rod can be withdrawn. Therefore, the refueling interlocks prevent any condition that could lead to an inadvertent criticality attributable to control rod removal during refueling.

The control rod removal error during refueling is applicable in operating state A (figure 15C-22).

No unique required actions are necessary for this event, because no protective system intervention is required. The reactor is shutdown and remains shutdown throughout the event. The normal operating RHR shutdown cooling system accomplishes the core cooling function.

RPV isolation and pressure relief are not required for event mitigation.

15C.4.1.6.3 Fuel Assembly Insertion Error During Refueling (Event 20)

The event description and the safety analysis for the fuel assembly insertion error during refueling are provided in paragraph 15.2.6.3. The event evaluation is documented in figure 15C-23.

The amount of reactivity in a single erroneously loaded fuel assembly during the refueling process is insufficient to cause an inadvertent criticality.

The fuel assembly insertion event is applicable in operating state A (figure 15C-23).

No unique required actions are necessary for this event, because no protective system intervention is required. The reactor is shut down and remains shutdown throughout the event. The normal operating RHR shutdown cooling system accomplishes the core cooling function. RPV isolation and pressure relief is not required for event mitigation.

15C.4.1.7 <u>Increase in Reactor Coolant Inventory</u>

15C.4.1.7.1 Feedwater Controller Failure - Maximum Demand (Event 21)

The event description and the safety analysis for the feedwater controller failure – maximum demand are provided in paragraph 15.2.7.1. The event evaluation is documented in figure 15C-24.

This event represents a combination of a coolant temperature reduction event and a rapid pressurization event. As a result of the increased feedwater flow mixing with the essentially constant recirculation flow, a gradual increase in core inlet subcooling (reduced core inlet temperature) results. The increased feedwater flow also results in an increase in RPV water level because of the steam and feedwater flow mismatch.

The gradual increase in core inlet subcooling causes a relatively slow power increase and a shift in power distribution towards the bottom of the core. The power increase continues until the RPV high water level trip setpoint is reached.

RPV high water level initiates a turbine trip (TSV closure) for equipment protection purposes and a trip of the feedwater system to terminate the increase in RPV inventory. The TSV closure initiates a scram and an EOC-RPT. The turbine trip initiates opening of the turbine bypass valves. Following the turbine trip, Doppler feedback, the EOC-RPT, and the scram limit the

increase in neutron flux. The RPV pressure increase is limited by opening the SRVs and is controlled by the turbine bypass system. Operation of either the HPCI or the RCIC system maintains RPV water level. Because the plant has turbine-driven feedwater pumps, a feedwater controller failure causing an excess RPV coolant inventory is only possible in operating state D (figure 15C-24).

As a result of the increase in RPV water inventory resulting from the increase in feedwater flow, a high RPV water level trip occurs, causing a turbine trip and a feedwater system trip. The required actions are dependent upon the conditions associated with these trips.

The shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

    1. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.
    2. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

    3. If the NMS high neutron flux and the high RPV pressure setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to restore the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the continuing water boiloff following the feedwater system and HPCI system trips, a low RPV water level trip initiates the RCIC and HPCI systems to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.1.8 Decrease in Reactor Coolant Inventory

15C.4.1.8.1 Inadvertent Opening of an SRV (Event 22)

The event description and the safety analysis for the inadvertent opening of an SRV are provided in paragraph 15.2.8.1. The event evaluation is documented in figure 15C-25.

The opening of an SRV provides a path for steam discharge to the suppression pool. The sudden increase in steam flow from the RPV causes a mild depressurization, leading to a slight reduction in power level, and the steam discharged to the suppression pool causes a suppression pool temperature increase. The normal control systems respond to the RPV pressure and level decreases to stabilize the reactor at a new steady-state operating condition. To limit the temperature rise, the operator responds to the suppression pool temperature increase in accordance with the emergency operating procedures (EOPs).

The inadvertent opening of one SRV event is considered in operating states C and D, with the reactor pressurized (figure 15C-25).

For this event, planned operation continues until the EOP entry condition on suppression pool temperature is reached. The remainder of the event is dependent upon plant conditions encountered and operator response to the EOPs.
In operating state D, the suppression pool temperature continues to increase until the temperature limit is reached requiring manual initiation of a scram. Based upon the suppression pool temperature indication, the operator manually initiates a scram.

For this event, feedwater is assumed to be available to provide initial core cooling. As a result of the steam transferred to the suppression pool through the stuck-open SRV, suppression pool temperature increases until the operator manually initiates the suppression pool cooling mode of RHR. The remainder of the event is dependent upon the plant conditions encountered and operator response to the EOPs. The suppression pool temperature and level can increase and reach the heat capacity temperature limit (which is based upon RPV pressure and suppression pool temperature) or the SRV tailpipe limit (which is based upon RPV pressure and suppression pool level). If either limit is reached, manually initiated RPV depressurization is required. Manual automatic depressurization system (ADS) initiation can depressurize the RPV, and the core cooling required action becomes dependent upon the availability of the RHR shutdown cooling system.

A. If the shutdown cooling mode of RHR is available when the reactor is depressurized to below the shutdown cooling pressure permissive, the shutdown cooling mode of the RHR system is manually initiated in accordance with plant operating procedures.

B. If the shutdown cooling mode of the RHR system is not available, the feedwater system continues to provide the initial core cooling water supply until the increase in suppression pool level, as indicated by the suppression pool level monitors, reaches the suppression pool level limit, requiring a trip of the feedwater system. The operator trips the feedwater system, and RPV water level decreases until a

low RPV water level condition is reached. Based upon the low water signal and once the RPV pressure permissive is satisfied, the operator initiates either the CS system, in combination with RHR suppression pool cooling, or RHR alternate shutdown cooling to restore and maintain water level (paragraph 15C.4.1.2.1).

Because this event results in a decrease in RPV pressure, no unique requirement for pressure relief arises. This required action is fulfilled either by the normal operating systems or through the stuck-open SRV.

RPV isolation is not required for event mitigation.

15C.4.1.8.2 Pressure Regulator Failure - Open (Event 23)

The event description and the safety analysis for the pressure regulator failure - open are provided in paragraph 15.2.8.2. The event evaluation is documented in figure 15C-26.

Failure of the controlling or backup pressure regulator causes increase in steam flow and initially results in an RPV depressurization, a level increase, and a coolant inventory decrease. During the initial depressurization, power level decreases and water level increases as a result of the additional void generation. The feedwater control system reduces feedwater flow in an attempt to limit the water level increase.

A. If the water level rise is large enough, the RPV high water level trip setpoint is reached, thereby initiating a turbine trip (TSV closure) for equipment protection purposes and a trip of the feedwater system to terminate the increase in RPV inventory. The TSV closure also initiates a scram and an EOC-RPT. The turbine trip initiates opening of the turbine bypass valves. Following the turbine trip, Doppler feedback, the EOC-RPT, and the scram limit the NMS neutron flux increase.

B. If the steam line pressure decrease is large enough with the reactor in the RUN mode, the low MSL pressure trip setpoint is reached, thereby initiating main steam isolation valve (MSIV) closure. If the MSIVs close, operation of the SRVs limits the RPV pressure increase. If feedwater is lost, either HPCI or RCIC system operation maintains RPV water level.

The pressure regulator failure - open is considered in operating states C and D (figure 15-26).

Depending upon the magnitude of the level swell, a high RPV water level trip can occur. Also, depending upon the magnitude of the depressurization, if operating in the RUN mode, a low MSL pressure trip can occur. The required actions are dependent upon whether or not these trips occur.

If neither a high RPV water level nor a low MSL pressure trip in the RUN mode occurs, the reactor will stabilize in a new steady-state operating condition. Feedwater control remains in operation throughout the event, and no unique requirement for pressure relief or core cooling

arises. The normal operating systems fulfill these required actions. Reactor shutdown and RPV isolation are not required.

In operating state D, the shutdown required action is dependent upon the specific trips encountered.

A. If a high RPV water level trip occurs during the event, the effects are expected to precede MSIV closure and the shutdown required action is dependent upon the initial power level.

    1. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

    2. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

        a. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

        b. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

        c. If the NMS high neutron flux and the high RPV pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

B. If a low MSL pressure trip in the RUN mode occurs, the MSIV position switches initiate a scram if one has not occurred and isolation of other systems is not required.

C. If low pressure in the RUN mode does not occur during the event, RPV isolation is not required.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from either TSV or MSIV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

If the turbine-driven feedwater pumps are lost due to either a high RPV water level trip or MSIV closure, resulting in the continuing water boiloff following a loss of the feedwater system, a low RPV water level trip setpoint for RCIC and HPCI initiation is reached. The RCIC and HPCI

systems are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

15C.4.1.8.3 Loss of Auxiliary Power (Event 24)

The event description and the safety analysis for the loss of auxiliary power are provided in paragraph 15.2.8.3. The event evaluation is documented in figure 15C-27.

The loss of auxiliary power covers both the loss of all auxiliary power and the loss of all grid connections.

A. The loss of all auxiliary power during power operation results in MSIV closure, a trip of the recirculation pumps, and the loss of condenser cooling water with a subsequent loss of condenser vacuum. The event is very similar to the loss of condenser vacuum event (paragraph 15C.4.1.3.4), but somewhat less severe from the challenge to event limits because of the initial trip of the recirculation pumps. The differences in system requirements are attributable to:

- The potential for a high RPV water level trip resulting from the level swell following the trip of the recirculation pumps.
- The loss of feedwater flow (LOFW).
- The reactor scram following the high RPV water level trip or MSIV closure.

Following MSIV closure, operation of the SRVs limits the pressure increase, and operation of the HPCI and RCIC systems maintains RPV water level.

B. The loss of all grid connections is identical to the generator load rejection with bypass (LRBP) event (paragraph 15C.4.1.3.2).

A loss of auxiliary power can occur in all operating states (figure 15-27). It should be noted that the loss of RHR shutdown cooling (event 4) bounds the loss of auxiliary power in the shutdown cooling mode and the required actions for the shutdown cooling mode are not shown on figure 15C-27.

In operating state D, the shutdown required action is highly dependent upon the event signature.

A. If the plant is operating at a significant power level and loss of auxiliary power resulting from a loss of the offsite grid, generator load rejection occurs.

B. If the initial power level is greater than the turbine first-stage pressure permissive, a TCV fast closure initiates a scram and an EOC-RPT.

C. If a generator load rejection does not occur or the initial power level is less than the turbine first-stage pressure permissive, the required action is dependent upon whether or not a high RPV water level trip occurs.

1. If a high RPV water level trip occurs, the shutdown required action is also dependent upon the initial power level.

   a. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

   b. If power level is less than the turbine first-stage pressure permissive, the TSV position switch scram is bypassed, and the required action is dependent upon the transient signature.

      1) If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

      2) If the NMS high neutron flux setpoint is not reached, but the high RPV pressure setpoint is reached, a scram is initiated.

2. If either the high RPV pressure scram setpoint is not reached or a high RPV water level trip does not occur, and the low RPV water level scram setpoint is reached, a scram is initiated on low RPV water level.

3. If no scram trip setpoint is reached, a scram (fail-safe design) is initiated following loss of the RPS power supply (coastdown of the RPS M-G set).

An alternate shutdown path on either low condenser vacuum or a loss of power (RPS power supply) can occur. The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed if the reactor is not in the RUN mode and the TSVs are < 90% open. In operating state D, an alternate shutdown path is established by closing the MSIVs in the RUN mode to initiate a scram.

If a low condenser vacuum trip does not occur, the loss of the RPS power supply results in the fail-safe MSIV closure.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from either TSV or MSIV closure.

A. If the SRV high pressure setpoint is not reached, pressure relief is not required.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the LOFW event, the low RPV water level trip setpoint for the initiation of the HPCI and RCIC systems is reached. The RCIC and HPCI systems are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

15C.4.1.8.4 LOFW (Event 25)

The event description and the safety analysis for the LOFW event are provided in paragraph 15.2.8.4. The event evaluation is documented in figure 15C-28.

The LOFW event initially is a mild depressurization event with a level decrease. The continuing level decrease causes a scram and the initiation of the RCIC and HPCI systems to restore and maintain water level. The event consequences are primarily dependent upon initial operating conditions.

Because the plant has turbine-driven feedwater pumps, an LOFW is possible only in operating state D (figure 15-28).

A scram on low RPV water level is initiated.

As a result of the continuing decrease in water level resulting from the LOFW, the low RPV water level trip setpoint for the initiation of the HPCI and RCIC systems is reached. Because of continued HPCI or RCIC system operation and continued suppression pool heating and level increase, the reactor may require operator initiated depressurization in accordance with the EOPs to assure continuity of long-term core cooling. The loss of RHR shutdown cooling (event 4) bounds this part of the required action for long-term core cooling.

Because the pressure regulation and turbine bypass systems remain in operation throughout the event, no unique requirement for pressure relief arises. The normal operating systems fulfill this required action.

RPV isolation is not required for event mitigation.

15C.4.2 ACCIDENTS

15C.4.2.1 <u>Control Rod Drop Accident (CRDA) (Event 31)</u>

The event description and the safety analysis for the CRDA are provided in subsection 15.3.2. The event evaluation is documented in figure 15C-29.

The dropping of a high-worth control rod results in a high local reactivity increase in a small region of the core and, for a large, loosely coupled core, significant shifts in spatial power generation. Doppler, void, and moderator reactivity limit the initial rapid power increase. Final shutdown is achieved by an NMS high neutron flux-initiated scram of all control rods, except for the dropped control rod. For the limiting case, fuel failure is predicted to occur as a consequence of this accident.

The CRDA, initiated from a critical condition at a very low power level with the banked position withdrawal sequence (BPWS) limiting control rod pattern represents the most severe challenge to the event acceptance limits. Core design, BPWS implementation, and the control rod velocity limiter limit the rate of reactivity addition. The rod worth minimizer, which is a normal operating

system that restricts control rod withdrawal at low power levels, enforces adherence to the BPWS. For postulated failures of the CRD housing, the CRD housing supports stop rod ejection.

For the limiting case, the reactor is assumed to be at a low power level discharging steam to the main condenser, with the mechanical vacuum pump in operation. The mechanical vacuum pump is assumed to be tripped due to high MSL radiation, and the radiological exposure is based on leakage from the main condenser. However, for the evaluation of the event in the cold condition, reactor conditions are consistent with shutdown cooling being in operation.

The CRDA is significant only in operating states B and D, with the reactor critical (figure 15-29).

No required actions are necessary in operating states A and C, because the reactor is more than one rod subcritical.

For any significant control rod drop, a flux trip occurs, and the NMS flux trip signal to the RPS initiates a scram.

The high pressure setpoint to open the SRVs may be reached because of the pressure increase.

A. If the SRV high pressure setpoint is not reached, either the pressure regulation and turbine bypass systems or the shutdown cooling system controls RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

The core cooling required action is dependent upon whether or not low RPV water level is reached.

A. If a low RPV water level trip is reached, the low RPV water level trip initiates the HPCI and RCIC[a] systems to maintain water level and provide initial core cooling. Because the potential exists for continued heating and an increase suppression pool level, the reactor may require operator-initiated depressurization in accordance with the EOPs to assure continuity of long-term core cooling. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term cooling.

B. If a low RPV water level trip does not occur, the event is relatively slow and is controlled by the normal operating systems. There is no unique requirement for core cooling.

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a. The CRDA limiting event path evaluated in the safety analysis (subsection 15.3.2) does not rely on RCIC to mitigate this design basis accident (DBA). None of the DBAs, as evaluated in the safety analysis (section 15.3), rely on RCIC for event mitigation. See subsection 15C.1.2 for an explanation of the relationship between the NSOA and the safety analysis.

If the reactor is vented (operating state B), or as a result of operation of the SRVs (operating state D), a primary containment high radiation trip that initiates closure of the primary containment isolation valves (PCIVs) may occur.

As a result of the postulated fission product release to the environment, a high radiation condition may be experienced in the air inlet to the main control room (MCR). If this condition exists, a high radiation signal from the MCR air intake radiation monitors initiates the filtration and pressurization mode of the MCR environmental control (MCREC) system.

RPV isolation and secondary containment are not required for event mitigation.

15C.4.2.2 Loss of Coolant Accident (LOCA) (Event 32)

The event description and the safety analysis for the LOCA are provided in subsection 15.3.3 and sections 6.2 and 6.3. The event evaluation is documented in figure 15C-30.
The LOCA is the postulated loss of coolant from pipe breaks in the reactor coolant pressure boundary (RCPB) up to and including a double-ended rupture of the largest pipe in the reactor coolant system (RCS). This leads to the requirement to evaluate the entire break spectrum and a number of possible single failures.

The response to a LOCA can be separated into the blowdown and core cooling phases.

A. During the blowdown phase, a net loss of coolant inventory and RPV water level occurs.

B. In the core cooling phase, the ECCS is functioning, and the heat transfer to the coolant limits the cladding temperature rise. The relative duration of each phase is dependent upon break size, location, and available ECCS components.

The LOCA is frequently separated into three break size ranges:

1. Small - The HPCI system provides sufficient inventory to prevent the core from becoming uncovered. If the HPCI system is not available, the ADS depressurizes the RPV to enable operation of the low pressure ECCS (CS and the LPCI mode of RHR).

2. Intermediate - The HPCI system performs a dual function by providing makeup water as well as supplementing the break in depressurizing the RPV. In this range, the combination of the HPCI system and break flow is sufficient to depressurize the RPV to allow the combination of the CS system and the LPCI mode of RHR to perform the core cooling function. If the HPCI system is not available, the ADS provides the RPV depressurization function.

3. Large - For large breaks, the RPV is depressurized through the break, and the CS system and the LPCI mode of RHR perform the core cooling function.

The complete, very rapid, circumferential failure of a reactor recirculation pipe represents the most severe challenge to the ECCS performance limits. However, the entire spectrum of break sizes and break locations, and single failures is considered in the LOCA analysis. The following breaks are included in the postulated break size and locations:

- Small, intermediate, and large liquid breaks.
- Small and large steam line breaks inside containment.
- Breaks in ECCS discharge lines inside containment.
- Breaks in feedwater lines inside containment.

The event is required to be evaluated assuming that offsite power is available and is not available. The most limiting analysis results are obtained for the assumption that offsite power is not available; however, the required actions may be different from the case where offsite power is available.

The LOCA is postulated to only occur in operating states C and D, with RPV pressure greater than the shutdown cooling pressure permissive (figure 15-30). For pressures less than the shutdown pressure permissive, the piping in the RCPB in not pressurized to a significant fraction of the piping system design pressure, and the probability of a pipe break is acceptably low.

In operating state D, a scram is initiated on either drywell high pressure or low RPV water level.

For small breaks, RPV pressure increases and the high pressure setpoint to open the SRVs may be reached because of the pressure increase resulting from closure of the isolation valves. The SRVs self actuate to limit the RPV pressure increase. If the high pressure setpoint is not reached, the break is of sufficient size for removing decay heat to limit the pressure increase.

The system requirements for core cooling are dependent upon break size. ECCS operation is required to provide the core cooling function. In some cases, the normal operating systems can supplement the ECCS if they are available. Because the plant has turbine-driven feedwater pumps, the feedwater system is not available for large breaks. Depending upon the analysis assumptions, it may be available for small and intermediate breaks.

A. For large breaks, the RPV depressurizes as a result of the break, and the CS system and the LPCI mode of the RHR system are initiated on either drywell high pressure or low RPV water level. Flow to the RPV begins once the RPV pressure permissive is satisfied, which allows the injection valve to open.

B. For intermediate breaks, there are two paths, depending upon the availability of the HPCI system. If the HPCI system is available, the HPCI system is initiated on either drywell high pressure or low RPV water level. For this break size range, the HPCI system is capable of acting as a depressurizer to enable the CS and the LPCI mode of RHR to perform effectively. The CS system and the LPCI mode of

RHR are initiated on either drywell high pressure or low RPV water level, and the injection valves open on low RPV pressure. If the HPCI system is assumed to fail, the RPV is depressurized through actuation of ADS, which is initiated by a low RPV water level and drywell high pressure signal after a time delay and with confirmation of a low RPV water level condition and the availability of a low pressure ECCS pump (ECCS pump discharge pressure permissive). If the feedwater system is available, the system requirements are essentially the same as for a small break with feedwater available.

C. For small breaks, the core cooling sequence is dependent upon the availability of the feedwater system.

1. If feedwater is available, a low RPV water level condition may not be reached and feedwater is used to provide core cooling consistent with the requirements of the EOPs, which are entered based upon a drywell high pressure condition. As a result of the steam and water transferred to the suppression pool through either the break or operation of the SRVs, suppression pool temperature and level may increase and reach either the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or the SRV tailpipe limit (which is based upon suppression pool level and RPV pressure), and manually initiated depressurization of the RPV is required. Manual initiation of the ADS can depressurize the RPV. Based upon the increase in suppression pool level the operator trips the feedwater system. Following the trip of the feedwater pumps, a low RPV water level trip will initiate the CS system and the LPCI mode of the RHR system, once the RPV pressure permissive is satisfied, to restore and maintain water level.

2. If the feedwater system is not available, the core cooling sequence is dependent upon the availability of the HPCI system. If the HPCI system is available, it is initiated on either drywell high pressure or low RPV water level. For this break size range, the HPCI system is capable of maintaining RPV water level and performing the core cooling function. If the HPCI system is not available, the CS system and the LPCI mode of RHR are initiated on either drywell high pressure or low RPV water level, and the injection valves are opened when low RPV pressure is reached. To enable the low pressure systems to perform their function, ADS actuation depressurizes the RPV. The ADS is initiated by a low RPV water level and a drywell high pressure signal after a time delay, with confirmation of a low RPV water level condition and the availability of a low pressure ECCS pump (ECCS pump discharge pressure permissive).

The primary containment is required to mitigate the consequences of the LOCA. To achieve containment isolation for the LOCA, both the PCIVs and the reactor isolation valves must be closed. A trip on drywell high pressure or low RPV water level initiates PCIV closure. Depending upon break size, operating mode, and system performance, a low RPV water level trip, a low MSL pressure trip in the RUN mode, or a low condenser vacuum trip initiates MSIV closure and other isolation valve closure. To limit the suppression pool temperature increase as

the result of a LOCA, the suppression pool cooling mode of the RHR system may be required. As a result of the energy transferred to the suppression pool resulting from the loss of coolant, the EOP entry condition on suppression pool temperature is reached. Due to the continuing mass and energy transfer to the suppression pool, a suppression pool high temperature condition is reached, requiring the operator to initiate the suppression pool cooling mode of the RHR system. If a high differential pressure occurs between the suppression chamber and the drywell, the vacuum breaker system self actuates.

The secondary containment is required to mitigate the consequences of the LOCA. A trip on either drywell high pressure or low RPV water level initiates closure of the isolation dampers in the secondary containment. The same signals initiate the standby gas treatment system (SGTS) to filter and maintain a negative pressure within the secondary containment.

As a result of the postulated fission product release, a high radiation condition in the air inlet to the MCR room can be experienced. If this condition exists, a high radiation signal from the MCR air intake radiation monitors initiates the filtration and pressurization mode of the MCREC system. RPV isolation occurs as part of the containment isolation process.

15C.4.2.3 Main Steam Line Break Accident (MSLBA) (Event 33)

The event description and the safety analysis for the MSLBA are provided in subsection 15.3.4. The event evaluation is documented in figure 15C-31.

The spectrum of postulated breaks in an NSSS pipe outside primary containment that result in the direct discharge of reactor coolant to the environment until the break is isolated is evaluated. The complete severance of an MSL leads to the most severe challenge to the event acceptance limits associated with the release of radioactive material to the environment. For this reason, the complete severance of the MSL, with the MSL flow restrictors limiting flow, is a DBA that bounds the consequences of the spectrum of pipe breaks outside primary containment.

The event is generally evaluated assuming offsite power is not available, however, the availability of offsite power can lead to different system requirements. For most considerations, the maximum power conditions lead to the most conservative results; however, low power and high flow conditions may be more limiting when considering the potential differential pressure loads on the reactor internals and reactor fuel.

Because an MSLBA is only postulated to occur when the reactor is significantly pressurized, it can only occur in operating states C and D, with the reactor pressurized to a significant fraction of the piping system design pressure (figure 15-31).

Figure 15-31 documents the event paths associated with the complete severance of the MSL, with the MSL flow restrictors limiting flow, the design basis accident (DBA). In addition, the other major pipe breaks outside primary containment, RCIC, HPCI, RWC and RHR shutdown cooling that result in a direct release to the environment are considered. In particular, the mechanism by which the pipe break is isolated varies depending upon the break size and location.

In operating state D, and depending upon the initial operating parameters, break size and location, and availability of offsite power and other normal operating systems, a scram can be initiated by:

- Low RPV water level.
- MSIV position switches following initiation of MSIV closure.
- TSV position switches if a turbine trip occurs.
- TCV fast closure if a generator load rejection occurs.

If a valid automatic scram does not occur, reactor shutdown is not required.

Based upon the EOPs and the maximum safe values for these parameters, the operator may be required to manually initiate a scram.

The pipe break is isolated by various mechanisms, depending upon break size and location.

A. Low RPV water level, high system flow, high area temperature, high differential temperature, or low RPV pressure in the RUN mode initiates closure of the isolation valves as required. If automatic RPV isolation does not occur, RPV isolation is not required.

The high pressure setpoint to open the SRVs may be reached because of the pressure increase.

A. If the high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. The SRVs self actuate to limit the RPV pressure increase resulting from the MSIV closure.

The required action for core cooling is dependent upon the availability of the feedwater system.

A. If the feedwater system is available, a low RPV water level condition may not be reached, and feedwater is used to provide core cooling consistent with the EOP requirements. If the main condenser is not available; e.g., as the result of postulated failures, suppression pool temperature may increase as the result of steam transferred to the pool through the SRVs until the EOP entry condition on suppression pool temperature is reached. If the SRVs are not cycling, planned operation continues with feedwater maintaining RPV water level. If an SRV is cycling, a suppression pool high temperature condition is reached, requiring the operator to initiate the RHR system in the suppression pool cooling mode to remove decay heat. Depending upon the effectiveness of the RHR system and the continued operation of the feedwater system, either the suppression pool temperature may reach the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or the suppression pool level

may reach the SRV tailpipe limit (which is based upon RPV pressure and suppression pool level), and manually initiated depressurization of the RPV is required. Manual initiation of the ADS depressurizes the RPV. For this path, the continuing operation of the feedwater system may result in a high water level condition in the suppression pool that requires the operator to trip the feedwater system. Following the trip of the feedwater system, a low RPV water level trip will initiate either the CS system or the LPCI mode of the RHR system to restore and maintain water level.

B. If the feedwater system is not available, a low RPV water level condition is reached. The required action depends upon the availability of the HPCI system. It should be noted that the HPCI system may be lost as a result of the event (a break in the HPCI system).

1. If available, the HPCI system is initiated on low RPV water level. As a result of either continued HPCI operation or the cycling of an SRV, a high suppression pool temperature condition is reached requiring the operator to initiate the RHR system in the suppression pool cooling mode. Depending upon the effectiveness of the RHR system, either the suppression pool temperature may reach the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or the suppression pool level may reach the SRV tailpipe limit (which is based upon suppression pool level and RPV pressure), and manually initiated depressurization of the RPV is required. Manual initiation of the ADS can depressurize the RPV. Following depressurization and satisfying the RPV pressure permissive, a low RPV water level trip initiates the CS system and the LPCI mode of the RHR system to restore and maintain water level.

2. If the HPCI system is not available, the CS system and the LPCI mode of RHR are initiated on low RPV water level. Flow into the RPV to restore and maintain water level begins once the RPV pressure permissive is satisfied. To enable the low pressure systems to perform their function, ADS actuation depressurizes the RPV. A low RPV water level trip, which bypasses the drywell high pressure initiation requirement after a time delay, initiates the ADS and after another time delay and with confirmation of a low RPV water level condition and the availability of a low pressure ECCS pump (ECCS pump discharge pressure permissive). As a result of the transfer of energy to the suppression pool resulting from operation of the SRVs and depressurization, an EOP entry condition on suppression pool temperature is reached. Based upon the suppression pool temperature indication, the operator manually initiates the suppression pool cooling mode of RHR to limit the suppression pool temperature rise.

As a result of the postulated fission product release, a high radiation condition in the air inlet to the MCR may be experienced. If this condition exists, a high radiation signal from the MCR air intake radiation monitors initiates filtration and pressurization mode of the MCREC system.

The primary containment and the secondary containment are not required for event mitigation.

15C.4.2.4 Fuel-Handling Accident (Event 34)

The event description and the safety analysis for the fuel-handling accident are provided in subsection 15.3.5. The event evaluation is documented in figure 15C-32.

The dropping of a fuel assembly can cause fuel rod failures in both the dropped assembly and any assemblies that are impacted. The fission products released from the fuel and directly escaping from the water surface enter the secondary containment atmosphere.

Because a fuel-handling accident can potentially occur any time when fuel assemblies are being manipulated either over the core (operating state A only) or in the spent fuel pool, this accident is considered in all operating states (figure 15-32).

No unique required actions relative to reactor shutdown, pressure relief, core cooling, and RPV isolation are required. A scram is not required because a fuel assembly dropped onto the core can only occur with all the control rods inserted, and the reactor continues in planned operation if the fuel assembly drop occurs in the spent fuel storage pool. The normal operating systems are not challenged and are assumed to remain operable throughout the event; therefore, feedwater control, recirculation flow control, pressure regulation, and turbine bypass or shutdown cooling accomplish the pressure relief and core cooling functions. RPV isolation is not required for event mitigation.

As a result of the postulated fission product release, a high radiation trip in the building exhaust radiation monitors is predicted. The high radiation trip initiates closure of the building isolation dampers to isolate the secondary containment and initiate the standby gas treatment system (SGTS). The SGTS filters and exhausts the secondary containment atmosphere to maintain a negative pressure within the secondary containment.

If a high radiation condition in the air inlet to the MCR occurs as a result of the postulated fission product release, a high radiation signal from the MCR air intake radiation monitors initiates the filtration and pressurization mode of the MCREC system.

The primary containment is not required for event mitigation.

15C.4.2.5 Fuel Assembly Loading Error (Event 35)

The event description and the safety analysis for the fuel assembly loading error are provided in subsection 15.3.6. The event evaluation is documented in figure 15C-33.

The fuel assembly loading error accident is the postulated loading of one fuel assembly either in an improper location (mislocated) or in an improper orientation (rotated). Furthermore, it is assumed the improper loading of a fuel assembly is not discovered and corrected as a result of the core verification program, and the plant is operated throughout the operating cycle. An improper fuel insertion discovered and corrected as part of the core verification program is discussed in paragraph 15C.4.1.6.3.

A. Mislocated Fuel Assembly - Fuel Assembly Loading Error

The mislocated fuel assembly - fuel assembly loading error causes a discrepancy between the design core configuration and the actual core configuration. The consequences of the mislocated fuel assembly are dependent upon the exposure, enrichment, and burnable poison differences between the fuel assembly that was incorrectly loaded and the fuel assembly that was designed to be in that location. Because of the low probability of this event, it is considered an accident. No other event or equipment failure is assumed to occur while the plant is operating with a mislocated fuel assembly loading error.

B. Rotated Fuel Assembly - Fuel Assembly Loading Error

The rotated fuel assembly - fuel assembly loading error causes a discrepancy between the design core configuration and the actual core configuration. The consequences of the rotated fuel assembly fuel assembly loading error are dependent upon the lattice design. In D-lattice plants, the water gaps between fuel assemblies are not uniform. In addition, the design of the spacer buttons at the top of the channel causes a rotated fuel assembly to be slightly tilted, causing axial variation of the water gap thickness outside the channel, and therefore, the local power distribution within the fuel assembly. The consequences of a rotated fuel assembly as a function of exposure throughout the operating cycle are considered. Because of the low probability of this event, it is also considered an accident.

Because the fuel assembly loading error is applicable to all modes of planned operation, it is considered in all operating states (figure 15-33).

No unique required actions are necessary for this event, because no protective system intervention is required for event mitigation. As a result, reactor shutdown, RPV isolation, primary containment, secondary **containment**, and MCR habitability systems are not required. The normal operating systems, including feedwater control, recirculation flow control, pressure regulation, and turbine bypass or shutdown cooling, accomplish the core cooling and pressure relief functions.

15C.4.2.6 Recirculation Pump Seizure (Event 36)

The event description and the safety analysis for the recirculation pump seizure are provided in subsection 15.3.7. The event evaluation is documented in figure 15C-34.

The instantaneous stoppage of the recirculation pump produces a very rapid decrease in core flow. The reduction in core flow causes a rapid decrease in power level because of the increase in core voids. RPV water level swells as the result of generation of additional voids and may reach the RPV high water level trip. If the RPV high water level trip occurs, it initiates a turbine trip (TSV closure) and a trip of the feedwater system. TSV closure initiates a scram and an EOC-RPT. The turbine trip initiates a turbine bypass valve opening signal. Following the turbine trip, the increase in core voids resulting from the lower core flow, Doppler feedback, and scram limits the NMS neutron flux increase. RPV pressure is limited by the SRVs and

controlled by the turbine bypass system. Operation of either the HPCI or the RCIC system maintains RPV water level. If a high level trip does not occur, the plant will stabilize into a new steady-state operating condition at a lower power level. The normal operating systems control the plant.

The recirculation pump seizure is considered in operating states C and D (figure 15C-34), but is significant only in operating state D, with the reactor critical and operating at a significant power level.

Depending upon the magnitude of the level swell, a high RPV water level trip can occur. The required actions are dependent upon whether or not a high RPV water level trip occurs.

A. If a high RPV water level trip does not occur, the reactor will stabilize in a new steady-state operating condition (single-loop operation). The feedwater control, pressure regulation, and turbine bypass systems remain in operation throughout the event, and no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions. Reactor shutdown and RPV isolation are not required.

B. If a high RPV water level trip occurs, a turbine trip and a feedwater system trip occur. The required actions are dependent upon the conditions associated with these trips.

   If a high water level trip occurs in operating state D, the shutdown required action is dependent upon the initial power level.

   1. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT (trip of the operating recirculation pump).

   2. If power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed.

   3. For the initial power levels less than the pressure permissive, the required action is dependent upon the transient signature.

      a. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on NMS high APRM neutron flux signal.

      b. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, a scram on high RPV pressure is initiated.

      c. If the high pressure scram setpoint is not reached, a scram is not required, and the reactor will stabilize in a new steady-state operating condition until action is taken to restore the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from TSV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the continuing water boiloff following these trips, a low RPV water level trip setpoint for the initiation of the RCIC and HPCI systems is reached. The RCIC and HPCI systems are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required actions for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.2.7 Feedwater Line Break Accident (Event 37)

The event description and the safety analysis for the feedwater break accident are provided in subsection 15.3.8. The event evaluation is documented in figure 15C-35.

A postulated break in a feedwater system pipe outside the primary containment results in the direct discharge of feedwater and its entrained radioactivity to the environment. This event, depending upon the location of the pipe break, can result in a significant change in the operating environment for equipment and instrumentation external to the primary containment relied upon in the development of the event diagrams. The feedwater line break accident is considered in operating states C and D (figure 15C-35).

In operating state D and depending upon the initial operating parameters and break size and location, a trip on low RPV water level will initiate a scram. If a valid automatic scram does not occur, reactor shutdown is not required.

The self actuation feature of the feedwater check valves isolates the pipe break. Depending upon the break location, the MSIVs can be closed on a low RPV water level, high area temperature, or high differential temperature. For some break sizes, an automatic MSIV isolation may not occur. If MSIV closure does not automatically occur, MSIV closure is not required.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from MSIV closure.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

Feedwater is assumed to be lost as a result of the postulated break. A low RPV water level condition is reached and the core cooling required action depends upon the availability of the HPCI system.

A. If the HPCI system is available, it is initiated on a low RPV water level. The HPCI system restores and maintains level. As a result of continued operation of the HPCI system or cycling of an SRV, a high suppression pool temperature condition is reached requiring the operator to initiate the RHR system in the suppression pool cooling mode. Depending upon the effectiveness of the RHR system, the suppression pool temperature may reach the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or the suppression pool level may reach the SRV tailpipe limit (which is based upon RPV pressure and suppression pool level), and manually initiated depressurization of the RPV is required. Manual initiation of the ADS depressurizes the RPV. Following depressurization and satisfying the RPV pressure permissive, a low RPV water level trip initiates the CS system and the LPCI mode of the RHR system to restore and maintain water level.

B. If the HPCI system is not available, the CS system and the LPCI mode of RHR are initiated on low RPV water level, and flow into the RPV begins once the RPV pressure permissive is satisfied to open the injection valves. To enable the low pressure systems to perform their function, ADS actuation depressurizes the RPV. A low RPV water level trip, which bypasses the drywell high pressure initiation requirement after a time delay initiates the ADS and after another time delay and with confirmation of a low RPV water level condition and the availability of a low pressure ECCS pump (ECCS pump discharge pressure permissive). As a result of the transfer of energy to the suppression pool resulting from SRV operation and depressurization, an EOP entry condition on suppression pool temperature is reached. Based upon the suppression pool temperature indication, the operator manually initiates the RHR system in the suppression pool cooling mode to limit the suppression pool temperature rise.

As a result of the postulated fission product release, a high radiation condition in the air inlet to the MCR may occur. If this condition exists, a high radiation signal from the MCR air intake radiation monitors initiates the filtration and pressurization mode of the MCREC system.

The primary and secondary containments are not required for event mitigation.

15C.4.3 SPECIAL EVENTS

15C.4.3.1 Stability (Event 41)

The event description and the safety analysis for stability are provided in subsection 15.4.1. The event evaluation is documented in figure 15C-36.

Significant power or flow oscillations can only occur when the reactor is in power operation. Therefore, this event is considered only in operating state D (figure 15C-36).

Depending upon core and fuel design, and the operating region entered on the power-to-flow map, reactor power and flow oscillations can occur. The required actions are dependent upon whether or not a scram is required.

A. If a scram is required, a trip of the NMS due to high oscillation power range monitor (OPRM) growth rate, amplitude, or period algorithm initiates a scram.

B. If a scram is not required, planned operation continues with the feedwater control, recirculation flow control, and pressure regulation systems available.

15C.4.3.2 Overpressure Protection (Event 42)

The event description and the safety analysis for overpressure protection are provided in subsections 15.4.2 and 5.2.2. The event evaluation is documented in figure 15C-37.

This event can only occur when the reactor is in power operation in operating state D (figure 15C-37).

The most severe pressurization event is the closure of all MSIVs at their fastest design closure time.

Based upon the event definition, an NMS high neutron flux scram is assumed in the analysis. The direct scram initiated by the MSIV position switches is conservatively ignored. Based upon this assumption, an APRM NMS high neutron flux trip initiates a scram.

Based upon the event definition, the event results in a significant pressurization, and the SRVs are actuated to limit the pressure increase.

15C.4.3.3 Shutdown Without Control Rod Insertion (SLCS Capability) (Event 43)

The event description and the safety analysis for shutdown without control rod insertion (SLCS capability) are provided in subsection 15.4.3. The event evaluation is documented in figure 15C-38.

This event can only occur when the reactor is not shutdown. Therefore, this event is considered only in operating states B and D (figure 15C-38).

For the shutdown without control rod insertion (SLCS capability) event, it is assumed the operator initiates the SLCS to inject sufficient sodium pentaborate into the reactor to enable a cold shutdown condition to be attained. To ensure the effectiveness of the SLCS, initiation of the SLCS generates a trip, closing the reactor water cleanup (RWC) system isolation valves, thereby completing the shutdown without control rod insertion.

15C.4.3.4 MCR Uninhabitability (Event 44)

The event description and the safety analysis for MCR uninhabitability are provided in subsection 15.4.4. The event evaluation is documented in figure 15C-39.

The MCR is designed to be continuously occupied at all times. The MCR uninhabitability (shutdown from outside the MCR) event is evaluated to demonstrate compliance with GDC 19, which requires that equipment at appropriate locations outside the MCR be provided with the following capabilities:

- A design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown.

- A potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

A shutdown outside the MCR can be postulated to occur under any operating condition. As a result, the event is considered in all operating states (figure 15C-39).

All actions are based upon plant procedures developed assuming the MCR becomes uninhabitable. All operator actions occur external to the MCR. No other failures are assumed to occur.

In operating state B or D, the operator can initiate a scram by opening the power supply breakers to the RPS. The remainder of the actions are dependent upon the initial operating state and whether or not a reactor isolation occurs following a shutdown.

A. If the reactor is initially operating in the shutdown cooling mode of RHR, planned operation in the shutdown cooling mode is continued.

B. If the reactor is not initially operating the shutdown cooling mode of RHR and the reactor does not isolate following a shutdown, planned operation continues with the feedwater, pressure regulation, and turbine bypass systems available.

C. If the reactor is not initially operating the shutdown cooling mode of RHR and the reactor is isolated following a shutdown, the SRVs self actuate to limit the RPV pressure increase resulting from the isolation.

As a result of the isolation, the steam supply to the turbine-driven feedwater pumps and the main condenser (heat sink) is lost. Following isolation, the continuing water boiloff resulting from RPV decay heat results in a low RPV water level trip that initiates the RCIC. Consistent with plant procedures, the operator takes the following actions:

- Confirms RCIC system initiation and controls the RCIC system to maintain water level.

- Initiates the suppression pool cooling mode of RHR to limit the temperature rise in the suppression pool.

- Opens the SRVs from the remote shutdown panel to depressurize the RPV until the shutdown cooling pressure permissive is reached.

- Following depressurization, initiates planned operation of the RHR system in the shutdown cooling mode.

15C.4.3.5 Anticipated Transient Without Scram (ATWS) (Event 45)

The event description and the safety analysis for ATWS are provided in subsection 15.4.5. The event evaluation is documented in figure 15C-40.

Any AOO that has a high frequency of occurrence and is terminated by an automatic or manually initiated scram can be postulated as an initiating event for ATWS. Because a failure to scram requires multiple failures, no specific causes are identified. However, postulated potential sources of failure include:

- Failure of the protective instrumentation to generate a scram signal when RPS setpoints are exceeded.

- Multiple failures in electrical components within the RPS.

- Failure of the CRD hydraulic (CRDH) system.

- Failure within individual control rods.

Plant design is such that, for AOOs requiring an automatic scram, a minimum of two, and in some cases three or four, diverse and redundant RPS instrument setpoints are predicted to be exceeded during a significant ATWS event.

This event can only occur when the reactor is in operating state D (figure 15C-40). The event consequences are significant only when the plant is in power operation at a significant power level.

In all ATWS cases considered, shutdown is required. For ATWS events, shutdown is considered in two phases:

A. Initial Negative Reactivity Insertion

Tripping the recirculation pumps through the ATWS-RPT circuitry accomplishes initial negative reactivity insertion. Automatic tripping of the ATWS-RPT occurs on either high RPV pressure or low RPV water level. For cases in which a shutdown is required but does not automatically occur, an EOP entry condition on scram required and power level > 5% is reached. The EOPs require that a manual scram

be initiated before the suppression pool temperature limit is reached. This scram is assumed to fail. Furthermore, on scram required and power level > 5%, the EOPs require manual initiation of ATWS-RPT if all control rods are not fully inserted.

B. Capability to Reach Cold Shutdown Condition

To reach a cold shutdown condition, operator action is necessary to ensure sufficient negative reactivity insertion is accomplished so that a cold subcritical condition can be attained. The ARI system is also assumed to fail to insert the control rods. Therefore, it is not included in the required action for this event. This leads to a requirement that operator action be taken to initiate SLCS operation. If an automatic RPT occurs, the EOP entry condition on scram required and power level > 5% can result. At this point, the same system conditions exist, regardless of the path. Manual SLCS initiation is required if the suppression pool temperature is predicted to reach the SLCS initiation limit prior to shutdown. The SLCS injects sufficient sodium pentaborate into the reactor to enable a cold shutdown condition to be attained. These actions complete the shutdown path.

The setpoint to open the SRVs may be reached if the event results in a significant pressurization.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

The required action for core cooling is dependent upon the availability of the feedwater system. If feedwater is not available, a low RPV water level trip initiates the HPCI and RCIC systems to maintain water level. Due to the continuing SRV operation, suppression pool temperature can increase until the EOP entry condition on suppression pool temperature is reached. For most ATWS scenarios, a suppression pool high temperature condition is reached, requiring the operator to initiate the RHR system in the suppression pool cooling mode to remove heat and, following shutdown, limit the pool temperature increase. Depending upon the effectiveness of suppression pool cooling, either the suppression pool temperature can reach the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or the suppression pool level may reach the SRV tailpipe limit (which is based upon suppression pool level and RPV pressure), and manually initiated depressurization of the RPV is required in accordance with the EOPs. Manual initiation of the ADS depressurizes the RPV. Following the depressurization of the system and in accordance with the EOPs, the RHR system can be manually initiated in the shutdown cooling mode to remove decay heat.

For some initiating events considered, the low RPV water level trip initiates MSIV other reactor isolation valve closure. If the low RPV water level setpoints are not reached, RPV isolation is not required.

As a result of the postulated ATWS events, a low RPV water level trip initiating PCIV closure is expected to be reached. If the low RPV water level trip setpoints are not reached, containment isolation is not required.

15C.4.3.6 Generator Load Rejection With Flux Scram and No Bypass or RPT (Event 46)

The event description and the safety analysis for generator load rejection with flux scram and no bypass or RPT are provided in subsection 15.4.6. The event evaluation is documented in figure 15C-41.

A generator load rejection with flux scram and no bypass or RPT can only occur in operating state D (figure 15C-41), with the main turbine operating.

NMS high neutron flux inputs into the RPS initiate a scram.

The SRVs self actuate to limit the RPV pressure increase resulting from TCV closure, assuming the unavailability of the turbine bypass valves.

The normally operating feedwater system provides initial core cooling. However, the continuing operation of the SRVs may result in an increase in suppression pool temperature such that an EOP entry condition is reached. The loss of RHR shutdown cooling (event 4) bounds the required actions for long-term cooling.

RPV isolation is not required for event mitigation.

15C.4.3.7 Turbine Trip With Flux Scram and No Bypass or RPT (Event 47)

The event description and the safety analysis for turbine trip with flux scram and no bypass or RPT are provided in subsection 15.4.7. The event evaluation is documented in figure 15C-42.

A turbine trip with flux scram and no bypass or RPT can only occur in operating state D (figure 15C-42), with the main turbine operating.

NMS high neutron flux inputs into the RPS initiate a scram. The SRVs self actuate to limit the pressure increase resulting from TCV fast closure and the assumed unavailability of the turbine bypass valves.

The normally operating feedwater system provides initial core cooling. However, the continuing SRV operation can result in an increase in suppression pool temperature such that an EOP entry condition is reached. The loss of RHR shutdown cooling (event 4) bounds the required actions for long-term core cooling.

RPV isolation is not required for event mitigation.

15C.4.3.8 Loss of One dc System (Event 48)

The event description and the safety analysis for the loss of one dc system are provided in subsection 15.4.8. The event evaluation is documented in figure 15C-43.

Because the loss of one dc system is applicable to all modes of planned operation, it is considered in all operating states (figure 15C-43). The loss of one dc system can initiate a turbine trip. For these cases, the evaluation of the TTBP event (paragraph 15C.4.1.3.5) is applicable. The required actions for this event are dependent upon whether or not a turbine trip occurs.

A. If a turbine trip does not occur, the reactor continues in normal operation consistent with the Technical Specifications. The feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, and no unique requirement for either pressure relief or core cooling arises. The normal operating systems fulfill these required actions. Reactor shutdown and RPV isolation are not required.

B. If a turbine trip occurs, the shutdown required action is dependent upon the initial power level.

   1. If the initial power level is greater than the turbine first-stage pressure permissive, the TSV position switches initiate a scram and an EOC-RPT.

   2. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

      a. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

      b. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

      c. If the NMS high neutron flux and the high RPV pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

The setpoint to open the SRVs may be reached, except when the event is initiated from very low power levels.

A. If the SRV high pressure setpoint is not reached, heat losses from the system may be sufficient to limit any pressure increase.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the pressure increase.

Because the feedwater control, recirculation flow control, pressure regulation, and turbine bypass systems remain in operation throughout the event, no unique requirement for core cooling arises. The normal operating systems fulfill this required action.

RPV isolation is not required for event mitigation.

It should be noted that the single-failure requirements identified on the event diagrams for the other events considered in the NSOA cover the loss of one dc system relative to the specific event.

15C.4.3.9 Loss of Instrument Air (Event 49)

The event description and the safety analysis for the loss of instrument air are provided in subsection 15.4.9. The event evaluation is documented in figure 15C-44.

Because the loss of the instrument air system is applicable to all modes of planned operation, it is considered in all operating states (figure 15C-44).

The required actions are dependent upon whether or not a loss of condenser vacuum occurs. The loss of condenser vacuum sequentially trips the TSVs closed, which in turn opens the turbine bypass valves, initiates MSIV closure, and closes the turbine bypass valves (initially opened as a result of the turbine trip).

A. If a loss of condenser vacuum does not occur, the reactor continues in normal operation. The feedwater control, pressure regulation, and turbine bypass systems remain in operation throughout the event, and no unique requirement for pressure relief or core cooling arises. The normal operating systems fulfill these required actions. Shutdown is not required unless a loss of air to the backup scram valves occurs. If a loss of air to the backup scram valves occurs, the fail-safe design of the CRD system inserts the control rods.

B. If a loss of condenser vacuum trip occurs, MSIV closure isolates the RPV. The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed if the reactor is not in the RUN mode and the TSVs are < 90% open. If a loss of condenser vacuum trip does not occur, RPV isolation is not required.

The required action for shutdown is dependent upon two factors:

- Loss of condenser vacuum that results in a turbine trip and an MSIV closure.
- Loss of the air supply to the backup scram valves.

A. If the initial power level is greater than the turbine first-stage pressure permissive, a low condenser vacuum trip sequentially trips the turbine, resulting in a TSV closure, which initiates a scram and an EOC-RPT.

B. If power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

1. If the NMS high neutron flux setpoint is reached, either the IRMs in the STARTUP mode, the APRMs (setdown) in the STARTUP mode, or the APRMs (in the RUN mode) initiate an NMS neutron flux trip signal to the RPS to initiate a scram.

2. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

C. An alternate shutdown path occurs as the result of the possibility the air supply to the backup scram valves is lost because of an instrument air failure. As described above, a loss of air to the backup scram valves inserts the control rods.

D. If either a scram setpoint is not reached or the air supply to the backup scram valves is not lost, shutdown is not required.

E. Another alternate shutdown path can occur if a low condenser vacuum trip initiates MSIV closure. In operating state D, MSIV closure in the RUN mode initiates a scram.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from either MSIV closure or a turbine trip.

A. If the SRV high pressure setpoint is not reached, the normal operating systems controls RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

If the MSIVs are closed as a result of the loss of condenser vacuum, the steam supply to the turbine-driven feedwater pumps is lost. The continuing water boiloff attributable to RPV decay heat results in a low RPV water level trip setpoint for the initiation of the RCIC and HPCI systems being reached. The RCIC and HPCI systems are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

15C.4.3.10 <u>Loss of Service Water System (Event 50)</u>

The event description and the safety analysis for the loss of service water system are provided in subsection 15.4.10. The event evaluation is documented in figure 15C-45.

One division of RHRSW and plant service water (PSW) is arbitrarily assumed to fail. Based upon this evaluation, it is concluded that, considering all AOOs and accidents that require the

service water system as an auxiliary support system, a single failure does not result in unacceptable consequences. The single-failure requirements identified on the event diagrams for the other events considered in the NSOA cover the loss of a service water system relative to the specific event.

Considering a failure of the RHRSW and PSW systems, the plant will continue in planned operation, consistent with plant procedures and the Technical Specifications. Because the loss of one division of the service water system is applicable to all modes of planned operation, it is considered in all operating states. No unique required actions are necessary, because no protective system intervention is required.

15C.4.3.11 <u>Fire (Event 51)</u>

The event description and the safety analysis for fire are provided in subsection 15.4.11. The event evaluation is documented in figure 15C-46.

For postulated fire events, it is necessary to demonstrate that fire protection features are capable of limiting fire damage so that:

A. One train of systems necessary to achieve and maintain hot shutdown conditions from either the MCR or emergency control station(s) is free of fire damage.

B. Systems necessary to achieve and maintain cold shutdown from either the MCR or the emergency control station(s) can be repaired within 72 hours.

Because fire can be postulated to occur under any operating condition, it is considered in all operating states (figure 15C-46). All actions are based upon plant procedures developed for safe shutdown for postulated fire locations.

In operating state B or D, the required actions are dependent upon whether or not an automatic scram occurs.

A. Depending upon the failures or equipment actuations that occur as a result of the fire, a scram can occur as a result of low RPV water level, MSIV position switches following initiation of MSIV closure, TSV position switches following a turbine trip, or on a TCV fast closure following a load rejection.

B. If an automatic scram does not occur, the operator can initiate a scram.

RPV isolation can occur on low RPV water level, low MSL pressure in the RUN mode, loss of ac power to the RPS power supply, or other fire-induced trips associated with the PC&RPV isolation control system. Any automatic trip that occurs initiates closure of the MSIVs. If an automatic RPV isolation does not occur, it is not required.

The setpoint to open the SRVs may be reached because of the pressure increase associated with the postulated fire-induced failures or isolation of the RPV.

A. If the SRV high pressure setpoint is not reached, the pressure regulation, turbine bypass, and shutdown cooling systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

The required action for core cooling is dependent upon the operability of the normal operating systems or the various standby systems.

A. If the normal operating systems are available, the initially operating feedwater control system or shutdown cooling system continues in planned operation and performs the core cooling requirements.

B. If the normal operating systems are not available, at least one of three acceptable pathways is available.

   1. Pathway 1

      Pathway 1 uses primarily Division 1 equipment. The core cooling path depends upon whether or not spurious operation of the ADS occurs as a result of the fire.

      For the most likely case, spurious operation of the ADS is not expected. For this case, a low RPV water level trip setpoint for the initiation of the RCIC system is reached. The RCIC system is automatically initiated to restore and maintain water level. As a result of continued operation of the RCIC system, the suppression pool temperature may reach the EOP entry condition. Either the suppression pool temperature may reach the heat capacity temperature limit (which is based upon suppression pool temperature or RPV pressure) or the suppression pool level may reach the SRV tailpipe limit (which is based upon the suppression pool level and RPV pressure) and manual initiation of RPV depressurization is then required. Once the reactor is depressurized to below the RPV pressure permissive, the operator initiates RHR alternate shutdown cooling to restore inventory and remove decay heat (paragraph 15C.4.1.2.1).

      If spurious operation of the ADS occurs, a low RPV water level trip for the initiation of the CS system is reached. The CS system is automatically initiated to restore and maintain water level. Following the initial refill of the core, the operator initiates RHR alternate shutdown cooling to maintain inventory and remove decay heat.

   2. Pathway 2

      Pathway 2 is the same as Pathway 1 except that it uses primarily Division 2 equipment. In Pathway 2, the HPCI system replaces the function of the RCIC system. All other functions remain the same.

3. Pathway 3

   Pathway 3 utilizes the RCIC system, SRVs, and shutdown cooling mode of RHR. For Pathway 3, a low RPV water level trip setpoint for the RCIC system initiation is reached. The RCIC system is automatically initiated to restore and maintain water level. Continued RCIC system operation can result in the suppression pool temperature reaching the EOP entry condition. Either the suppression pool temperature may reach the heat capacity temperature limit (which is based upon suppression pool temperature and RPV pressure) or suppression pool level may reach the SRV tailpipe limit (which is based upon suppression pool level and RPV pressure), and manual initiation of RPV depressurization is then required. Once the reactor is depressurized to below the RHR shutdown cooling permissive, the operator resumes planned operation by initiating the shutdown cooling mode of RHR to remove decay heat.

15C.4.3.12 <u>Miscellaneous Small Releases Outside Containment (Event 52)</u>

The event description and the safety analysis for miscellaneous small releases outside of containment are provided in subsection 15.4.12. The event evaluation is documented in figure 15C-47.

Since the miscellaneous small releases outside containment event is applicable to all modes of planned operation, it is considered in all operating states (figure 15C-47).

No unique required actions are necessary for this event, because no protective system intervention is required. Therefore, for miscellaneous small releases outside containment during normal plant operation, the plant continues in planned operation.

15C.4.3.13 <u>Instrument Line Break (Event 53)</u>

The event description and the safety analysis for an instrument line break are provided in subsection 15.4.13. The event evaluation is documented in figure 15C-48.

An instrument line break results in a release of reactor coolant to the reactor building until the reactor is depressurized. Because an instrument line break is only postulated to occur when the reactor is significantly pressurized, it can only occur in operating states C and D (figure 15C-48), with the reactor pressurized to a significant fraction of the piping system design pressure.

Only the secondary containment is required. As a result of the postulated radioactivity release from the postulated break, a high radiation trip of the reactor building ventilation exhaust radiation monitors is predicted. The high radiation trip initiates closure of the building isolation dampers to isolate the secondary containment and initiate the SGTS, which filters and exhausts the secondary containment atmosphere to maintain a negative pressure within the secondary

containment. These actions are necessary to establish and maintain the secondary containment.

Automatic shutdown and RPV isolation are not required for event mitigation. If required, operator action can accomplish these functions. The normal operating systems, including feedwater control, pressure regulation, and turbine bypass, accomplish core the cooling and pressure relief functions. The MCR habitability systems are not required.

15C.4.3.14 Liquid Radwaste Tank Failure (Event 54)

The event description and the safety analysis for liquid radwaste tank failure are provided in subsection 15.4.14. The event evaluation is documented in figure 15C-49.

Because the liquid radwaste tank failure event is applicable to all modes of planned operation, it is considered in all operating states (figure 15C-49).

No unique required actions are necessary for this event, because no protective system intervention is required. As a result, reactor shutdown, RPV isolation, primary containment, secondary containment, and MCR habitability systems are not required. The normal operating systems, including feedwater control, recirculation flow control, pressure regulation, and turbine bypass or shutdown cooling, accomplish the core cooling and pressure relief functions.

15C.4.3.15 Gaseous Radwaste Tank Failure (Event 55)

The event description and the safety analysis for gaseous radwaste tank failure are provided in subsection 15.4.15. The event evaluation is documented in figure 15C-50.

The limiting failure of components in the offgas system, steam jet air ejectors (SJAEs), and turbine gland-sealing system bound the consequences of the various types of gaseous radwaste system failures.

The gaseous radwaste system is only operable in operating state D (figure 15C-50). The required actions are dependent upon whether or not a loss of condenser vacuum occurs as a result of the event.

A. If a loss of condenser vacuum does not occur, the reactor continues in planned operation.

B. If a low condenser vacuum trip occurs, the required action for shutdown is dependent upon the initial power level.

In operating state D, the shutdown required action is dependent upon the initial power level.

A. If the initial power level is greater than the turbine first-stage pressure permissive, a low condenser vacuum trip sequentially trips the turbine, resulting in a TSV closure, which initiates a scram and an EOC-RPT.

B. If the initial power level is less than the turbine first-stage pressure permissive, the TSV position switch scram and EOC-RPT are bypassed, and the required action is dependent upon the transient signature.

1. If the NMS high neutron flux setpoint is reached, the high APRM neutron flux initiates an NMS neutron flux trip signal to the RPS to initiate a scram.

2. If the NMS high neutron flux setpoint is not reached, but the high RPV pressure scram setpoint is reached, the RPS initiates a scram on high RPV pressure.

3. If the NMS high neutron flux and the RPV high pressure scram setpoints are not reached, the reactor will stabilize in a new steady-state operating condition until action is taken to return the reactor to a planned operating condition.

An alternate shutdown path can occur if a low condenser vacuum trip initiates MSIV closure. The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed if the reactor is not in the RUN mode and the TSVs are < 90% open. In operating state D, MSIV closure in the RUN mode initiates a scram.

The setpoint to open the SRVs may be reached, except when the event is initiated from very low power levels.

A. If the SRV high pressure setpoint is not reached, heat losses from the system may be sufficient to limit any pressure increase.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the pressure increase.

If the MSIVs are closed as a result of the loss of condenser vacuum, the steam supply to the turbine-driven feedwater pumps is lost. The continuing water boiloff due to RPV decay heat results in a low RPV water level trip setpoint for the initiation of the RCIC and HPCI systems being reached. The HPCI and RCIC systems are automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling.

If the MSIVs are not closed, the normal operating systems provide core cooling.

Primary containment, secondary containment and MCR habitability systems are not required.

15C.4.3.16 <u>Station Blackout (SBO) (Event 56)</u>

The event description and the safety analysis for SBO are provided in subsection 15.4.16. The event evaluation is documented in figure 15C-51.

SBO demonstrates compliance with the SBO coping capability requirements of 10 CFR 50.63. For postulated SBO events, it is necessary to demonstrate the plant is capable of coping with SBO having a duration of 4 h. In the coping capability evaluation, an alternate ac power source (standby onsite power supply) is assumed to be available within 1 h to the blacked-out unit. After the 4-h coping period, it is assumed station operators either restore offsite power or start an additional emergency diesel generator to bring the plant to a cold shutdown condition.

Because SBO can be postulated to occur under any operating condition, it is considered in all operating states (figure 15C-51). All actions are based upon plant procedures developed for SBO.

In operating state D, the required action for shutdown is highly dependent upon the event signature.

A. If a generator load rejection occurs and the initial power level is greater than the turbine first-stage pressure permissive, the TCV fast closure initiates a scram and an EOC-RPT.

B. If a generator load rejection does not occur or the initial power level is less than the turbine first-stage pressure permissive, the required action is dependent upon whether or not a turbine trip occurs.

C. If a turbine trip occurs and initial power level is greater than the turbine first-stage pressure permissive, TSV position switches and EOC-RPT initiate a reactor scram.

D. If a turbine trip occurs and initial power level is less than the turbine first-stage pressure permissive, the TSV position switches scram are bypassed, and the required action is dependent upon the transient signature.

   1. If the NMS high neutron flux setpoint is reached, the RPS initiates a scram on an NMS high APRM neutron flux signal.

   2. If the NMS high neutron flux is not reached, the RPS initiates a scram on high RPV pressure if the high RPV pressure scram setpoint is reached.

   3. If the NMS high neutron flux and the RPV high pressure scram setpoints are not reached, the RPS initiates a scram on low RPV water level if the RPV low water level scram setpoint is reached.

E. A scram (fail-safe design) is initiated following loss of the RPS power supply (coastdown of the RPS M-G set).

RPV isolation occurs either on loss of condenser vacuum or loss of power (RPS power supply). The low condenser vacuum input into the PC&RPV isolation control system initiates MSIV closure. A low condenser vacuum trip can be manually bypassed if the reactor is not in the RUN mode and the TSVs are < 90% open. If a low condenser vacuum trip does not occur, the loss of the RPS power supply results in the fail-safe closure of the MSIVs. In operating state D, an alternate shutdown path is established by closing the MSIVs in the RUN mode to initiate a scram.

The setpoint to open the SRVs may be reached because of the pressure increase resulting from closure of the TCVs, TSVs, or MSIVs.

A. If the SRV high pressure setpoint is not reached, the pressure regulation and turbine bypass systems control RPV pressure.

B. If the SRV high pressure setpoint is reached, the SRVs self actuate to limit the RPV pressure increase.

As a result of the LOFW, the low RPV water level trip setpoint for the initiation of the RCIC system is reached. The RCIC system is automatically initiated to restore and maintain water level, satisfying initial core cooling requirements. The loss of RHR shutdown cooling (event 4) bounds the required action for long-term core cooling following the 4-h coping period.

15C.5 SETPOINT METHODOLOGY

Setpoint methodology includes the following key elements:

- Identifying the scope of the setpoint methodology as it applies to the safety analysis.
- Defining the relationship with the NSOA and safety analysis.
- Identifying safety-related setpoints and uncertainties.
- Determining the setpoint classification process.
- Establishing the setpoint identification process and its basis.
- Defining the required setpoint calculation process.

15C.5.1 SCOPE

The scope of setpoint methodology is limited to setpoints associated with the safety analysis and NSOA (safety analysis input assumptions for process variables included in the Technical Specifications or Technical Requirements Manual (TRM)), Technical Specification limiting conditions for operation and surveillance requirements for installed process instrumentation and safety/relief valves, EOP parameters controlled by the Technical Specifications and TRM through requirements on post accident monitoring instrumentation, and TRM surveillance requirements for installed process instrumentation. These setpoints are controlled to assure safe operation of the plants.(6) The setpoint methodology does not apply to the setpoints associated with normal operating system or setpoints provided for other purposes, including the setpoints controlled by the Offsite Dose Calculation Manual (ODCM) and fire protection program.

15C.5.2 RELATIONSHIP TO NSOA AND SAFETY ANALYSIS

The goal of the application of the combined NSOA, safety analysis, and setpoint methodologies is to demonstrate that the plant can safely operate without unacceptable constraints on the desired operating envelope due to the potential for undesirable automatic trips. The combined NSOA, safety analysis, and setpoint process is shown on figure 15C-52. It should be noted that, although the safety analysis and setpoint methodologies are described separately, they are actually a single highly interrelated process that must be considered in developing the specific setpoint limits.

The process for establishing an acceptable set of instrument setpoints generally begins with the definition of the regulatory requirements, the physical plant design, and the expected modes of planned operation and the desired operating envelope limits. Based on the regulatory requirements, a spectrum of safety analysis events (anticipated operational occurrences, accidents, and special) and the related event limits are identified. The safety analysis and setpoint methodologies are the analytical methods and processes developed to demonstrate conformance to the regulatory requirements by providing acceptable analysis techniques for these events and acceptable limits for plant operation. The performance evaluation demonstrates the operational acceptability of the instrument setpoints.

The safety analysis is comprised of a number of event analyses documented in chapter 15. The safety analysis demonstrates conformance to the event limits using the safety analysis methodology and is based on inputs from plant design and the operating envelope limits. The event analyses are the cornerstone of the safety analysis process. Event analyses are performed using assumed values for the automatic trips, system initiations, and system performance characteristics. These assumed values are defined as analytical limits. It is the specific analytical limit value assumed in the safety analysis for an automatic trip or system initiation that is used in the development of an appropriate set of instrument setpoints.

The NSOA is used to identify the system and instrumentation requirements associated with the event analyses. The matrices provided in tables 15C-7 through 15C-10 identify the required systems, automatic instrument trips, monitored parameters (associated with required operator actions), and auxiliary systems for the safety analysis events. The limiting values for analytical limits assumed in the safety analysis are used as inputs in the development of the instrument setpoints.

The setpoint methodology is applied to the analytical limits for automatic trips or system initiations identified through the NSOA. Based on the evaluation of the uncertainties in the instrumentation loop, the setpoint methodology establishes the two required values for instrument setpoints: (1) nominal trip setpoints (NTSPs) and (2) allowable values (AVs). NTSPs are used in the operation of the plant. AVs are provided to the NRC as proposed Technical Specifications. These values have margin to the analytical limits based on measurement uncertainties and provide a high level of assurance that the true parameter value will not exceed the analytical limits. Supplemental evaluations may be performed to assure the operational acceptability of the required setpoints.

The Technical Specifications are constraints placed on the plant and its operation by the NRC. Technical Specifications frequently represent simplifications of the spectrum of setpoints to provide a practical set of limits that satisfy the regulatory requirements.

The final step in development of an acceptable set of setpoints is the plant performance evaluation. The plant performance evaluation demonstrates the operational acceptability of setpoints identified based on the safety analysis that identified and validated the analytical limits. An acceptable plant performance evaluation is one that demonstrates that the desired plant operating envelope is acceptable.

15C.5.3 SAFETY ANALYSIS-RELATED SETPOINTS AND UNCERTAINTIES

An overview of the relationship between the safety analysis and instrument setpoints, including the margins and uncertainties in both the safety analysis and setpoint processes, is shown on figure 15C-55.

In the plant safety analysis there are three basic types of inputs: model inputs, operating envelope limits, and analytical limits. The model inputs represent the plant design. Analytical limits are the assumed values input to the safety analysis for automatic instrument trips, monitored parameters for assumed operator actions, and mitigating system performance assumptions. The operating envelope limits represent the initial conditions for process parameters existing prior to the postulated occurrence of a safety analysis event. The set of safety analysis event analyses that satisfy all of the applicable event limits validates the acceptability of the model inputs, operating envelope limits, and analytical limits.

The treatment of uncertainties in the combined safety analysis and setpoint process begins by establishing the applicable event limits for each event. Event limits are the figures of merit for comparison to the results of the safety analysis. Event limits are conservatively established to demonstrate an acceptable level of plant safety. Some event limits are established to demonstrate the certain fission product barriers are adequately protected. For anticipated operational occurrences, a subset of the event limits are established to assure the fuel cladding integrity and reactor coolant pressure boundary limits are not exceeded. These event limits are the same as the Technical Specification safety limits. The specific event limits for all safety analysis events are identified in chapter 15.

The difference between the fission product barrier integrity and the event limits can be characterized as safety margin. Safety margin is generally selected to provide a high level of confidence that the overall safety analysis process has adequately treated all uncertainties.

The event analysis process conservatively predicts the plant dynamic results associated with each safety analysis event. Conservatism is introduced in the specific event analyses through the consideration of the model input uncertainties and safety analysis methodology uncertainties in the event analysis. The model inputs establish the values for the required inputs to the safety analysis methodology except for the operating envelope limits and the analytical limits. There are two general approaches to treating the methodology and model input uncertainties. In the first approach, the model inputs are selected to be adequately conservative to assure that the overall event analysis results are conservative. In the second

approach, the nominal model inputs are used and a set of conservative adjustments factors are applied to the results before being compared to the event limits. In either case, the safety analysis introduces a substantial amount of conservatism into the combined safety analysis and setpoint processes.

Operating envelope limits are the values of the normal operating parameters used by the plant operators to constrain plant operation. They are used to establish the initial operating conditions for the plant safety analysis. In the safety analysis process, the limiting conditions or a conservative representation of the limiting conditions on the allowable operating envelope are used in the safety analysis. Uncertainties in the normal operating parameters are accounted for in the representation of the operating envelope, in establishing the event limits, or in establishing the adjustment factors applied to the analysis results. As a result, there is no specific treatment of uncertainties related to the operating envelope limits, except as a part of the instrument setpoint process to assure that there is an acceptably low probability of an unnecessary instrument trip due to instrument uncertainties.

The safety analysis is performed using assumed values for instrument trips. The specific value input to the safety analysis is the analytical limit. The analytical limit does not include specific measurement uncertainties. Treatment of uncertainties in the instrument trips is through the instrument setpoint process. The instrument setpoint process treats the applicable measurement uncertainties to establish an acceptable set of instrument setpoints. In this process, the instrument accuracy under trip conditions is combined with the calibration uncertainties to establish the AV for the instrument. It is the AV that is incorporated into the Technical Specifications. The overall measurement uncertainty (including uncertainties due to instrument drift) is used to establish the instrument setpoint. In addition, the overall measurement uncertainty is used to demonstrate there is an acceptable probability of spurious trip avoidance. The approved HNP setpoint methodology is consistent with Regulatory Guide 1.105 [(1)] and with the NRC approved General Electric methodology.[(2)] The HNP setpoint methodology provides at least a 95% probability that the analytical limit will not be exceeded and assures that the results produced are established with high confidence.

The safety analysis is performed to simulate the dynamic response of the plant to predefined postulated events. As shown on figure 15C-55, there is generally margin between the safety analysis dynamic response to an event and the event limit. This analytical margin is considered to be excess margin in the safety analysis process and, if desired, can be used to relax instrument setpoints.

15C.5.4 SETPOINT CLASSIFICATION

Setpoint classification provides a means to evaluate and document setpoints in accordance with their importance to safety. This is done to establish an appropriate level of documentation and analysis or evaluation for each setpoint through a graded approach.

Setpoint classification is accomplished by developing a hierarchy of setpoints and applying appropriate standards in the development of the specific values associated with the instrumentation performance. The specific instrument hierarchy used is based on the importance to safety associated with the documentation that controls the use of the setpoint.

This approach results in setpoints being separated into categories determined by the importance to safety of the controlling documentation. By applying this approach, an appropriate level of rigor is applied to each setpoint classification consistent with the requirements associated with the safety analysis. This approach results in the most rigor being applied to those setpoints having the highest safety significance, while less important setpoints have a correspondingly less amount of rigor. This allows the available resources to be applied in the most effective manner. The setpoint classification and evaluation are based on the methodology provided in reference 5.

Figure 15C-56 shows the hierarchy of setpoints used at HNP. There are eight sets of controlled setpoints that are considered in the establishing the rigor required in the development and control of the setpoint. These sets, in terms of decreasing importance, are:

- Technical Specification Limiting Safety System Settings.
- Technical Specification Limiting Conditions and Surveillance Requirements for automatic trips assumed in the safety analysis.
- Emergency operating procedure (EOP) setpoints identified in the Technical Specification and assumed in the safety analysis.
- TRM trip setpoints assumed in the safety analysis.
- Safety analysis input parameters not associated with automatic trips but identified in Technical Specification Surveillance Requirements or TRM.
- Technical Specification Limiting Conditions for Operation and Surveillance Requirements for automatic trips not credited in safety analysis.
- EOP setpoints identified in the Technical Specifications or TRM and not credited in the safety analysis.
- TRM automatic trip setpoints not credited in the safety analysis.

15C.5.4.1 <u>Technical Specifications</u>

The Regulations (10 CFR 50.36) require that each applicant for a license include in the Final Safety Analysis Report proposed Technical Specifications. These Technical Specifications are based on the safety analysis and are intended to assure that the plant operates in an analyzed condition. Technical Specifications developed on this basis are intended only to preserve the integrity of the safety analysis, as maintained in the Updated Final Safety Analysis Report. For measured parameters implemented in the Technical Specifications, the integrated NSOA, safety analysis, and instrument setpoint processes need to be considered in the treatment of measurement uncertainties to establish appropriately conservative values.

In issuing an operating license, the NRC may include additional Technical Specifications, as it finds appropriate. These additional Technical Specifications cover other parameters and functional requirements, as described in the FSAR that are not associated with the safety analysis. For parameters not directly associated with the safety analysis, the overall design process needs to be considered as it relates to margins to accommodate measurement uncertainties. For these instrument setpoints, less rigor is required.

Technical Specifications that specifically relate to measurement uncertainties include:

- Safety Limits.
- Limiting Safety System Settings.
- Limiting Conditions for Operation.
- Surveillance Requirements.

Further, Technical Specification Limiting Conditions for Operation are to be established for each functional capability or performance level for equipment required for safe plant operation meeting one or more of the following criteria:

A. Installed instrumentation that is used to detect and indicate in the control room a significant abnormal degradation of the RCPB.

B. A process variable, design feature, or operating restriction that is an initial condition of a DBA or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

C. A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a DBA or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

D. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

15C.5.4.2 Safety Limits and Limiting Safety System Settings

In the safety analysis process, the highest level of importance is assigned to protection of the safety limits through the assumption of automatic trips occurring at the controlled values for the limiting safety system settings.

Safety limits are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity.

The HNP Technical Specifications identify four safety limits:

- The limit on reactor power at low pressure or flow conditions.

- The minimum critical power ratio safety limit.

- The RPV water level safety limit.

- The reactor pressure safety limit.

Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded.

It should be noted that, with the conversion to Improved Standard Technical Specifications, the specific identification of limiting safety system settings was eliminated for HNP. However, because of their importance in protecting the barriers to fission product release, a process for identifying limiting safety system settings has been developed based on the identified safety limits.

Based on the HNP safety limits, the set of limiting safety system settings that provide protection of the safety limits are identified. This is done by employing a consistent set of requirements based on the current safety analysis, and considering setpoint parameters in the Technical Specifications. These requirements are:

A. Limiting safety system settings are those parameters that prevent a safety limit from being exceeded. A confirmation is that if the trip did not occur, then the possibility of exceeding a safety limit exists under any allowed plant normal or anticipated operational conditions. Limiting safety system settings that have an equivalent function may be selected.

B. The Technical Specification safety limits are applicable only to steady state operation, normal operational transients, and anticipated operational occurrences. Accidents and events that are beyond the plant design basis are excluded, because the event limits for these events allow safety limits to be exceeded.

C. The single failure criterion applies, to the extent assumed in the specific event analysis.

The process to establish a set of limiting safety system settings involves a review of the anticipated operational occurrences that are considered in safety analyses. Each anticipated operational occurrence is evaluated until the challenge to the safety limits is mitigated. The specific Technical Specification instrument setpoints that are necessary for initiating automatic system action to prevent the safety limits from being exceeded were identified.

The results of applying this process are documented in table 15C-11.

15C.5.4.3 Limiting Conditions for Operation and Surveillance Requirements

The second highest level of importance is assigned to Limiting Conditions for Operations and Surveillance Requirements that are assumed in the safety analysis process.

Limiting Conditions for Operations are the lowest functional capability or performance levels of equipment required for safe plant operation. Limiting Conditions for Operation must be established using the criteria identified in paragraph 15.5.4.2.

Surveillance Requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that plant operation will be within safety limits, and that the Limiting Conditions for Operation will be met.

The Limiting Conditions for Operations and Surveillance Requirements assumed in the safety analysis are identified by evaluating each automatic trip necessary to satisfy any required action for any event in the NSOA as shown on the event diagrams and have a quantified value in the Technical Specifications.

For Limiting Conditions for Operations and Surveillance Requirements not credited in the safety analysis, these setpoints are given the highest level of importance of the parameters not associated with the safety analysis. These Limiting Conditions for Operations and Surveillance Requirements are the remaining automatic trips that have a quantified value in the Technical Specifications.

15C.5.4.4 Emergency Operating Procedures

Third highest level of importance is assigned to EOPs that are controlled by the Technical Specifications and assumed in the safety analysis process to assure that all event limits are satisfied for anticipated operational occurrences and accidents.

In the analysis of many anticipated operational occurrences and accidents, there are specific planned operator actions that are required for which no automatic control is provided. These planned manually controlled actions are identified based on an evaluation of the anticipated operational occurrences and accidents in the NSOA and documented on the event diagrams and are considered credited in the safety analysis. The required planned manually controlled actions are associated with long-term core cooling (following the initial automatic system initiation) and long-term decay heat removal.

Based on the NSOA, there are five EOP setpoints that are assumed in primary success paths associated with the analysis of anticipated operational occurrences or accidents. These are:

- Reactor water level.
- Reactor pressure.
- Suppression pool temperature.

- Suppression pool water level.

- Drywell pressure.

The EOP setpoints associated with the safety analysis are limited to these five setpoints.

The EOPs are symptom-based procedures, thus their associated actions cover anticipated operational occurrences and accidents (credited in the safety analysis), as well as plant conditions considered beyond the plant design basis (not credited in the safety analysis). The EOP setpoints not credited in the safety analysis are considered contingency actions and are given the second highest level of importance of the parameters not associated with the safety analysis. With the exception of the five setpoints specifically identified, the remaining EOP setpoints controlled by the Technical Specification or TRM are in this classification.

15C.5.4.5 Technical Requirements Manual

The fourth level of importance is assigned to the automatic trip setpoints in the TRM that are assumed in the safety analysis process.

The TRM contains specifications and operational conveniences. The TRM specifications include operational requirements, surveillances, and required actions for inoperable equipment. From a safety analysis perspective, the TRM is considered a lower tier document when compared to the Technical Specifications or EOPs.

The TRM specifications assumed in the safety analysis are identified by evaluating each automatic trip necessary to satisfy a required action for any event in the NSOA and documented on the event diagrams and have a quantified value in the TRM specifications.

For TRM specifications not associated with the safety analysis, these parameters are given the lowest level of importance of the parameters not credited in the safety analysis. These TRM specifications are the remaining automatic trips that have a quantified value.

15C.5.4.6 Safety Analysis Inputs

The lowest level of importance is assigned to safety analysis inputs that are surveillances quantified in the Technical Specifications or TRM.

The safety analysis contains a number of inputs that define system performance parameters but are not associated with automatic trips or operator actions. These parameters because of their relationship to the safety analysis are treated in the same manner as setpoints, even though they are functionally different. Because of their potential safety significance, they are considered sufficiently important to assure that their uncertainties are appropriately considered in the determination of their surveillance values.

The safety analysis inputs in the Technical Specifications or TRM are identified by evaluating each surveillance with a quantified value to determine if it is used as a safety analysis input.

15C.5.5 SETPOINT IDENTIFICATION PROCESS AND BASES

The process used to establish the specific methodology required to be used to quantify specific setpoint value for the Technical Specification or TRM setpoints is based on the hierarchy of setpoints described in subsection 15C.5.4. The methodology used to determine the controlled values can be a formal calculation, analysis input assumptions, vendor document, engineering judgment, or other documentation as appropriate. The basis can also be simply the documentation of engineering judgment. The minimum required setpoint quantification methodology for each type of setpoint identified in subsection 15C.5.4 is shown on figure 15C-57.

15C.5.5.1 Limiting Safety System Settings

Limiting safety system settings are considered of primary importance and require the most conservative treatment of uncertainties. As a result, all of these instrument setpoints require a controlled setpoint calculation using methodology that satisfies the intent of Regulatory Guide 1.105. The specific analysis process for treating measurement uncertainties is described in subsection 15C.3.3. Further, consideration of the specific reset requirements is to be consistent with the intent of the Technical Specifications.

15C.5.5.2 Technical Specification Automatic Trips Assumed in Safety Analysis

Technical Specifications for automatic trips assumed in the safety analysis are also considered of primary importance and require the conservative treatment of uncertainties. As a result, all of these instrument setpoints require a controlled setpoint calculation using methodology that satisfies the intent of NRC Regulatory Guide 1.105. The specific analysis process for treating measurement uncertainties is described in subsection 15.5.6.

15C.5.5.3 EOP Setpoints Assumed in Safety Analysis

The treatment of measurement uncertainties related to the BWR symptom-oriented EOP setpoints controlled by the Technical Specifications and assumed in the safety analysis must be consistent with the philosophy used to identify and quantify these setpoints. The specific setpoints that satisfy this requirement are those that are associated with instruments and measurements that are related solely to the monitoring of parameters which provide information for operator action in accordance with the EOPs.

The EOPs for BWRs are symptom oriented. In the symptom-oriented approach, the operator responds to the phenomena occurring during an event, not to specific events. In this approach, the operator performs the critical safety functions based on the symptoms of the event rather than actions based on the identification of the event. As a result, all equipment that may be available to respond to phenomena occurring is identified as options for satisfying the critical safety functions. This approach leads to the identification of equipment as options in the EOPs that exceed the minimal set required by the safety analysis. EOP action points are calculated

using the methodology defined in Appendix C to the Emergency Procedure Guidelines (EPGs).[4]

There are four critical safety functions necessary to respond to phenomena that may occur during an event for a BWR that may require operator action. These are:

- Reactivity control.
- Pressure control.
- Level control.
- Primary containment control.

Based on these critical safety functions, the applicable critical safety parameters that provide the primary information to the control room operators to assess the plant critical safety functions can be identified.

There are fundamental differences between the parameters used for symptomatic control consistent with the EOPs and parameters required to be addressed using controlled setpoint methodology consistent with Regulatory Guide 1.105. Parameters using setpoint methodology are generally associated with Limiting Conditions for Operations that are used to support automatic plant safety functions. The AVs associated with these Limiting Conditions for Operations are intended to provide protection of safety limits or other event limits used in the safety analysis process. EOPs are derived using nominal analysis models and do not ensure strict conformance with event limits, Technical Specifications, or Technical Specification Bases. This position is stated in the introduction to Emergency Procedure Guidelines, Revision 4 and in Emergency Procedure Guidelines (EPG)/Severe Accident Guidelines (SAG), Revision 1.[3][4] Specifying nominal action level values in the EOPs without addressing the measurement uncertainty is consistent with the nominal analysis models used to develop the EOPs.

The BWROG Emergency Procedures Committee has previously considered the affect of measurement uncertainties on EPG action levels. The committee has determined that in the unlikely event that instrument redundancy and diversity were unavailable and the value of a parameter was not satisfactorily inferred from equipment operation, adjustment of the EOP limit or action level to compensate for instrument setpoint bias would not be a viable consideration. The application of the Regulatory Guide 1.105 methodology introduces setpoint biases that are inconsistent with the established EOP limits. Virtually every key BWR EOP limit and action level can be shown to produce an undesirable consequence when an instrument setpoint bias is applied in one direction or the other. To satisfy the broad spectrum of events addressed by the symptom-based EOPs, an optimized response for one event cannot be accepted at the expense of an unsatisfactory response in other events. Even if a bounding bias could be defined for all mechanistically possible events, application of an instrument setpoint calculation methodology to BWR EOP limits and action levels unnecessarily removes operating margin that could be beneficial if the event that is occurring is not the one assumed in developing the instrument setpoint bias.

Based on these considerations, nominal values are used for EOP setpoints assumed in the safety analysis.

15C.5.5.4 Technical Requirement Manual Automatic Trips Assumed in Safety Analysis

Consistent with the development of TRM specifications, TRM automatic trips assumed in the safety analysis are not considered of primary safety importance. As a result, engineering judgment can be used in the development and maintenance of these setpoints. If desired, a formal calculation or implementation of a vendor recommendation can be used.

15C.5.5.5 Safety Analysis Inputs

The treatment of measurement uncertainties related to safety analysis inputs in the Technical Specifications or TRM that are not associated with automatic trips or operator actions must be consistent with the philosophy used to identify and quantify these analytical limits. The specific surveillance requirements that are associated with these safety analysis inputs were established based on engineering judgment that has sufficient conservatism to account for measurement uncertainties. Thus, the specific parameter values that are established as surveillance requirements are also based on the same engineering judgment, which is supported by the cumulative plant operating experience of a large number of plants operating for many years.

For example, many of these surveillance requirements are based on the application of industry standards to, or the use of special test instrumentation for, the specific surveillance test (e.g., American Society of Mechanical Engineers (ASME), American National Standards Institute (ANSI), and Institute of Electrical and Electronics Engineers (IEEE) that are implemented by programs such as Inservice Testing, Ventilation Filter Testing, Diesel Fuel Oil Testing, and Chemical Laboratory Analysis). These tests require the use of equipment that has reasonably small measurement uncertainties that is consistent with the objectives of the tests being performed. These tests demonstrate that there has been no significant degradation of system capability.

Further, the testing is performed on equipment that is conservatively treated in the safety analysis process or there is substantial margin to the event limits. Therefore, as long as there is no significant degradation of equipment performance as measured by the installed instrumentation and the required reference values are correctly established, no further consideration of measurement uncertainties in the test equipment is required.

Therefore, no additional consideration of measurement uncertainties other than that associated with the engineering judgment used to establish the values used as input to the safety analysis process is required.

15C.5.5.6 Technical Specification Automatic Trips Not Credited in Safety Analysis

Technical Specifications for automatic trips not credited in the safety analysis are not considered of primary safety importance. As a result, engineering judgment can be used in the development and maintenance of these setpoints. If desired, a formal calculation or implementation of a vendor recommendation can be used.

15C.5.5.7 EOP Setpoints for Contingency Actions

EOP setpoints for contingency actions are not considered of primary safety significance. However, consistent with the philosophy of the development of symptom-oriented EOPs, nominal setpoints should be used.

15C.5.5.8 Technical Requirement Manual Automatic Trips Not Credited in Safety Analysis

TRM automatic trips not credited in the safety analysis are considered to have little or no safety importance. As a result, engineering judgment can be used in the development and maintenance of these setpoints. If desired, a formal calculation or implementation of a vendor recommendation can be used.

15C.5.6 SETPOINT CALCULATION PROCESS

Formal calculations to develop an acceptable set of instrument setpoints, considering the sources of instrument uncertainties, are required for selected setpoints. The methodology described in this subsection or a conservative approximation is applied in the development of instrument setpoints for all limiting safety system settings and of Technical Specification setpoints assumed in the safety analysis. This calculation process may be used to conservatively establish other instrument setpoints not assumed in the safety analysis. The methodology described in this subsection is consistent with Regulatory Guide 1.105. It should be noted that setpoint calculations are not required for mechanical devices such as safety/relief valves or valve position switches.

To assure that the safety analyses remain valid, the instrument setpoints are established with sufficient margin to the analytical limit to conservatively account for measurement uncertainties. The setpoint methodology, consistent with reference 2, is used to conservatively treat instrument uncertainties such that there is at least a 95% probability that the analytical limit used in the safety analysis process will not be exceeded due to measurement uncertainties. When combined with the conservatism inherent in the safety analysis process, there is a very high probability with high confidence that the results predicted by the safety analysis will not be exceeded.

It should be noted that the current regulatory guidance states that a 95% probability limit for errors such that for the observed distribution of values (empirical data) for a particular error component, 95% of the data point will be bounded by the value selected. The methodology

described in this subsection does not provide setpoints with a defined confidence level. The NRC has previously accepted that results produced by a setpoint methodology are acceptable if it can be established that they are determined with a high confidence level. [2]

15C.5.6.1 Calculation Process Overview

The overall setpoint calculation process for decreasing setpoints is depicted on figure 15C-58. This process includes the calculational requirements necessary to demonstrate compliance with licensing commitments and provide additional margin where desirable for other practical considerations.

The setpoint calculation process starts with the quantification of the analytical limit based on the assumptions in the safety analysis. The analytical limit is the process parameter value used in the safety analysis and represents a limiting value for the automatic initiation of protective actions. In the safety analysis, the analytical limit does not generally include an allowance for measurement uncertainties. The setpoint calculation methodology provides a sufficient margin between the analytical limit and setpoint to assure with at least a 95% probability that the analytical limit will not be exceeded due to measurement uncertainties. The setpoint margin is determined from statistical principles and assumes that various random instrument errors can be added by taking the square root of the sum of the squares (SRSS), while bias errors are added algebraically. The errors are determined for the ambient environmental conditions occurring at the time the protective trip action occurs.

Consistent with the setpoint methodology; there are two required setpoint margins. These are also the margins identified in Regulatory Guide 1.105. The first setpoint margin is between the analytical limit and the AV. This margin is dependent on the process measurement uncertainties, the inherent instrument accuracies, and the calibration errors, but does not include error due to instrument drift. The analytical limit to AV margin corresponds to the required margin just after the instrument has been calibrated, and has no allowance for additional measurement errors that may occur due to time between calibrations. The second setpoint margin is that between the analytical limit and the minimum NTSP. This margin includes all the errors used to determine the margin between the analytical limit and AV and includes an additional margin for instrument drift. The analytical limit to AV and analytical limit to minimum NTSP margin represent the minimum margins required by the instrument setpoint methodology to meet the minimum probability demonstration margin.

The AV represents the value at which the setpoint could be found during calibration and is the setpoint value that is used in the Technical Specifications, whereas minimum NTSP for decreasing setpoints and maximum NTSP for increasing setpoints corresponds to the minimum instrument setting value required to assure that there is a minimum of a 95% probability that the analytical limit will not be exceeded.

The following process steps may be included in a formal setpoint calculation to assure there is adequate margin for other practical reasons not associated with safety analysis considerations. These considerations include:

- Avoidance of Licensing Event Reports (LERs).

- Frequency of recalibration.
- Spurious trip avoidance (STA).

The actual NTSP may be more conservative than minimum (maximum) NTSP because setpoint methodology also is generally applied to assure an acceptable margin between the AV and the NTSP that there is generally at least a 90% probability that during calibration the setpoint does not exceed the AV to avoid a potential LER. To make this LER probability calculation, the setpoint methodology takes into account whether multiple or single instrument channels are used for taking the protective action. Also, since an instrument loop could contain several devices, the methodology adjusts the NTSP to assure that with the device leave alone tolerances (LAT), LER conditions are avoided for each device in the loop.

The selected NTSP (minimum or maximum NTSP or actual NTSP) represents the “limiting” value of the setpoint with no tolerance. This means that if, during calibration, the setpoint was observed to be beyond this value, the loop would need to be recalibrated for the next cycle. To avoid this condition, potential instrument setpoints require an LAT within which instrument recalibration is not required. To accommodate this, the NTSP may need to be adjusted to provide margin for the LAT.

An STA test may be performed for an instrument setpoint where there is a significant practical consequence to spurious trips, such as inadvertent scram or inadvertent device actuation. It is generally not performed for setpoints that are associated with rod blocks or system permissives. In some cases, the STA test includes analyses of anticipated operational transients to establish setpoints that reduce the probability of a scram or safety system actuation. The STA test is generally performed to assure that there is a greater than 95% probability of avoiding a spurious trip when the setpoint is at its limiting NTSP value towards operating envelope limit due to device LATs. This test recognizes that, due to loop LAT, the actual setpoint may be closer to operating envelope limit, and conservatively assures that the margin between this adjusted NTSP and operating envelope limit is sufficient to make the probability of spurious trips acceptably low. If the STA test result is not satisfactory, then further setpoint adjustments, based on a compromise between LER and STA requirements, need to be performed.

15C.5.6.2 Instrument Setpoint Calculation

The setpoint calculation method requires a calculation of the accuracy or uncertainty of the measurement for each device in the measurement channel including the trip unit, which gives the final trip signal. This includes, as applicable:

- Instrument accuracy.
- Calibration uncertainty.
- Drift uncertainty.
- Process measurement accuracy.

- Primary element accuracy.

For the instrument setpoint calculation, it is required that the entire instrument or measurement channel accuracy, including accuracy, drift, and calibration errors be evaluated. Measurement uncertainties are obtained by SRSS addition of the random device accuracy, drift, and calibration errors. Bias errors, if present, are added algebraically. There is one channel drift value (D), one channel calibration error (C), and potentially three different instrument channel accuracy (A) values of interest in the setpoint calculation.

The three different A values are:

- The instrument channel accuracy consistent with trip environment conditions (A_T) during the postulated safety analysis event. A_T is required for the AV and the minimum NTSP calculation.

- The instrument channel accuracy for the calibration conditions (A_C). A_C is required for the LER avoidance calculation.

- The instrument channel accuracy for normal operating conditions (A_N). A_N is required for the STA calculation.

Process measurement accuracy (PMA) errors are errors which are present regardless of how accurate the channel measurement devices are.

Process element accuracy (PEA) errors are errors in the primary element, which is in contact with the process, and are also present regardless of how accurate the channel devices are. Primary elements are generally not calibrated by themselves after installation.

15C.5.6.2.1 Required Calculations

Consistent with the combined safety analysis and setpoint methodology, there are two required setpoint margins that are calculated to establish the required instrument setpoints (AV and NTSP). These required instrument setpoints are necessary to assure the validity of the safety analysis. These margins are the AV and the minimum NTSP margins. The minimum margins are obtained by combining the relevant channel random errors using SRSS, and adding the bias errors, as follows:

- AV Margin = $(1.645/2) \times (A_T^2 + C^2 + PMA^2 + PEA^2)^{1/2}$ + Bias errors.
- Minimum NTSP Margin = $(1.645/2) \times (A_T^2 + C^2 + D^2 + PMA^2 + PEA^2)^{1/2}$ + Bias errors.

All random error values represent 2σ values, and the 1.645/2 factor is a statistical factor that converts a 2σ value to 1.645σ. Because setpoints are approached from one side (low to high for an increasing setpoint and high to low for a decreasing setpoint), 1.645σ corresponds to 95% probability for one-sided approaches for normal distributions.

The AV is obtained by subtracting (or adding) the AV margin from the analytical limit, depending on whether the variable increases (or decreases) to the setpoint.

The minimum NTSP setpoint is obtained by subtracting (or adding) the NTSP margin from the analytical limit, depending on whether the variable increases (or decreases) to the setpoint.

In developing the AV and minimum (or maximum) NTSP, it is acceptable to use conservative values for measurement uncertainties, if sufficient margin exists, to minimize the potential for Technical Specification changes. Also, it is acceptable to combine uncertainties in a manner that yields a higher probability than a single sided 95% of not being exceeded.

15C.5.6.2.2 Supplemental Calculations

Supplemental calculations may be performed to avoid licensing or operational problems associated with instrument setpoints having insufficient margin for other purposes. These calculations are not required; however, they may be performed to optimize setpoints for selected instrument trips. These supplemental calculations are for:

- LER avoidance.
- Recalibration frequency reduction.
- Spurious trip avoidance.

15C.5.6.2.2.1 **<u>LER Avoidance</u>**. To determine if there is sufficient margin between the minimum NTSP and AV to avoid the necessity of filing LERs as a consequence of surveillance testing, an LER test is performed to determine if the chance of the NTSP exceeding AV is < 10%. This test conservatively assumes that, if the measured setpoint for one of the channels is found to be beyond AV during calibration, the actual setpoint may have exceeded AV during operation prior to calibration. If the LER condition is satisfied for the given values of minimum NTSP and AV, then the probability of an LER is acceptably low, and the NTSP is kept at minimum NTSP; otherwise, a new, actual NTSP is determined with increased margin to satisfy the LER condition.

The errors during surveillance testing, which cause an instrument setpoint measured in one calibration to be different to that measured in the next calibration, come from three different sources. These are random errors and include accuracy under calibration conditions (A_C), loop calibration errors (C), and loop drift errors (D).

15C.5.6.2.2.2 **<u>Recalibration Frequency Reduction</u>**. The LER avoidance calculation provides the minimum margin between the controlling NTSP and AV required to meet LER avoidance criteria, assuming that the setpoint was at NTSP at the start of the cycle. Use of the minimum margin can lead to an increase in recalibration frequency. The frequency of recalibration can be reduced by providing a LAT adjustment. This LAT adjustment is performed to assure that:

- There is no device in the channel where the LAT (in the conservative direction) added to the NTSP exceeds the AV.

- The stack up or all the channel device LATs (in the conservative direction) added to the NTSP does not put the setpoint so close to the AV that the LER avoidance criterion is violated on a statistical basis.

If the controlling NTSP has sufficient margin to meet these requirements for the LAT, no adjustment to the controlling NTSP is required. However, in some cases, an additional margin for LAT may be desired. If the controlling NTSP does not have sufficient margin, the new NTSP is established as the adjusted NTSP.

15C.5.6.2.2.3 **Spurious Trip Avoidance**. The STA test is performed to assure that the margin between the setpoint and the operating envelope limit or other limit selected is large enough to make the probability of spurious trips acceptably low. The operating envelope limit is the value that the parameter may have during normal operation from which margin to the setpoint is required to prevent undesirable actuations due to random instrument and process errors. STA evaluations are typically not performed for those setpoints (rod blocks or permissives) that do not result in actuations that cause operational problems, or those for which there is no realistic normal operational condition that could approach the vicinity of the setpoint.

The STA evaluation is done by first determining the limit of the setpoint close to operating envelope limit (based on the device LATs) and then determining the margin of this to the operating envelope limit in terms of the errors that may be present during normal operation. If the STA criterion is not met, then some further setpoint adjustments may be required. The setpoint limit, for purposes of performing the spurious trip avoidance evaluation, is obtained by subtracting (for increasing setpoint) or adding (for decreasing setpoint) from the adjusted NTSP the SRSS addition of the LATs for all devices in the loop.

15C.5.6.3 Simplified Setpoint Methodology

15C.5.6.3.1 Methodology Description and Limitations

HNP has implemented the General Electric developed simplified setpoint methodology for modifying setpoints for power uprates based on a constant maximum normal operating pressure assumption. The constant maximum normal operating pressure requirement minimizes the potential effect on instruments by maintaining the same fluid properties at the instruments. This process is based in part on the substantial margin in the safety analysis process that can be considered in establishing the Technical Specification AVs and NTSPs. This process is documented in the NRC approved constant pressure power uprate (CPPU) licensing topical report.

The basis for the use of this process is that if the changes in instrument uncertainties are sufficiently small a simplified process can be used to determine the instrument AV and NTSP for most instruments. This conclusion is justified on the basis of the substantial amount of

conservatism in the safety analysis process. This simplified process is based on extensive power uprate experience, has only a small overall effect on setpoints, and allows the current license basis to be maintained through the application of the same uncertainties in the same manner as previous setpoint evaluation.

This process is limited to those instrument setpoints that are affected by increases in the core thermal power and steam flow. The setpoints that can be modified using this process are:

- Main steam line high flow isolation.
- Turbine first stage pressure scram bypass.
- Average power range monitor (APRM) flow biased scram.
- Rod worth minimizer.
- APRM setdown in STARTUP mode.

In the simplified process, these setpoints are adjusted to maintain comparable differences between system settings and actual limits, and reviewed to ensure that adequate operational flexibility and necessary safety functions are maintained at the uprated power level. The simplified process is shown on figure 15C-59.

The simplified process involves establishing the change in analytical limit (ΔAL) between the new safety analysis performed to support the power uprate and the original safety analysis. This ΔAL is then applied to the original AV and NTSP to establish the new setpoints for power uprate. This process retains the original measurement uncertainties in establishing the new setpoints. Because of the relatively small changes in setpoints, changes to the measurement uncertainties are considered to be second order effects.

An inherent part of the simplified methodology is the recognition that the Technical Specification AVs are highly dependent on the results of the safety analysis. The safety analysis generally establishes the analytical limits, and there is typically substantial margin in the safety analysis process that can be considered in establishing the setpoint process used to establish the Technical Specification AVs and other setpoints. Further, to assure the applicability of the simplified setpoint process, it is specifically limited in application to setpoint calculations that:

A. Use NRC approved GE or plant-specific instrument setpoint methodology. (HNP uses approved methodology.)

B. Do not involve a change in instrumentation (measurement system).

C. Are not effected by changes to the high-pressure turbine, if the high-pressure turbine is modified.

Using the simplified methodology, the plant design basis is maintained. The original setpoint calculation is required to establish the treatment of uncertainties used to define the margin required to establish the AV and NTSP from the original analytical limit. This margin is then used in the simplified process to establish the required changes to the AV and NTSP.

15C.5.6.3.2 Current Applications

The simplified methodology was used in HNP thermal power optimization (TPO) license amendment.

15C.5.6.3.3 Criteria for Future Applications

The simplified setpoint methodology is relatively easy to apply and maintains the continuity of the original setpoint design basis. As a result, it is anticipated that additional applications will be identified. The following criteria have been developed to control future applications of the simplified setpoint methodology.

To utilize the simplified setpoint methodology on a new application, the setpoint change must:

A. Involve a change to the safety analysis that results in a change to an analytical limit or design limit that is used as the basis for a Regulatory Guide 1.105 setpoint calculation that is included in the Technical Specifications.

B. Be based on a setpoint calculation that uses HNP instrument setpoint methodology.

C. Be demonstrated to have a nonconservatism of < 1% of the Technical Specification parameter.

D. Not involve a significant change in instrumentation (measurement system).

E. Not involve a plant modification that would significantly change the instrument loop performance characteristics.

The last two criteria are subject to the overall < 1% nonconservatism demonstration requirement.

Changes that satisfy these criteria are considered to be consistent with the NRC approval of the CPPU methodology and approval of other specific applications.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

***"GESTAR II - General Electric Standard Application for Reactor Fuel,"* *NEDE-24011-P-A*.**

Unit 1 and Unit 2 Core Operating Limits Reports (located in each unit's Technical Requirements Manual, Appendix A).

REFERENCES

1. Regulatory Guide 1.105, Revision 1, "Instrument Setpoints," November 1976.

2. NEDC-31336-P-A, "General Electric Instrument Setpoint Methodology," September 1996.

3. NEDO-31331, "BWR Owners' Group, Emergency Procedures Guidelines, Revision 4," March 1987.

4. BWR Owners' Group, "Emergency Procedure and Severe Accident Guidelines," Revision 1, July 1997.

5. NEDC-32973P, "Safety Analysis Evaluations Relative to Measurement Uncertainties for the BWR/4 Improved Standard Technical Specifications," February 2001.

6. A-46487, "Hatch Nuclear Plant Units 1 and 2 Setpoint Control Program."

TABLE 15C-1

OPERATIONAL CRITERIA

	Applicability	Criteria
1.	Planned operation	The plant shall be operated observing operating state monitoring requirements identified to preserve safety analysis assumptions and establish initial conditions for event analyses. Normal plant operating procedures are followed as applicable.
2.	AOOs, accidents, and special events	All required actions to bring the plant to a stable condition consistent with the plant licensing basis shall be satisfied.
3.	AOOs, accidents, and special events	EOPs and AOPs are followed when applicable.
4.	AOOs	The plant shall be designed and operated such that no single failure in mitigation systems can prevent required actions from being satisfied.[a]
5.	Accidents	The plant shall be designed and operated to satisfy required actions, considering limiting single failure as defined by applicable regulatory requirements and licensing commitments.[a]
6.	AOOs and accidents	Single-failure criterion is not applicable during periods of system or component testing required by Technical Specifications (TS) or when operating under limiting conditions for operation required by Technical Specifications.[a]
7.	Special events	The plant shall be designed and operated consistent with applicable regulatory requirements and licensing commitments.

a. Single-failure is described more completely in subsection 15.1.6.

TABLE 15C-2 (SHEET 1 OF 2)

BWR OPERATING STATES/OPERATING MODES

STATE A - RPV VENTED AND REACTOR SHUTDOWN[a]

Allowable Mode Switch Positions:
    SHUTDOWN
    REFUEL

Pressure Considerations:
    Atmospheric Pressure

Power Considerations:
    Decay Heat Only

STATE B - RPV VENTED AND REACTOR NOT SHUTDOWN[a][b]

Allowable Mode Switch Positions:
    SHUTDOWN
    REFUEL
    STARTUP

Pressure Considerations:
    Atmospheric Pressure

Power Considerations:
    Decay Heat Only

STATE C - REACTOR HEAD ON (RPV NOT VENTED) AND REACTOR SHUTDOWN[a]

Allowable Mode Switch Positions:
    SHUTDOWN
    REFUEL
    STARTUP

Pressure Considerations:
    Hot Shutdown ≥ Reactor Pressure ≥ Shutdown Cooling Permissive
    Shutdown Cooling Permissive ≥ Reactor Pressure ≥ Atmospheric

Power Considerations:
    Decay Heat Only

TABLE 15C-2 (SHEET 2 OF 2)

STATE D - REACTOR HEAD ON (RPV NOT VENTED)
AND
REACTOR NOT SHUTDOWN[a]

Allowable Mode Switch Positions:
- STARTUP
- RUN

Pressure Considerations:
- Normal Operation ≥ Reactor Pressure ≥ Shutdown Cooling Permissive
- Shutdown Cooling Permissive ≥ Reactor Pressure ≥ Atmospheric

Power Considerations:
- Licensed Power Level ≥ Reactor Power ≥ Scram Bypass on Turbine First-Stage Pressure
- Scram Bypass on Turbine First-Stage Pressure ≥ Reactor Power ≥ Recirculation Flow Runback
- Recirculation Flow Runback ≥ Reactor Power ≥ RWM Bypass
- RWM Bypass ≥ Reactor Power ≥ PRM Setdown
- APRM Setdown ≥ Reactor Power ≥ uncritical

a. Reactor shutdown is defined as subcritical by more than the worth of the highest-worth rod.
b. Plant procedures only allow operation in operating state B for a short period of time to achieve criticality and begin heatup following an outage. Per plant procedures, operating state B can only occur with the primary containment intact (i.e., RPV vented to the primary containment).

TABLE 15C-3 (SHEET 1 OF 2)

EVENTS ASSOCIATED WITH OPERATING STATES

Event Title	Operating State A	B	C	D
AOOs				
• LFWH				x
• Inadvertent start of the HPCI pump			x	x
• Shutdown cooling (RHR) malfunction - decreasing temperature	x	x	x	
• Loss of RHR shutdown cooling	x	x	x	x
• LRNBP				x
• LRBP				x
• TTNBP				x
• Loss of condenser vacuum			x	x
• TTBP				x
• Closure of all MSIVs			x	x
• Closure of one MSIV			x	x
• Pressure regulator failure - closed				x
• Trip of one recirculation pump			x	x
• Trip of two recirculation pumps			x	x
• Recirculation flow controller failure - decreasing flow				x
• Recirculation flow controller failure - increasing flow				x
• Startup of idle recirculation pump			x	x
• RWE	x	x	x	x
• Control rod removal error during refueling	x			
• Fuel assembly insertion error during refueling	x			
• FWCF				x
• Inadvertent opening of an SRV			x	x
• Pressure regulator failure - open			x	x
• Loss of auxiliary power	x	x	x	x
• LOFW				x
ACCIDENTS				
• CRDA	x	x	x	x
• LOCA			x	x
• MSLBA			x	x
• Fuel-handling accident	x	x	x	x
• Fuel assembly loading error	x	x	x	x
• Recirculation pump seizure			x	x
• Feedwater line break			x	x

TABLE 15C-3 (SHEET 2 OF 2)

Event Title	Operating State			
	A	B	C	D
SPECIAL EVENTS				
• Stability				x
• Overpressure protection				x
• Shutdown without control rod insertion (SLCS capability)		x		x
• MCR uninhabitability	x	x	x	x
• ATWS				x
• Generator load rejection with flux scram and no bypass or RPT				x
• Turbine trip with flux scram and no bypass or RPT				x
• Loss of one dc system	x	x	x	x
• Loss of instrument air	x	x	x	x
• Loss of service water system	x	x	x	x
• Fire	x	x	x	x
• Miscellaneous small releases outside containment	x	x	x	x
• Instrument line break			x	x
• Liquid radwaste tank failure	x	x	x	x
• Gaseous radwaste tank failure				x
• SBO	x	x	x	x

TABLE 15C-4

KEY BOUNDING PARAMETERS FOR PLANNED OPERATION

Parameter	Implementing Document
Maximum thermal power level	Operating license
Allowable power-to-flow map	Plant procedures
Minimum water level	Plant procedures/Technical Specifications
Maximum reactor steam dome pressure	Technical Specifications
Maximum feedwater temperature	Plant procedures/Technical Specifications
SAFDLs	***COLR***
Minimum shutdown margin	Technical Specifications
Core configuration	***GESTAR***
Allowable control rod withdrawal sequences	Technical Specifications
Water quality limits	Technical Requirements Manual
Coolant activity limits	Technical Specifications
Gaseous radwaste release limits	Offsite Dose Calculation Manual (ODCM)
Liquid radwaste release limits	ODCM
Solid radwaste release limits	ODCM/Process Control Program
RPV rate of temperature change limit	Technical Specifications
Maximum ΔT between recirculation loops limit	Technical Specifications
RPV pressure and temperature limits	Technical Specifications
RPV head boltup limits	Technical Specifications
RCS leakage limit	Technical Specifications
Shutdown cooling maximum pressure	Technical Specifications
Primary containment pressure limit	Technical Specifications
Primary containment temperature limit	Technical Specifications
Primary containment oxygen limit	Technical Specifications
Suppression pool temperature limit	Technical Specifications
Suppression pool volume limit	Technical Specifications
Spent fuel storage limits	Technical Specifications
New fuel storage limits	Technical Specifications
Fuel-handling restrictions	Technical Specifications
Control rod housing supports installed	FSAR section 4.5
Normal operating procedures followed	Plant procedures

TABLE 15C-5 (SHEET 1 OF 3)

REQUIRED ACTIONS

Event Category	Required Actions	Relationship to Event Acceptance Limits[a]
AOOs	Reactor shutdown (scram)	Satisfy TS limits for release of radioactive effluents, SAFDLs, and RPV safety limit.
	Pressure relief	Satisfy RPV safety limit.
	Core cooling	Satisfy TS limits for release of radioactive effluents, SAFDLs, and primary containment design limits.
	RPV isolation	Satisfy TS limits for release of radioactive effluents and SAFDLs.
	Rod movement block	Satisfy TS limits for release of radioactive effluents and SAFDLs.
ACCIDENTS	Reactor shutdown (scram)	Satisfy fuel and nuclear system design limits applicable to accidents.
	Pressure relief	Satisfy nuclear system design limits applicable to accidents.
	Core cooling	Satisfy fuel limits, including ECCS limits, applicable to accidents.
	RPV isolation	Satisfy guideline dose values for accidents and radiation exposure limits for plant personnel.
	Establish and maintain primary containment	Satisfy guideline dose values for accidents and radiation exposure limits for plant personnel.
	Establish and maintain secondary containment	Satisfy guideline dose values for accidents and radiation exposure limits for plant personnel.
	MCR habitability	Satisfy radiation exposure limits for plant personnel.
SPECIAL EVENTS		
• Stability	Reactor shutdown	Demonstrate conformance to SAFDLs.
• Overpressure protection	Reactor shutdown; pressure relief	Demonstrate conformance to ASME Code limits.

TABLE 15C-5 (SHEET 2 OF 3)

Event Category	Required Actions	Relationship to Event Acceptance Limits[a]
SPECIAL EVENTS (continued)		
• Shutdown without control rod insertion (SLCS capability)	Reactor shutdown; RPV isolation	Demonstrate ability to reach shutdown independent of control rods.
• MCR uninhabitability	Reactor shutdown; pressure relief; core cooling	Demonstrate ability to reach cold shutdown condition.
• ATWS	Reactor shutdown; pressure relief; core cooling; RPV isolation Establish and maintain primary containment	Demonstrate conformance to limits associated with requirements of 10 CFR 50.62.
• Generator load rejection with flux scram and no bypass or RPT	Reactor shutdown; pressure relief; core cooling	Demonstrate acceptable radiological consequences.
• Turbine trip with flux scram and no bypass or RPT	Reactor shutdown; pressure relief; core cooling	Demonstrate acceptable radiological consequences
• Loss of one dc system	Reactor shutdown; pressure relief	Demonstrate acceptable radiological consequences.
• Loss of instrument air	Reactor shutdown; pressure relief; core cooling; RPV isolation	Demonstrate acceptable radiological consequences.
• Loss of service water system	NA	Demonstrate acceptable radiological consequences.
• Fire	Reactor shutdown; pressure relief; core cooling; RPV isolation	Demonstrate conformance to limits associated with requirements of 10 CFR 50.48.

TABLE 15C-5 (SHEET 3 OF 3)

Event Category	Required Actions	Relationship to Event Acceptance Limits[a]
SPECIAL EVENTS (continued)		
• Miscellaneous small releases outside containment	NA	Demonstrate acceptable radiological consequences.
• Instrument line break	Establish and maintain secondary containment	Demonstrate acceptable radiological consequences.
• Liquid radwaste tank failure	NA	Demonstrate acceptable radiological consequences.
• Gaseous radwaste tank failure	Reactor shutdown; pressure relief; core cooling; RPV isolation	Demonstrate acceptable radiological consequences.
• SBO	Reactor shutdown; pressure relief; core cooling; RPV isolation	Demonstrate conformance to limits associated with requirements of 10 CFR 50.63.

a. A complete description of safety analysis event acceptance limits is provided in subsection 15.1.5.

TABLE 15C-6 (SHEET 1 OF 3)

EVENT ANALYSIS RULES

	Rule	Explanation
A.	<u>General Rules</u>	
A.1	Include all events that are part of the plant safety analysis.	All events considered in the plant safety analysis are included in the NSOA, consistent with NSOA goals and objectives.
A.2	Identify on event diagrams all required systems, automatic trips, and operator actions necessary to either satisfy operational criteria or perform required actions.	Systems, automatic trips, and operator actions are identified only if they are uniquely necessary to either accomplish required actions or satisfy operational criteria.
A.3	Identify all support or auxiliary systems on auxiliary system diagrams.	Auxiliary systems are systems required to enable front-line systems (systems identified on event diagrams) or other auxiliary systems to perform their required functions.
A.4	Consider all plant systems, including passive plant features required in the mitigation of events.	The functions of passive plant features (e.g., MSL flow restrictors and CRD housing supports) used to mitigate the consequences of events are identified.
A.5	Consider hardware restrictions included in the plant design to prevent operation outside the operating envelope.	Hardware restrictions (e.g., control rod withdrawal restrictions and refueling interlocks) are included in the plant design to constrain plant operation to within the allowable operating envelope.
B.	<u>Planned Operation Rules</u>	
B.1	Consider only systems, limits, and restrictions necessary to attain planned operation and satisfy operational criteria (as opposed to AOOs, accidents, and special events that are followed through to completion).	Consideration of planned operation is limited and not followed through to completion, because planned operation is constrained by normal plant operating procedures. During planned operation, the plant is operated within the allowable operating envelope for the specific operating mode.
B.2	Limit initial conditions for AOOs, accidents, and special events to operating modes and envelopes allowed during planned operation in the applicable operating state.	All events in the safety analysis are initiated from an operating mode within the allowable operating envelope.

TABLE 15C-6 (SHEET 2 OF 3)

B. Planned Operation Rules (continued)	Explanation
B.3 Consider the full range of initial conditions for each event analyzed.	This rule assures all event paths are identified. Different initial conditions can lead to different paths that may establish unique system requirements.
B.4 Apply hardware restrictions only to planned operation.	Restrictions are hardware-implemented constraints on normal plant operation to limit the consequences of postulated events.
B.5 Identify normal operating systems considered for a planned operation function during an event as “Planned Operation - Specific System Available.”	Normal operating systems are considered if the system is employed in the same manner during the event as it was prior to the event or if continued operation can significantly change the event path.
C. Event Diagram Rules	
C.1 Consider the entire duration of the event from the spectrum of possible initial conditions and aftermath until either some mode of planned operation is resumed or the plant is in a stable condition with continuity of core cooling.	Planned operation is considered "resumed" when normal operating procedures are being followed and plant operation is identical to that used in any operating state consistent with allowable operating modes and envelopes. A stable operating condition is defined as the completion of all required actions and the stabilization of plant parameters.
C.2 Identify systems, automatic trips, and operator actions if there is a unique requirement as a result of the event. If a normal operating system that was operating prior to the event will be employed in the same manner during the event and if the event did not affect system operation, the system does not appear as a unique requirement on the event diagram.	Systems, limits, and operator actions are identified as "required" only if a unique requirement to satisfy either required actions or operational criteria is established. When normal operating systems are considered, specific systems assumed to be available are identified.
C.3 Credit operator action only if the operator can reasonably be expected to accomplish the required action under existing conditions and has availability of necessary information to implement required plant procedures.	Operator action may be necessary to either attain planned operation or a stable condition.

TABLE 15C-6 (SHEET 3 OF 3)

C. Event Diagram Rules (continued)	Explanation
C.4 Identify two types of parameters: • Parameters that initiate an automatic trip or system actuation. • Monitored parameters (available to the operator) that require action.	Parameter are instrument setpoints at which either an automatic trip or system initiation or operator action is assumed to occur. Where either an automatic action or operator action accomplishes the same function, the automatic action is identified.
C.5 Consider a system that plays a unique role in response to an AOO, accident, or special event "required" unless system effects are not included in the event analysis.	Systems that have a unique role in an event are considered "required" unless the safety analysis for the event provides a basis that operation of the system is not required.
C.6 Identify operating states in which the event is applicable.	Because of plant operational considerations and the definition of operating states, not all events can occur in all operating states.
C.7 Identify the essential paths that include: • Required actions. • Front-line systems. • Automatic trips. • Monitored parameters. • Normal operating systems evaluated in analysis.	Event diagrams are the primary source of documentation of NSOA results. Notes identify required actions that are not applicable and required actions satisfied by the normal operating systems.
C.8 Identify passive plant features necessary at the system level.	Passive plant features are associated with system level requirements but are not included on the event diagrams, because they add unnecessary complexity.

TABLE 15C-7 (SHEET 1 OF 2)
NSOA SYSTEM/EVENT MATRIX

	ANTICIPATED OPERATIONAL OCCURENCES	Loss of Feedwater Heating	Inadvertent Start of HPCI Pump	Shutdown Cooling (RHR) Malfunction Decreasing Temperature	Loss of RHR Shutdown Cooling	Generator Load Rejection with No Bypass (LRNBP)	Generator Load Rejection with Bypass (LRBP)	Turbine Trip with No Bypass (TTNBP)	Loss of Condenser Vacuum	Turbine Trip with Bypass (TTBP)	Closure of All MSIVs (MSIVD)	Closure of One MSIV	Pressure Regulator Failure - Closed	Trip of One Recirculation Pump	Trip of Two Recirculation Pumps	Recirculation Flow Controller Failure - Decreasing Flow	Recirculation Flow Controller Failure - Increasing Flow	Startup of Idle Recirculation Pump	RWE During Power Operation	Control Rod Removal Error During Refueling	Fuel Assembly Insertion Error During Refueling	Feedwater Control Failure - Maximum Demand (FWCF)	Inadvertent Opening of an SRV	Pressure Regulator Failure - Open	Loss of Auxiliary Power	Loss of Feedwater Flow (LOFW)	ACCIDENTS	CRDA	LOCA	MSLBA	Fuel-Handling Accident	Fuel Assembly Loading Error	Recirculation Pump Seizure	Feedwater Line Break	SPECIAL EVENTS	Stability	Overpressure Protection	Shutdown Without Control Rod Insertion (SLCS Capability)	MCR Uninhabitability	ATWS	Generator Load Rejection with Flux Scram and No Bypass or RPT	Turbine Trip with Flux Scram and No Bypass or RPT	Loss of One dc System	Loss of Instrument Air	Loss of Service Water System	Fire	Miscellaneous Small Releases Outside Containment	Instrument Line Break	Liquid Radwaste Tank Failure	Gaseous Radwaste Tank Failure	SBO (including coping period)
System		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25		31	32	33	34	35	36	37		41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56
NMS		X	X	X	X	X	X	X	X	X	X	X			X		X	X	X			X		X	X			X					X			X	X				X	X	X	X						X	X
RPS		X	X	X	X	X	X	X	X	X	X	X			X		X	X	X			X	X	X	X	X		X	X	X			X	X		X	X		X		X	X	X	X		X				X	X
CRD System		X	X	X	X	X	X	X	X	X	X	X			X		X	X	X			X	X	X	X	X		X	X	X			X	X		X	X		X		X	X	X	X		X				X	X
SRVs			X		X	X	X	X	X	X	X				X							X		X	X			X	X	X			X	X			X		X	X	X	X	X	X		X				X	X
RCIC (Note 1)			X		X				X		X				X							X		X	X	X		X					X						X	X				X		X				X	X
HPCI			X		X				X		X				X							X		X	X	X		X	X	X			X	X						X				X		X				X	X
ADS			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X						X	X	X		X		X				X	X
Core Spray System			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X							X	X		X		X				X	X
RHR-LPCI Mode																													X	X				X																	
RHR-Supression Pool Cooling Mode			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X					X	X	X	X		X						X	X
RHR-Alternate Shutdown Cooling			X		X	X		X	X		X				X							X	X	X	X	X		X					X								X	X		X		X				X	X
EOC-RPT					X	X	X	X	X	X					X							X		X	X								X										X	X						X	X
ATWS-RPT																																								X											
PC&RPV Isolation Control System					X				X															X	X			X	X	X	X			X				X		X				X		X		X		X	X
MSIVs					X				X															X	X				X	X				X						X				X		X				X	X
RPV Isolation Valves					X																								X	X								X		X											
RBM System																			X																																
Containment Isolation Valves																												X	X											X											
Vacuum Breaker System																													X																						
Reactor Building Isolation Dampers																													X		X																	X			
SGTS																													X		X																	X			
MCREC System																												X	X	X	X			X																	
SLCS																																						X		X											

X ←System Required   ←System Not Required

TABLE 15C-7 (SHEET 2 OF 2)
NSOA SYSTEM/EVENT MATRIX

NOTE:

1. The CRDA limiting-event path evaluated in the safety analysis (subsection 15.3.2) does not rely upon RCIC to mitigate this DBA. None of the DBAs, as evaluated in the safety analysis (section 15.3), rely upon RCIC for event mitigation. See subsection 15C.1.2 for an explanation of the relationship between the NSOA and the safety analysis.

TABLE 15C-8 (SHEET 1 OF 2)

NSOA AUTOMATIC INSTRUMENT TRIP/EVENT MATRIX

	AOOs	Loss of Feedwater Heating	Inadvertent Start of HPCI Pump	Shutdown Cooling (RHR) Malfunction - Decreasing Temperature	Loss of RHR Shutdown Cooling	Generator Load Rejection with No Bypass (LRNBP)	Generator Load Rejection with Bypass (LRBP)	Turbine Trip with No Bypass (TTNBP)	Loss of Condenser Vacuum	Turbine Trip with Bypass (TTBP)	Closure of All MSIVs (MSIVD)	Closure of One MSIV	Pressure Regulator Failure - Closed	Trip of One Recirculation Pump	Trip of Two Recirculation Pumps	Recirculation Flow Controller Failure - Decreasing Flow	Recirculation Flow Controller Failure - Increasing Flow	Startup of Idle Recirculation Pump	RWE During Power Operation	Control Rod Removal Error During Refueling	Fuel Assembly Insertion Error During Refueling	Feedwater Controller Failure - Maximum Demand (FWCF)	Inadvertent Opening of an SRV	Pressure Regulator Failure - Open	Loss of Auxiliary Power	Loss of Feedwater Flow (LOFW)	ACCIDENTS	CRDA	LOCA	MSLBA	Fuel-Handling Accident	Fuel Assembly Loading Error	Recirculation Pump Seizure	Feedwater Line Break	SPECIAL EVENTS	Stability	Overpressure Protection	Shutdown without Control Rod Insertion (SLCS Capability)	MCR Uninhabitability	ATWS	Generator Load Rejection with Flux Scram and No Bypass or RPT	Turbine Trip with Flux Scram and No Bypass or RPT	Loss of One dc System	Loss of Instrument Air	Loss of Service Water System	Fire	Miscellaneous Small Releases Outside Containment	Instrument Line Break	Liquid Radwaste Tank Failure	Gaseous Radwaste Tank Failure	SBO (including coping period)
Automatic Instrument Trip		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25		31	32	33	34	35	36	37		41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56
Trip on Low Water Level - Scram																									X	X			X	X				X												X					X
Trip on Low Water Level - RCIC Initiation (Note 1)			X		X				X		X				X							X		X	X	X		X					X						X	X				X		X				X	X
Trip on Low Water Level - HPCI Initiation			X		X				X		X				X							X		X	X	X		X	X	X			X	X						X				X		X				X	
Trip on Low Water Level - Core Spray Initiation																													X	X				X												X					
Trip on Low Water Level - RHR-LPCI Mode Initiation																													X	X				X																	
Trip on Low Water Level - ADS Inputs																													X	X				X																	
Trip on Low Water Level - RPV Isolation																													X	X				X						X						X					
Trip on Low Water Level - Primary Containment																													X											X											
Trip on Low Water Level - Secondary Containment																													X																						
Trip on Low Water Level - ATWS-RPT																																								X											
Trip on High Drywell Pressure Scram																													X																						
Trip on High Drywell Pressure HPCI Initiation																													X																						
Trip on High Drywell Pressure Core Spray Initiation																													X																						
Trip on High Drywell Pressure RHR-LPCI Mode Initiation																													X																						
Trip on High Drywell Pressure ADS Input																													X																						
Trip on High Drywell Pressure Primary Containment																													X																						
Trip on High Drywell Pressure Secondary Containment																													X																						
Trip on High Pressure - Scram					X	X	X	X	X	X	X				X							X		X	X								X										X	X						X	X
Trip on High Pressure - ATWS-RPT																																								X											
Trip on High Pressure - Shutdown Cooling Isolation					X																																														
High Pressure Setpoint - SRV Opening			X		X	X	X	X	X	X	X				X							X		X	X			X	X	X			X	X			X		X	X	X	X	X	X		X				X	X
Trip on High APRM Neutron Flux - Scram			X		X	X	X	X	X	X	X	X			X		X	X	X			X		X	X			X					X				X				X	X	X	X						X	X
Trip on IRM High Neutron Flux - Scram			X	X					X		X								X																									X							
Trip on High Simulated Thermal Power - Scram		X																																																	
Trip on RBM High Neutron Flux - Rod Block																			X																																
Trip on High OPRM Gr. Rate, Amp., or Period Algo. - Scram																																				X															

X ← System Required

☐ ← System Not Required

TABLE 15C-8 (SHEET 2 OF 2)

Automatic Instrument Trip	ADOs	Loss of Feedwater Heating	Inadvertent Start of HPCI Pump	Shutdown Cooling (RHR) Malfunction - Decreasing Temperature	Loss of RHR Shutdown Cooling	Generator Load Rejection with No Bypass (LRNBP)	Generator Load Rejection with Bypass (LRBP)	Turbine Trip with No Bypass (TTNBP)	Loss of Condenser Vacuum	Turbine Trip with Bypass (TTBP)	Closure of All MSIVs (MSIVD)	Closure of One MSIV	Pressure Regulator Failure - Closed	Trip of One Recirculation Pump	Trip of Two Recirculation Pumps	Recirculation Flow Controller Failure - Decreasing Flow	Recirculation Flow Controller Failure - Increasing Flow	Startup of Idle Recirculation Pump	RWE During Power Operation	Control Rod Removal Error During Refueling	Fuel Assembly Insertion Error During Refueling	Feedwater Controller Failure - Maximum Demand (FWCF)	Inadvertent Opening of an SRV	Pressure Regulator Failure - Open	Loss of Auxiliary Power	Loss of Feedwater Flow (LOFW)	ACCIDENTS	CRDA	LOCA	MSLBA	Fuel-Handling Accident	Fuel Assembly Loading Error	Recirculation Pump Seizure	Feedwater Line Break	SPECIAL EVENTS	Stability	Overpressure Protection	Shutdown without Control Rod Insertion (SLCS Capability)	MCR Uninhabitability	ATWS	Generator Load Rejection with Flux Scram and No Bypass or RPT	Turbine Trip with Flux Scram and No Bypass or RPT	Loss of One dc System	Loss of Instrument Air	Loss of Service Water System	Fire	Miscellaneous Small Releases Outside Containment	Instrument Line Break	Liquid Radwaste Tank Failure	Gaseous Radwaste Tank Failure	SBO (including coping period)
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25		31	32	33	34	35	36	37		41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56
Trip on TSV Position - Scram					X			X	X	X					X							X		X	X					X			X										X	X		X				X	X
Trip on TSV Position - EOC-RPT					X			X	X	X					X							X		X	X								X										X	X						X	X
Trip on TCV Fast Closure - Scram						X	X																		X					X																X					X
Trip on TCV Fast Closure - EOC-RPT						X	X																		X																										X
Turbine First-Stage Presssure Permissive					X	X	X	X	X	X					X							X		X	X								X										X	X						X	X
Trip on MSIV Position Switches - Scram					X				X		X													X	X					X														X		X				X	X
Trip on Low Condenser Vacuum - MSIV Closure					X				X																X				X															X						X	X
Trip on Low MSL Pressure in RUN Mode - MSIV Closure																								X					X	X																X					
Trip on High Area Temp - RPV Isolation																														X				X																	
Trip on High Area ΔT - RPV Isolation																														X																					
Trip on High Flow - RPV Isolation																														X																					
Trip on SLCS Initiation - RWC Isolation																																						X		X											
Trip on High Radiation - Primary Containment																												X																							
Trip on High Radiation - Secondary Containment																															X																	X			
Trip on High Radiation - MCR Environment																												X	X	X	X			X																	
ECCS (LPCI & CS) Pump Disch Press Permissive - ADS Input																													X	X				X																	
RPV Pressure Permissive - Core Spray			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X							X	X		X		X				X	X
RPV Pressure Permissive - RHR LPCI Mode																													X	X				X																	
RPV Pressure Permissive - RHR Alt Shutdown Cooling			X		X	X		X	X		X				X							X	X	X	X	X		X					X	X							X	X		X		X				X	X

X = System Required; blank = System Not Required

NOTE:

1. The CRDA limiting-event path evaluated in the safety analysis (subsection 15.3.2) does not rely upon RCIC to mitigate this DBA. None of the DBAs, as evaluated in the safety analysis (section 15.3), rely upon RCIC for event mitigation. See subsection 15C.1.2 for an explanation of the relationship between the NSOA and the safety analysis.

TABLE 15C-9

NSOA MONITORED PARAMETER/EVENT MATRIX FOR THE SAFETY ANALYSIS

Monitored Parameter	ANTICIPATED OPERATIONAL OCCURRENCES	1 Loss of a Feedwater Heater	2 Inadvertent Start of HPCI Pump	3 Shutdown Cooling (RHR) Malfunction Decreasing Temperature	4 Loss of RHR Shutdown Cooling	5 Generator Load Rejection without Bypass	6 Generator Load Rejection with Bypass	7 Turbine Trip without Bypass	8 Loss of Condenser Vacuum	9 Turbine Trip with Bypass	10 Closure of All MSIVs	11 Closure of One MSIV	12 Pressure Regulator Failure - Closed	13 Trip of One Recirculation Pump	14 Trip of Two Recirculation Pumps	15 Recirculation Flow Controller Failure - Decreasing Flow	16 Recirculation Flow Controller Failure - Increasing Flow	17 Startup of Idle Recirculation Pump	18 Control Rod Withdrawal Error (All Power Levels)	19 Control Rod Removal Error During Refueling	20 Fuel Assembly Insertion Error During Refueling	21 Feedwater Controller Failure - Maximum Demand	22 Inadvertent Opening of a Safety/Relief Valve	23 Pressure Regulator Failure - Open	24 Loss of Auxiliary Power	25 Loss of Feedwater Flow	ACCIDENTS	31 Control Rod Drop Accident	32 Loss of Coolant Accident	33 Main Steam Line Break Accident	34 Fuel Handling Accident	35 Fuel Assembly Loading Error	36 Recirculation Pump Seizure	37 Feedwater Line Break	SPECIAL EVENTS	41 Stability	42 Overpressure Protection	43 Shutdown without Control Rods	44 Control Room Uninhabitability	45 Anticipated Transients without Scram	46 Generator Load Rejection with Flux Scram and No Bypass or RPR	47 Turbine Trip with Flux Scram and No Bypass or RPR	48 Loss of One DC System	49 Loss of Instrument Air	50 Loss of Service Water	51 Fire	52 Miscellaneous Small Releases Outside of Containment	53 Instrument Line Break	54 Liquid Radwaste Tank Rupture	55 Gaseous Radwaste Failure	56 Station Blackout (Including Coping Period)
Suppression Pool Temperature - EOP Entry Condition			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X						X	X	X		X		X				X	X
Suppression Pool Temperature - Manual Scram																							X																												
Suppression Pool Temperature - Suppression Pool Cooling			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X						X	X	X		X						X	X
Suppression Pool Temperature - RHR Alternate Shutdown Cooling																																														X					
Heat Capacity Temperature Limit - Reactor Depressurization			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X						X	X	X		X		X				X	X
SRV Tailpipe Limit - Reactor Depressurization			X		X	X		X	X		X				X							X	X	X	X	X		X	X	X			X	X						X	X	X		X		X				X	X
Suppression Pool Level - Feedwater Pump Trip						X		X															X						X	X											X	X									
Low Water Level - Low Pressure ECCS Initiation			X		X	X		X	X		X				X							X	X	X	X	X		X					X								X	X		X						X	X
Drywell Pressure - EOP Entry Condition																													X																						
Scram Required and Reactor Power > 5% - EOP Entry Condition																																								X											
Reactor Power - ATWS-RPT Initiation																																								X											
Suppression Pool Temperature - SLCS Initiation																																								X											
Shutdown Cooling Pressure Permissive - Shutdown Cooling																																								X											

X ← System Required

☐ ← System Not Required

TABLE 15C-10

NSOA AUXILIARY SYSTEM/EVENT MATRIX

Auxiliary System	AOOs	Loss of Feedwater Heating	Inadvertent Start of HPCI Pump	Shutdown Cooling (RHR) Malfunction - Decreasing Temperature	Loss of RHR Shutdown Cooling	Generator Load Rejection with No Bypass (LRNBP)	Generator Load Rejection with Bypass (LRBP)	Turbine Trip with No Bypass (TTNBP)	Loss of Condenser Vacuum	Turbine Trip with Bypass (TTBP)	Closure of All MSIVs (MSIVD)	Closure of One MSIV	Pressure Regulator Failure - Closed	Trip of One Recirculation Pump	Trip of Two Recirculation Pumps	Recirculation Flow Controller Failure - Decreasing Flow	Recirculation Flow Controller Failure - Increasing Flow	Startup of Idle Recirculation Pump	RWE During Power Operation	Control Rod Removal Error During Refueling	Fuel Assembly Insertion Error During Refueling	Feedwater Controller Failure - Maximum Demand (FWCF)	Inadvertent Opening of an SRV	Pressure Regulator Failure - Open	Loss of Auxiliary Power	Loss of Feedwater Flow (LOFW)
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
dc Power System			X		X	X		X	X		X				X							X	X	X	X	X
Auxiliary ac Power			X		X	X		X	X		X				X							X	X	X	X	X
Standby ac Power					X																				X	
Offsite ac Power System			X		X	X		X	X		X				X							X	X	X	X	X
Equipment Area Cooling System			X		X	X		X	X		X				X							X	X	X	X	X
RHRSW System			X		X	X		X	X		X				X							X	X	X	X	X
PSW System			X		X	X		X	X		X				X							X	X	X	X	X
Suppression Pool Storage			X		X	X	X	X	X	X	X				X							X	X	X	X	X
Ultimate Heat Sink			X		X	X		X	X		X				X							X	X	X	X	X
Alternate ac Power																										

Auxiliary System	ACCIDENTS	CRDA	LOCA	MSLBA	Fuel-Handling Accident	Fuel Assembly Loading Error	Recirculation Pump Seizure	Feedwater Line Break	SPECIAL EVENTS	Stability	Overpressure Protection	Shutdown without Control Rod Insertion (SLCS Capability)	MCR Uninhabitability	ATWS	Generator Load Rejection with Flux Scram and No Bypass or RPT	Turbine Trip with Flux Scram and No Bypass or RPT	Loss of One dc System	Loss of Instrument Air	Loss of Service Water System	Fire	Miscellaneous Small Releases Outside Containment	Instrument Line Break	Liquid Radwaste Tank Failure	Gaseous Radwaste Tank Failure	SBO (including coping period)
		31	32	33	34	35	36	37		41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56
dc Power System		X	X	X	X		X	X				X	X	X	X	X		X		X		X		X	X
Auxiliary ac Power		X	X	X	X		X	X				X	X	X	X	X		X		X		X		X	X
Standby ac Power			X	X				X						X						X					X
Offsite ac Power System		X	X	X	X		X	X				X	X	X	X	X		X		X		X		X	X
Equipment Area Cooling System		X	X	X			X	X					X	X	X	X		X		X				X	X
RHRSW System		X	X	X			X	X					X	X	X	X		X		X				X	X
PSW System		X	X	X			X	X					X	X	X	X		X		X				X	X
Suppression Pool Storage		X	X	X			X	X			X		X	X	X	X	X	X		X				X	X
Ultimate Heat Sink		X	X	X			X	X					X	X	X	X		X		X				X	X
Alternate ac Power																									X

X ← System Required

☐ ← System Not Required

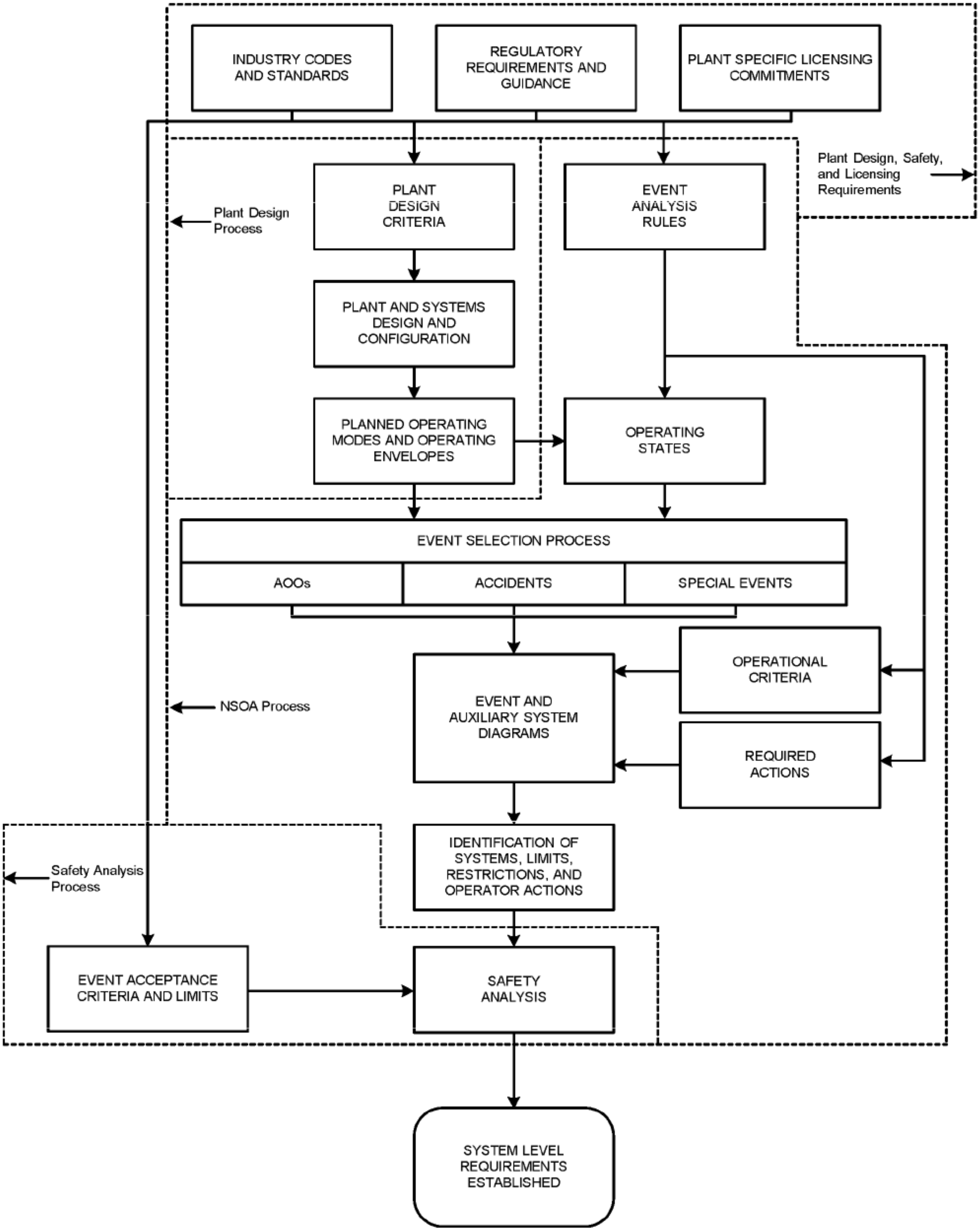
TABLE 15C-11 (SHEET 1 OF 2)

LIMITING SAFETY SYSTEM SETTINGS

LSSS	Safety Limit	Basis
Reactor Protections System Instrumentation		
APRM Neutron Flux-High (Setdown)	Low Pressure or Low Core Flow Safety Limit	It will effectively limit any power increase at low flow and power conditions. Could limit the power increase for MSIV closures and control rod withdrawal errors in the startup mode.
APRM Flow Biased Simulated Thermal Power–High	MCPR Safety Limit	Could limit the power increase for a loss of feedwater heating. May not be required if analyzed with the 3-D simulator and a scram is not assumed.
APRM Neutron Flux-High	MCPR Safety Limit Reactor Pressure Safety Limit	Assumed in the ASME Code overpressure protection analysis that is assumed to bound the pressure increase for all anticipated operational occurrences.
Reactor Vessel Steam Dome Pressure-High	MCPR Safety Limit	Assumed in establishing operating limits at off-rated power or flow condition.
Reactor Vessel Water Level-Low, Level 3	RPV Water Level Safety Limit	Assumed in the analysis of closure of all loss of feedwater flow.
Main Steam Isolation Valve-Closure	MCPR Safety Limit	Assumed in the analysis of closure of all MSIVs.
Turbine Stop Valve-Closure	MCPR Safety Limit	Assumed in the analysis of turbine trip events.
Turbine Control Valve Fast Closure, Trip Oil Pressure-Low	MCPR Safety Limit	Assumed in the analysis of generator load rejection events.

TABLE 15C-11 (SHEET 2 OF 2)

LSSS	Safety Limit	Basis
End of Cycle Recirculation Pump Trip Instrumentation		
Turbine Stop Valve-Closure	MCPR Safety Limit	Assumed in the analysis of turbine trip events.
Turbine Control Valve Fast Closure, Trip Oil Pressure-Low	MCPR Safety Limit	Assumed in the analysis of generator load rejection events.
Rod Block Monitor Instrumentation		
Low Power Range-Upscale	MCPR Safety Limit	Assumed in the analysis of control rod withdrawal error events.
Intermediate Power Range-Upscale	MCPR Safety Limit	Assumed in the analysis of control rod withdrawal error events.
High Power Range-Upscale	MCPR Safety Limit	Assumed in the analysis of control rod withdrawal error events.
High Pressure Coolant Injection System Instrumentation		
Reactor Vessel Water Level-Low Low, Level 2	RPV Water Level Safety Limit	RCIC initiation for events involving a loss of feedwater flow.
Reactor Core Isolation Cooling System Instrumentation		
Reactor Vessel Water Level-Low Low, Level 2	RPV Water Level Safety Limit	RCIC initiation for events involving a loss of feedwater flow.
Safety/Relief Valves		
Lift Setpoint	Reactor Pressure Safety Limit	Assumed in the analysis of all anticipated operational occurrences involving a significant pressure increase.



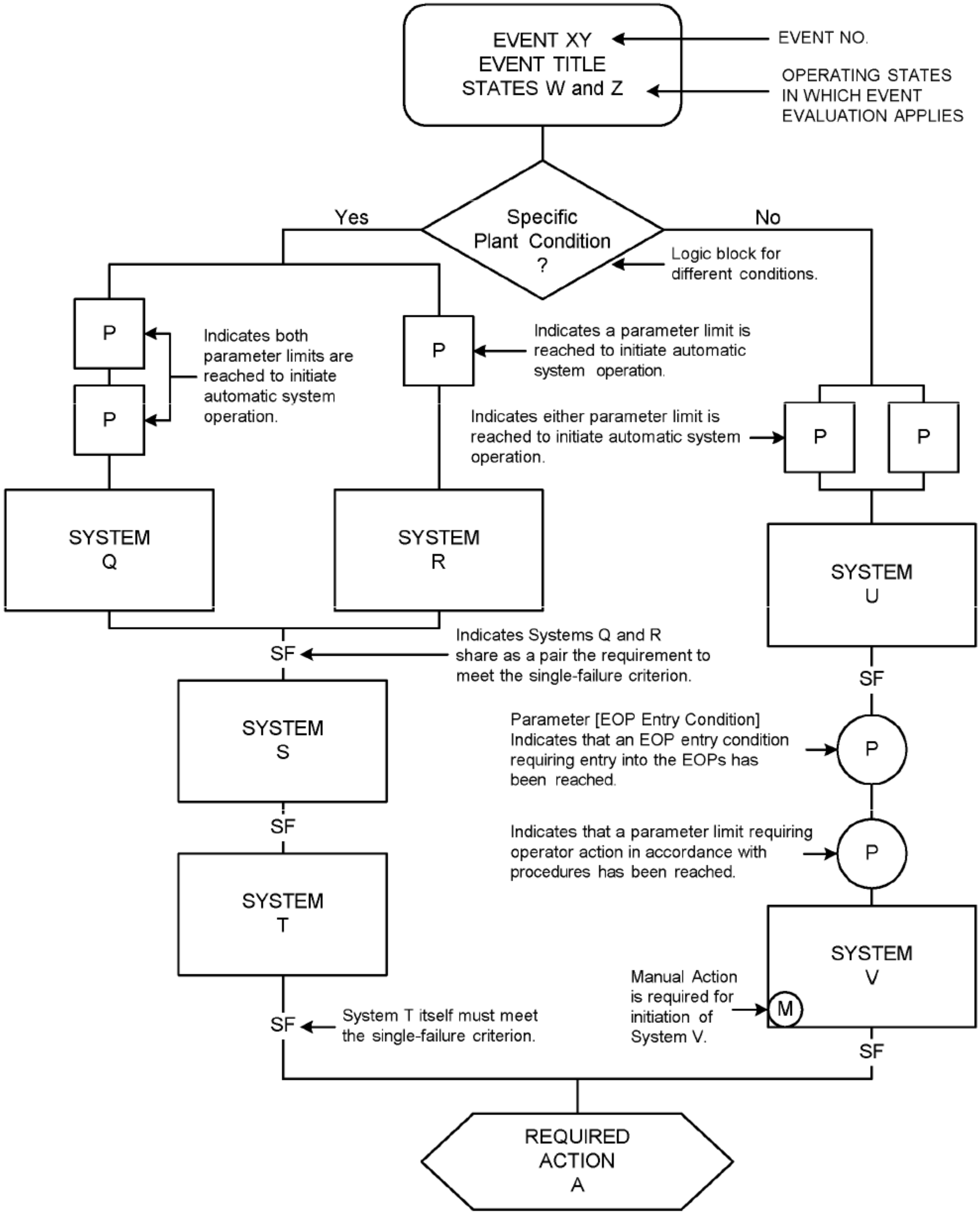
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NSOA RELATIONSHIP TO SAFETY ANALYSIS AND DESIGN PROCESS

FIGURE 15C-1



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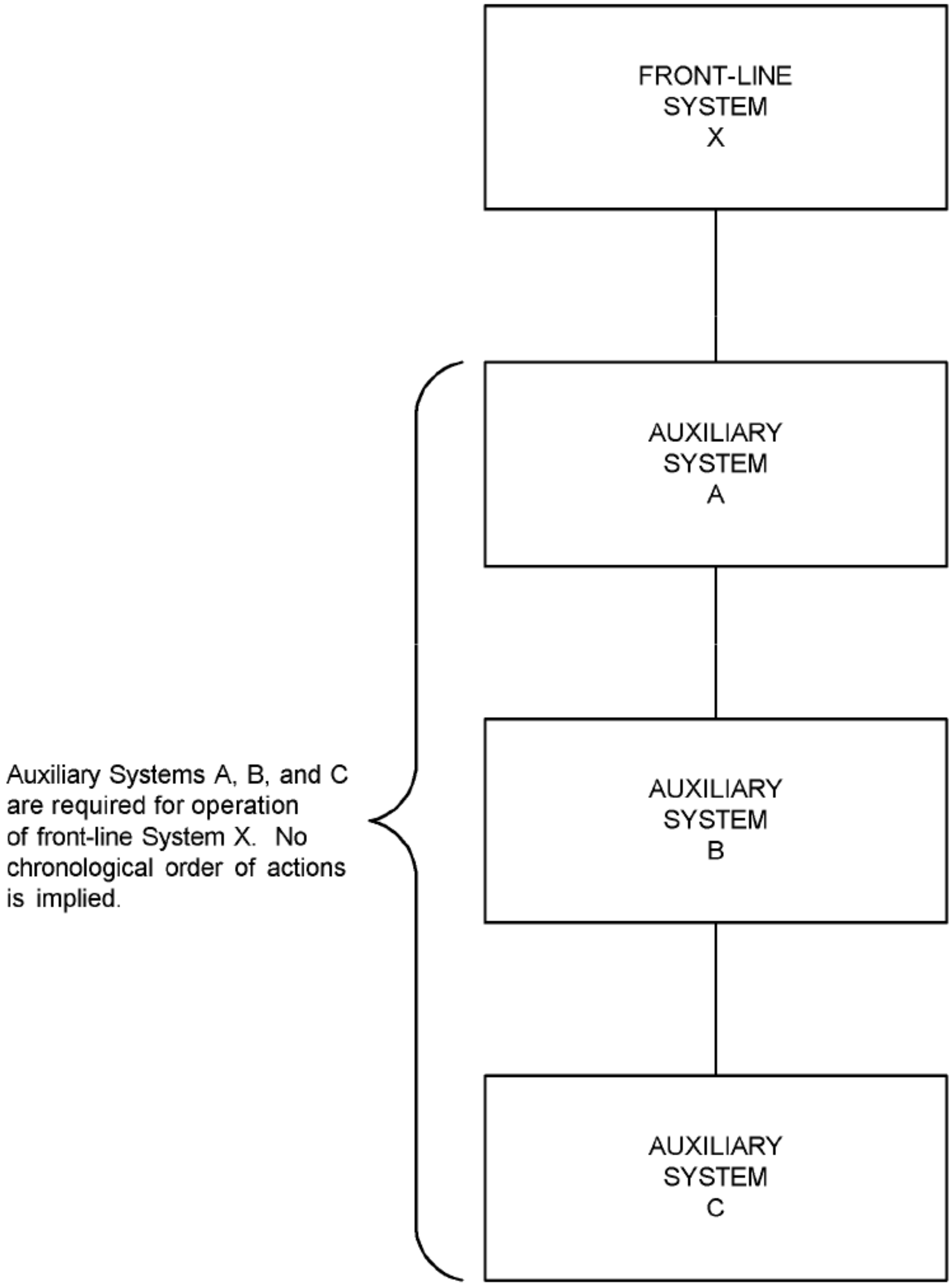
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM FORMAT

FIGURE 15C-2



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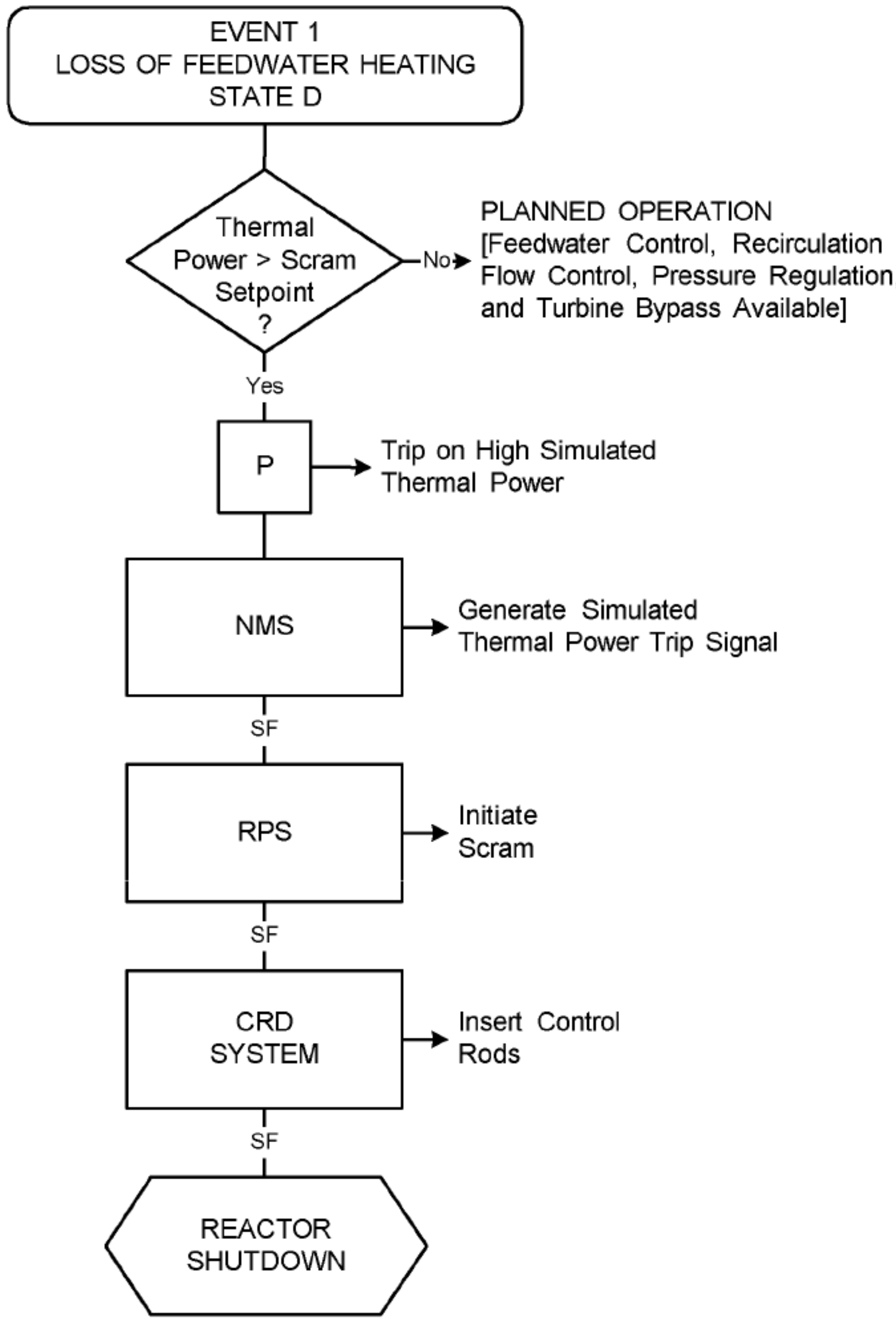
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

AUXILIARY SYSTEM DIAGRAM FORMAT

FIGURE 15C-3



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.1.1.

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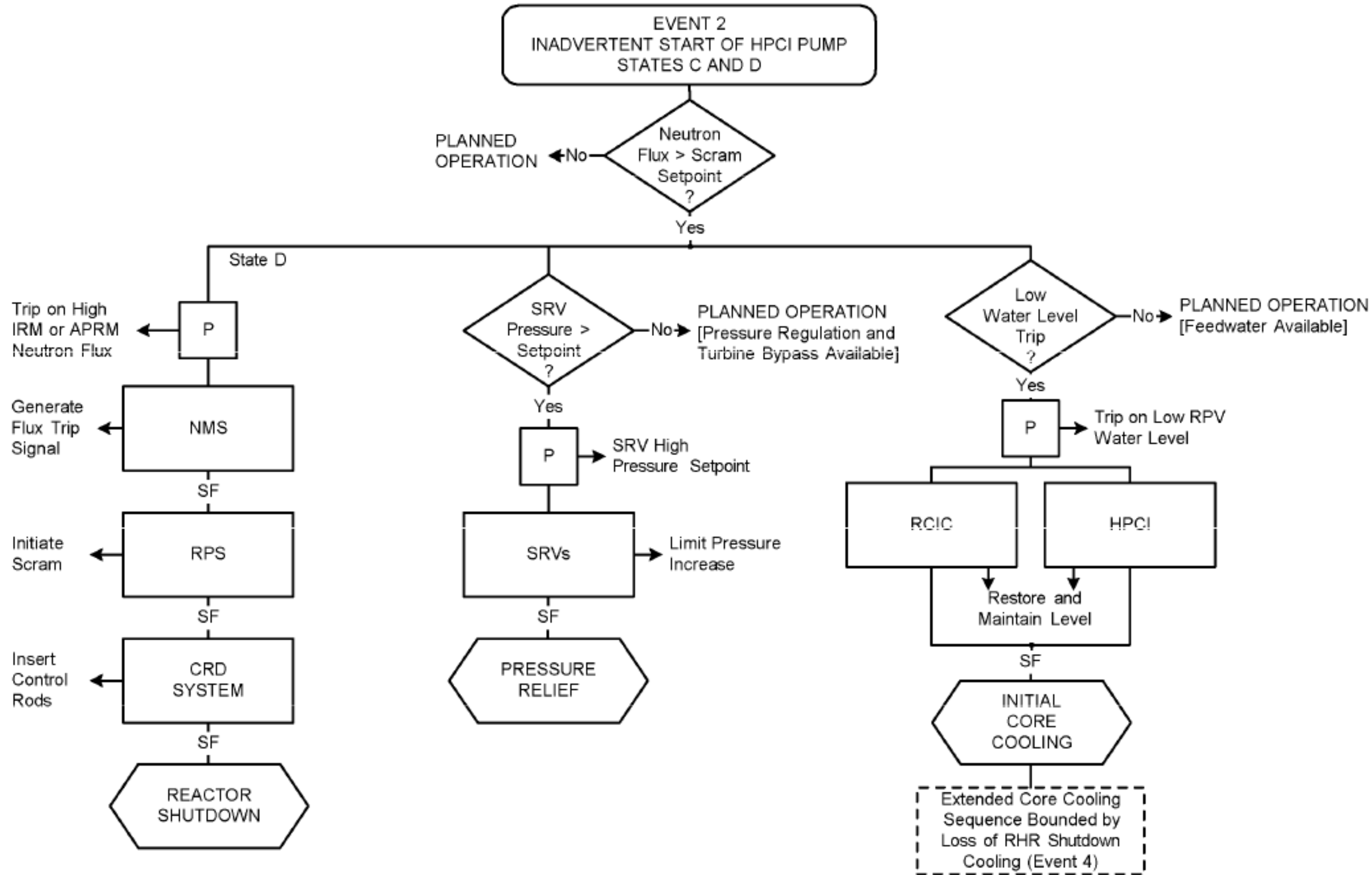
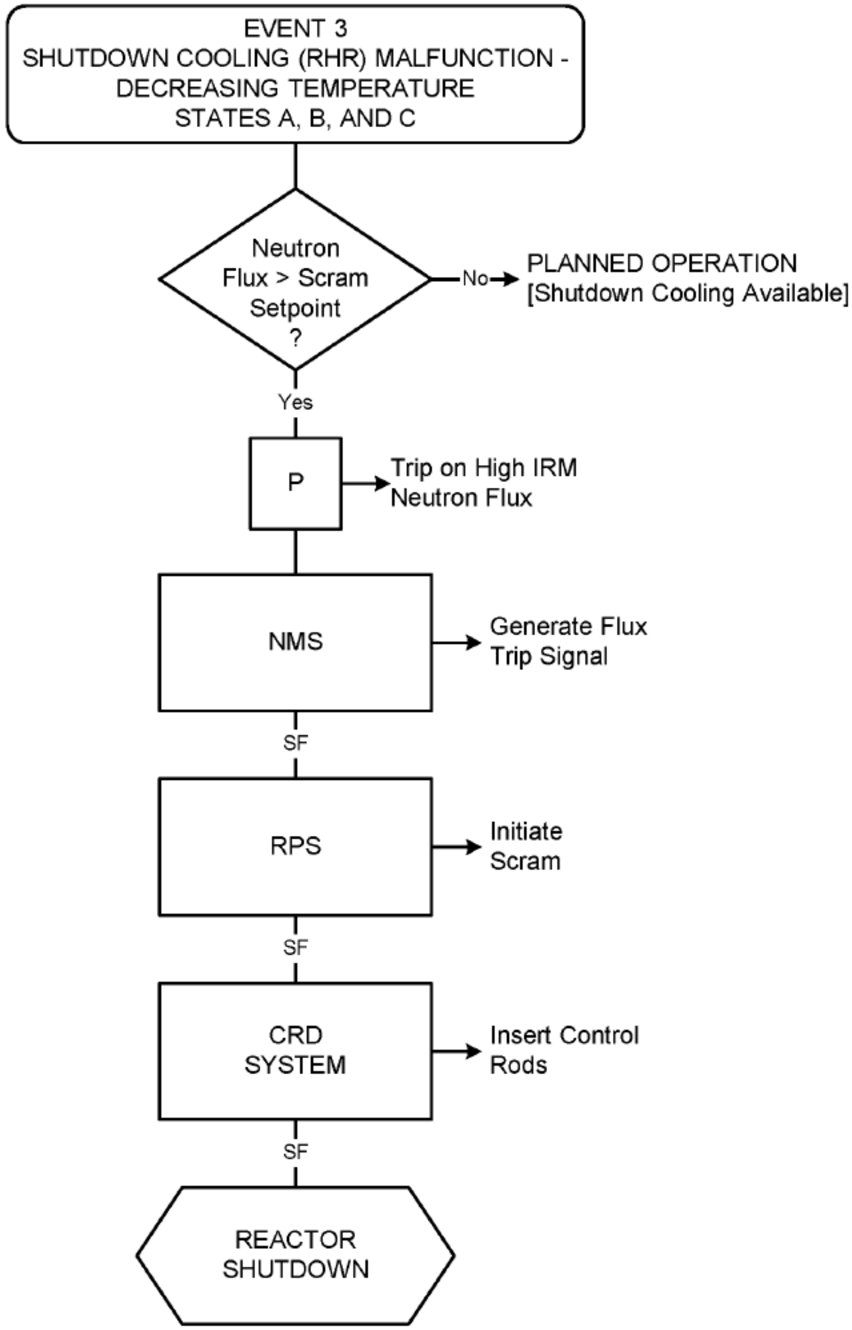


NOTES:

1. RPV isolation is not required for event mitigation.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Normal operating systems accomplish core cooling if level remains above low water level trip.
4. Event is described in 15C.4.1.1.2.

REV 19 7/01

SOUTHERN COMPANY *Energy to Serve Your World®* — **SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2**	EVENT DIAGRAM INADVERTENT START OF HPCI PUMP
	FIGURE 15C-5



NOTES:

1. RPV isolation and pressure relief are not required for event mitigation.
2. Normal operating systems accomplish core cooling function.
3. Event is described in 15C.4.1.1.3.

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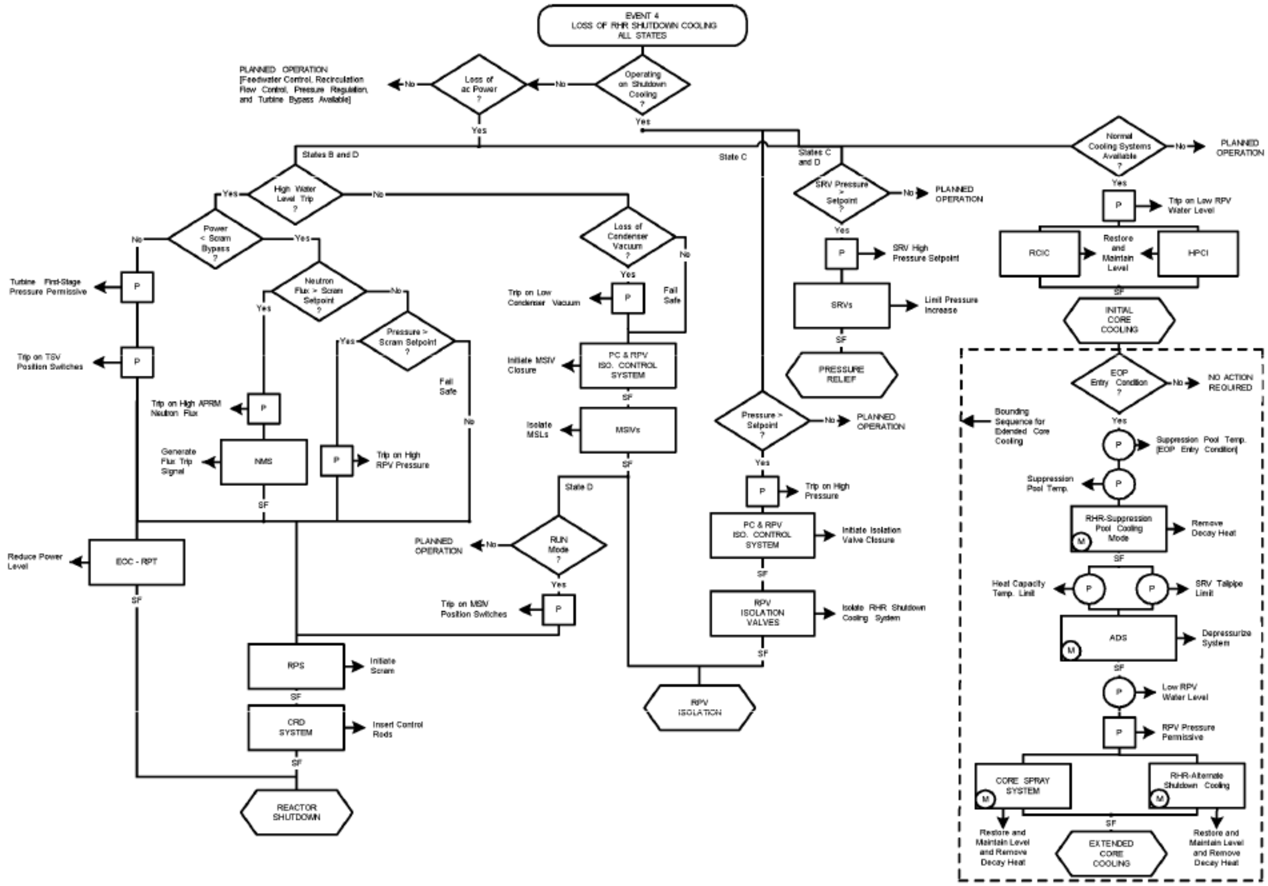
EVENT DIAGRAM
SHUTDOWN COOLING (RHR) MALFUNCTION –
DECREASING TEMPERATURE

FIGURE 15C-6

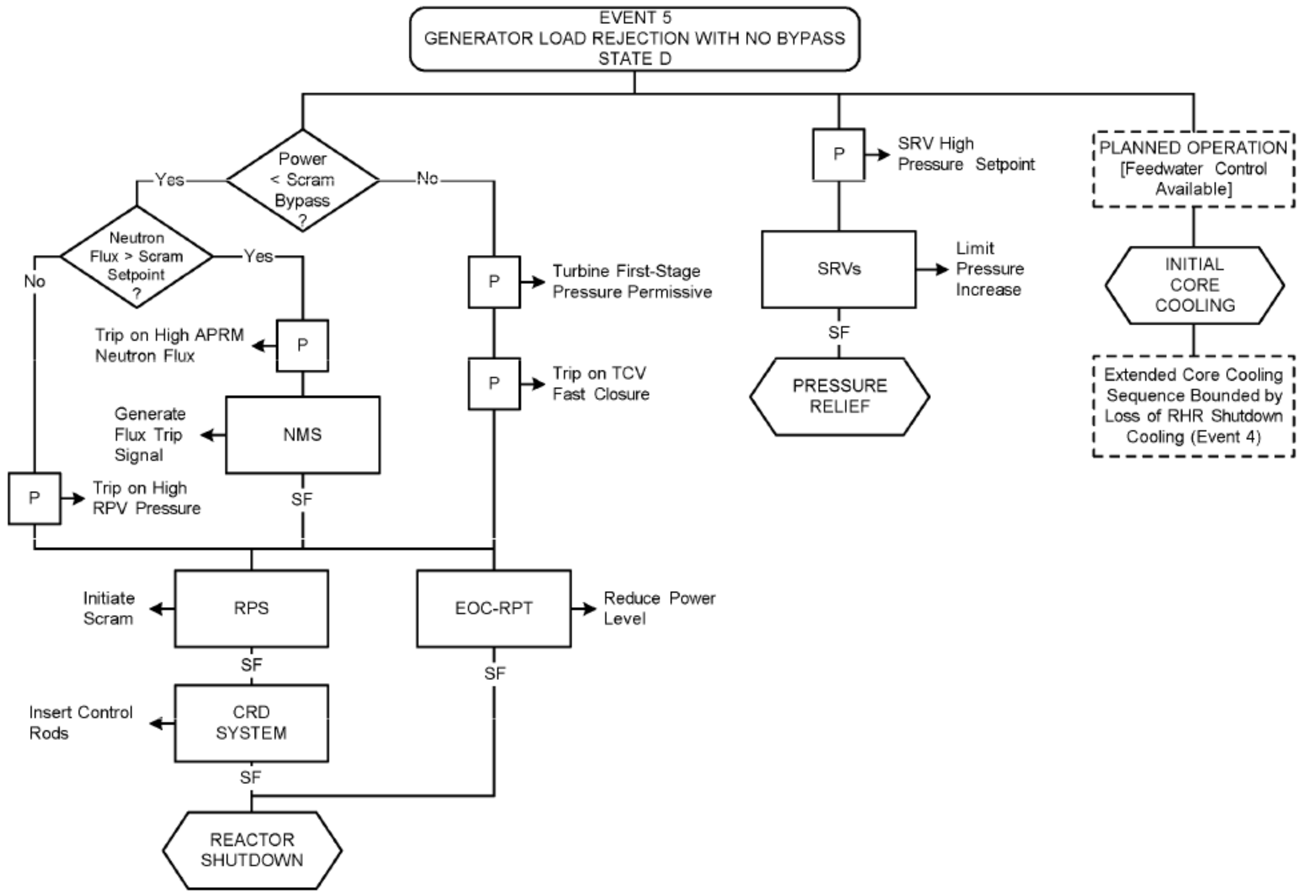


NOTES:

1. Fail-safe scram or MSIV closure is initiated by RPS M-G set coastdown if scram or MSIV closure has not been initiated.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Normal operating systems accomplish core cooling if level remains above low water level trip.
4. Event is described in 15C.4.1.2.1.

REV 19 7/01

SOUTHERN COMPANY Energy to Serve Your World®	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	EVENT DIAGRAM LOSS OF RHR SHUTDOWN COOLING FIGURE 15C-7



NOTES:

1. Normal operating systems accomplish initial core cooling; feedwater trip may be required due to high suppression pool level.
2. RPV isolation is not required for event mitigation.
3. Reactor shutdown is not required if scram setpoint is not reached.
4. Event is described in 15C.4.1.3.1.

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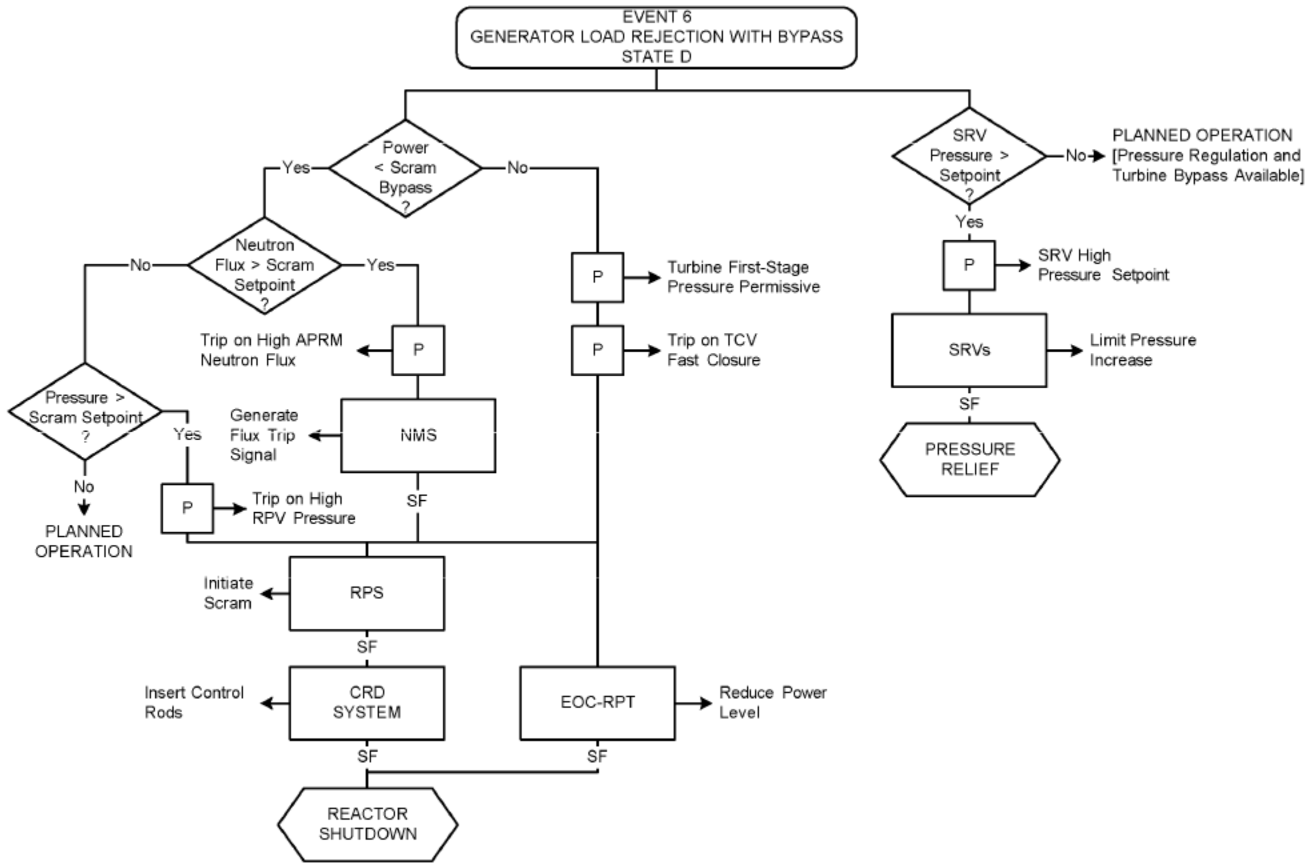
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
GENERATOR LOAD REJECTION WITH NO BYPASS

FIGURE 15C-8



NOTES:

1. Normal operating systems accomplish core cooling function.
2. RPV isolation is not required for event mitigation.
3. Reactor shutdown is not required if scram setpoint is not reached.
4. Pressure relief is not required if SRV setpoint is not reached.
5. Event is described in 15C.4.1.3.2.

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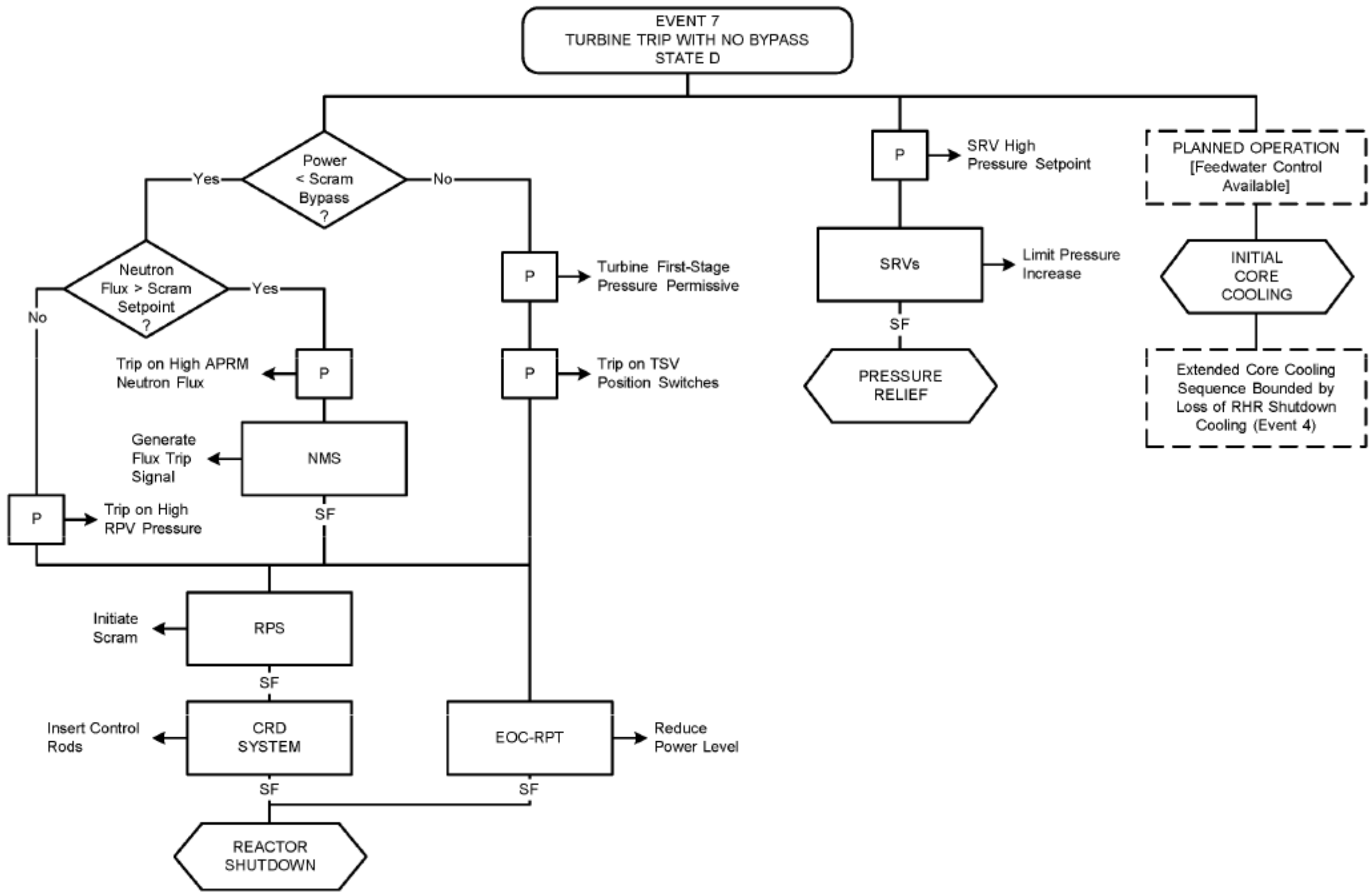
UNIT 2

EVENT DIAGRAM
GENERATOR LOAD REJECTION WITH BYPASS

FIGURE 15C-9



NOTES:

1. Normal operating systems accomplish initial core cooling; feedwater trip may be required due to high suppression pool level.
2. RPV isolation is not required for event mitigation.
3. Reactor shutdown is not required if scram setpoint is not reached.
4. Event is described in 15C.4.1.3.3.

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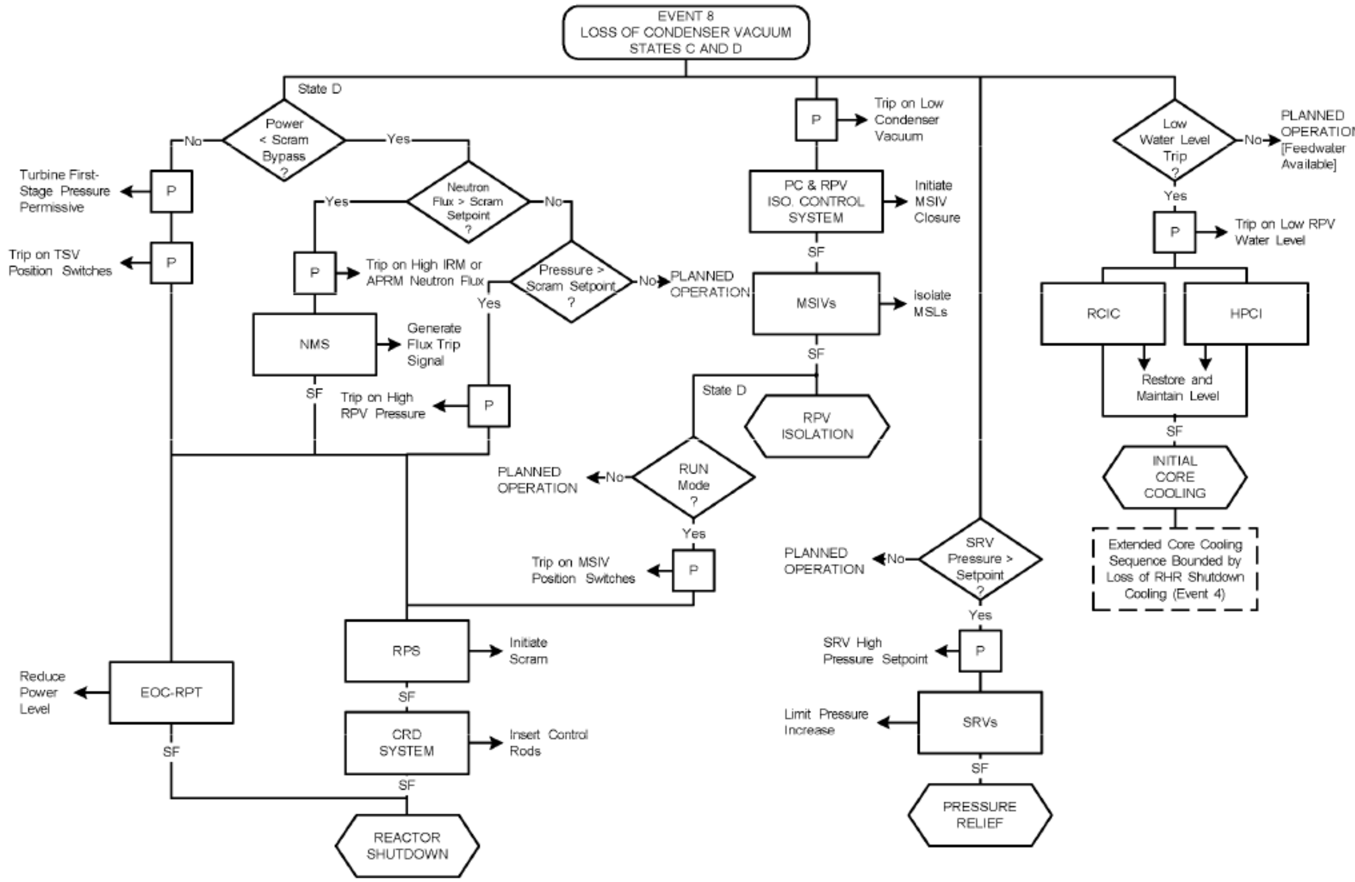
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
TURBINE TRIP WITH NO BYPASS

FIGURE 15C-10



NOTES:

1. Reactor shutdown is not required if RPV pressure permissive to bypass scram is not reached.
2. Pressure relief is not required if SRV setpoint is not reached.
3. RPV isolation is not required if reactor is not in RUN mode.
4. Event is described in 15C.4.1.3.4.

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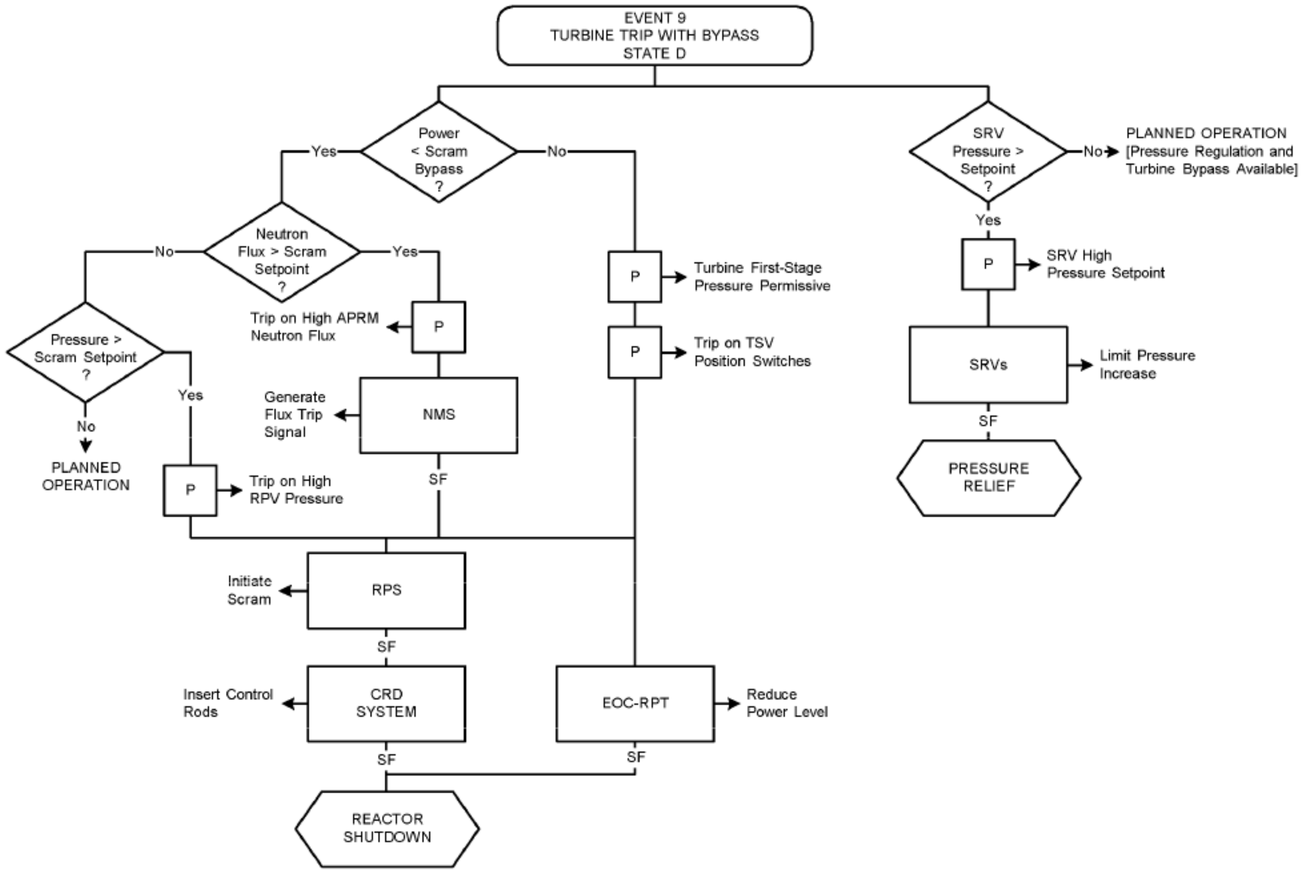
SOUTHERN COMPANY *Energy to Serve Your World®*	**SOUTHERN NUCLEAR OPERATING COMPANY** **EDWIN I. HATCH NUCLEAR PLANT** **UNIT 2**	EVENT DIAGRAM LOSS OF CONDENSER VACUUM FIGURE 15C-11



NOTES:

1. Normal operating systems accomplish core cooling function.
2. RPV isolation is not required for event mitigation.
3. Reactor shutdown is not required if scram setpoint is not reached.
4. Pressure relief is not required if SRV setpoint is not reached.
5. Event is described in 15C.4.1.3.5.

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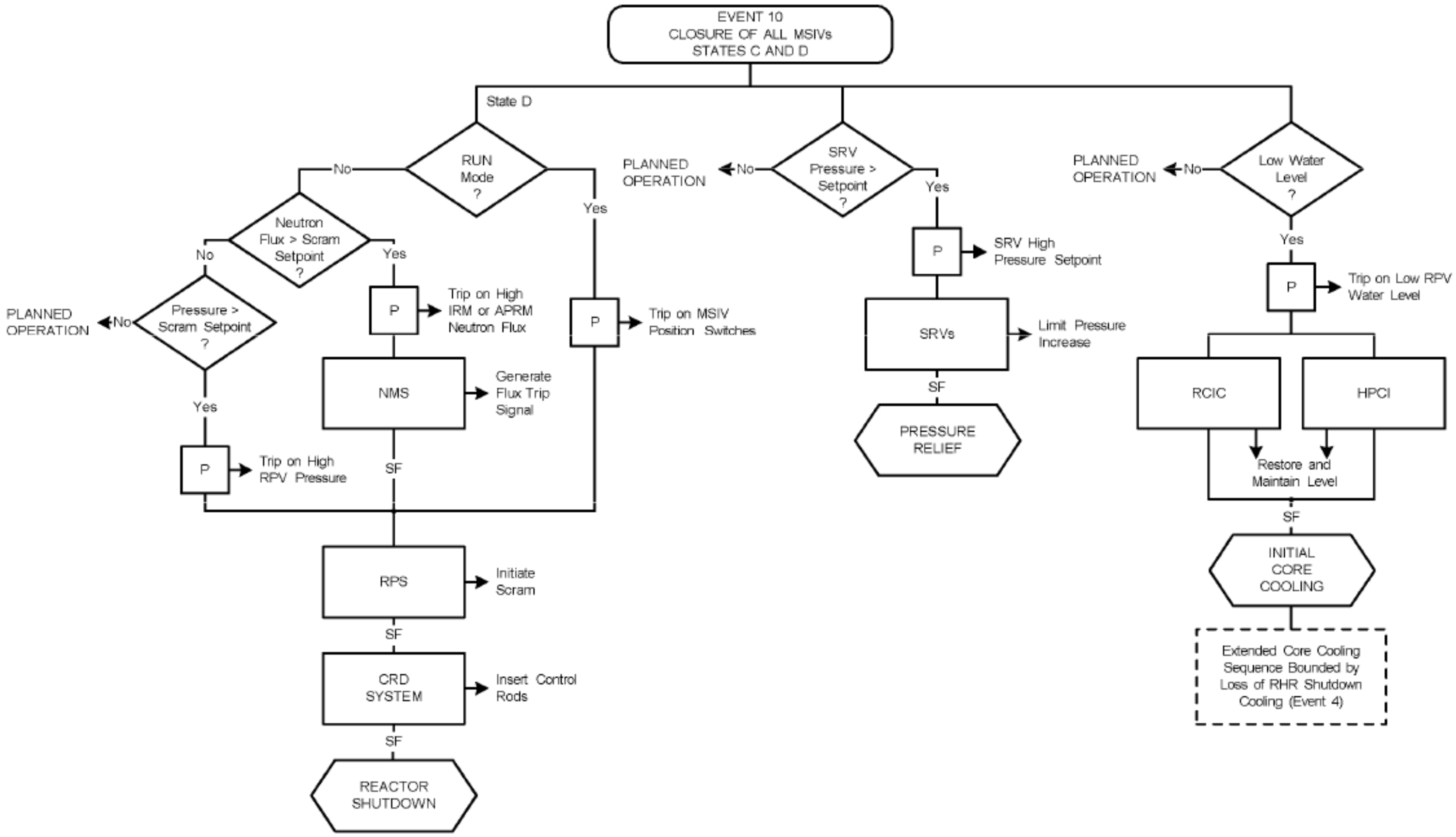
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
TURBINE TRIP WITH BYPASS

FIGURE 15C-12



NOTES:

1. Reactor shutdown is not required if scram setpoint is not reached.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Normal operating systems accomplish core cooling function if low water level does not occur.
4. Initiating event accomplishes RPV isolation.
5. Event is described in 15C.4.1.3.6.

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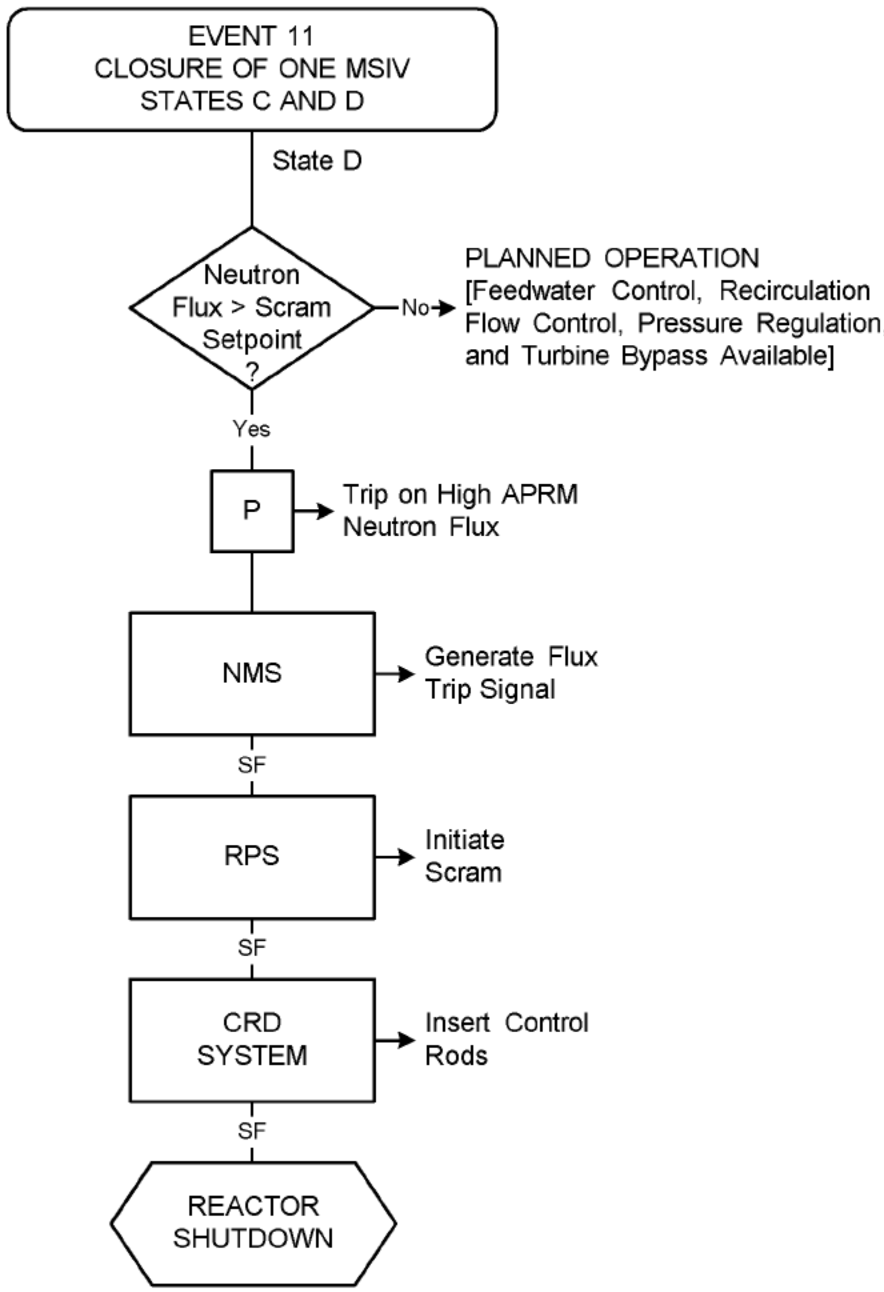
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
CLOSURE OF ALL MSIVs

FIGURE 15C-13



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.3.7.

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SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
CLOSURE OF ONE MSIV

FIGURE 15C-14

EVENT 12
PRESSURE REGULATOR FAILURE - CLOSED
STATE D

↓

PLANNED OPERATION
[Feedwater Control, Recirculation Flow Control, Backup Pressure Regulation, and Turbine Bypass Available]

NOTES:

1. Reactor shutdown and RPV isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.3.8.

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SOUTHERN COMPANY Energy to Serve Your World® SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	EVENT DIAGRAM PRESSURE REACTOR FAILURE - CLOSED
	FIGURE 15C-15

EVENT 13
TRIP OF ONE RECIRCULATION PUMP
STATES C AND D

↓

PLANNED OPERATION
[Feedwater Control, Pressure Regulation, and Turbine Bypass Available]

NOTES:

1. Reactor shutdown and RPV isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.4.1.

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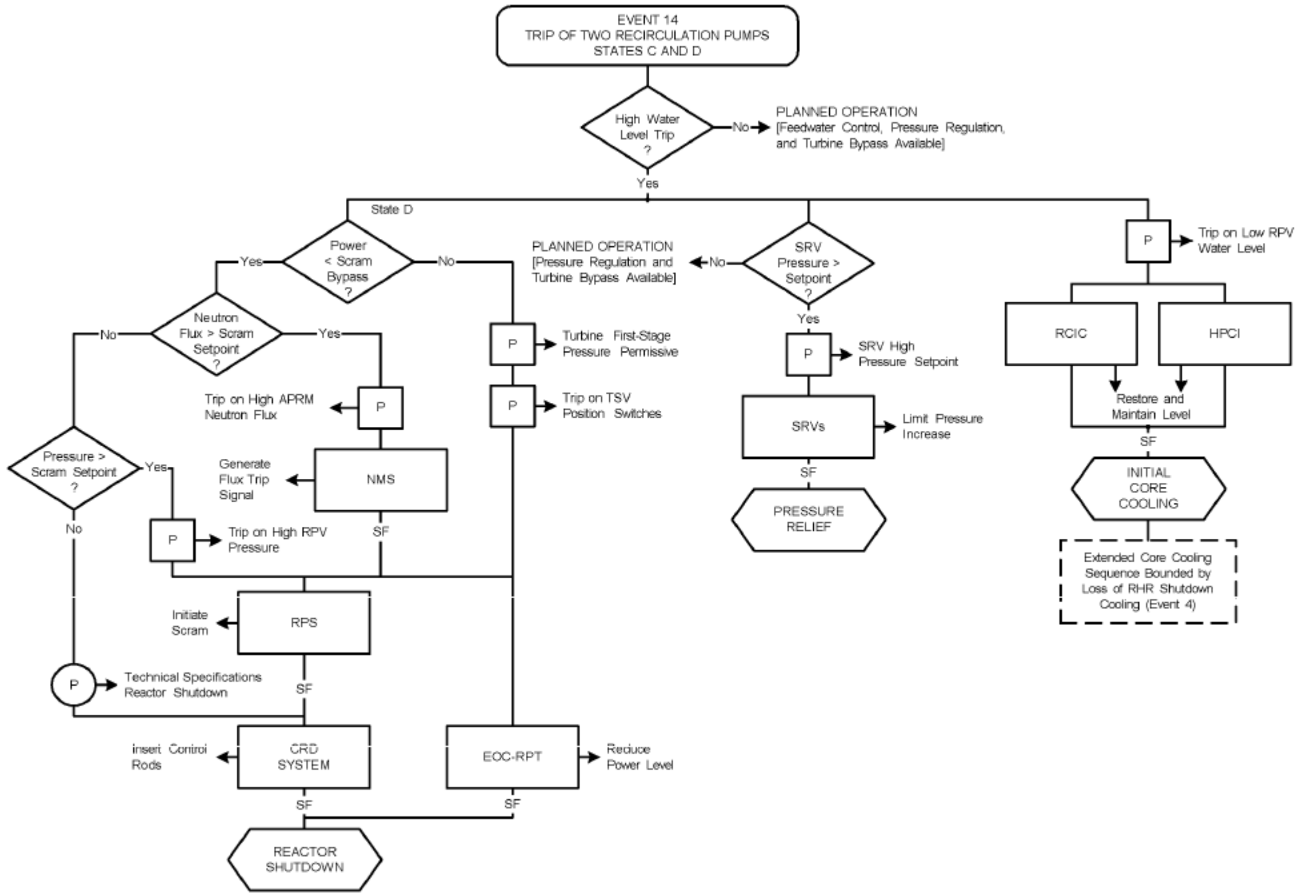
SOUTHERN COMPANY *Energy to Serve Your World®* **SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2**	EVENT DIAGRAM TRIP OF ONE RECIRCULATION PUMP
	FIGURE 15C-16



NOTES:

1. RPV isolation is not required for event mitigation.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Technical Specifications require shutdown if recirculation pumps cannot be restarted.
4. Event is described in 15C.4.1.4.2.

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EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
TRIP OF TWO RECIRCULATION PUMPS

FIGURE 15C-17

EVENT 15
RECIRCULATION FLOW CONTROLLER FAILURE - DECREASING FLOW
STATE D

↓

PLANNED OPERATION
[Feedwater Control, Pressure Regulation, and Turbine Bypass Available]

NOTES:

1. Reactor shutdown and RPV isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.4.3.

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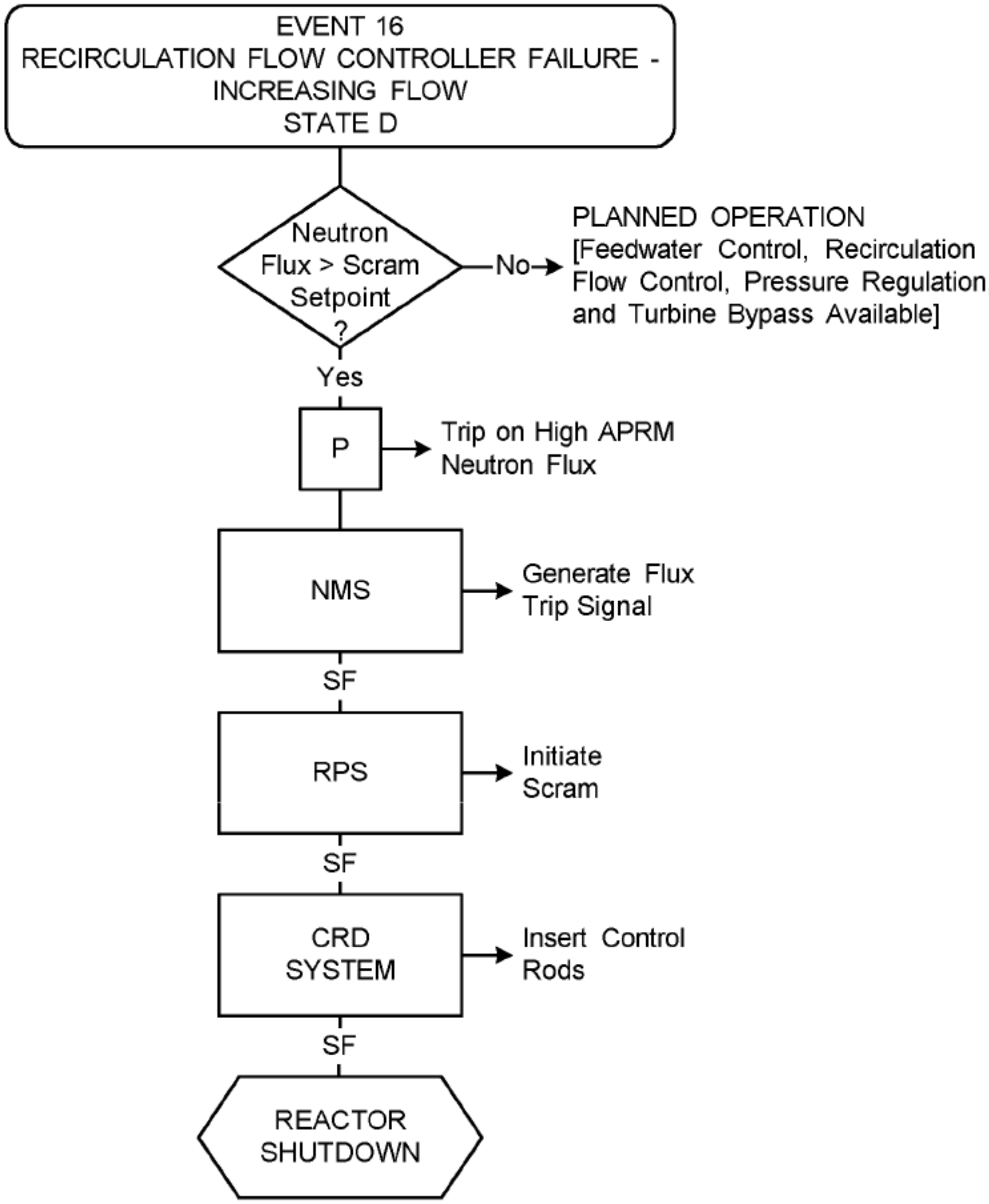
EVENT DIAGRAM
RECIRCULATION FLOW CONTROLLER FAILURE – DECREASING FLOW

FIGURE 15C-18



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.5.1.

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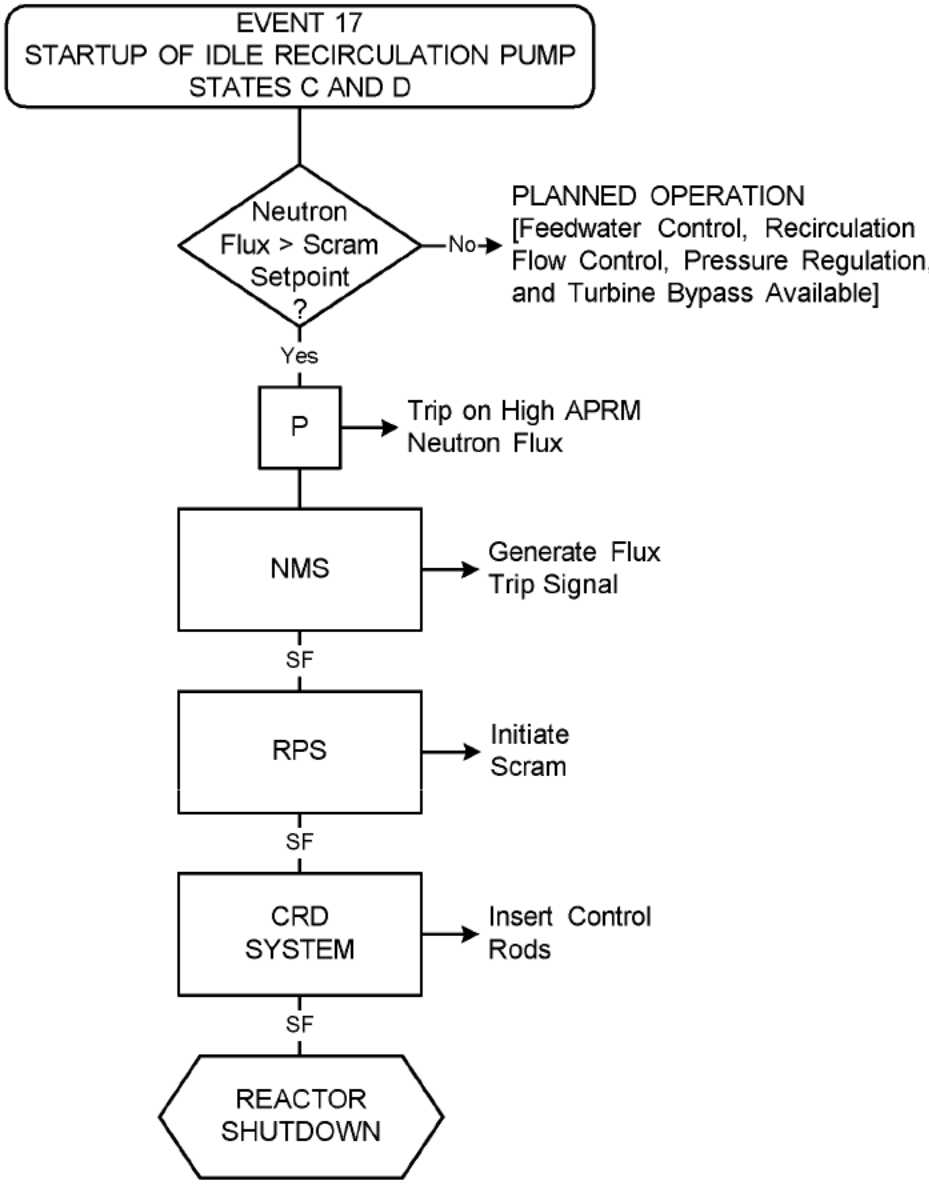
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
RECIRCULATION FLOW CONTROLLER FAILURE – INCREASING FLOW

FIGURE 15C-19



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.5.2.

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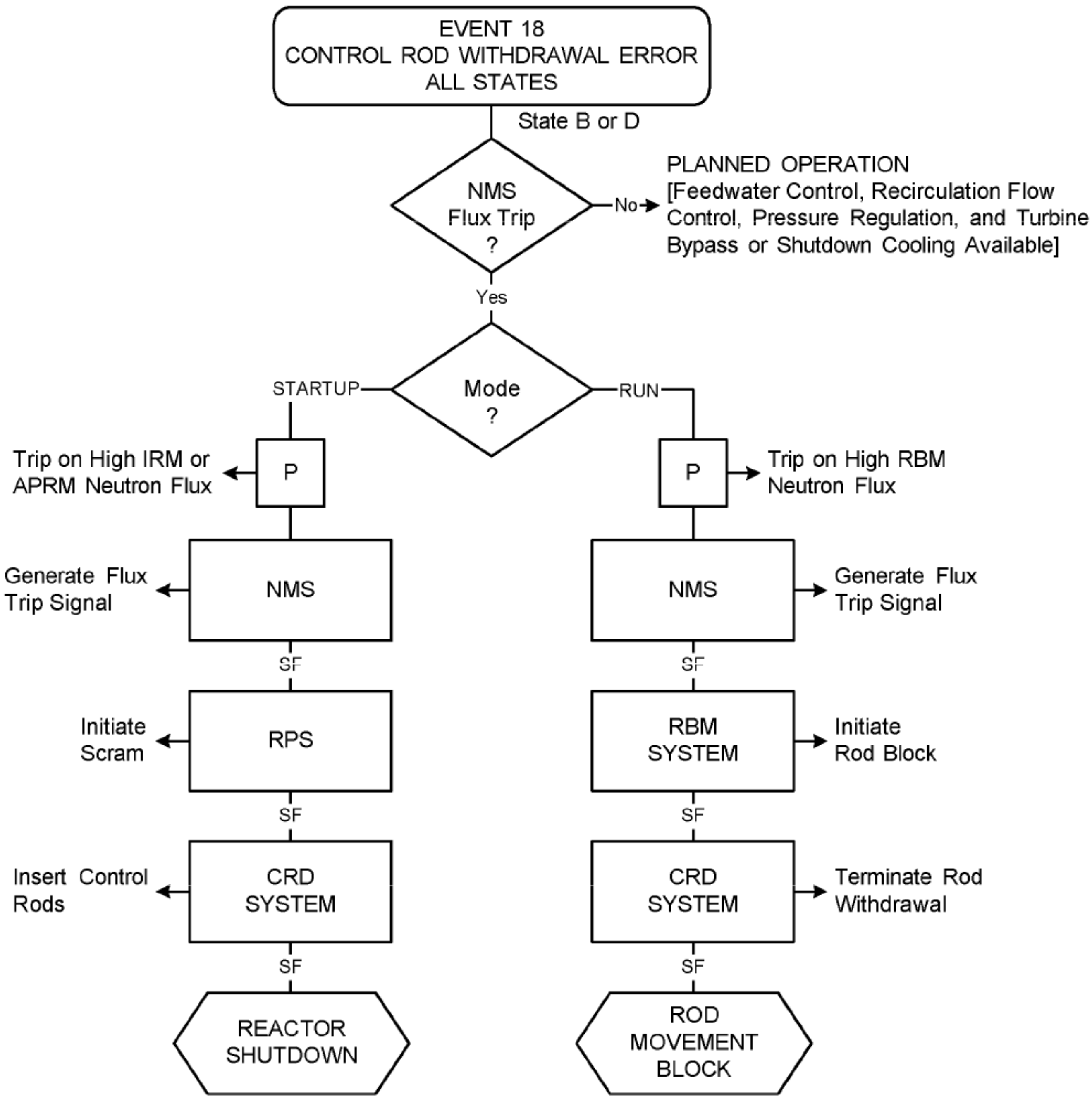
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
STARTUP OF IDLE RECIRCULATION PUMP

FIGURE 15C-20



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.1.6.1.

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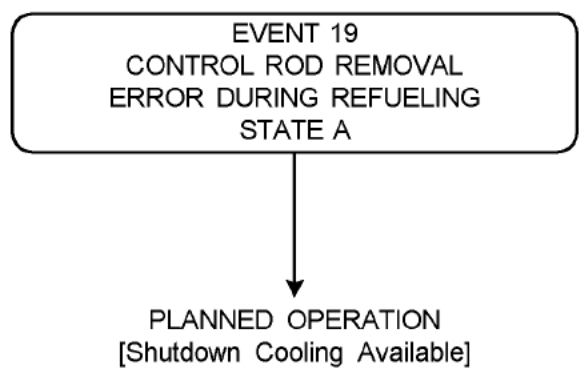

NOTES:

1. Reactor shutdown, RPV isolation, and pressure relief are not required for event mitigation.
2. Normal operating systems accomplish core cooling functions.
3. Event is described in 15C.4.1.6.2.

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SOUTHERN COMPANY *Energy to Serve Your World®* **SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2**	EVENT DIAGRAM CONTROL ROD REMOVAL ERROR DURING REFUELING
	FIGURE 15C-22

EVENT 20
FUEL ASSEMBLY INSERTION
ERROR DURING REFUELING
STATE A

↓

PLANNED OPERATION
[Shutdown Cooling Available]

NOTES:

1. Reactor shutdown, RPV isolation, and pressure relief are not required for event mitigation.
2. Normal operating systems accomplish core cooling function.
3. Event is described in 15C.4.1.6.3.

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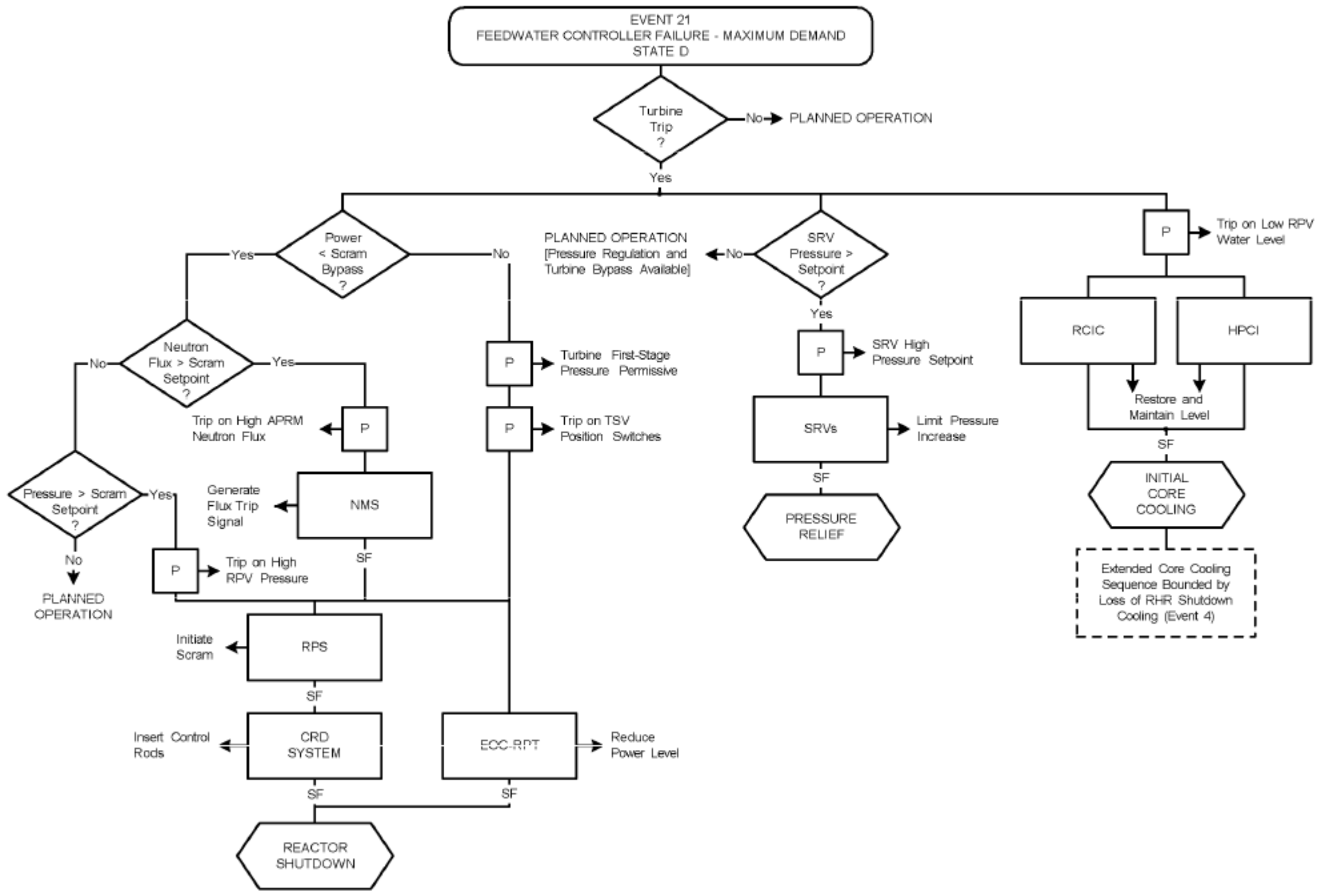
EVENT DIAGRAM
FUEL ASSEMBLY INSERTION
ERROR DURING REFUELING

FIGURE 15C-23



NOTES:

1. RPV isolation is not required for event mitigation.
2. Reactor shutdown is not required if scram setpoint is not reached.
3. Pressure relief is not required is SRV setpoint is not reached.
4. Event is described in 15C.4.1.7.1.

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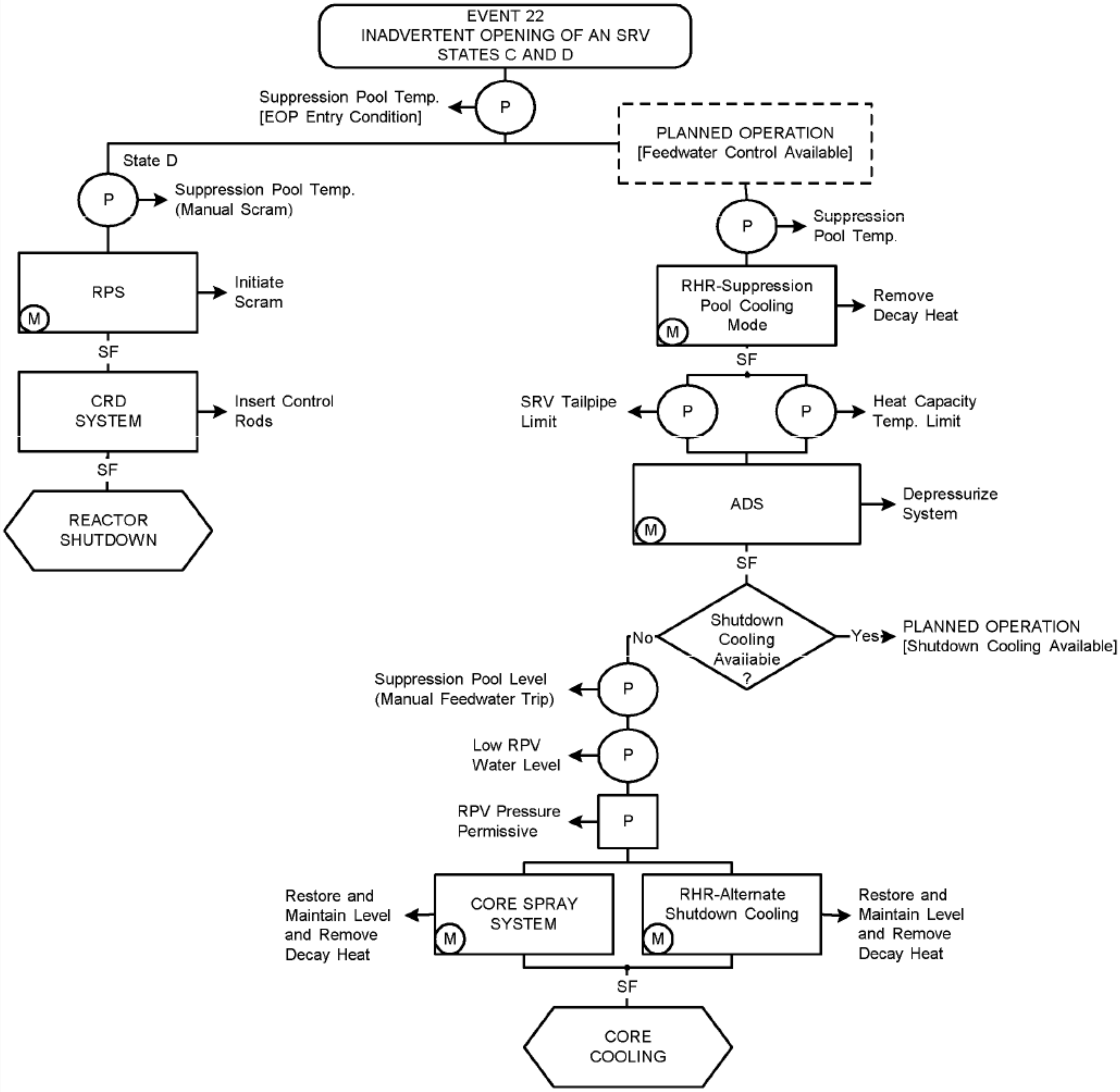
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
FEEDWATER CONTROLLER FAILURE – MAXIMUM DEMAND

FIGURE 15C-24



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems or stuck open relief valve accomplish pressure relief function.
3. Event is described in 15C.4.1.8.1.

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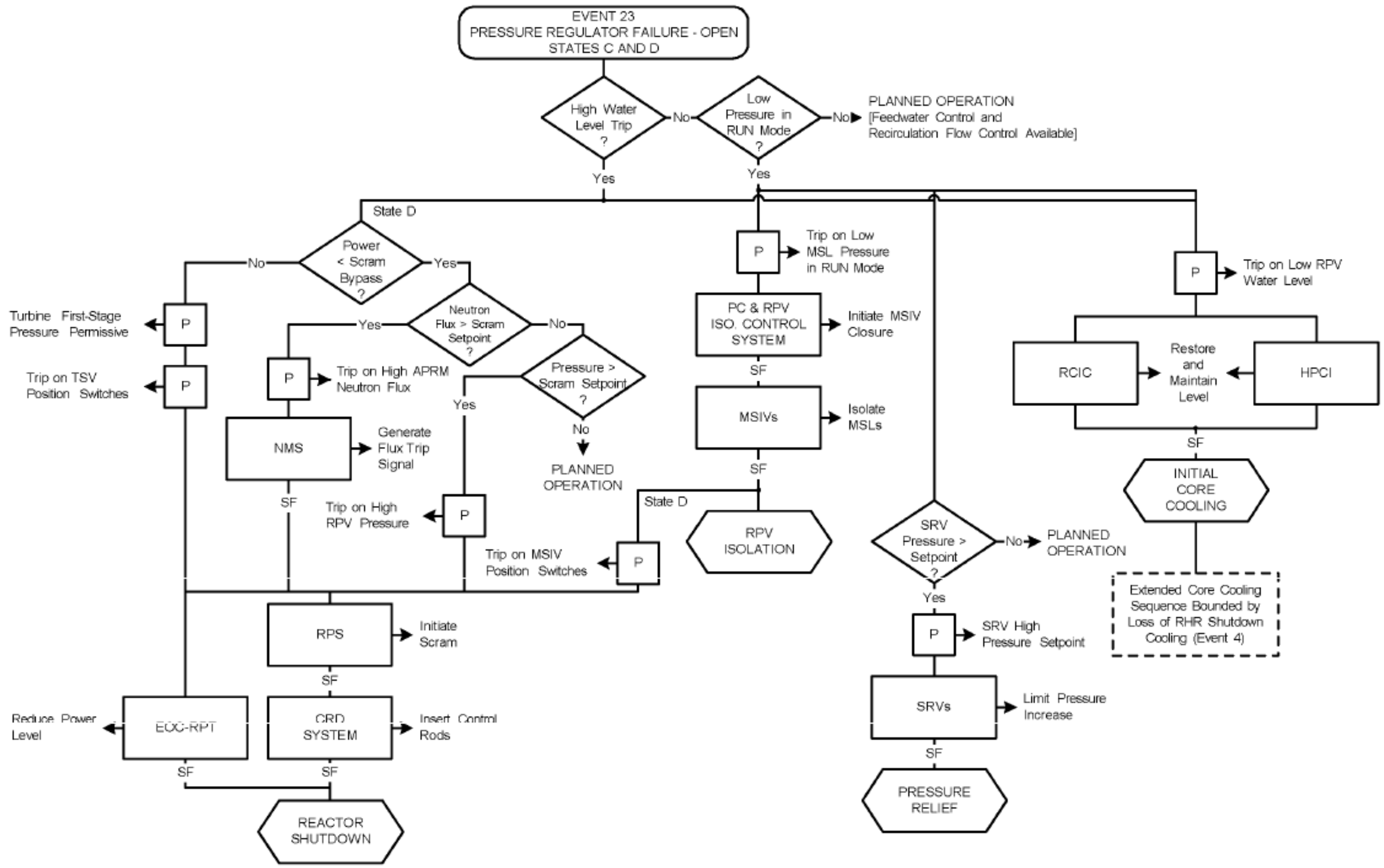
SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	EVENT DIAGRAM INADVERTENT OPENING OF AN SRV
	FIGURE 15C-25



NOTES:

1. Pressure relief is not required unless SRV setpoint is reached.
2. Event is described in 15C.4.1.8.2.

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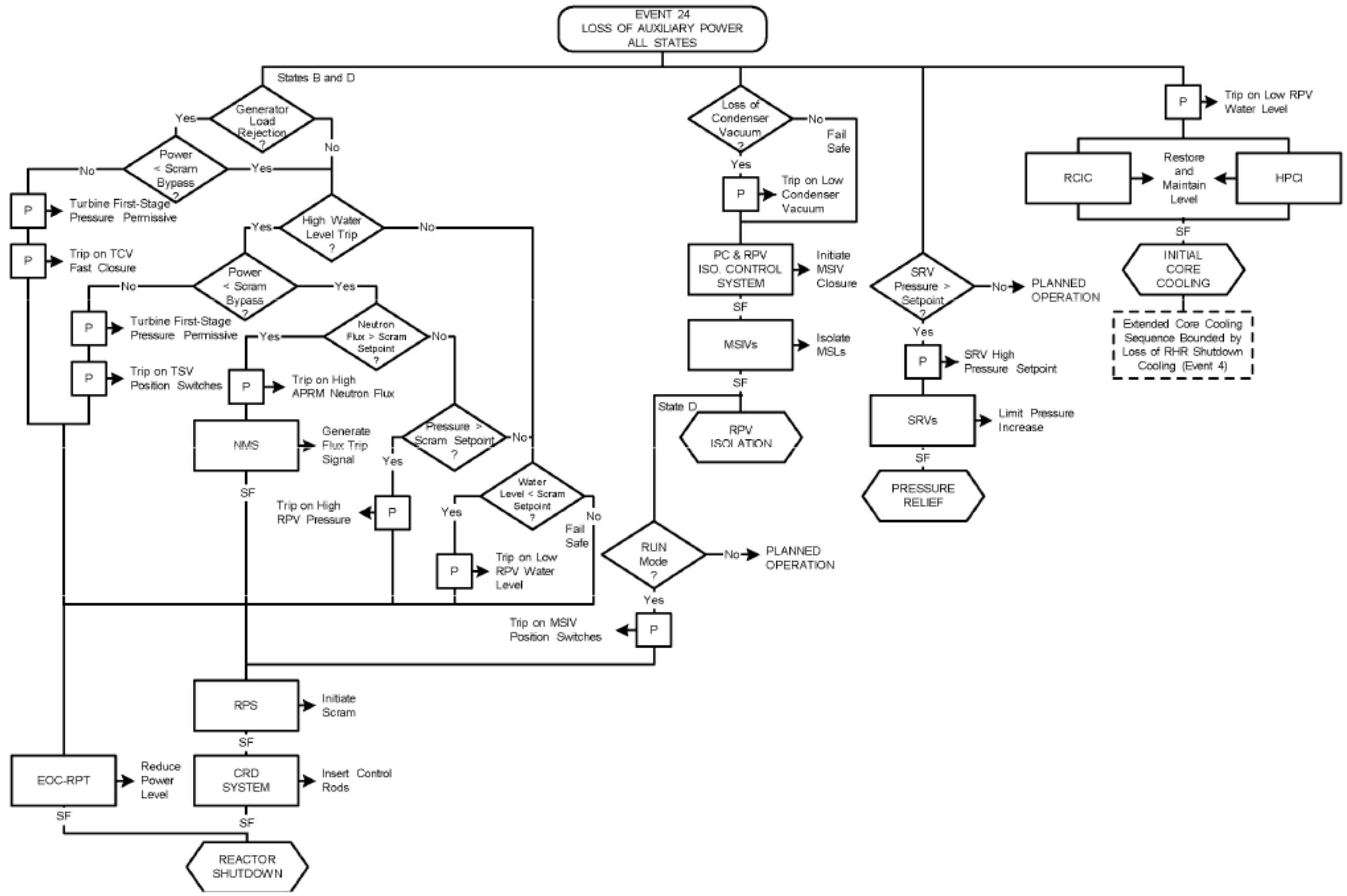
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
PRESSURE REGULATOR FAILURE - OPEN

FIGURE 15C-26



NOTES:

1. RPS M-G set coastdown initiates fail-safe scram or MSIV closure if not previously initiated.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Event 4, Loss of Shutdown Cooling, bounds loss of auxiliary power when operating in RHR shutdown cooling mode.
4. Event is described in 15C.4.1.8.3

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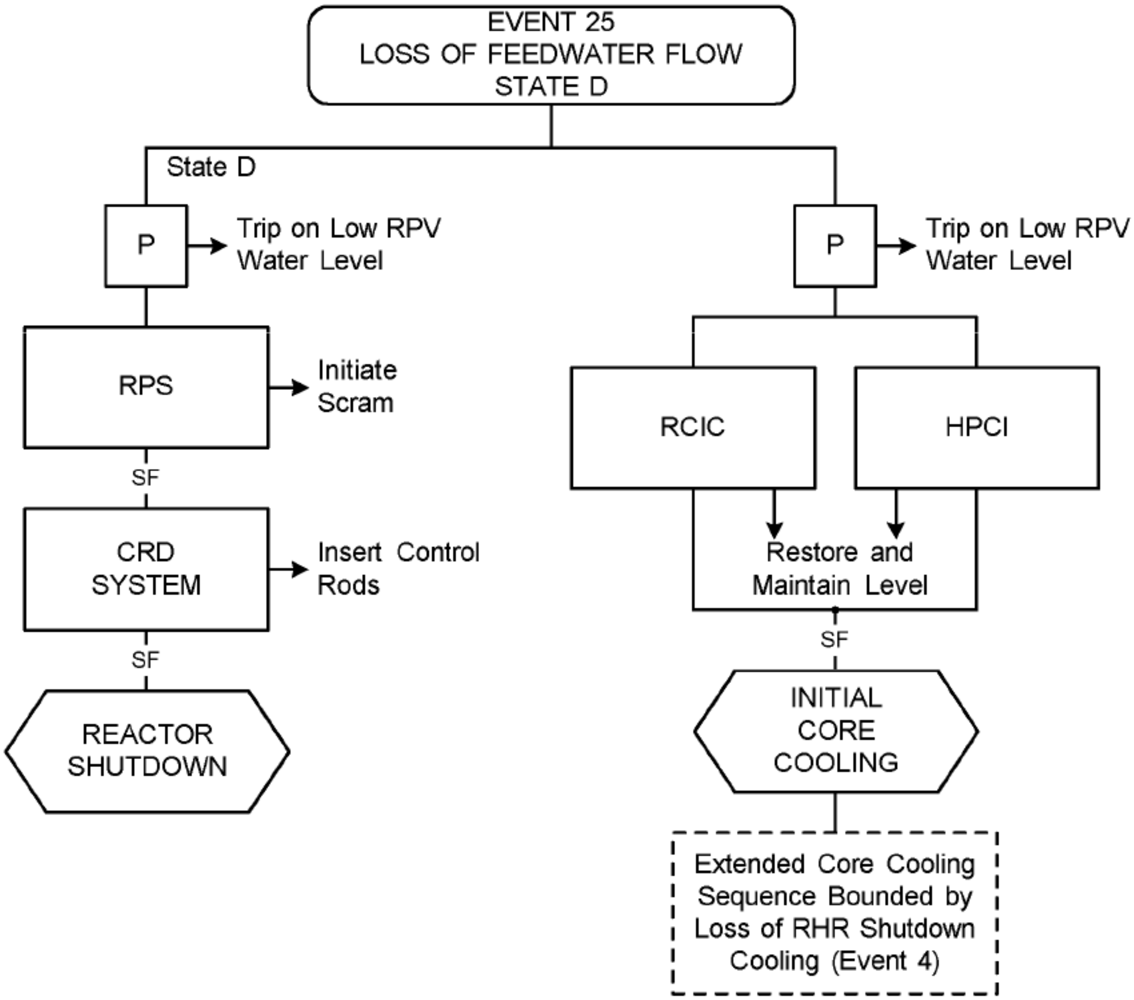
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
LOSS OF AUXILIARY POWER

FIGURE 15C-27



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish pressure relief function.
3. Event is described in 15C.4.1.8.4.

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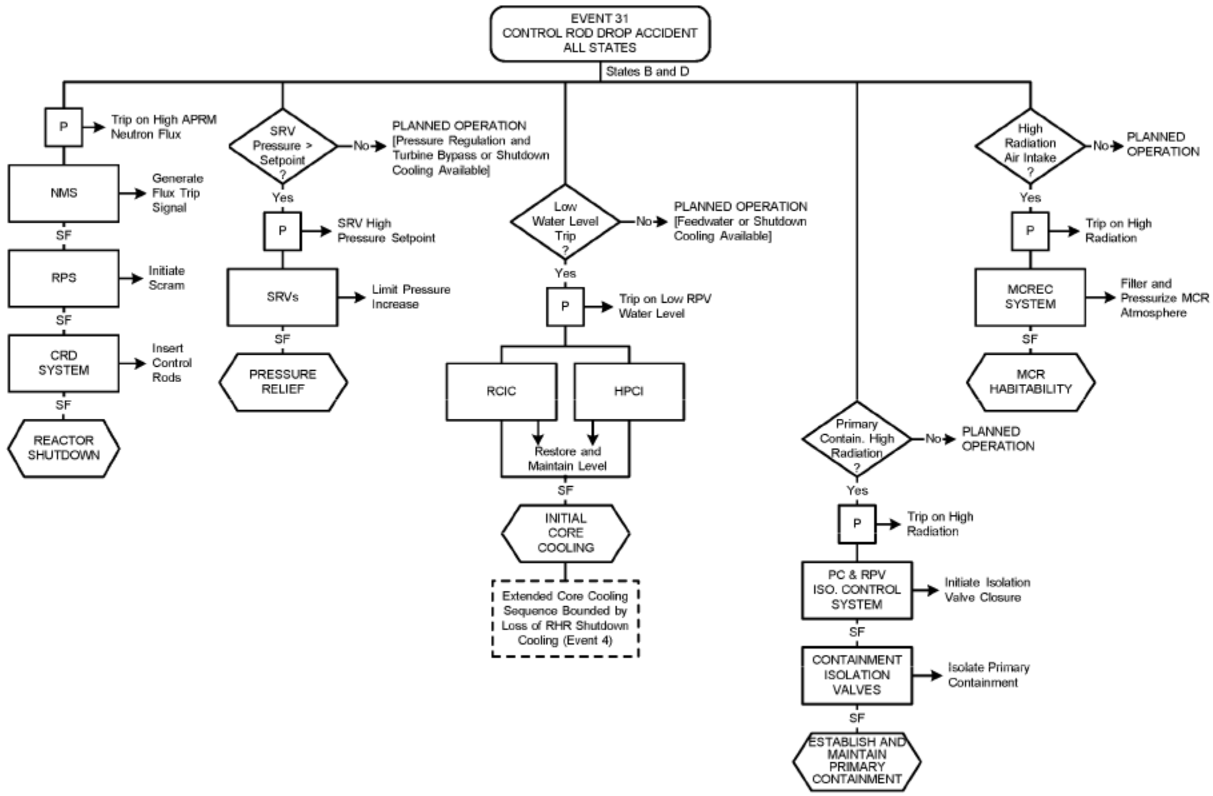
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
LOSS OF FEEDWATER FLOW

FIGURE 15C-28



NOTES:

1. RPV isolation is not required for event mitigation.
2. MCR habitability is not required if high radiation in MCR air intake does not occur.
3. Primary containment isolation is not required if radiation trip setpoint is not reached.
4. Event is described in 15C.4.2.1.
5. The CRDA limiting event path evaluated in the safety analysis (subsection 15.3.2) does not rely on RCIC to mitigate this DBA. None of the DBAs, as evaluated in the safety analysis (section 15.3), rely on RCIC for event mitigation. See subsection 15C.1.2 for an explanation of the relationship between the NSOA and the safety analysis.

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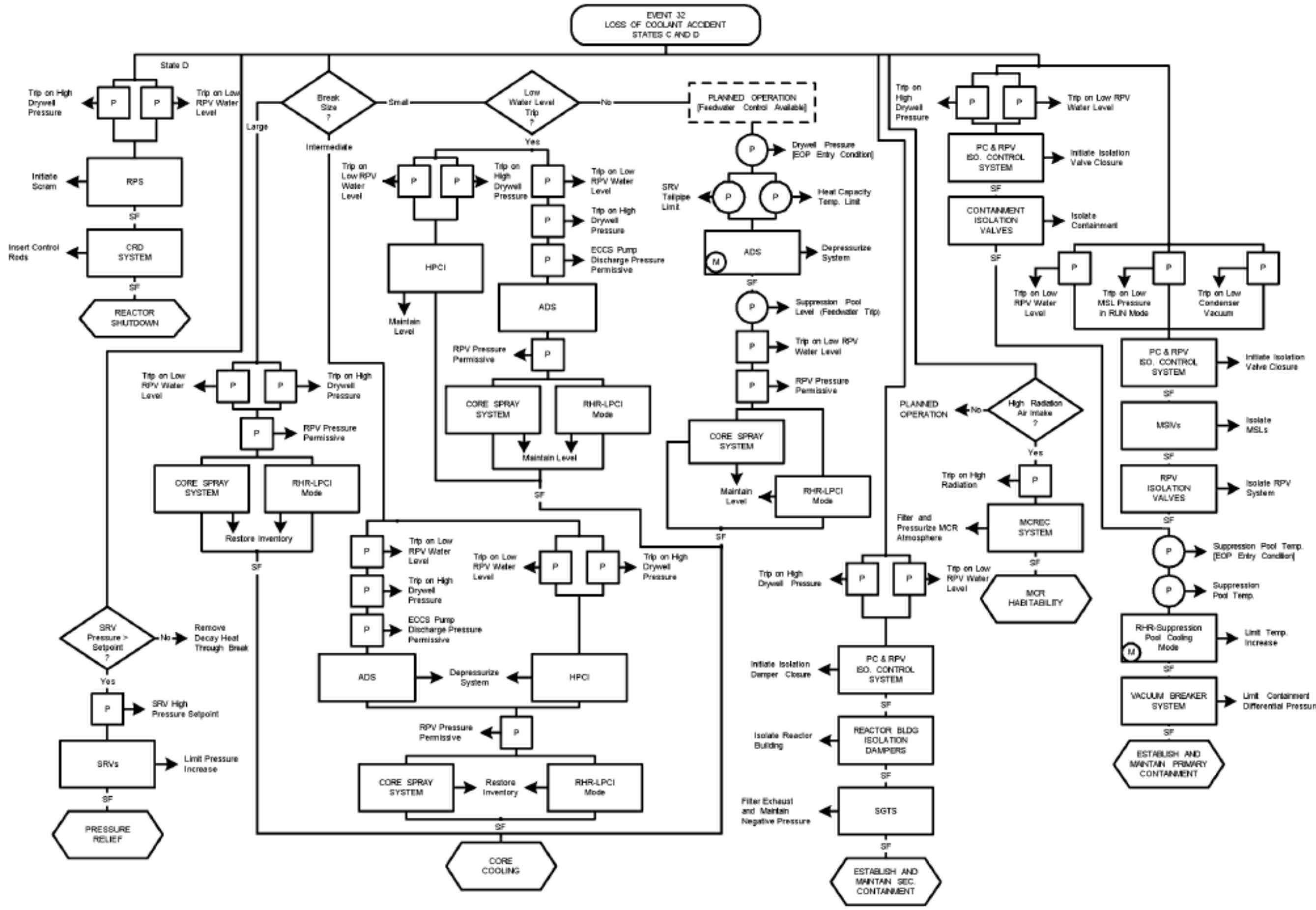
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
CONTROL ROD DROP ACCIDENT

FIGURE 15C-29



NOTES:

1. MCR habitability is not required if high radiation in MCR air intake does not occur.
2. RPV Isolation occurs as a part of the containment isolation process.
3. Event is described in 15C.4.2.2.

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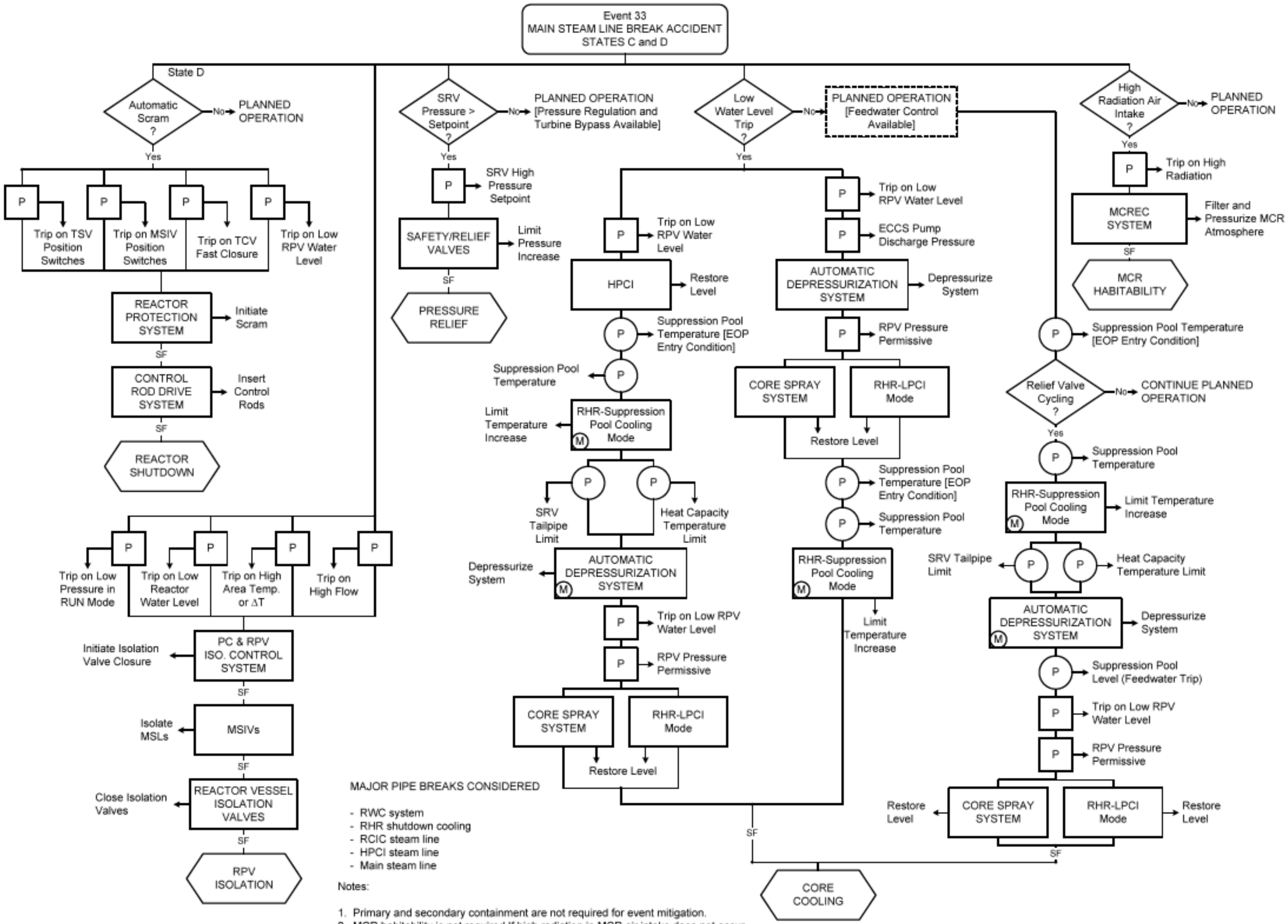
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
LOSS OF COOLANT ACCIDENT

FIGURE 15C-30



MAJOR PIPE BREAKS CONSIDERED

- RWC system
- RHR shutdown cooling
- RCIC steam line
- HPCI steam line
- Main steam line

Notes:

1. Primary and secondary containment are not required for event mitigation.
2. MCR habitability is not required If high radiation in MCR air intake does not occur.
3. Major pipe breaks considered by event are listed above
4. Event is described in 15C.4.2.3

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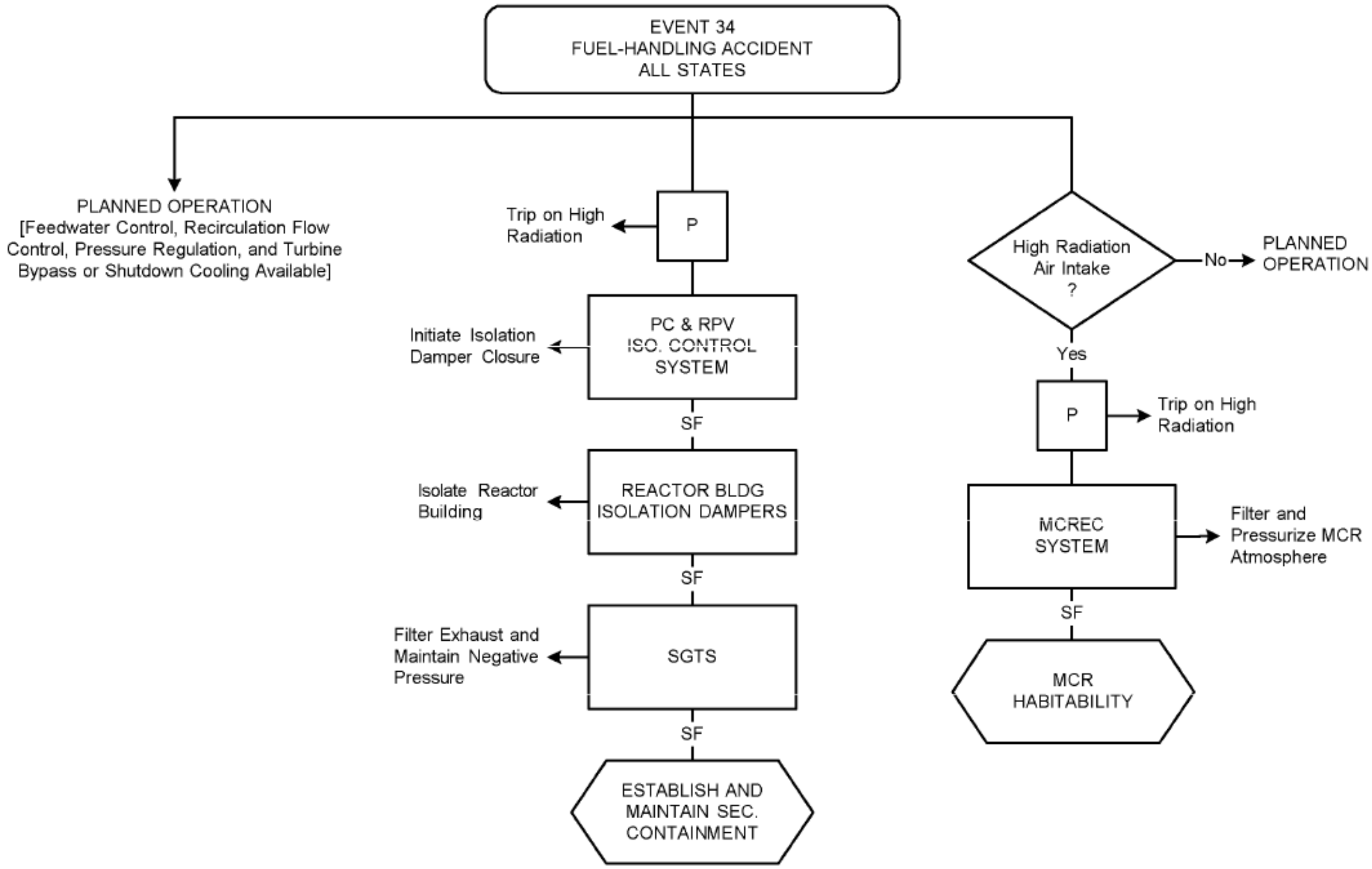
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
MAIN STEAM LINE BREAK ACCIDENT

FIGURE 15C-31



NOTES:

1. Scram, RPV isolation, and primary containment isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. MCR habitability is not required if high radiation in MCR air intake does not occur.
4. Event is described in 15C.4.2.4.

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SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	EVENT DIAGRAM FUEL-HANDLING ACCIDENT
	FIGURE 15C-32

EVENT 35
FUEL ASSEMBLY LOADING ERROR
ALL STATES

↓

PLANNED OPERATION
[Feedwater Control, Recirculation Flow Control, Pressure Regulation, and Turbine Bypass or Shutdown Cooling Available]

NOTES:

1. Reactor shutdown, RPV isolation, primary containment, secondary containment, and MCR habitability are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.2.5.

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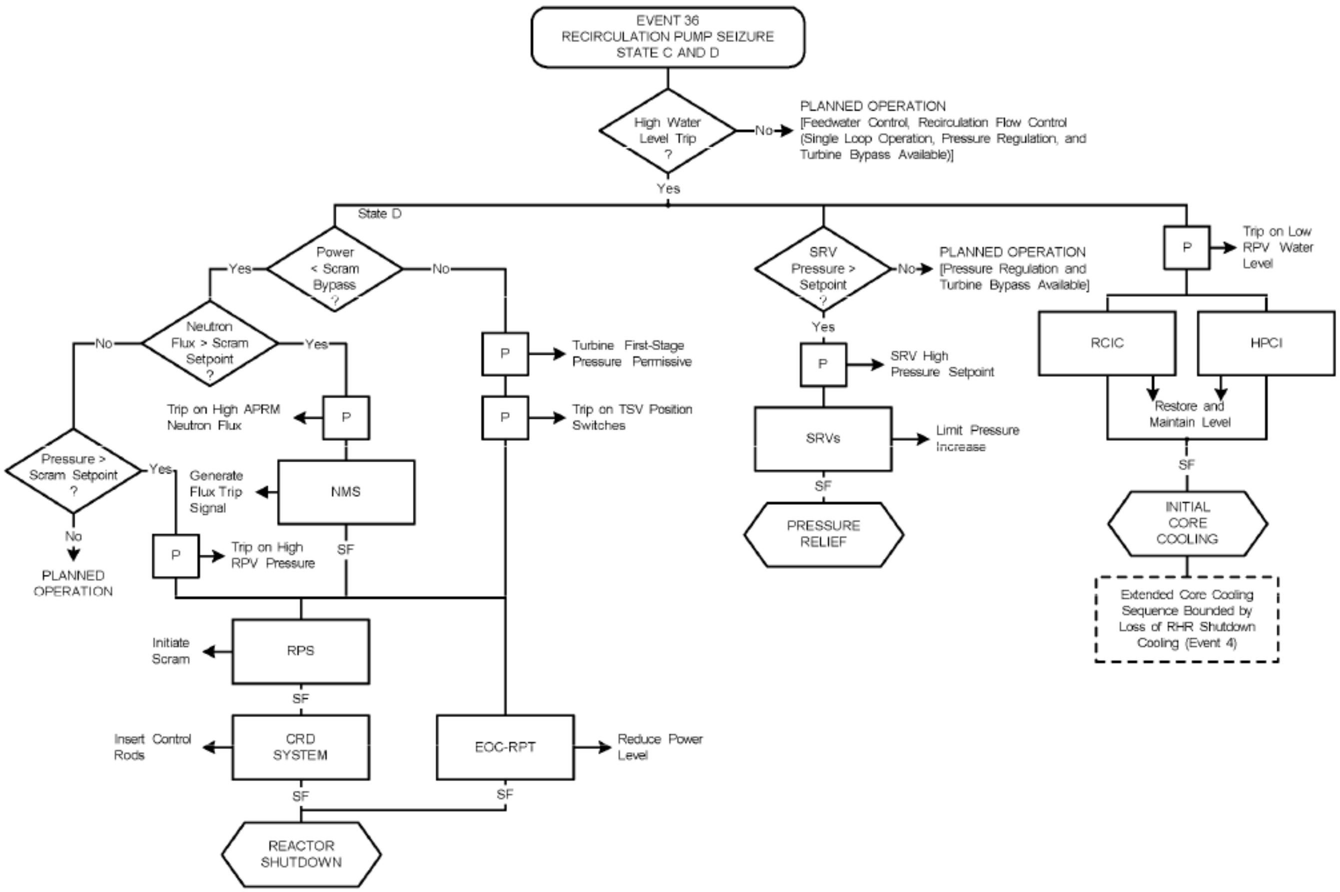
SOUTHERN NUCLEAR OPERATING COMPANY **EDWIN I. HATCH NUCLEAR PLANT** **UNIT 2**	EVENT DIAGRAM FUEL ASSEMBLY LOADING ERROR
	FIGURE 15C-33



NOTES:

1. RPV isolation, primary containment, secondary containment, and MCR habitability are not required for event mitigation.
2. Reactor shutdown is not required if scram setpoint is not reached.
3. Pressure relief is not required if SRV setpoint is not reached.
4. Event is described in 15C.4.2.6.

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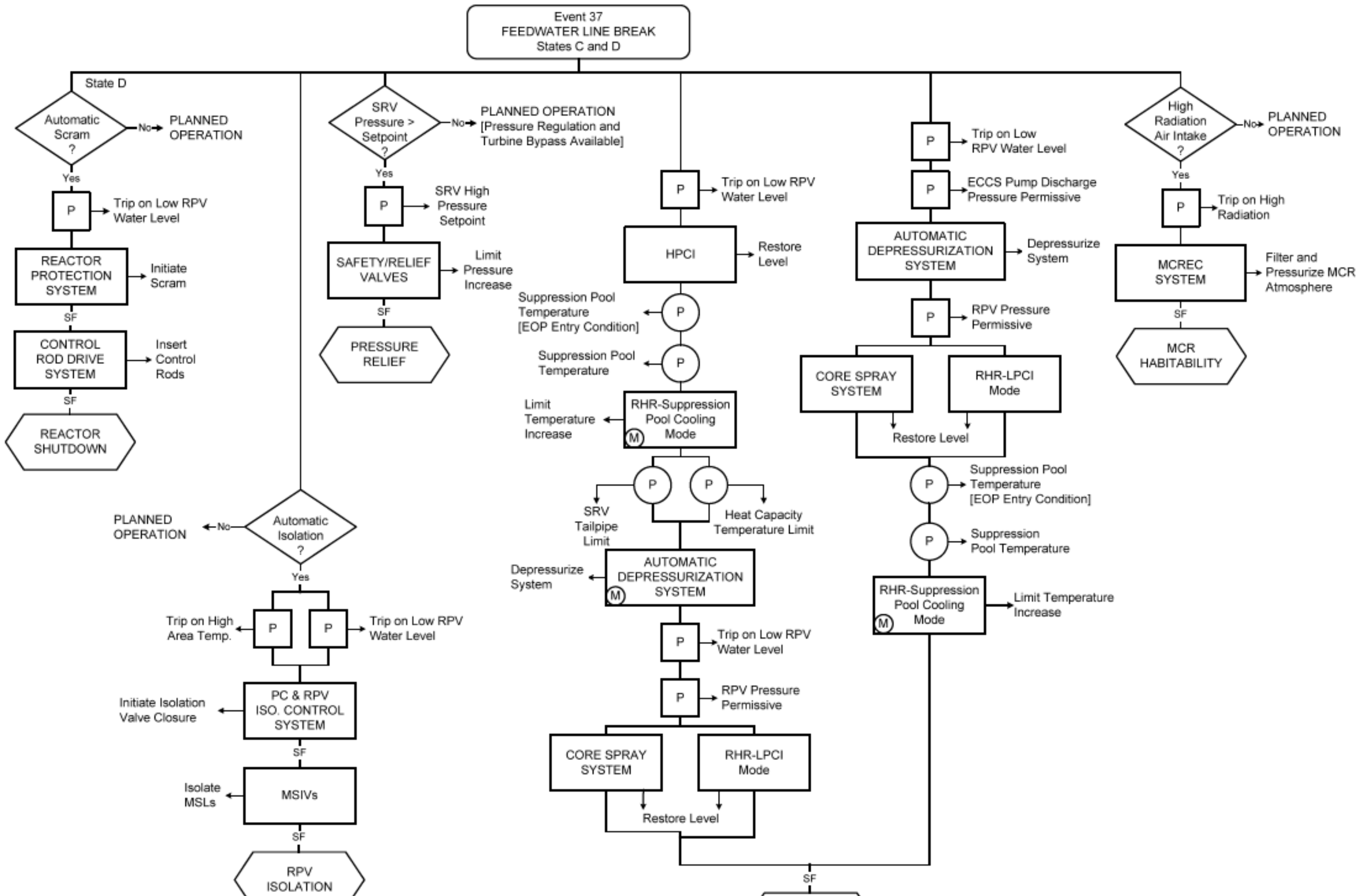
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
RECIRCULATION PUMP SEIZURE

FIGURE 15C-34



Notes:

1. Primary and secondary containment not required for event mitigation.
2. MCR habitability not required if high radiation in MCR air intake does not occur.
3. Event is described in 15C.4.2.7

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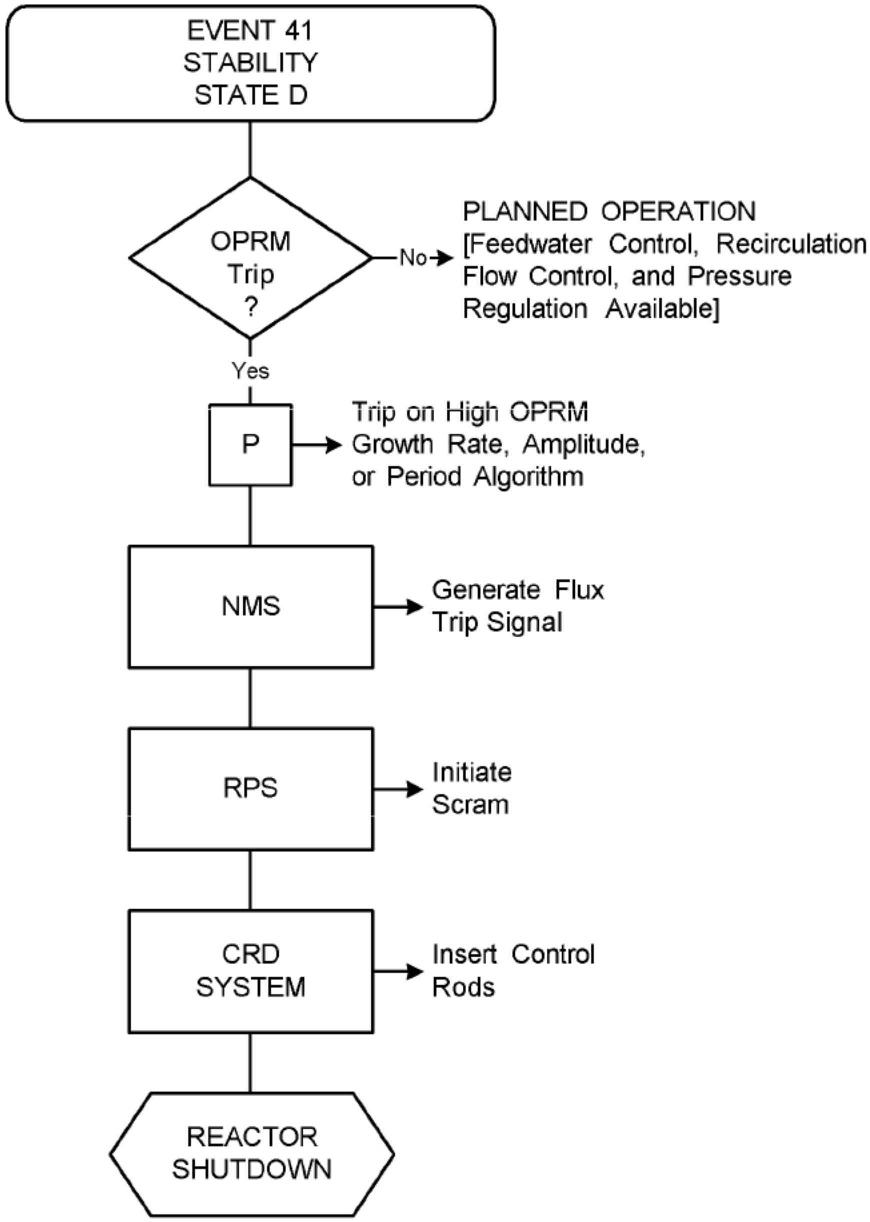
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
FEEDWATER LINE BREAK

FIGURE 15C-35



NOTES:

1. RPV isolation is not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.3.1.

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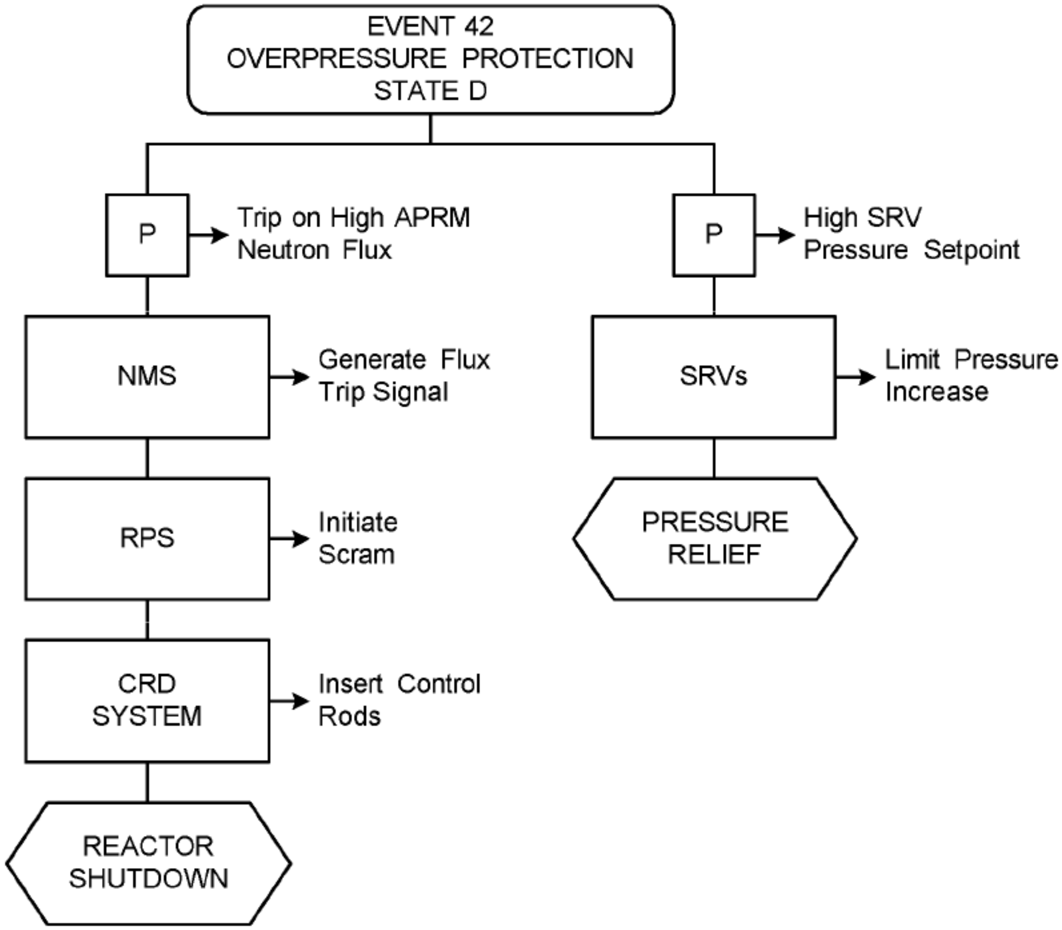

NOTES:

1. Event is closure of all MSIVs with flux scram.
2. Event is described in 15C.4.3.2.

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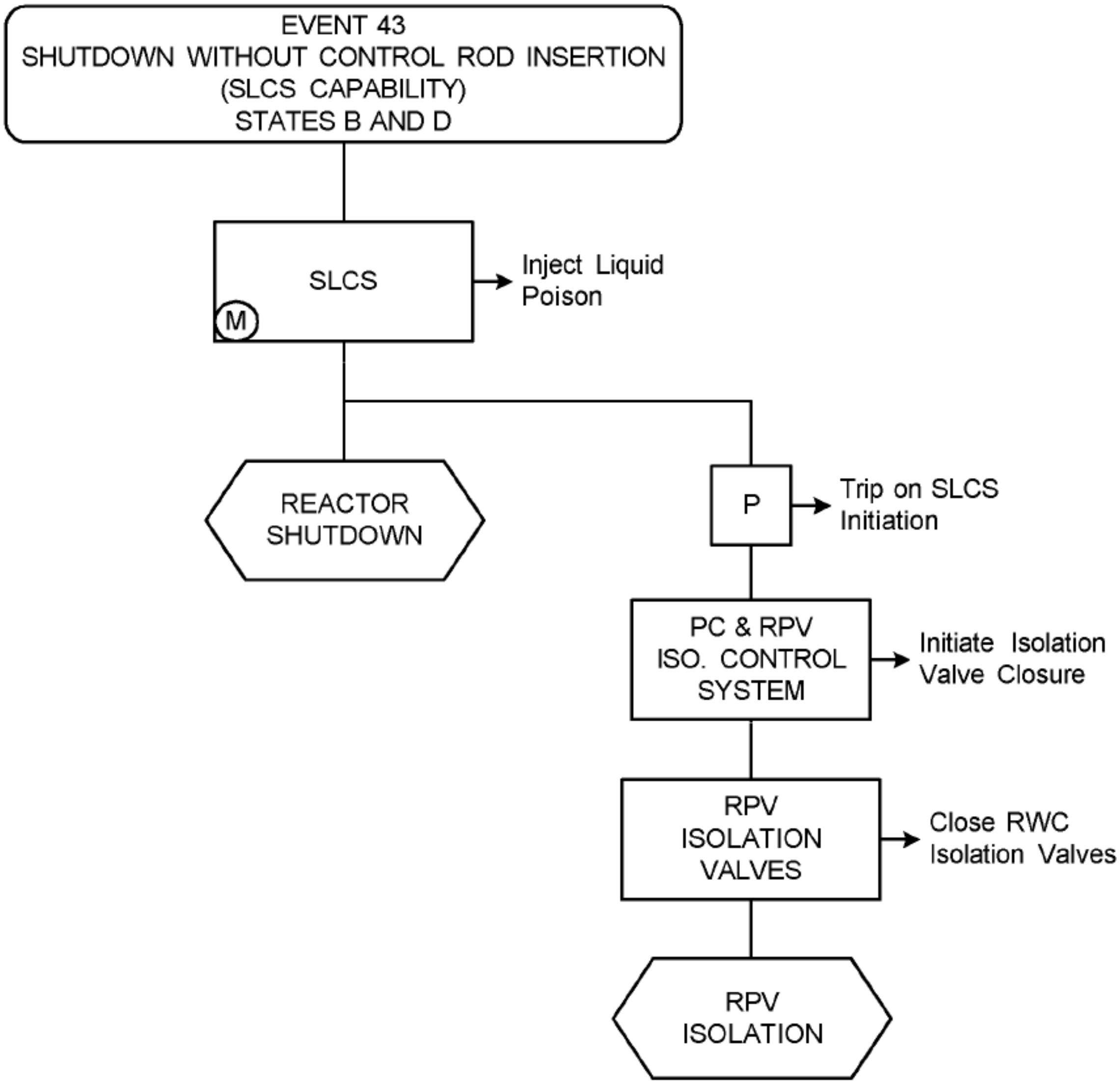
EVENT DIAGRAM
OVERPRESSURE PROTECTION

FIGURE 15C-37



NOTES:

1. Normal operating systems accomplish core cooling and pressure relief functions.
2. Event is described in 15C.4.3.3.

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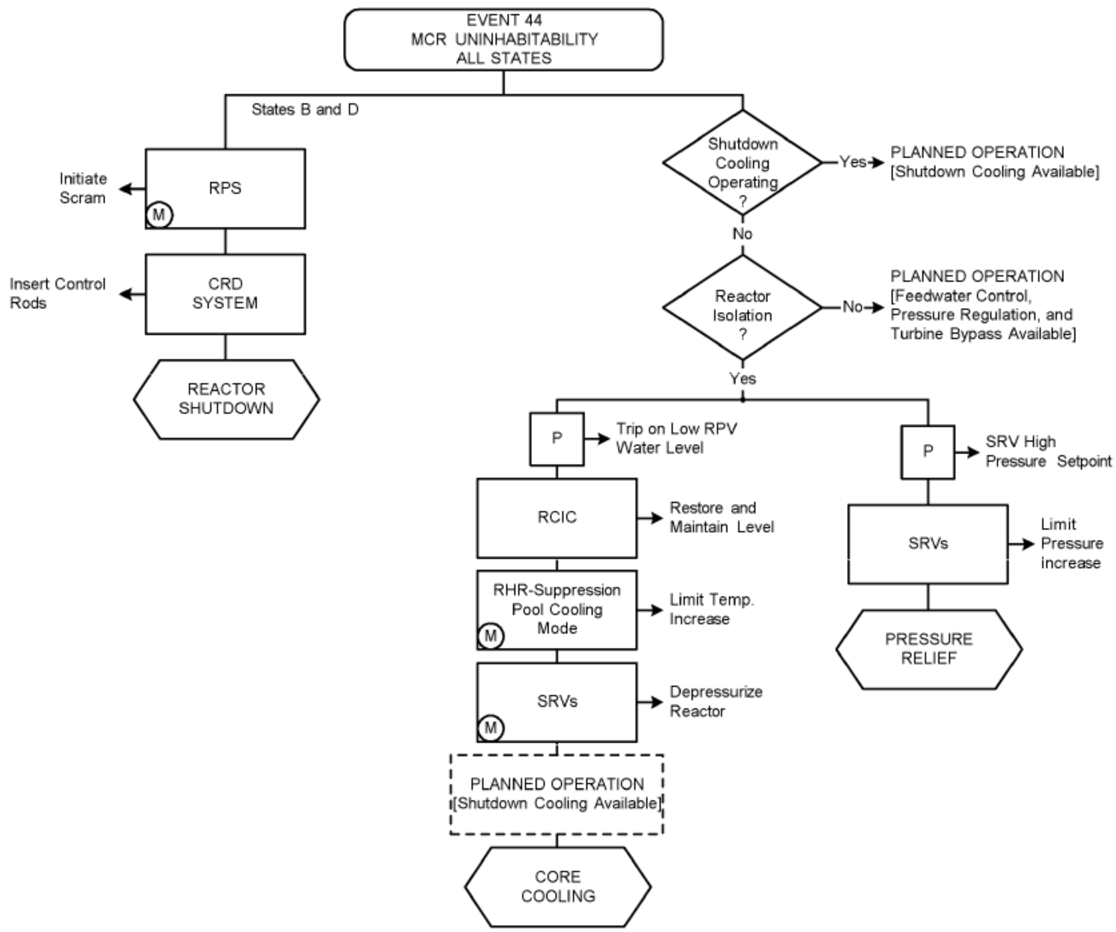
SOUTHERN COMPANY *Energy to Serve Your World®* **SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2**	EVENT DIAGRAM SHUTDOWN WITHOUT CONTROL ROD INSERTION (SLCS CAPABILITY)
	FIGURE 15C-38



NOTES:

1. Normal operating systems accomplish core cooling and pressure relief functions if reactor is not isolated.
2. Manual operation of SRVs is from shutdown panel.
3. Event is described in 15C.4.3.4.

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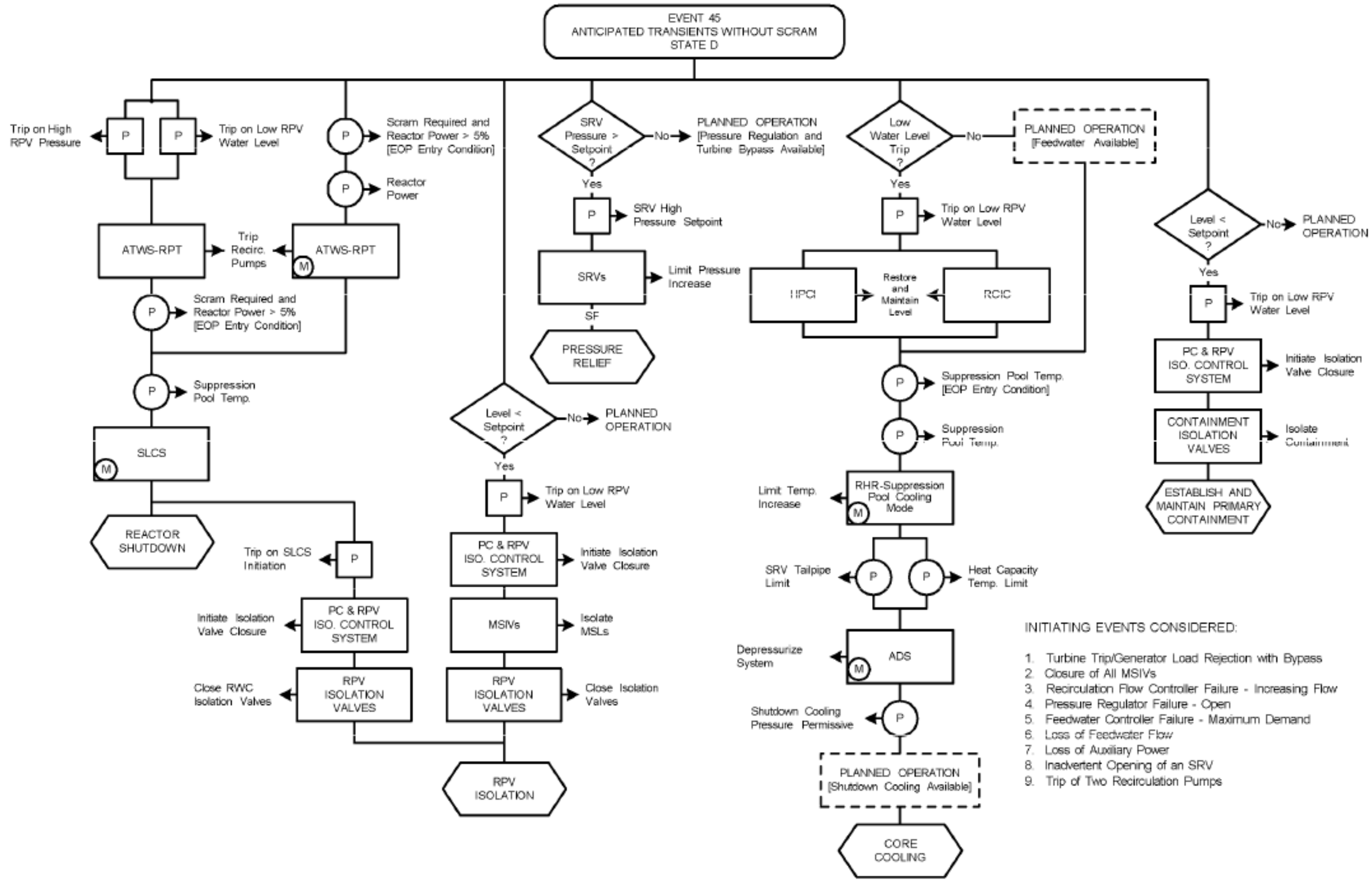
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
MCR UNINHABITABILITY

FIGURE 15C-39



NOTES:

1. RPV and containment isolations are not required if low waster level does not occur.
2. Pressure relief is not requires if SRV setpoint is not reached.
3. Event is described in 15C.4.3.5.

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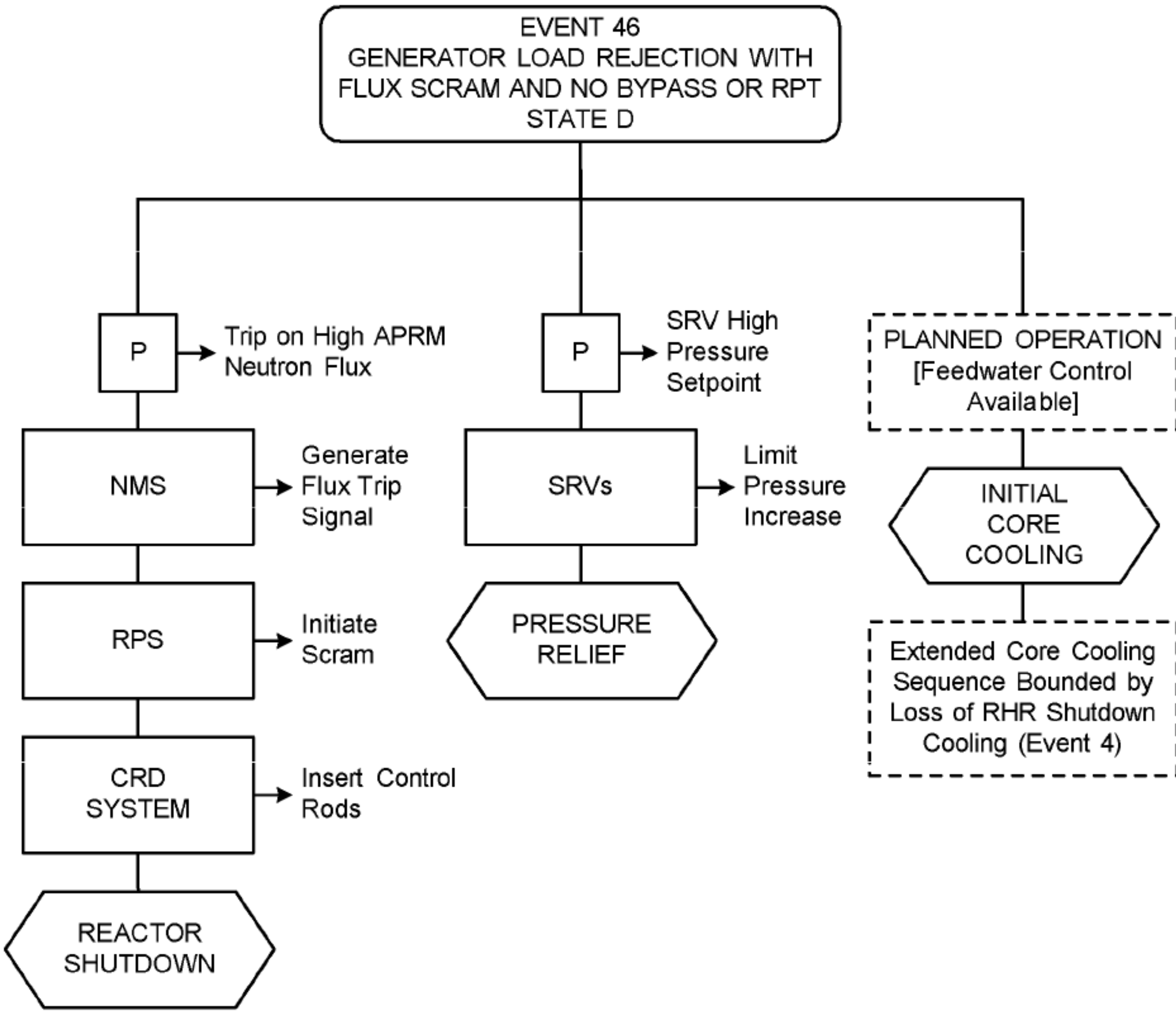
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
ANTICIPATED TRANSIENT WITHOUT SCRAM

FIGURE 15C-40



NOTES:

1. Normal operating systems accomplish initial core cooling; feedwater trip may be required due to high suppression pool level.
2. RPV isolation is not required for event mitigation.
3. Event is described in 15C.4.3.6.

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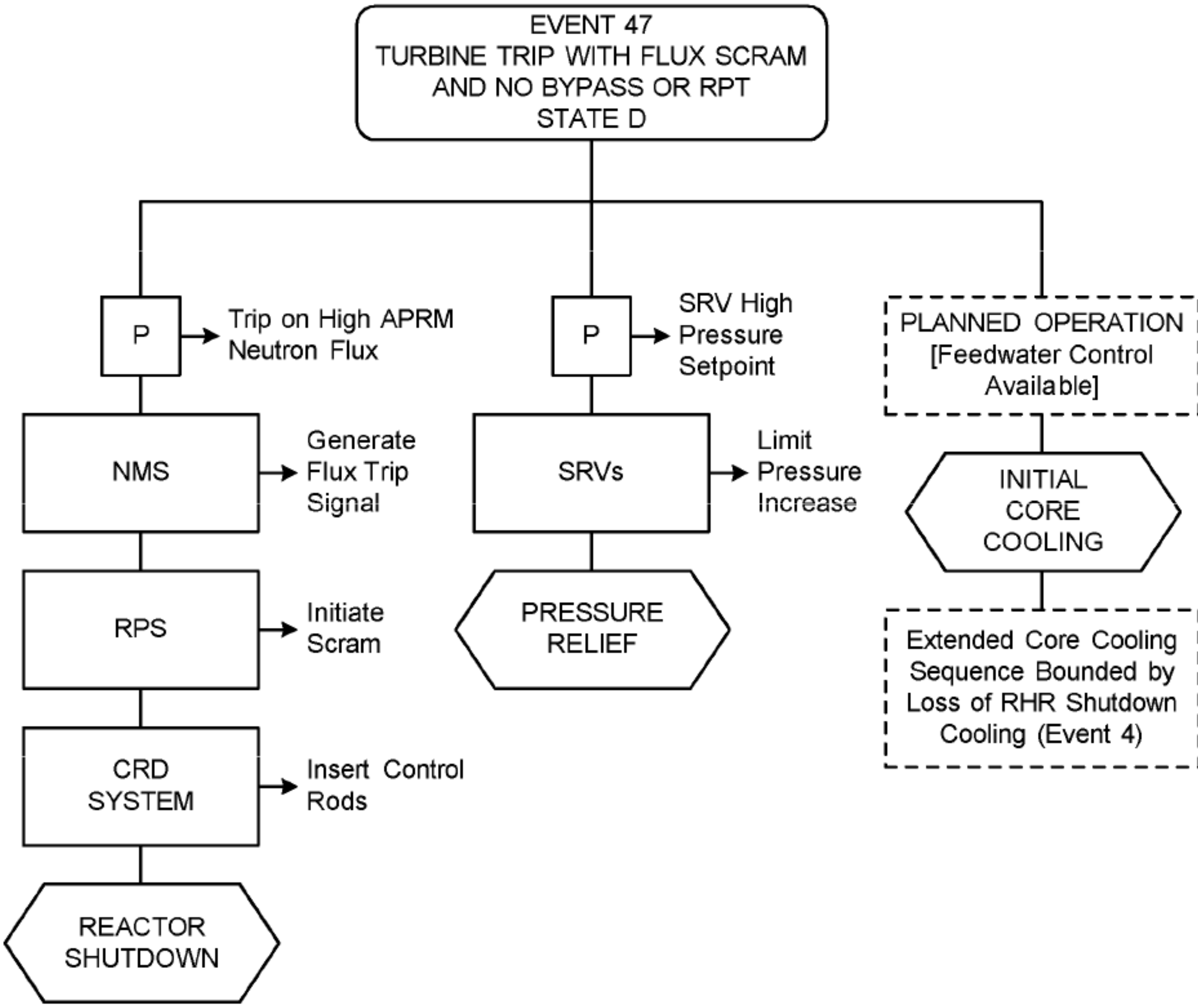
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

EVENT DIAGRAM
GENERATOR LOAD REJECTION WITH
FLUX SCRAM AND NO BYPASS OR RPT

FIGURE 15C-41



NOTES:

1. Normal operating systems accomplish initial core cooling; feedwater trip may be required due to high suppression pool level.
2. RPV isolation is not required for event mitigation.
3. Event is described in 15C.4.3.7.

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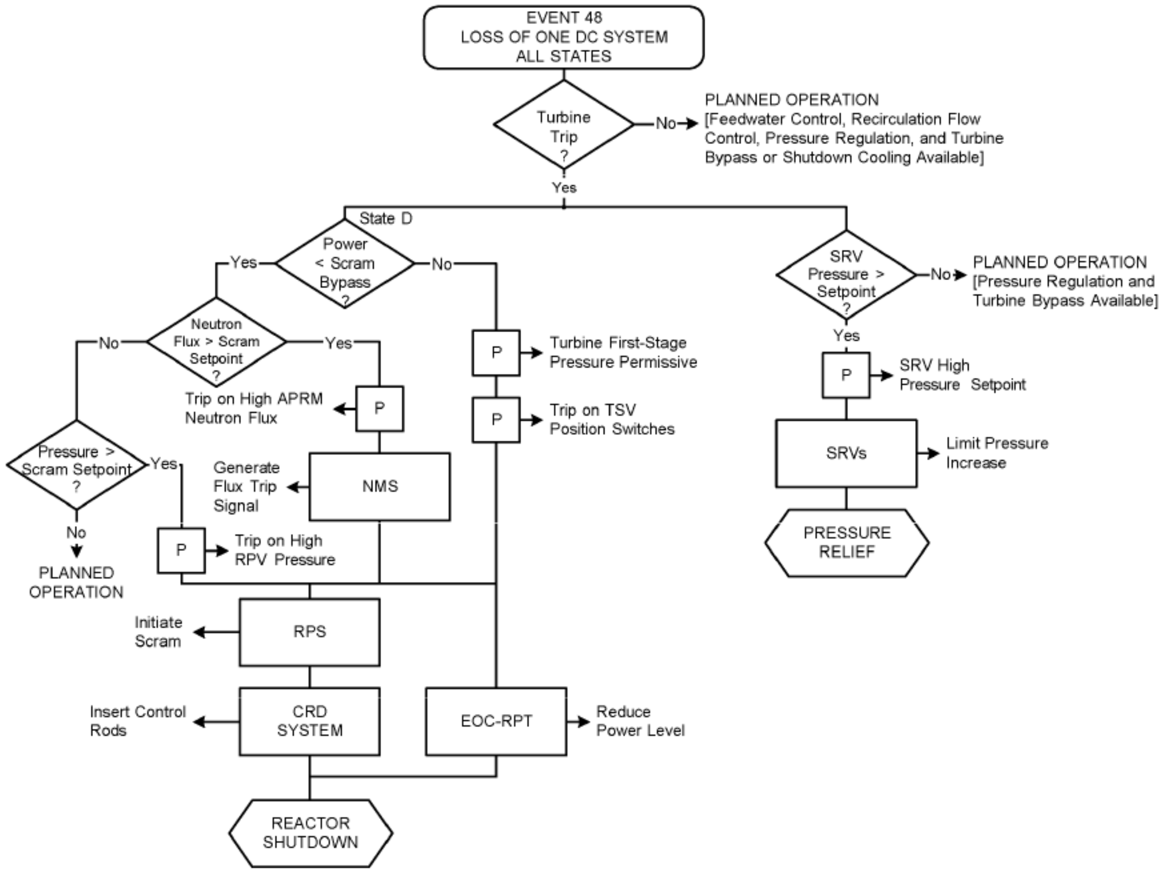
EVENT DIAGRAM
TURBINE TRIP WITH FLUX SCRAM AND NO BYPASS OR RPT

FIGURE 15C-42



NOTES:

1. Normal operating systems accomplish core cooling function.
2. RPV isolation is not required for event mitigation.
3. Reactor shutdown is not required if scram setpoint is not reached.
4. Pressure relief is not required if SRV setpoint is not reached.
5. Event is described in 15C.4.3.8.

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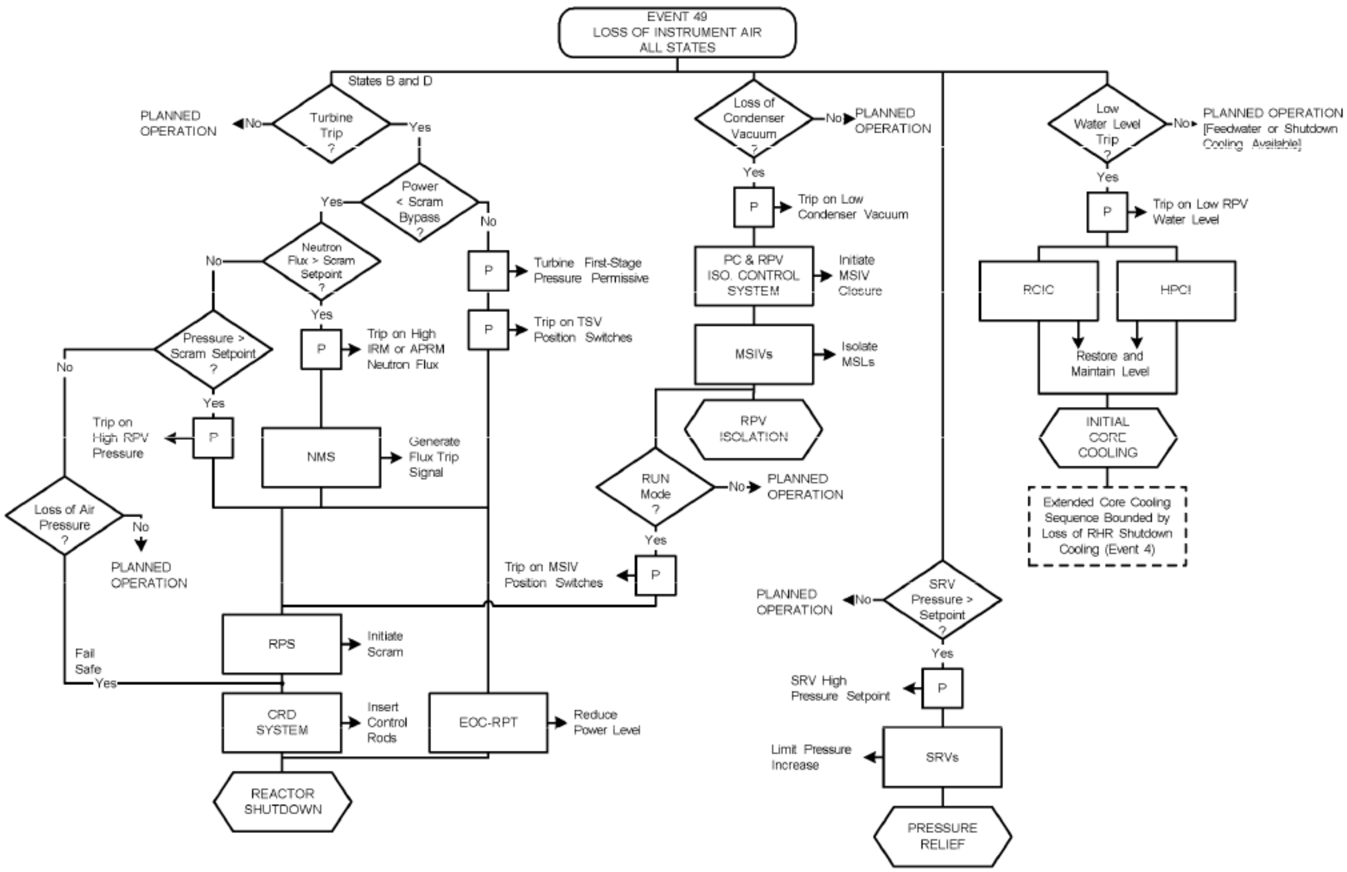
EVENT DIAGRAM
LOSS OF ONE dc SYSTEM

FIGURE 15C-43



NOTES:

1. Reactor shutdown is not required if scram or loss of air pressure to backup scram valves does not occur.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Scram will occur on MSIV closure in RUN mode.
4. Turbine trip can occur on either high RPV water level due to feedwater controller failure or loss of condenser vacuum.
5. Event is described in 15C.4.3.9

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EVENT DIAGRAM
LOSS OF INSTRUMENT AIR

FIGURE 15C-44

EVENT 50
LOSS OF SERVICE WATER SYSTEM
ALL STATES

↓

PLANNED OPERATION
[Feedwater Control, Recirculation Flow Control, Pressure Regulation, and Turbine Bypass or Shutdown Cooling Available]

NOTES:

1. Reactor shutdown and RPV isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.3.10.

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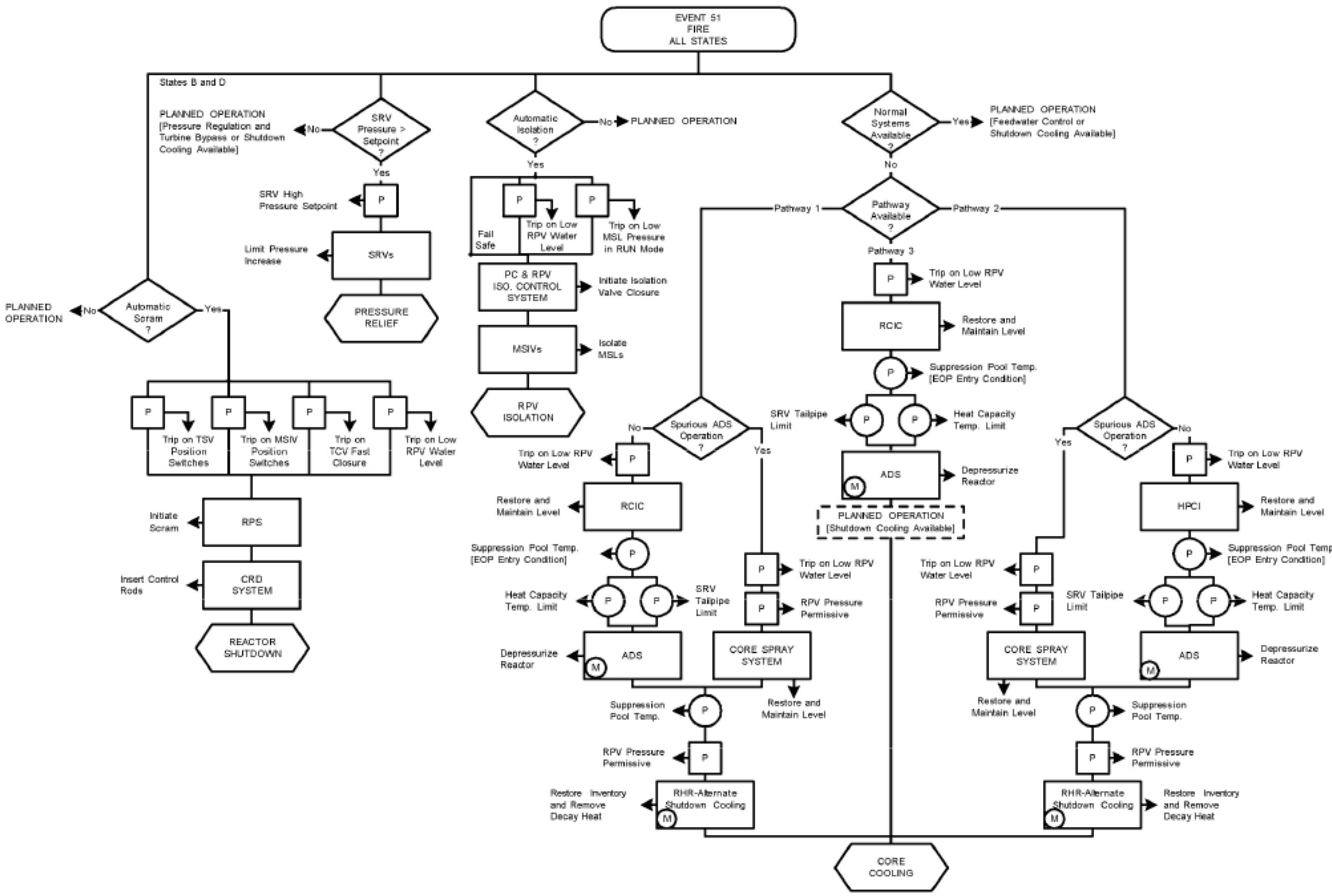
EVENT DIAGRAM
LOSS OF SERVICE WATER SYSTEM

FIGURE 15C-45



NOTES:

1. Normal operating systems accomplish core cooling and pressure relief functions.
2. Normal operating systems are feedwater or shutdown cooling depending on the operating mode.
3. RPV isolation is not required if not automatically initiated.
4. Event is described in 15C.4.3.11.

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EVENT DIAGRAM
FIRE

FIGURE 15C-46

EVENT 52
MISCELLANEOUS SMALL RELEASES
OUTSIDE CONTAINMENT
ALL STATES

↓

PLANNED OPERATION
[Feedwater Control, Recirculation Flow Control, Pressure Regulation, and Turbine Bypass or Shutdown Cooling Available]

NOTES:

1. Reactor shutdown and RPV isolation are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.3.12.

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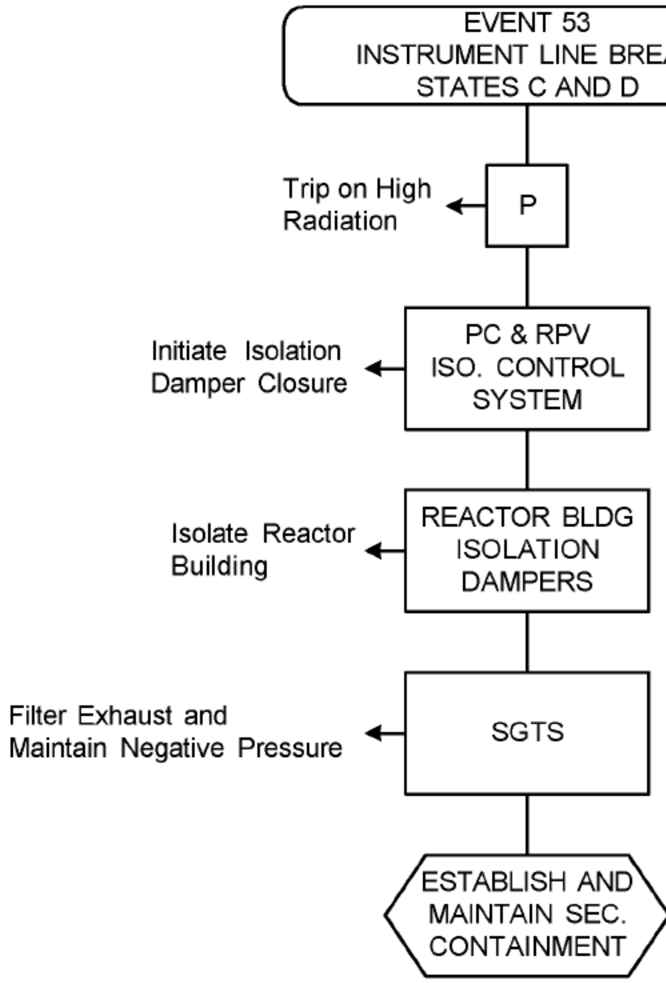
EVENT DIAGRAM
MISCELLANEOUS SMALL RELEASES
OUTSIDE CONTAINMENT

FIGURE 15C-47



NOTES:

1. Reactor shutdown, RPV isolation, primary containment, and MCR habitability are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.3.13.

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UNIT 2

EVENT DIAGRAM
INSTRUMENT LINE BREAK

FIGURE 15C-48

EVENT 54
LIQUID RADWASTE TANK FAILURE
ALL STATES

PLANNED OPERATION
[Feedwater Control, Recirculation Flow Control, Pressure Regulation, and Turbine Bypass or Shutdown Cooling Available]

NOTES:

1. Reactor shutdown, RPV isolation, primary containment, secondary containment, and MCR habitability are not required for event mitigation.
2. Normal operating systems accomplish core cooling and pressure relief functions.
3. Event is described in 15C.4.3.14.

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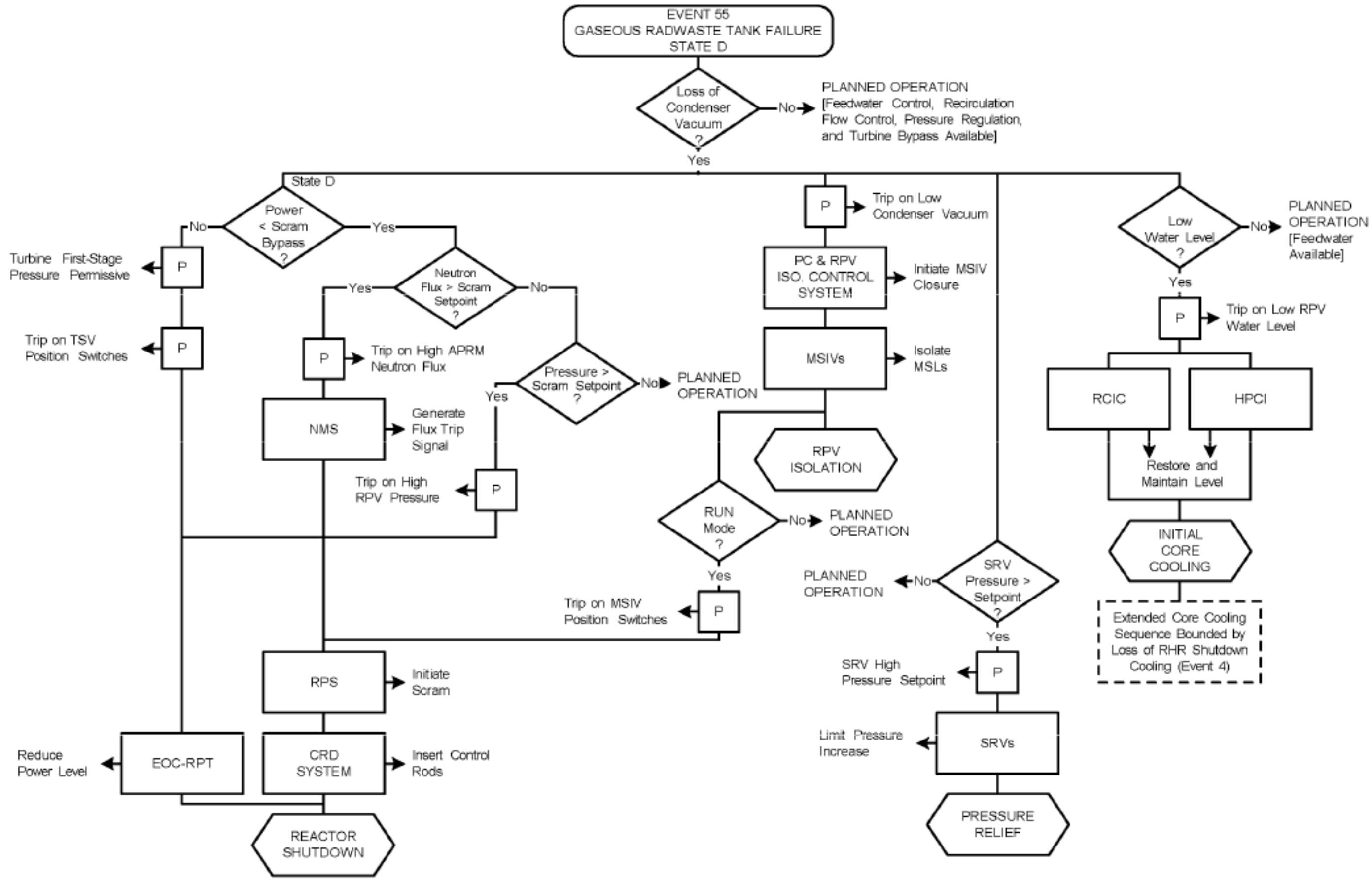
SOUTHERN NUCLEAR OPERATING COMPANY **EDWIN I. HATCH NUCLEAR PLANT** **UNIT 2**	EVENT DIAGRAM LIQUID RADWASTE TANK FAILURE
	FIGURE 15C-49



NOTES:

1. Reactor shutdown is not required if RPV pressure permissive to bypass scram is not reached.
2. Pressure relief is not required if SRV setpoint is not reached.
3. RPV isolation is not required if reactor is not in RUN mode.
4. Event is described in 15C.4.3.15.

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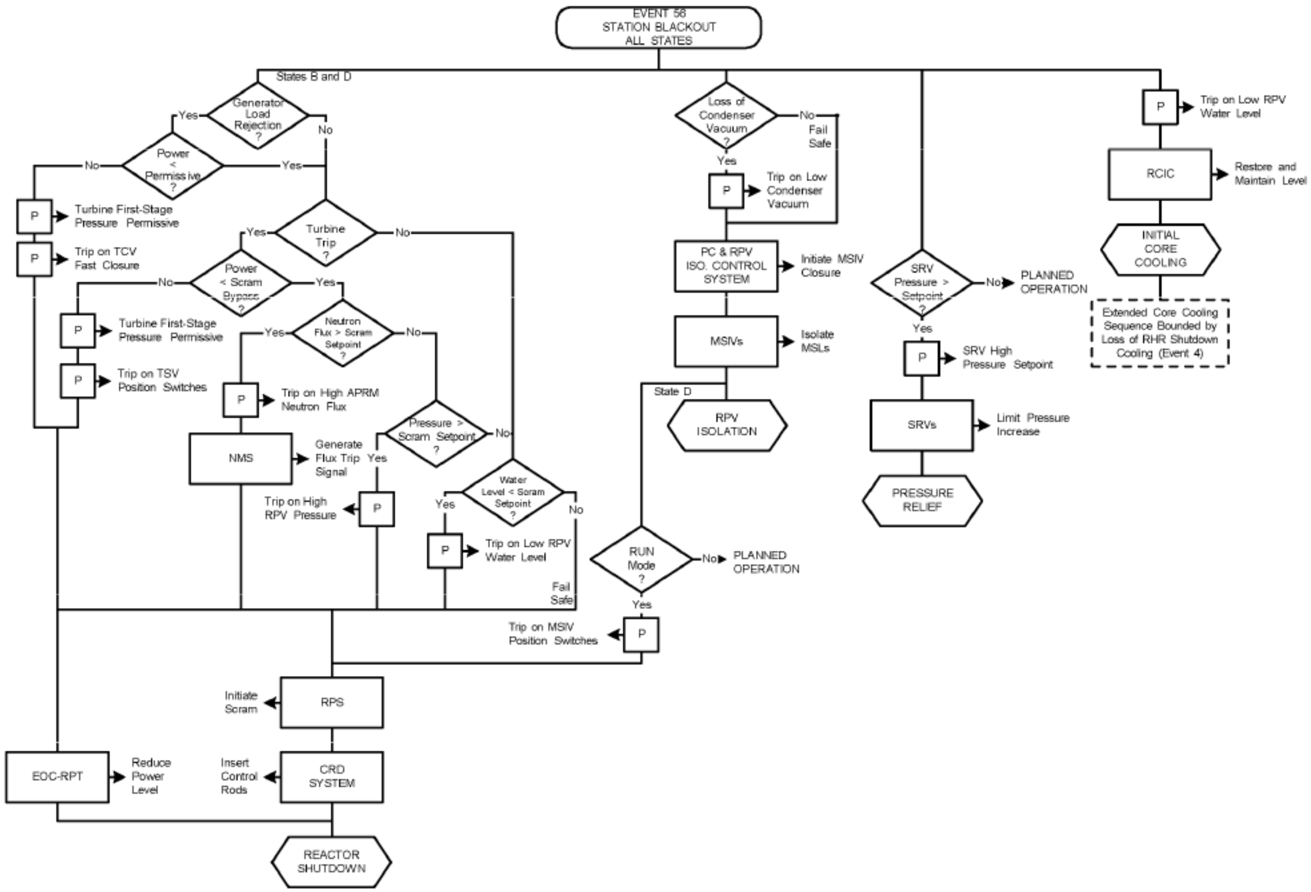
EVENT DIAGRAM
GASEOUS RADWASTE TANK FAILURE

FIGURE 15C-50



NOTES:

1. RPS M-G set coastdown initiates fail-safe scram or MSIV closure if not previously initiated.
2. Pressure relief is not required if SRV setpoint is not reached.
3. Event 4, Loss of Shutdown Cooling, bounds loss of power when operating in RHR-shutdown cooling mode.
4. Event is described in 15C.4.3.16.

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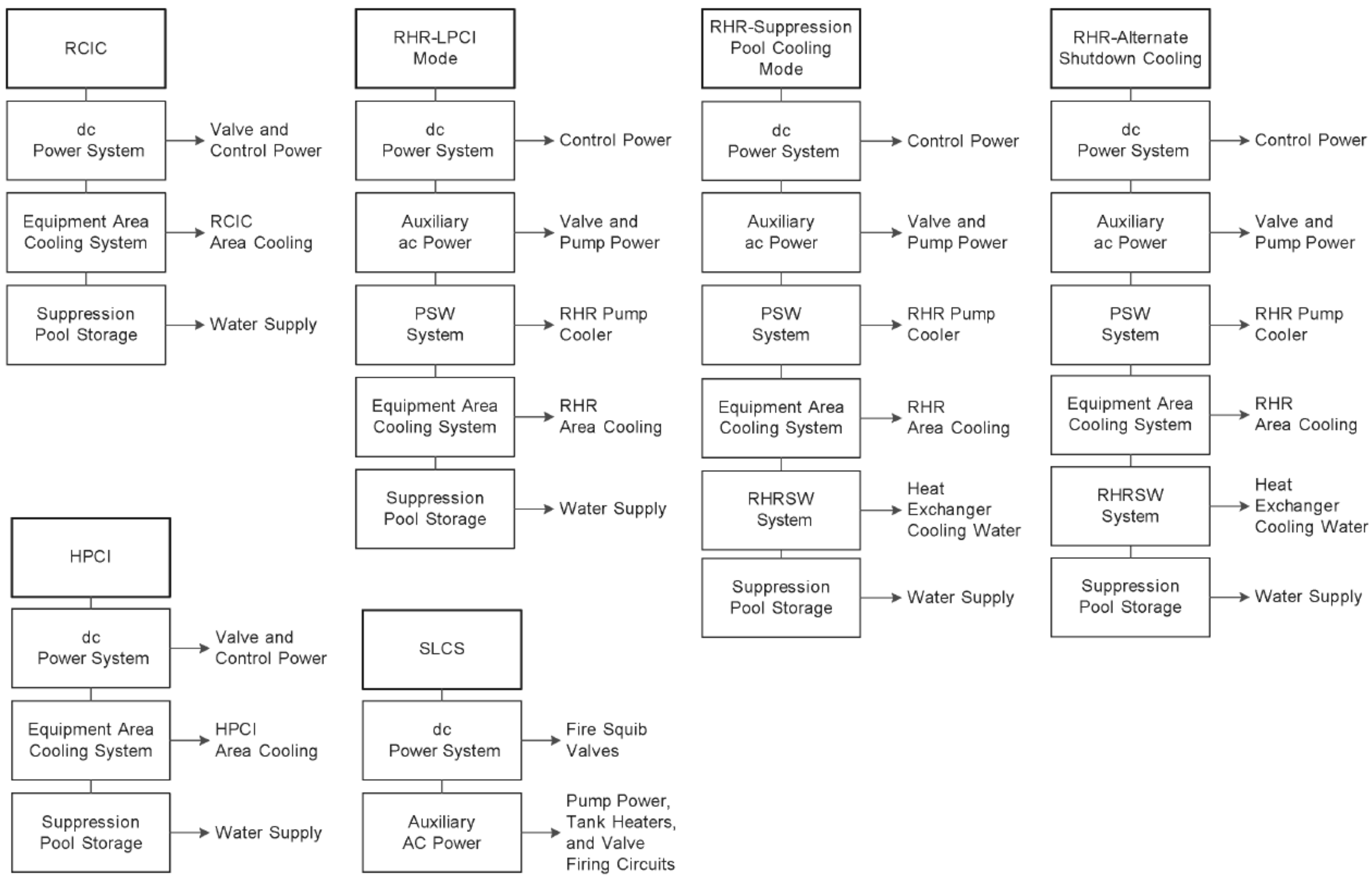
EVENT DIAGRAM
STATION BLACKOUT

FIGURE 15C-51



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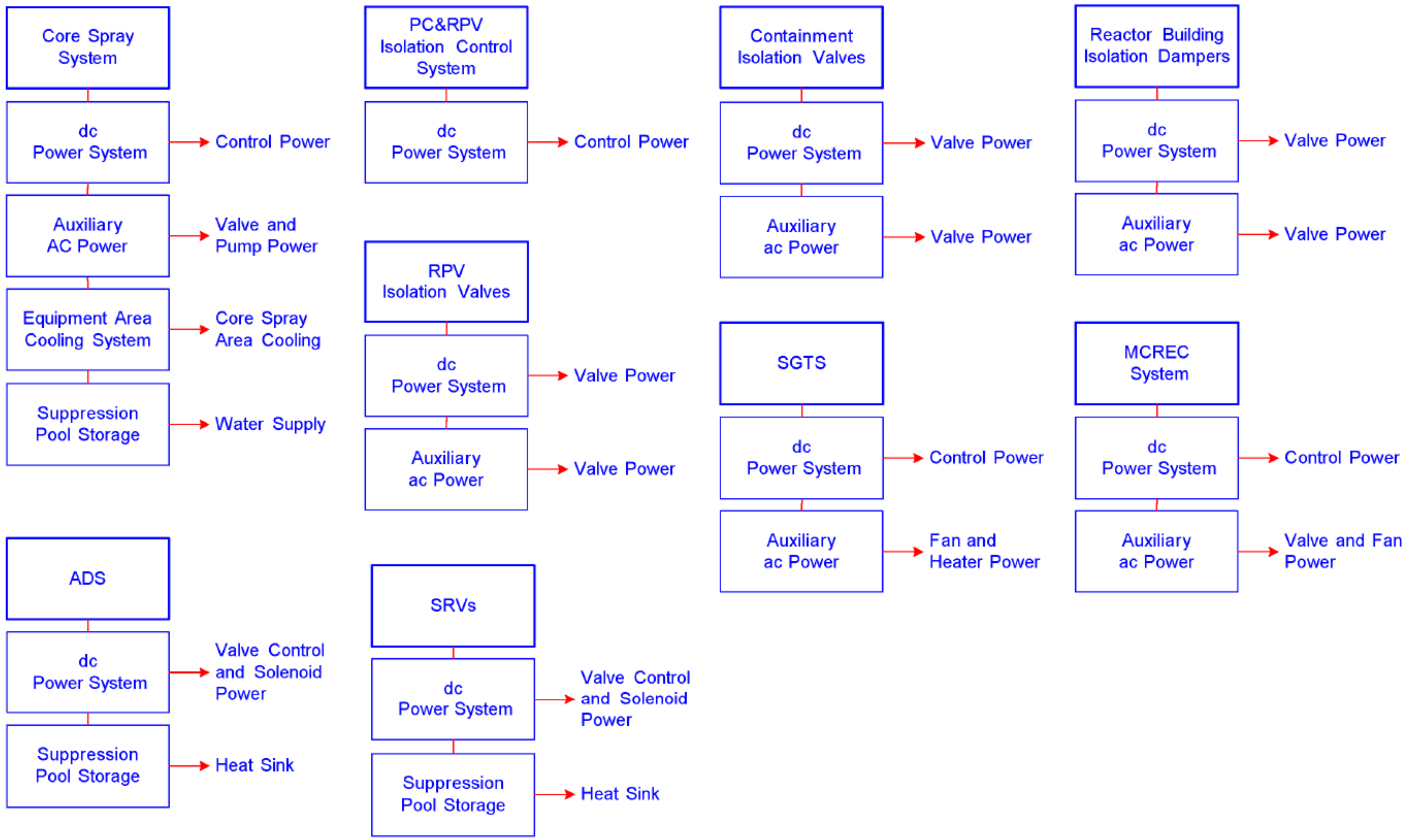
AUXILIARY SYSTEMS FOR FRONT-LINE SYSTEMS

FIGURE 15C-52 (SHEET 1 OF 2)



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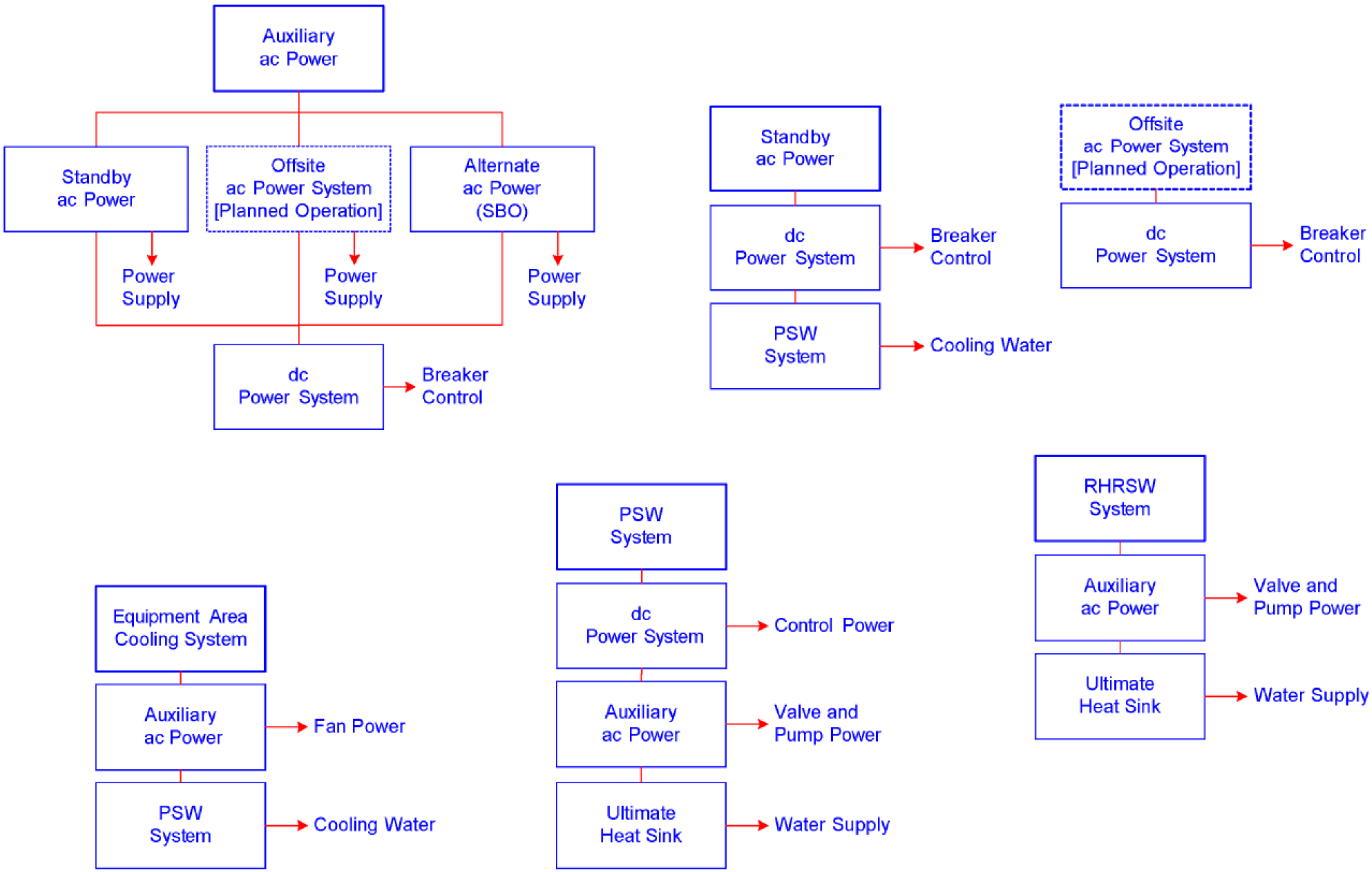
UNIT 2

AUXILIARY SYSTEMS FOR FRONT-LINE SYSTEMS

FIGURE 15C-52 (SHEET 2 OF 2)



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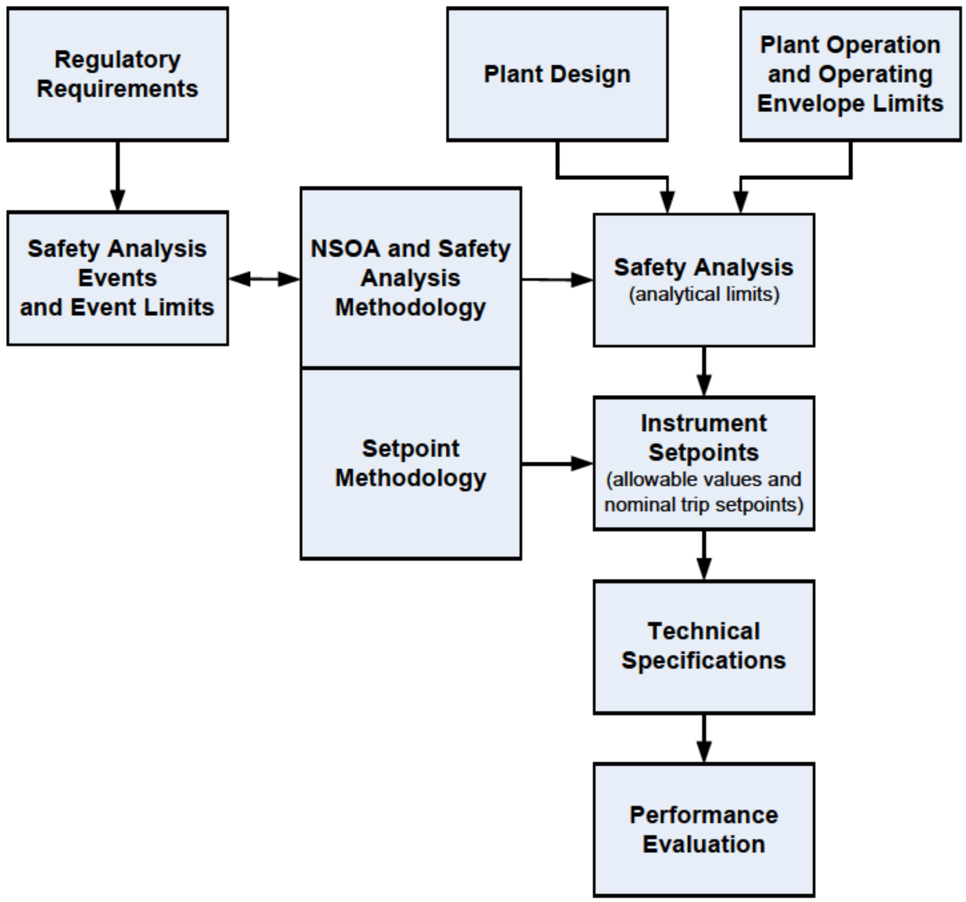
AUXILIARY SYSTEMS FOR OTHER AUXILIARY SYSTEMS

FIGURE 15C-53



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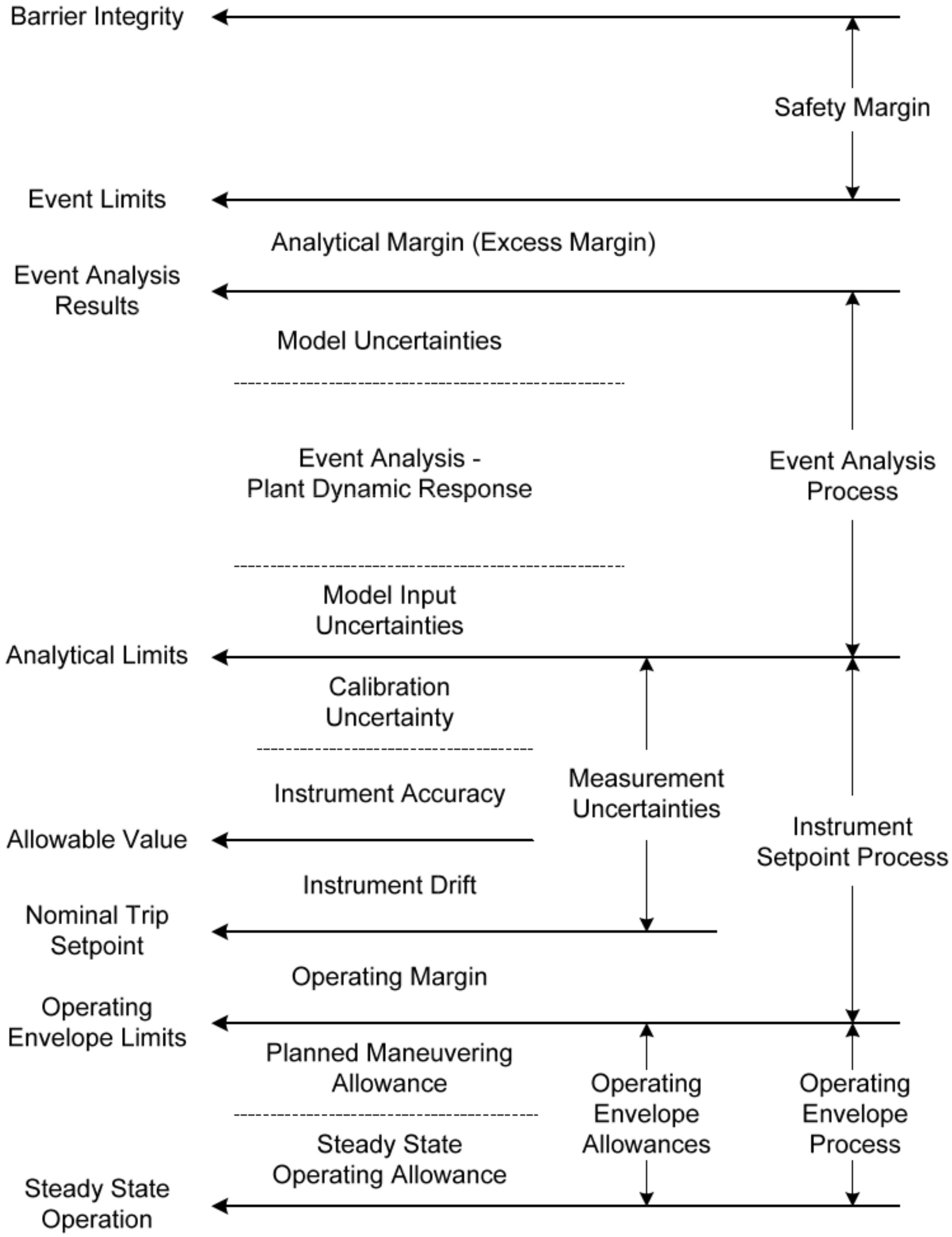
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NSOA, SAFETY ANALYSIS, AND SETPOINT METHODOLOGY RELATIONSHIPS

FIGURE 15C-54



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SAFETY ANALYSIS RELATED SETPOINTS AND UNCERTAINTIES

FIGURE 15C-55

SETPOINTS

Parameters Assumed in the Safety Analysis

- **Technical Specification Limiting Safety System Settings**
- **Technical Specification Limiting Condition for Operation or Surveillance Requirements for Automatic Trips Assumed in Safety Analysis**
- **Emergency Operating Procedure Setpoints Assumed in Safety Analysis**
- **Technical Requirement Manual Automatic Trip Setpoints Assumed in the Safety Analysis**
- **Safety Analysis Input Parameters Not Associated with Automatic Trips but Identified in Technical Specification Surveillance Requirements**

Parameters Not Credited in the Safety Analysis

- **Technical Specification Limiting Condition for Operation or Surveillance Requirements for Automatic Trips Not Credited in Safety Analysis**
- **Emergency Operating Procedure Setpoints Setpoints Not Credited in Safety Analysis**
- **Technical Requirement Manual Automatic Trip Setpoints Not Credited in the Safety Analysis**

Decreasing Importance

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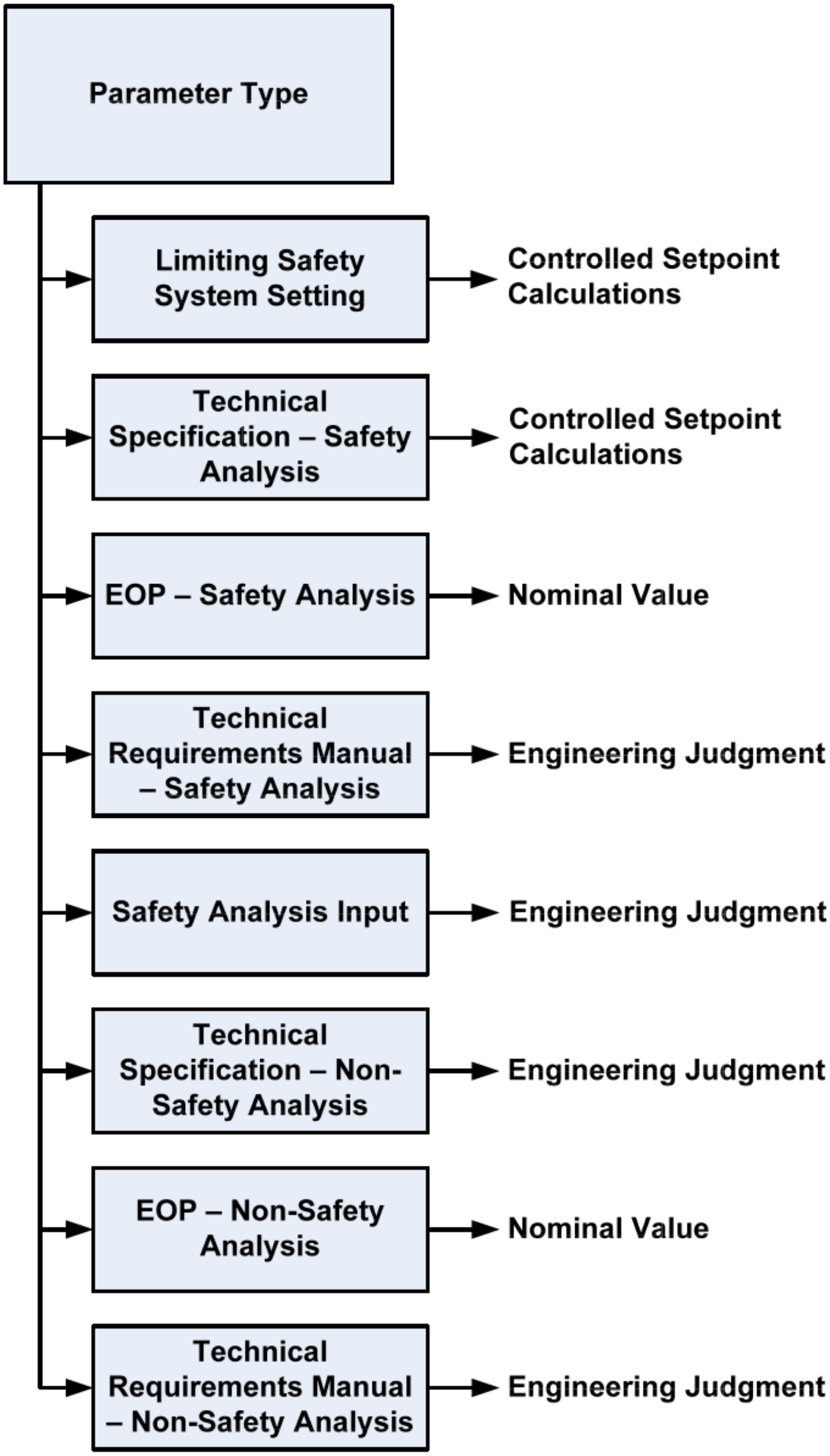

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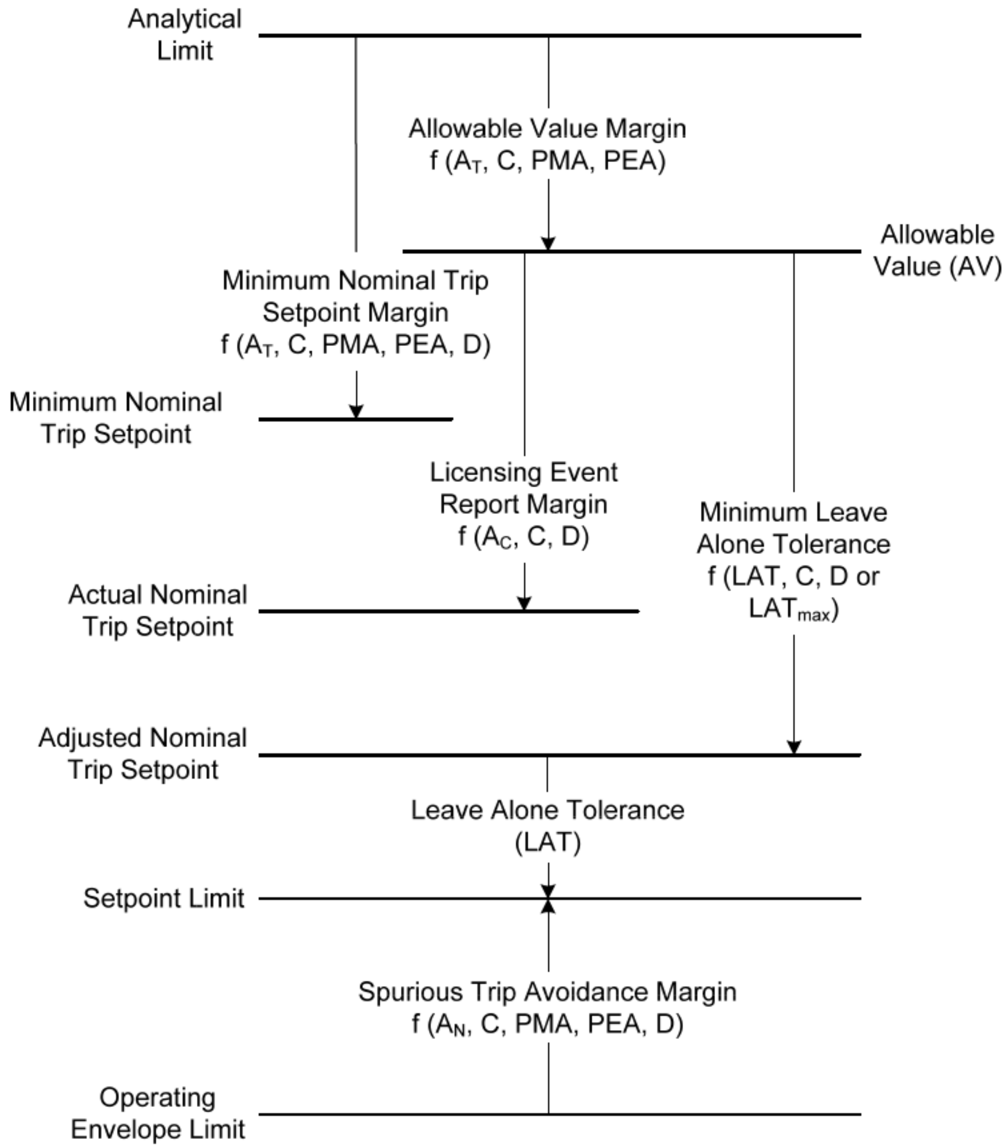
SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	SETPOINT QUANTIFICATION METHODOLOGY FIGURE 15C-57



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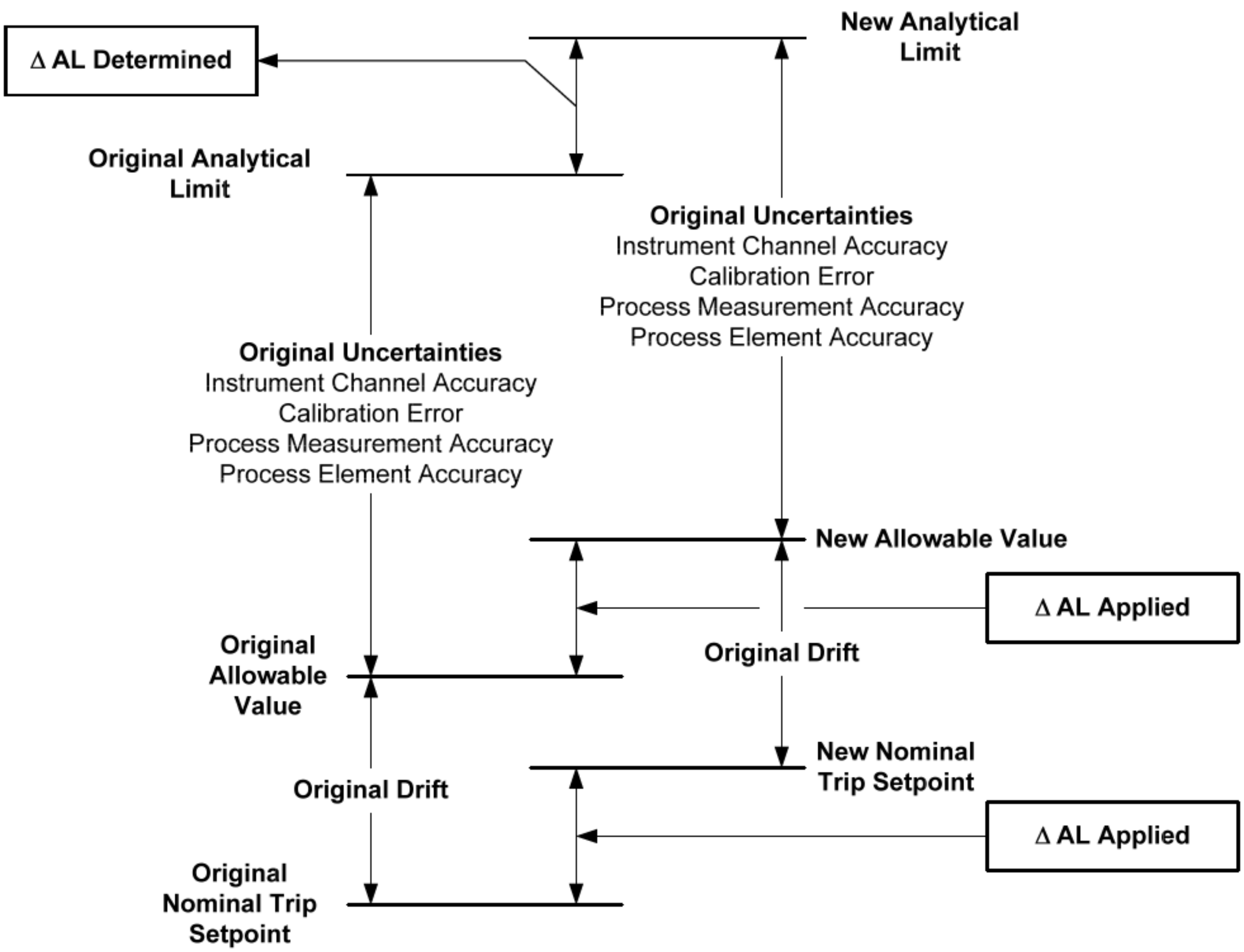
UNIT 2

SETPOINT ANALYSIS PROCESS

FIGURE 15C-58



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SIMPLIFIED SETPOINT PROCESS

FIGURE 15C-59

16.0 TECHNICAL SPECIFICATIONS

The HNP-2 Technical Specifications are contained in Appendix A to the Operating License. The Environmental Protection Plan (Nonradiological) is contained in Appendix B to the Operating License.

17.0 QUALITY ASSURANCE

This chapter describes the quality assurance program (QAP) which provides assurance that operation of the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) conforms to applicable regulatory requirements and to the design bases specified in the license application.

17.1 (Deleted)

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

The operations phase quality assurance program for Hatch Nuclear Plant (HNP) is designed to assure the plant's safe and reliable operation and to satisfy the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. The QA applicable to operation phase activities for HNP is described in the Southern Nuclear Operating Company (SNC) Quality assurance Topical Report (QATR). Quality Assurance program requirements formerly contained in HNP FSAR section 17.2 are superseded by those contained in the SNC QATR.

FSAR table 17.2.2 provides a list of safety-related structures, systems, and components. This information is retained and is identified as historical information.

TABLE 17.2-1

EDWIN I. HATCH NUCLEAR PLANT QA/QC PROCEDURES

THIS TABLE HAS BEEN
INTENTIONALLY DELETED

TABLE 17.2-2 (SHEET 1 OF 10)

LIST OF SAFETY-RELATED STRUCTURES, SYSTEMS, AND COMPONENTS [a]

I. Reactor System

Reactor vessel
Reactor vessel support skirt
Reactor vessel appurtenances, pressure retaining portions
Control rod drive (CRD) housing supports
Reactor internal structures, engineered safety features (ESFs)
Control rods
CRDs
Core supply structure
Power range detector hardware
Fuel assemblies

II. Nuclear Boiler System

Vessels, level instrumentation condensing chambers
Vessels, air accumulators, air supply check valves, piping downstream of air supply check valve
Piping, relief valve discharge
Piping, main steam, within outermost isolation valve
Pipe supports, main steam
Piping, other within outermost isolation valves
Piping, instrumentation beyond outermost isolation valves
Relief valves
Valves, main steam isolation valves (MSIV)
Valves, other, isolation valves and within
Valves, instrumentation beyond outermost isolation valves
Mechanical modules, instrumentation, with safety function
Electrical modules with safety function
Cable, with safety function

III. Recirculation System

Piping
Piping suspension, recirculation line
Pipe restraints, recirculation line
Pumps (structural integrity post-design basis accident (DBA))
Valves
Motors, pump (structural integrity post-DBA)
Electrical modules with safety function
Cable, with safety function

IV. CRD Hydraulic System

TABLE 17.2-2 (SHEET 2 OF 10)

Valves, isolation, water return line
Valves, scram discharge volume lines
Valves, insert and withdraw lines
Piping, water return line within isolation valves
Piping, scram discharge volume lines
Piping, insert and withdraw lines
Hydraulic control unit
Electrical modules, with safety function
Cable, with safety function

V. Engineered Safety Features

A. Residual Heat Removal (RHR) System

Heat exchangers, primary side
Heat exchangers, secondary side
Piping, within outermost containment isolation valves
Piping, beyond outermost containment isolation valves
Containment spray line piping within isolation valve
Containment spray line piping beyond isolation valve
Pumps
Pump motors
Valves, isolation, low-pressure coolant injection line
Valves, isolation, other
Valves, beyond isolation valves
Mechanical modules
Electrical modules, with safety function
Cable, with safety function

B. Core Spray

Piping, within outermost isolation valves
Piping, beyond outermost isolation valves
Pumps
Pump motors
Valves, containment isolation and within
Valves, beyond outermost containment isolation valves
Electrical modules, with safety function
Cable, with safety function

TABLE 17.2-2 (SHEET 3 OF 10)

C. High-Pressure Coolant Injection

Piping, within outermost containment isolation valve
Piping, beyond outermost containment isolation valve, other than return test line, turbine gland-seal line and drain pot line
Pumps
Pump turbines
Valves, within outermost isolation valve
Valves, beyond isolation valves, motor operated
Valves, other
Electrical modules, with safety function
Electrical auxiliary equipment
Cable, with safety function

VI. Safe Shutdown Systems

A. Reactor Core Isolation Cooling (RCIC) System

Piping, within outermost containment isolation valves
Piping, beyond outermost containment isolation valves
Pumps
Valves, containment isolation and within
Valves, other
RCIC turbine
Electrical modules, with safety function
Cable, with safety function

B. Standby Liquid Control (SLC) System

SLC tank
Pump
Pump motor
Valves, explosive
Valves, isolation and within
Valves, beyond isolation valves
Piping, within isolation valves
Piping, beyond isolation valves
Electrical modules, with safety function
Cable, with safety function

TABLE 17.2-2 (SHEET 4 OF 10)

VII. Fuel Handling and Storage

A. Reactor Service Equipment

Fuel preparation machine
General purpose grapple (common to both units)
Control rod grapple (common to both units)
Dryer and separator sling and reactor pressure vessel (RPV) strongback (common to both units)

B. Refueling Equipment

Refueling equipment assembly platform
Bridge crane

C. Storage Equipment

Fuel storage racks
Defective fuel storage container
Defective fuel storage rack

VIII. Radioactive Waste Systems

A. Liquid Radwaste System

Piping, containment penetration
Valves, containment isolation

B. Reactor Water Cleanup System

Piping, within reactor coolant pressure boundary
Valves, reactor coolant pressure boundary isolation valves and within

IX. Fuel Pool Cooling and Cleanup System

Valves and piping, makeup

X. Water Systems

A. RHR Service Water System

Cross connect piping to RHR system, within second automatic isolation valve
Piping, other with safety function
Pumps
Pump motors

TABLE 17.2-2 (SHEET 5 OF 10)

Valves, isolation
Valves, other
Electrical modules, with safety function
Cable, with safety function

B. Reactor Building Closed Cooling Water System

Piping and valves forming part of containment boundary

C. Plant Service Water System

Piping and valves, with safety function
Pumps
Pump motors
Heat exchangers, with safety function
Electrical modules, with safety function
Cable, with safety function

D. Torus Drainage and Purification System Piping and Valves within Containment Boundary

XI. Diesel Generator Systems

Day tanks
Pumps, fuel oil system
Pump motors, fuel oil system
Diesel generators
Electrical modules, with safety functions
Cables, with safety functions
Diesel fuel storage tanks
Diesel lube oil system
Diesel starting air system
Piping and valves from receiver to diesel receivers

XII. Heating, Ventilation, and Air-Conditioning (HVAC) Systems

A. Control Building

1. Control room HVAC Common for Units 1 and 2. (See HNP-1list.)

2. Battery room HVAC

Fans
Fan motors
Dampers
Ductwork

3. LPCI inverter rooms HVAC Common for Units 1 and 2.

TABLE 17.2-2 (SHEET 6 OF 10)

B. Reactor Building

1. Reactor building HVAC

Piping connected to standby gas treatment system (SGTS)
Piping penetration (emergency core cooling system (ECCS) pump rooms)
Isolation valves

2. ECCS pump rooms

Motors
Fans
Coils, cooling
Ductwork

C. Fuel Handling Area

1. Spent-fuel pool exhaust system

Valves/dampers, isolation
Ductwork

D. Reactor Containment (Drywell)

1. Containment cooling system

Ductwork
Dampers

2. Combustible gas control system
(This system was deleted in 2007.)

Motors
Fans
Adsorber/scrubber units
Hydrogen recombiners
Piping, containment penetration
Valves, containment isolation
Containment/drywell monitoring system

TABLE 17.2-2 (SHEET 7 OF 10)

3. SGTS

Motors
Fans
Prefilters
Demisters
High-efficiency particulate air filters
Adsorber units
Ductwork
Dampers
Piping
Valves

E. Diesel Generator Building HVAC

Motors
Fans
Dampers

XIII. Main Steam and Power Conversion Systems

A. Main Steam System

Main steam piping to turbine stop valves and branch line piping (> 2 in.) up to and including first valve

B. Condensate and Feedwater System

Reactor feedwater piping and valves, RPV to outermost isolation valve

XIV. Instrumentation and Control Systems

A. Reactor Instrumentation

1. Reactor protection system (RPS)

All portions that must operate to control and safely shut down the reactor to a hot shutdown condition

2. Neutron monitoring system

Piping, traversing incore probe (TIP)
Valves, isolation, TIP subsystem
Electrical modules, intermediate range monitor (IRM), and average power range monitor (APRM) Cable, IRM and APRM, with safety function

TABLE 17.2-2 (SHEET 8 OF 10)

3. Nonnuclear instrumentation

All portions that input to the RPS
All portions that input to the ESFs actuation system

B. ESFs Actuation System

All portions

C. ESFs Systems (Controls and Instrumentation Required for Safety Associated with Each Actuated System)

ECCS
Containment isolation system
Containment purge systems
Emergency diesel generator systems
Main steam line break detection system

D. Controls and Instrumentation Associated with Safe Shutdown Systems

Control rod drive system
Fluid system contacts for safe shutdown
Main control room habitability system
Combustible gas monitor system
Drywell Pneumatic System

E. Instrumentation Associated with Other Systems Required for Safety

Spent-fuel pool cooling system
Fuel handling area ventilation isolation system
Control room panels
Turbine building flood detection instruments

F. Process Radiation Monitoring System

XV. Electrical Systems

A. ESFs ac Equipment

Essential 4.16-kV buses
Essential 600-V load centers
Essential 600- and 600/208-V control centers

TABLE 17.2-2 (SHEET 9 OF 10)

B. ESFs dc Equipment

125-V and 250-V station and diesel generator batteries and racks, battery charges
125 - 250-V switchgear and distribution panels

C. Electric Cables for ESFs Equipment

5-kV power cables
600-V power cables
Control and instrumentation cables

D. Miscellaneous Electrical

Reactor containment building electrical penetration assemblies
Conduit supports, safety related
Tray supports, underground ducts, fittings and encasement, safety related
Emergency lighting systems
Emergency communications systems
Diesel generator
Remote shutdown system

XVI. Auxiliary Systems

A. Compressed Air Systems

Accumulators for safety-related equipment
Piping and valves, with safety function

B. Nitrogen Inerting System

Storage tank
Makeup supply piping and valves
Ambient vaporizer
Piping and valves forming part of containment

C. Sampling Systems

Piping and valves on ASME III - 1 Systems
Piping and valves on ASME III - 2 Systems
Piping and valves on ASME III - 3 Systems
Piping and valves, containment penetration, isolation
Post loss-of-coolant accident radiation monitoring system

D. Reactor Building and Containment Chilled Water System

Containment isolation valves

TABLE 17.2-2 (SHEET 10 OF 10)

XVII. Buildings

Primary containment
- *Access watches/locks/doors*
- *Liner plate*
- *Penetration assemblies*
- *Coating*

Diesel generator building (common to both units)
Control building (common to both units)
Reactor building
- *Vacuum relief valves*
- *Access hatches/locks/doors*

Intake structure (common to both units)

XVIII. Structures

Condensate storage tank foundation and enclosure
Diesel generator fuel tank vault
Station battery rooms
Spent-fuel pool and liner
Unit vent stack (common to both units)
Containment coatings

XIX. Miscellaneous Mechanical

Whip restraints and supports for Seismic Class 1 piping

---

a. Listed systems include at least one safety-related item.

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SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

QUALITY ASSURANCE ORGANIZATION

FIGURE 17.2-1

SUPPLEMENT 17.2A

QUALITY ASSURANCE OF THE INDEPENDENT SPENT FUEL STORAGE INSTALLATION

The operations phase quality assurance program for Hatch Nuclear Plant (HNP) is designed to assure the plant's safe and reliable operation and to satisfy the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. The QA program applicable to important-to-safety (ITS) structures, systems, and components associated with the HNP independent spent fuel storage installation (ISFSI) is described in the Southern Nuclear Operating Company (SNC) Quality Assurance Topical Report (QATR). QA program requirements formerly contained in HNP FSAR section 17.2a are superseded by those contained in the SNC QATR.

TABLE 17.2A-1

CLASSIFICATION OF INDEPENDENT SPENT FUEL STORAGE INSTALLATION'S STRUCTURES, SYSTEMS, AND COMPONENTS

I. CATEGORY A

- Items specified as Category A in the applicable dry cask storage vendor's Safety Analysis Report (SAR), unless other category is assigned by this document.

II. CATEGORY B

- Items specified as Category B in the applicable dry cask storage vendor's SAR, unless other category is assigned by this document.

III. CATEGORY C

- Items specified as Category C in the applicable dry cask storage vendor's SAR, unless other category is assigned by this document.
- HI-STAR cradle.
- Concrete storage pad.
- Roadways for transport of cask and associated equipment.

IV. NOT IMPORTANT TO SAFETY

- Items specified as not important to safety by dry cask storage vendor in SAR, unless other category is assigned by this document.
- Security system.
- Dose rate boundary fence.
- Facility lighting.
- Electric power system and backup.
- Railways for transport of cask and associated equipment.
- Transfer cart.

18.0 AGING MANAGEMENT PROGRAMS/ACTIVITIES (HNP-1 and HNP-2)

18.1 INTRODUCTION (HNP-1 AND HNP-2)

18.1.1 BACKGROUND

The renewed operating licenses for Edwin I. Hatch Nuclear Plant (HNP) Unit 1 (HNP-1) and Unit 2 (HNP-2) were issued on January 15, 2002, after Nuclear Regulatory Commission (NRC) review of the license renewal applications submitted in February 2000. As such, the original licensed term of operation of 40 years was extended to 60 years, with the renewal term for HNP-1 ending August 6, 2034, and for HNP-2 on June 13, 2038.

As part of the process of obtaining renewed operating licenses, Southern Nuclear Operating Company (SNC) was required to demonstrate that certain aging effects would be adequately managed for the term of the renewed operating licenses. The process used to demonstrate adequate aging management to the NRC included the grouping of various aging management activities into 31 aging management programs. The license renewal rule, 10 CFR 54, requires that a description of these aging management programs become part of the FSAR. As such, sections 18.2 through 18.6 are incorporated into the FSAR as approved by the NRC during the license renewal process. The program and activity descriptions in sections 18.2 through 18.6 represent the HNP-1 and HNP-2 commitments for managing aging of the in-scope systems, structures, and components during the period of extended operation.

In order to provide a common basis for understanding and using this chapter, certain terms are defined. Some of these terms are commonly used in other contexts but have a different meaning in relation to the program descriptions and discussion in this chapter. Other terms may be less common or may be unique to 10 CFR 54. The following definitions should be applied to information contained in this chapter:

A. In-Scope

The term "in-scope" refers to whether a specific function falls within the regulatory requirements of 10 CFR 54. Those functions that are in-scope are intended functions.

B. Active/Passive

Each component that is in-scope can be characterized as either active or passive. An active component performs its intended function with moving parts or a change in properties or configuration. Conversely, a passive component performs its intended function without moving parts or a change in properties or configuration. Only in-scope passive components and structures (all structures are passive) were subject to aging management review. The programs described in Chapter 18 apply only to the passive structures and components that are within the scope of license renewal; i.e., that fall within the regulatory requirements of 10 CFR 54.

C. Intended Function

Intended functions are those functions that meet one or more of the criteria described in 10 CFR 54.4. In summary, intended functions are either safety-related functions, functions whose failure would prevent a safety-related function, or functions credited with meeting the regulatory requirements associated with certain specific regulations as described in 10 CFR 54.4. These intended functions define the part of the plant that is subject to the regulatory requirements of 10 CFR 54. That is, every intended function is in-scope.

D. Evaluation Boundary

A unique set of components can be identified as being required to support the performance of a function. Required components, however, are adjacent to, and connected with, other components not required for performance of the function. The border between the components required and the components not required for performance of the function is a boundary. In order to evaluate the components that support intended functions, an evaluation boundary was established for each intended function. Since intended functions define the part of the plant that is in-scope for the regulatory requirements of 10 CFR 54, the evaluation boundaries for the intended functions contain the set of structures and components that are in-scope for 10 CFR 54. Aging management reviews were performed for the passive structures and components within the evaluation boundaries.

E. Aging Management Review

In-scope passive components were evaluated on the basis of their materials and environments (both exterior and interior as applicable). Industry and plant operating experiences were also considered as part of the aging management reviews. Aging effects that might result in the loss of the ability of a component or structure to support the intended function for that structure or component during the period of extended operation require aging management. The aging management reviews identified the aging effects requiring management for the set of passive in-scope components.

F. Aging Mechanism

An aging mechanism is a physical or chemical process that results in degradation. Aging mechanisms include, but are not limited to, fatigue, erosion, corrosion, thermal and radiation embrittlement, microbiologically influenced corrosion, creep, and shrinkage. Aging mechanisms produce aging effects.

G. Aging Effect

An aging effect is either a change in a structure or component's performance or a change in physical or chemical properties resulting in whole or part from one or more aging mechanisms that degrade the ability of a structure or component to perform its function. Examples of aging effects include loss of material, cracking, and material property changes.

H. Aging Management Program

The programs described in this chapter are the 31 aging management programs SNC credited to manage aging effects for the renewal term. Each program is described in terms of attributes that constitute an acceptable aging management program, as described in the draft Standard Review Plan - License Renewal.

I. Period of Extended Operation

The period of extended operation is the time period that extends from the date of expiration of the original license to the date of expiration of the renewed license. Specifically, the period of extended operation for HNP-1 extends from August 6, 2014, through August 6, 2034. The period of extended operation for HNP-2 extends from June 13, 2018, through June 13, 2038.

J. Renewal Term

The renewal term is the period of operation beginning with the date of issuance of the renewed operating license and ending 60 years from the effective date of the original license. Specifically, the renewal term for HNP-1 extends from January 15, 2002, through August 6, 2034. The renewal term for HNP-2 extends from January 15, 2002 through June 13, 2038.

K. Time-Limited Aging Analysis (TLAA)

TLAAs are those licensee calculations and analyses that:

- Involve in-scope systems, structures, and components.

- Consider the effects of aging.

- Involve time-limited assumptions defined by the terms of the original operating licenses, e.g., 40 years.

- Were determined by the licensee to be relevant in making a safety determination.

- Either involve conclusions or provide the basis for conclusions related to the capability of the system, structure, or component to perform its intended functions.

- Are either contained or incorporated by reference into the current licensing basis, as referenced in 10 CFR 54.

18.1.2 AGING MANAGEMENT PROGRAMS

In many cases, programs and activities existing prior to the renewal term were found adequate for managing aging in the renewal term. In some cases, aging management reviews revealed that existing programs or activities required some degree of enhancement to adequately manage aging. Also, a number of new inspections were developed to provide additional objective evidence that aging was, in fact, being adequately managed by the credited programs and activities. In the Plant Hatch License Renewal Application, aging management programs were grouped under the generally arbitrary headings of Existing Programs, Enhanced Programs, and New Programs. These labels have no relevance subsequent to the issuance of the renewed operating licenses. Thus, the program groupings are relabeled as Group I, Group II, and Group III. The placement of programs within the groupings remains as initially presented in the Plant Hatch License Renewal Application.

More than one program or activity may be credited to manage aging in a single system, structure, or component. Conversely, in other cases, one program or activity may manage the effects of aging in multiple systems. Except where otherwise stated, the programs and activities credited for aging management are applicable to both HNP-1 and HNP-2.

It is important to note that only a portion of certain programs or activities may be required to manage aging during the renewal term. Accordingly, only the commitments identified in the aging management program descriptions are credited with meeting the regulatory requirements of 10 CFR 54.

Because the program descriptions represent the set of commitments made to NRC regarding management of aging of in-scope structures and components, changes to the aging management programs or program descriptions in the FSAR will require an evaluation. The purpose of the evaluation is to ensure the aging management commitments are maintained, and the programmatic coverage of the in-scope structures and components is maintained to provide reasonable assurance the in-scope structures and components will maintain their intended functions during the period of extended operation.

Also, 10 CFR 54.37(b) requires that any newly identified systems, structures, and components that would have been subject to an aging management review if identified before issuance of the renewed operating license must be included in the FSAR update required by 10 CFR 50.71(e). This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in §54.4(b) will be effectively maintained during the period of extended operation. For Plant Hatch, this requirement is met by updating A-47039, "E. I. Hatch Nuclear Plant Unit No. 1/2 License Renewal Aging Management Review Summary."[60] A-47039 contains aging management review (AMR) results for each License Renewal Application (LRA) System within the scope of license renewal. These AMR results are presented in tabular form following the system description information for each LRA System. AMR results are presented at the same level of detail as originally contained in the LRA, as amended by docketed

correspondence prior to issuance of the renewed licenses for Hatch Units 1 and 2, and also incorporating any changes due to 10 CFR 54.37(b) reviews and evaluations since then.

18.1.3 TIME-LIMITED AGING ANALYSES

10 CFR 54 requires that TLAAs be evaluated to capture certain plant-specific aging analyses explicitly based upon the original 40 year operating life of the plant. In addition, Part 54 requires that any exemptions based upon TLAAs be identified and analyzed to justify extension of those analyses through the renewal term. These evaluations were performed as part of the Plant Hatch License Renewal Application.

In addition to requiring that a description of the aging management programs be placed in the FSAR, 10 CFR 54 also requires that summary descriptions of TLAAs be placed in the FSAR. Section 18.5 contains the required summary descriptions of TLAAs identified and evaluated as part of the activities involved in obtaining the renewed operating licenses. No exemptions based upon TLAAs were identified.

10 CFR 54 also requires that any newly identified calculations or analyses that would have been a TLAA be evaluated and a summary description be placed in the FSAR. Thus, the only changes to section 18.5 should be due to either the addition or removal of TLAA descriptions.

18.2 PROGRAMS/ACTIVITIES - GROUP I

18.2.1 REACTOR WATER CHEMISTRY CONTROL

Reactor water chemistry control is a mitigating activity designed to manage loss of material and cracking by controlling fluid purity and composition. Control of reactor water chemistry is based on the guidance and standards provided within BWRVIP-190[1] or the latest approved industry guidance.

A. Program Scope

Portions of the following systems, structures, and components within the scope of license renewal are directly or indirectly monitored by reactor water chemistry control:

- Reactor assembly.
- Nuclear boiler.
- Reactor recirculation.
- High-pressure coolant injection.
- Reactor core isolation cooling.
- Electrohydraulic control.
- Main condenser auxiliaries.

B. Preventive or Mitigative Actions

Reactor water chemistry control mitigates loss of material and cracking by minimizing the oxidizing power, or electrochemical corrosion potential, of the reactor water. Reactor coolant system chemistry standards are met through the use of filtration and ion exchange operations accomplished by powdered resin condensate polishers. Hydrogen injection and noble metal chemical application have been utilized to further reduce the electrochemical corrosion potential of the reactor coolant.

C. Parameters Inspected or Monitored

BWRVIP-190, or the latest approved industry guidance, provides the basis for the reactor coolant chemistry parameters monitored to assure adequate chemistry control. Control parameters include coolant conductivity, sulfate concentrations, and chloride concentrations.

D. Detection of Aging Effects

Reactor water chemistry control is a mitigative activity not intended to directly detect age-related degradation of reactor assembly and reactor coolant system components.

E. Monitoring and Trending

BWRVIP-190, or the latest approved industry guidance, provides guidelines for trending, tracking, and regular evaluations of reactor water chemistry parameters. During normal power operations, sulfates, chlorides, and conductivity are monitored in accordance with the guidance provided in the latest approved industry guidance.

F. Acceptance Criteria

Specific acceptance criteria are contained in BWRVIP-190 or the latest approved industry guidance. Acceptance criteria vary based on plant operating conditions and the water chemistry mode currently in use (normal water chemistry or HWC).

18.2.2 CLOSED COOLING WATER CHEMISTRY CONTROL

Closed cooling water (CCW) chemistry control is a mitigating activity designed to manage loss of material by controlling fluid purity and composition. Control of CCW chemistry is based on the guidance provided within EPRI 1007820[2], or the latest approved industry guidance.

A. Program Scope

While CCW chemistry control is applicable to all closed cycle cooling water systems, only limited portions of CCW systems are within the scope of license renewal. Operation of these systems is not vital to the safe shutdown of the plant under normal or accident conditions. However, certain portions of these systems are in scope to maintain primary containment integrity. Portions of the following systems are included:

- Reactor building CCW.
- Primary containment chill water (applicable to Unit 2 only).

B. Preventive or Mitigative Actions

Control of CCW chemistry manages loss of material through the use of corrosion inhibitor additions, biocide additions, and chemical additions to control pH. Concentrations of detrimental impurities are monitored. Should CCW chemistry parameters exceed the limitations established by the EPRI guidelines, appropriate

corrective actions to minimize the potential for significantly increased corrosion rates and to restore CCW purity will be taken.

C. Parameters Inspected or Monitored

EPRI 1007820, or the latest approved industry guidance, provides the basis for CCW chemistry chemical additions and monitoring to assure adequate chemistry control. This guideline provides several different treatment options and provides recommendations for applicable control parameters.

Control parameters include pH (proper pH reduces corrosion rates and increases corrosion inhibitor effectiveness) and corrosion inhibitor concentrations. Diagnostic parameters include biocide concentrations and microbe populations; concentrations of detrimental impurities such as chloride, sulfate, and conductivity.

Additionally, RBCCW system carbon steel corrosion coupons are analyzed periodically to verify the effectiveness of the corrosion inhibitor system.

D. Detection of Aging Effects

CCW chemistry control is a mitigative activity and not intended to directly detect age-related degradation of components subjected to CCW.

E. Monitoring and Trending

EPRI 1007820, or the latest approved industry guidance, provides guidelines for trending, tracking, and regular evaluations of CCW chemistry parameters.

F. Acceptance Criteria

Acceptance criteria for CCW chemistry control are based on the recommendations of EPRI 1007820, or the latest approved industry guidance. This document specifies appropriate parameter limitations and analysis methods for adequate CCW chemistry control. The industry guidance contains recommended ranges and limitations for corrosion inhibitor concentrations, pH, and concentrations of detrimental impurities. In addition, bacteria populations are monitored to validate the effectiveness of biocide additions.

Carbon steel corrosion coupons are weighed periodically to assure that corrosion rates occurring within CCW systems are acceptable when evaluated against the target values in the industry guidance.

18.2.3 DIESEL FUEL OIL TESTING

Diesel fuel oil testing is a mitigating activity designed to manage loss of material by monitoring fuel oil content for water and other contaminants.

A. Program Scope

Diesel fuel oil testing applies to the emergency diesel generator (EDG) fuel oil storage tanks, the diesel generator fuel oil day tanks, and the associated transfer piping and components. It additionally covers the in-scope fire pump diesel fuel oil storage tanks and the associated piping and components. The following systems within the scope of license renewal are monitored directly or indirectly by diesel fuel oil testing.

- Fuel oil supply.
- Fire protection.

B. Preventive or Mitigative Actions

Diesel fuel oil testing activities mitigate loss of material by detecting intrusion of water or other contaminants to preclude loss of material due to corrosion. Program elements include sampling and analysis of new fuel prior to off loading to prevent contamination of stored fuel oil, and periodic sampling and analysis of stored fuel oil in storage and day tanks. Should the concentration of water or other contaminants exceed established acceptance criteria, appropriate actions are taken to minimize the potential for significantly increased corrosion rates and reduce concentrations of water or other contaminants.

Additionally, biocide is added during the offloading of new fuel. The addition of a biocide, when properly controlled, minimizes the potential for microorganism growth and the potential for microbiologically influenced corrosion.

C. Parameters Inspected or Monitored

New fuel oil is sampled and analyzed for water and sediment content. In addition, stored fuel oil is tested using the following methods:

1) A three level composite sample from the EDG storage tank for water and sediment content is 0.05% or less by volume (monitored quarterly).

2) A middle sample from the fire pump diesel fuel oil storage tanks for water and sediment content is 0.05% or less by volume (monitored quarterly).

3) A bottom sample content from the EDG storage tanks, EDG day tanks, and fire pump diesel fuel oil storage tanks for water and sediment is 0.1% or less by volume (monitored semiannually).

4) Acceptance criteria for water and sediment content of new fuel to be added to the EDG storage tanks or fire pump diesel fuel oil storage tanks is <0.05% by volume.

5) Total particulate content of the EDG storage tanks, EDG day tanks, and fire pump diesel tanks will not exceed 10mg/L on a quarterly basis.

D. Detection of Aging Effects

Diesel fuel oil testing is a mitigating activity not intended to directly detect age-related degradation of diesel fuel oil supply system components.

E. Monitoring and Trending

There are no monitoring or trending aspects associated with diesel fuel oil testing activities.

F. Acceptance Criteria

Stored fuel oil water and sediment and total particulate limits are established within the plant Technical Specifications and implementing procedures.

18.2.4 PLANT SERVICE WATER AND RHR SERVICE WATER CHEMISTRY CONTROL

Plant service water (PSW) and residual heat removal service water (RHRSW) chemical control activities are intended to reduce loss of material, loss of heat exchanger performance, and flow blockage (fouling) with service water system components through a biocide application program based on the requirements of Generic Letter 89-13[3].

A. Program Scope

Portions of the following systems within the scope of license renewal undergo biocide additions:

- RHRSW.
- PSW.
- Reactor building HVAC.
- Traveling screen wash (PSW isolation valve only).
- Control building HVAC.

B. Preventive or Mitigative Actions

Sodium hypochlorite alone, or in conjunction with sodium bromide, is periodically injected into PSW to control biological growth in the service water systems. Additionally, this program is coordinated with the periodic operation of RHRSW to maximize chemical treatment in this system. These biocide additions are intended

to reduce loss of material, loss of heat exchanger performance, and flow blockage (fouling).

C. Parameters Inspected or Monitored

During plant PSW system chlorination and bromination, free available oxidant concentration is periodically monitored at the PSW discharge to the circulating water flume to ensure program efficacy.

The Plant Hatch NPDES Permit[4] requires periodic monitoring of plant effluent to the Altamaha River for residual oxidant.

D. Detection of Aging Effects

PSW and RHRSW chemistry control is a mitigative activity not intended to directly detect age-related degradation of PSW and RHRSW system components.

E. Monitoring and Trending

Free available oxidant is monitored during the treatment cycle to provide reasonable assurance that sufficient biocide is being added to meet the system chlorine demand and result in an effective residual free available oxidant concentration.

Sample results also provide indication that the program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

F. Acceptance Criteria

During chlorination and bromination, the PSW effluent should indicate a free available oxidant concentration equal to, or exceeding, the limitations specified within implementing procedures.

In accordance with the Plant Hatch NPDES Permit, the final plant effluent to the Altamaha River is sampled to detect the presence of any residual oxidant. These sample results are reported to the State of Georgia Department of Natural Resources on a quarterly basis.

18.2.5 FUEL POOL CHEMISTRY CONTROL

Fuel pool chemistry control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant systems and components by controlling fluid purity and composition. Control of fuel pool chemistry is based on the guidance provided within BWRVIP-190[1] or the latest approved industry guidance.

A. Program Scope

Fuel pool chemistry control activities are applicable to the spent fuel pool liners, spent fuel pool plugs, the spent fuel pool gate, the refueling canal, spent fuel pool storage racks (including restraints), miscellaneous steel inside the spent fuel pool, and portions of the leak chase system.

B. Preventive or Mitigative Actions

Fuel pool chemistry control mitigates loss of material by minimizing detrimental ionic species and conductivity. Control of fuel pool chemistry is maintained through the use of filtration and ion exchange operations accomplished by filter / demineralizers. Should fuel pool water chemistry parameters exceed the limitations established by the industry guidance, appropriate actions to minimize the potential for significantly increased corrosion rates and to restore fuel pool purity will be taken.

C. Parameters Inspected or Monitored

BWRVIP-190, or the latest approved industry guidance, provides the basis for fuel pool chemistry parameters monitored to assure adequate chemistry control. Industry guidance specified fuel pool chemistry diagnostic parameters include conductivity, chloride and sulfate concentrations, and total organic carbon content. In addition, pH and filterable solids content are monitored.

D. Detection of Aging Effects

Fuel pool chemistry control is a mitigative activity not intended to directly detect age-related degradation of the fuel pool and associated internal structures.

E. Monitoring and Trending

BWRVIP-190, or the latest approved industry guidance, provides guidelines for trending, tracking, and regular evaluations of fuel pool chemistry parameters. Sulfate and chloride concentrations, conductivity, and total organic carbon content are monitored in accordance with the guidance provided in BWRVIP-190 or the latest approved industry guidance. In addition, pH and filterable solids content are monitored.

F. Acceptance Criteria

Specific acceptance criteria are contained within BWRVIP-190 or the latest approved industry guidance.

18.2.6 DEMINERALIZED WATER AND CONDENSATE STORAGE TANK CHEMISTRY CONTROL

Demineralized water chemistry control is a mitigating activity designed to manage loss of material by controlling fluid purity and composition. Control of demineralized water chemistry is based on the guidance provided within BWRVIP-190[1] or the latest approved industry guidance.

A. Program Scope

Portions of the following systems within the scope of license renewal are directly or indirectly monitored by demineralized water chemistry control.

- Nuclear boiler.
- Control rod drive.
- Standby liquid control.
- High-pressure coolant injection.
- Reactor core isolation cooling.
- Condensate transfer and storage.
- Service demineralized water (primary containment function).
- EDG auxiliaries.

B. Preventive or Mitigative Actions

Demineralized water chemistry control mitigates loss of material by minimizing detrimental ionic species and conductivity. The demineralizer system provides demineralized water to meet tank chemistry limitations through the use of filtration, ion exchange, and degasification processes. Control of demineralized water chemistry parameters, within the condensate storage tank (CST) and demineralized water storage tank (DWST), is not maintained by any type of control system, such as ion exchange or filtration. Should demineralized water chemistry parameters exceed the limitations established by the industry guidance, appropriate corrective actions to minimize the potential for significantly increased corrosion rates and to restore demineralized water purity will be taken.

C. Parameters Inspected or Monitored

BWRVIP-190 or the latest approved industry guidance provides the basis for demineralized water chemistry parameters monitored to assure adequate chemistry control. Industry guidance specified demineralized water chemistry diagnostic parameters include conductivity, chloride and sulfate concentrations, total organic carbon content, and silica content. In addition, pH is monitored.

D. Detection of Aging Effects

Demineralized water chemistry control is a mitigative activity not intended to directly detect age-related degradation of systems and components exposed to a demineralized water environment.

E. Monitoring and Trending

BWRVIP-190, or the latest approved industry guidance, provides guidelines for trending, tracking, and regular evaluations of demineralized water chemistry parameters. Chloride and sulfate concentrations, total organic carbon content, and silica content are monitored in accordance with the guidance provided in BWRVIP-190 or the latest approved industry guidance. In addition, pH is monitored.

F. Acceptance Criteria

Specific acceptance criteria are contained within BWRVIP-190 or the latest approved industry guidance.

18.2.7 SUPPRESSION POOL CHEMISTRY CONTROL

Suppression pool chemistry control is a mitigating activity designed to manage loss of material and cracking by controlling fluid purity and composition. Control of suppression pool chemistry is based on the guidance provided within BWRVIP-190[1] or the latest approved industry guidance.

A. Program Scope

Portions of the following systems, structures, and components within the scope of license renewal are directly or indirectly monitored by suppression pool chemistry control:

- Nuclear boiler.
- RHR.
- Core spray.
- High-pressure coolant injection.
- Reactor core isolation cooling.
- Primary containment purge and inerting (vacuum relief piping).
- Containment isolation components having torus penetrations below the water level.
- Torus internal structures and components.

B. Preventive or Mitigative Actions

Suppression pool chemistry control mitigates loss of material and cracking by minimizing detrimental ionic species and conductivity. Control of suppression pool chemistry parameters is not maintained by any type of control system, such as ion exchange or filtration. Should suppression pool chemistry parameters exceed the limitations established by the industry guidance, appropriate corrective actions to minimize the potential for significantly increased corrosion rates and to restore suppression pool purity will be taken.

C. Parameters Inspected or Monitored

BWRVIP-190, or the latest approved industry guidance, provides the basis for suppression pool chemistry parameters monitored to ensure adequate chemistry control. Industry guidance specified suppression pool chemistry diagnostic parameters include conductivity (zinc corrected), chloride and sulfate concentrations, and total organic carbon content.

D. Detection of Aging Effects

Suppression pool chemistry control is a mitigative activity not intended to directly detect age-related degradation of components exposed to a suppression pool environment.

E. Monitoring and Trending

BWRVIP-190, or the latest approved industry guidance, provides guidelines for trending, tracking, and regular evaluations of suppression pool water chemistry parameters. Zinc corrected conductivity, sulfate and chloride concentrations, and total organic carbon content are monitored in accordance with the guidance provided in BWRVIP-190 or the latest approved industry guidance.

F. Acceptance Criteria

Specific acceptance criteria are contained within BWRVIP-190 or the latest approved industry guidance.

18.2.8 CORRECTIVE ACTIONS PROGRAM

SNC has established and implemented a QA program that conforms to the criteria set forth in 10 CFR 50, Appendix B[5]. The QA program addresses all aspects of quality assurance at Plant Hatch.

The two elements of the QA program that are most pertinent to the aging management programs credited for license renewal are corrective actions and administrative controls. These

elements are discussed in chapter 17 and are outlined below. Corrective action and administrative control requirements apply to all components within the scope of license renewal.

A. Program Scope

The plant condition reporting process applies to all plant systems and components within the scope of license renewal. Administrative controls are in place for existing aging management programs and activities and for the currently required portions of enhanced programs and activities. Administrative controls will also be applied to new programs and activities as they are implemented. As a minimum, these programs and activities are or will be performed in accordance with written procedures. Those procedures are or will be reviewed and approved in accordance with Plant Hatch's 10 CFR 50, Appendix B, QA Program.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with the corrective actions program that are credited for license renewal.

C. Parameters Inspected or Monitored

No specific parameters are inspected or monitored as part of this program. Generally, when parameters inspected or monitored by other plant programs indicate a condition adverse to quality, the corrective actions program provides a means to correct the identified condition.

D. Detection of Aging Effects

Detecting aging effects is not part of the corrective actions program. The corrective actions program provides a means to address the aging effects identified by other aging management activities.

E. Monitoring and Trending

The corrective actions program does not monitor or trend aging effects. The corrective action program monitors corrective actions to assure identified conditions are addressed in a timely manner. Conditions that are identified as being adverse to quality are trended. Plant Hatch monitors significant conditions that are adverse to quality (significant occurrence reports) and requires a formal cause determination and corrective actions to prevent recurrence.

F. Acceptance Criteria

The corrective actions program does not include specific acceptance criteria for aging effects. Generally, when the acceptance criteria of other aging management activities are not met, the corrective actions program provides a means to assure appropriate corrective actions are taken.

G. Corrective Actions

The corrective action program is initiated following the determination of conditions adverse to quality, and documented as required by appropriate procedures. Various processes are used to identify problems requiring corrective action. The primary vehicle for initiating corrective action is the condition reporting process described in the SNC Quality Assurance Topical Report (QATR).

The various components of the corrective action program provide for timely corrective actions, including root cause determination and prevention of recurrence. The QA program provides control over activities affecting the quality of systems, structures, and components consistent with their importance to safety. In accordance with plant procedures, condition reports are analyzed for adverse trends. Any identified adverse trends are reported to the appropriate department for corrective action.

H. Confirmation Process

As described in the QATR, condition reports are reviewed to determine the regulatory reportability and significance. Those items determined to be significant conditions adverse to quality (significant occurrence reports) are also reviewed by the plant review board. Corrective actions taken for significant items are reviewed for assurance that appropriate action has been taken.

I. Administrative Controls

Activities affecting quality are prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and are accomplished in accordance with these instructions, procedures, or drawings. They contain appropriate acceptance criteria and documentation requirements for determining whether important activities have been satisfactorily accomplished. Site procedures establish review and approval requirements.

18.2.9 INSERVICE INSPECTION PROGRAM

The inservice inspection (ISI) program is a condition monitoring program that provides for the implementation of ASME Section XI[6] in accordance with the provisions of 10 CFR 50.55a[7]. The ISI program also includes augmented examinations required to satisfy commitments made by SNC. The 10-year examination plan provides a systematic guide for performing required examinations. The period of extended operation will include the fifth and sixth ISI intervals. Only a portion of the ISI program is credited for license renewal.

A. Program Scope

The ISI program contains examination requirements and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as associated supports.

For license renewal, the ISI program is credited for monitoring potential age-related degradation in portions of the following systems:

- Reactor assembly.
- Nuclear boiler.
- Reactor recirculation.
- RHRSW.
- PSW.
- Primary containment.
- Containment penetrations.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The ISI program utilizes visual, surface, and volumetric examinations to detect loss of material, cracking, and preload.

D. Detection of Aging Effects

Three types of inspection methods are used for inservice examination. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in ASME Section XI paragraph IWA-2210; surface examinations are performed as defined in IWA-2220; and volumetric examinations are performed as defined in IWA-2230.

E. Monitoring and Trending

Deficiencies discovered during the performance of the program activities are documented in accordance with ISI program implementing procedures and are monitored in accordance with ASME Code requirements. The plant corrective actions program addresses deficiencies requiring repair or replacement.

F. Acceptance Criteria

Components not meeting the acceptance criteria defined in ASME Section XI, Tables IWB-2500-1, IWC-2500-1, IWD-2500-1, and IWE-2500 are evaluated, repaired, or replaced prior to return to service.

18.2.10 OVERHEAD CRANE AND REFUELING PLATFORM INSPECTIONS

The overhead crane and refueling platform inspection (OC&RPI) procedures were developed using ANSI B30.2.0-1976[8] and NUREG-0612[9]. Inspection procedures for fuel handling equipment were developed using ANSI B30.9-1971[10], ANSI/ASME B30.10-1982[11], ANSI N14.6 1978[12], and NUREG-0612.

The OC&RPI program ensures the overhead crane and refueling platform are capable of safely handling loads. The aging management review for passive structural elements identified one aging effect, loss of material due to corrosion, as requiring management. This program also satisfies the requirements of the Unit 1 Technical Requirements Manual, which requires surveillance testing of the 5-ton hoist and the crane/hoist used for handling fuel assemblies or control rods.

A. Program Scope

The OC&RPI program will perform inspections on the following systems that are within the scope of license renewal.

- Fuel and control rod handling equipment.
- Refueling floor cranes and hoists.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The OC&RPI provides for visual inspection of the contacting surfaces of the steel rails and the passive structural load bearing components of the overhead crane and refueling platform such as crane girder, rail, and bolts. These inspections are intended to detect loss of material due to corrosion. Overhead cranes within the boundary of License Renewal will be inspected daily when in use, and general visual inspection will be performed monthly.

D. Detection of Aging Effects

Visual inspections are performed to detect the loss of material.

E. Monitoring and Trending

Inspection test results are maintained in plant records. Engineering personnel track and trend results in accordance with implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the OC&RPI is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.11 TORQUE ACTIVITIES

Torque activities mitigate loss of preload through use of proper torque techniques. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities. Torque activities are based on the guidance of EPRI NP-5769[59]. This EPRI document has been generally endorsed by the NRC in NUREG 1339.

Other codes and standards considered during development of the torquing procedure were ASME, Section VIII[13], Div. 1, App. 2; ASME, Section II[14], ASTM Standards[15], Section 15, Volume 15.08; and ASME B31.1[16].

A. Program Scope

Torque activities are applicable to bolts, studs, nuts, and washers within systems in the scope of license renewal.

B. Preventive or Mitigative Actions

The torque activities require that appropriate hardware is used in bolted connections. Additionally, proper torque techniques assure that adequate preload is applied to the connection. These attributes of the torque activities assure that loss of preload is mitigated.

C. Parameters Inspected or Monitored

There are no parameters inspected or monitored with this activity.

D. Detection of Aging Effects

There are no actions performed by this activity to detect aging effects.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of preload will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. Any significant loss of preload is noted and corrective actions will be implemented in accordance with the corrective action program.

18.2.12 COMPONENT CYCLIC OR TRANSIENT LIMIT PROGRAM

The component cyclic or transient limit program (CCTLP) is a surveillance program required by Technical Specifications. It is a monitoring program designed to track cyclic and transient occurrences to assure that reactor coolant pressure boundary components and the torus will remain within the ASME Code Section III fatigue limits, including the effects of a reactor water environment.

Plant cycles and transients that significantly contribute to fatigue usage of Class 1 components have been identified. Periodically, each unit's operating records are reviewed to determine the number of design transients that have occurred since the last time cumulative usage factor (CUF) was calculated. Applying the actual cycles that have occurred to the formulas that represent design severity of cycles results in sufficient conservatism, including effects due to environmental factors, that cracking due to thermal fatigue is not expected as long as the CUF does not exceed 1.0.

A. Program Scope

The scope includes the RPV, the torus, and all Class 1 piping. Unit 1 FSAR subsection 4.2.5 and Unit 2 FSAR paragraph 5.4.6.4 document the bounding RPV locations monitored for CUF. The four limiting high stress RPV boundary components are the RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles. The CCTLP also monitors the fatigue for the critical locations of the torus and Class 1 piping. Class 1 piping locations monitored are the highest CUF location from each fatigue calculation with at least one location having a 40-year design CUF of 0.10 or more. For Unit 1, the Class 1 piping locations that are monitored include the limiting locations on the reactor vessel equalizer piping, the core spray piping, the standby liquid control piping, the feedwater piping (including connections to high pressure coolant injection, reactor core isolation cooling, and reactor water cleanup piping), RHR discharge piping outside the drywell, recirculation system drains, and the main steam piping. For Unit 2, the monitored piping includes the limiting locations for the feedwater piping, the primary steam condensate drainage, and the main steam piping.

The monitoring formulas in the CCTLP account for any effects due to power uprate or extended power uprate. The monitoring of locations corresponding to the seven locations identified in NUREG/CR-6260 for the older vintage boiling water reactor (BWR) plant includes appropriate Fen factors to account for the effects due to a reactor water environment. Those NUREG/CR-6260 locations not previously

monitored because their design CUF is below the 0.10 screening criteria have been added to the program with an appropriate Fen factor applied. Fatigue monitoring software has been developed for Plant Hatch that can be used to calculate the CUF of all monitored locations and include the effects due to a reactor water environment for those locations in NUREG/CR-6260 for the older vintage boiling water reactor (BWR) plant. Therefore, the bounding locations for the RPV, torus, and all Class 1 piping significantly susceptible to cracking due to fatigue are monitored.

In addition, a criterion of 0.1 CUF was used, along with other criteria from Branch Technical Position MEB 3-1, in establishing postulated break locations for Class 1 piping. Piping locations with design CUFs < 0.1 for 40 years and that did not meet other criteria of MEB 3-1 were not further evaluated for installation of pipe whip restraints and a pipe break was not postulated at those locations. Using a linear extrapolation, Class 1 piping locations with design CUF > 0.067 but < 0.1 for 40 years might exceed 0.1 for 60 years. Cracking due to fatigue in these locations is managed by tracking fatigue usage for three bounding locations in the set of piping locations with a 40-year design CUF between 0.067 and 0.1. Those three locations are in the Unit 2 reactor water cleanup piping, the Unit 2 feedwater piping, and the Unit 1 standby liquid control piping and have been incorporated into the fatigue monitoring software.

The scope of the CCTLP includes long-lived passive components in the following systems or structures, within the scope of license renewal:

- RPV.
- Nuclear boiler.
- Reactor recirculation.
- Primary containment.
- Containment penetrations.
- Core spray.
- Standby liquid control (Unit 1 only).
- Feedwater (including Unit 1 connections to high pressure coolant injection, reactor core isolation cooling, and reactor water cleanup piping.
- Main steam.
- Primary steam condensate drains (Unit 2 only).
- Residual heat removal.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

To address cracking, the CCTLP calculates the CUF for the critical locations in the RPV, the torus, and the Class 1 piping by monitoring for events that can significantly contribute to the fatigue of components at the locations and applying the appropriate CUF impact for those events that have occurred.

D. Detection of Aging Effects

This program does not detect cracking.

E. Monitoring and Trending

The CCTLP utilizes plant records to ascertain if events that could significantly contribute to components CUF have occurred. The calculations of the component CUF are documented in the plant records. Engineering personnel track and trend the CUF in accordance with the CCTLP implementing procedures.

F. Acceptance Criteria

The CCTLP tracks high fatigue usage components to assure that the plant will continue to meet the ASME Code, Section III[17] and CUF design requirement value of ≤ 1.0. The three bounding potential breakpoints that have not been analyzed as such are monitored to verify they have an actual CUF of < 0.10. If the 60-year CUF is projected to exceed the acceptance criteria, a condition report is initiated to determine and take appropriate corrective action in accordance with the corrective actions program.

G. Corrective Actions

If the 60 year CUF projection exceeds a value of 1.0, perform the following actions as necessary:

1. Refine the fatigue analysis and modify the monitoring formula.

2. Use fracture mechanics analysis to determine a critical flaw size and establish an appropriate inspection schedule. NOTE: The use of fracture mechanics analysis for cases where the CUF is projected to exceed 1.0 requires staff review and approval on a case by case basis.

3. Perform corrective maintenance.

4. Replace the component.

18.2.13 PLANT SERVICE WATER AND RHR SERVICE WATER INSPECTION PROGRAM

During the period of extended operation, the following aging effects could occur to PSW and RHRSW passive components within the scope of license renewal: loss of material, loss of heat exchanger performance, flow blockage (fouling), and cracking (of RHR heat exchanger tubes). The PSW and RHRSW inspection program manages these effects for those components. This program is designed to detect wall thickness degradation, fouling, or cracking in the components associated with the PSW and RHRSW systems. The specific inspection locations in the PSW and RHRSW systems are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are infrequently used piping (stagnated water), submerged piping, piping with low fluid velocity, small diameter piping, backing rings, socket welds, and the heat affected zone of a weld. Locations prone to clogging include those prone to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, and low point drains. Locations prone to cracking include locations susceptible to vibration fatigue and stress corrosion cracking (RHR heat exchanger tubes). Locations prone to erosion include the areas with high velocity.

This program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13[18]. In addition, other industry standards and codes are used as guidance.

A. Program Scope

The PSW and RHRSW inspection program will inspect those portions of the following systems that are within the scope of license renewal:

- RHR and RHRSW.
- PSW.
- Reactor building HVAC.
- Travelling water screen wash isolation valve.
- Control building HVAC.

B. Preventive or Mitigative Actions

The PSW and RHRSW piping inspection program requires that divers visually inspect the intake structure pump suction pit every 12 months. Any accumulations of biological fouling organisms, sediment, and corrosion products found during the inspection are removed to prevent these foreign materials from entering the system.

C. Parameters Inspected or Monitored

The PSW and RHRSW piping inspection program provides for visual and volumetric examinations intended to detect wall thinning, surface indications, and reduction of flow area within service water system components. This program also provides hardness testing to detect selective leaching.

D. Detection of Aging Effects

PSW and RHRSW piping inspection program inspections to detect loss of material include volumetric inspections (radiographic and ultrasonic) and visual inspections (including use of depth gages). Volumetric inspections, visual inspections, and flow testing are utilized to detect flow blockage (fouling) and loss of heat exchanger performance. Additionally, the program has provisions for hardness testing on brass and gray cast iron in the PSW or RHRSW system.

E. Monitoring and Trending

Inspection and hardness test results are maintained in plant records. Engineering personnel track and trend results in accordance with PSW and RHRSW piping inspection program implementing procedures. Visual inspections are performed on safety-related heat exchangers and coolers supplied with raw water at frequencies prescribed in the implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional testing will be performed. Any significant degradation of components inspected or tested by the PSW and RHRSW piping inspection program is noted and corrective actions will be implemented in accordance with the existing corrective actions program.

18.2.14 PRIMARY CONTAINMENT LEAKAGE RATE TESTING PROGRAM

The primary containment leakage rate testing program (PCLRTP) satisfies the requirements that primary containment meets the leakage-rate test requirements in either option A or B of 10 CFR 50, Appendix J[19]. Plant Hatch has opted for option B which identifies the performance-based requirements and criteria for preoperational and subsequent periodic leakage-rate testing. This program is designed to ensure that (a) leakage through the primary containment or systems and components penetrating the primary containment does not exceed allowable leakage rates specified in the Technical Specifications and (b) integrity of the containment structure is maintained during its service life. The PCLRTP manages the aging effect of loss of material.

There are three performance-based leakage test requirements: Type A [also known as integrated leak rate test (ILRT)], Type B, and Type C [also known as local leak rate test (LLRT)]. Type A tests measure the containment system overall integrated leakage rate and are conducted under conditions representing design basis loss-of-coolant accident containment peak pressure. Type B pneumatic tests are performed to detect and measure local leakage

rates across pressure retaining, leakage-limiting boundaries. Type C pneumatic tests are performed to measure containment isolation valve leakage rates. These tests ensure the integrity of the overall containment system as a barrier to fission product release following a postulated accident.

The PCLRTP was developed through the use of 10 CFR 50, Appendix J, Option B; Regulatory Guide 1.163[20]; NEI 94-01[21]; ANSI/ANS 56.8-1994[22]; and Bechtel Topical Report BN-TOP-1[23]. The allowable leakage rate (L_a) with margin is based on as specified in the Technical Specifications[24]. No exceptions will be taken to regulatory positions C.1 through C.4 of RG 1.163.

A. Program Scope

The PCLRTP applies to the structures, systems, and components within the scope of license renewal. These components include the steel primary containment, containment penetrations, and containment internal structures that perform a pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive (CRD) removal hatches.

B. Preventive or Mitigative Actions

There are no preventive or mitigative actions associated with this program.

C. Parameters Inspected or Monitored

The PCLRTP provides for visual inspection and performance testing intended to detect loss of material.

A general visual inspection of the accessible interior and exterior surfaces of the drywell and torus are performed prior to conducting a Type A test. The containment pressure boundary integrity is monitored by performance testing.

D. Detection of Aging Effects

The containment leakage rate testing program utilizes pressure tests of containment to verify that primary containment pressure integrity remains intact. In addition, general visual inspections are conducted prior to performing a Type A (ILRT) test.

E. Monitoring and Trending

Inspection and performance testing results are maintained in plant records. Engineering personnel track and trend results in accordance with PCLRTP implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. Any significant degradation of components tested and inspected by PCLRTP is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.15 BOILING WATER REACTOR VESSEL AND INTERNALS PROGRAM

The boiling water reactor pressure vessel and internals inspection program (BWRVIP) developed inspection and evaluation reports for the RPV and reactor internal components and submitted them to the NRC for review and approval. These reports address both the current term and the extended term of operation. Additionally, these reports specifically addressed the RPV components and reactor internals relative to the requirements of 10 CFR 54[25]. The BWRVIP criteria documented in the final NRC safety evaluations regarding these inspections and evaluation reports are used, except where a specific exception has been identified to the NRC.

For the RPV and reactor internals, applicable ASME Section XI[6] ISI requirements and applicable augmented inspection requirements mandated by NRC correspondence, such as NUREG 0619[26], are considered within BWRVIP inspection and evaluation reports and are addressed by BWRVIP inspection requirements.

A. Program Scope

RPV components which require aging management for license renewal include RPV, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles penetration seals, core ΔP and standby liquid control nozzle, RPV support skirt, closure studs, attachment welds for internal core spray pipe, jet pump riser brace pad, and shroud support.

Reactor internals which require aging management for license renewal are the shroud and associated shroud repair hardware, shroud supports, internal core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, top guides, dry tubes, and steam dryers.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

BWRVIP inspection and evaluation reports contain approved inspection methodologies to detect cracking of RPV and reactor internals.

D. Detection of Aging Effects

The BWRVIP inspection and evaluation documents provide for RPV and reactor internals examination utilizing a combination of ultrasonic, visual, and surface methods. Pressure testing is also utilized. The specific methods to be used and the frequency of examination are specified in the applicable BWRVIP inspection and evaluation report, unless a specific exception is identified to the NRC.

E. Monitoring and Trending

Monitoring requirements for the detrimental effects of aging within reactor assembly components are specified within BWRVIP inspection and evaluation reports. The frequency of examination specified within applicable BWRVIP inspection and evaluation reports varies for each component or subassembly. The frequency is based on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used.

F. Acceptance Criteria

BWRVIP inspection and evaluation reports provide specific acceptance criteria and proper corrective actions. BWRVIP inspection and evaluation reports applicable to Plant Hatch reactor assembly components are listed below:

BWRVIP-18	Core Spray Internals[27]
BWRVIP-26	Top Guide[28]
BWRVIP-27	SLC Penetrations[29]
BWRVIP-38	Shroud Support and Connecting Welds[30]
BWRVIP-41	Jet Pump Assembly[31]
BWRVIP-47	Control Rod Guide Tube[32]
BWRVIP-48	RPV ID Attachment Welds[33]
BWRVIP-74	RPV Shell and Heads, Nozzles, and Appurtenances[34]
BWRVIP-76	Shroud (including repair hardware) [35]
BWRVIP-139	Steam Dryers[61]
BWRVIP-183	Top Guide Grid Beams[62]

18.2.16 WETTED CABLE ACTIVITIES

Several 4-kV power cables and transformer feeder cables within the scope of license renewal run through conduits that junction in below grade pull boxes located outside. These cables might become immersed in rainwater if left unattended. In turn, wetted cable insulation might result in loss of insulation resistance.

A. Program Scope

The wetted cable activities monitor insulated cable in portions of the following systems that are within the scope of license renewal.

- RHR system.

- RHRSW system.
- Core spray system.
- PSW system.

B. Preventive or Mitigative Actions

In-scope pull boxes have automatic sump pumps that maintain the water level below the routed cables and are checked routinely. By routinely monitoring for water in the applicable pull boxes and draining accumulated water when necessary, these activities prevent or mitigate loss of insulation resistance that might otherwise occur if cables were left immersed.

C. Parameters Inspected or Monitored

Wetted cable activities provide for testing of cables to measure cable insulation resistance. A reduction in cable insulation resistance indicates aging degradation due to loss of insulation resistance.

D. Detection of Aging Effects

The condition of the cable insulation is periodically assessed using one or more of the following techniques: Dielectric loss (dissipation factor/power factor); AC voltage withstand; partial discharge; step voltage; time domain reflectometry; insulation resistance and polarization index; line resonance analysis; or other testing that is state of the art at the time of the tests. Periodic use of one or more of these tests is the method by which actual power cable insulation degradation is detected, regardless of whether or not the degradation was attributable to immersion.

E. Monitoring and Trending

Inspection and test results are maintained in plant records. Engineering personnel track and trend results in accordance with wetted cable activities implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of insulation resistance will be evaluated by engineering. Any significant degradation of components tested by the wetted cable activities is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.17 REACTOR PRESSURE VESSEL MATERIALS SURVEILLANCE PROGRAM

The reactor pressure vessel (RPV) materials surveillance program meets the requirements of 10 CFR 50, Appendix H[36]. This program provides for testing and evaluation of in-core surveillance capsule tensile and charpy specimens and evaluation of capsule neutron exposure for the purpose of evaluating the results of operation on RPV beltline material upper-shelf energy (USE) and nil-ductility transition temperature (NDTT).

Compliance with 10 CFR 50, Appendix H may be demonstrated either through an NRC approved site-specific program or an integrated surveillance program that meets the technical requirements documented within BWRVIP-86, Revision 1-A[37] or latest NRC approved guidance.

A. Program Scope

RPV components requiring aging management within the scope of the RPV materials surveillance program include only RPV ferritic plates and welds within the beltline region.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The RPV materials surveillance program provides for evaluation of charpy and tensile specimens and flux wires to estimate changes in the USE and NDTT of beltline ferritic materials.

D. Detection of Aging Effects

The RPV materials surveillance program monitors reduction of fracture toughness within ferritic RPV beltline materials. Testing methodologies are provided within ASTM E185[38], with revision, as applicable. See Unit 1 FSAR section 4.2 and section 5.2.

E. Monitoring and Trending

Reductions in ferritic vessel beltline material fracture toughness are monitored by the surveillance program. For the period of extended operation, the capsule removal schedule will be determined by the integrated surveillance program or an NRC approved site-specific program.

F. Acceptance Criteria

Data obtained from the materials surveillance program or from use of estimation methodologies provided within NRC Regulatory Guide 1.99[39] are ultimately utilized to evaluate USE reduction and shifts in NDTT. Limits are imposed on USE, NDTT, and operating pressure and temperature by 10 CFR 50 Appendix G[40].

18.2.18 DIESEL GENERATOR MAINTENANCE ACTIVITIES

The diesel generator maintenance activities (DGMA) provide for management of the aging effects of loss of material, loss of preload, cracking, and loss of heat exchanger performance for the EDG components that are within the scope of license renewal. The DGMA are limited to the EDG components on the EDG skid.

A. Program Scope

The DGMA address the aging effects for the EDG skid-mounted components that contain jacket cooling water, lubrication oil, scavenging air, and raw water. The components are limited to the piping, tubing, bolting, restricting orifices, valve bodies, pump casings, heat exchangers, heater casings, filter housings, strainer bodies, and strainer elements.

B. Preventive or Mitigative Actions

The DGMA are performance monitoring activities and preventive maintenance activities, as well as surveillance tests. During these activities, aging effects such as loss of material, loss of preload, cracking, and loss of heat exchanger performance that adversely impact the performance of the EDG component intended functions can be identified.

The DGMA also include periodic preventive maintenance on the EDG components. These maintenance activities include disassembly and refurbishment of the components, as needed. Replacement of adversely affected components (and fluids, such as the jacket cooling water and lubrication oil) is also an option within the DGMA.

The DGMA include provisions to address the loss of preload for bolting through the normal torque activities (see subsection 18.2.11).

C. Parameters Inspected or Monitored

The DGMA include visual inspections and chemical and performance-based tests and analyses. Lubricating oil is tested for corrosion or wear products, water, fuel oil, and antifreeze. Heat exchanger inspections visually inspect heat exchanger water boxes, tubes, tube sheets, and sacrificial zinc rods for damage, debris, deposits, and evidence of corrosion to discern the impact of loss of material. Heat exchanger inspections also include the option for eddy current testing of the heat exchanger tubes (exposed to raw water) on an as-needed basis. The quality of the ethylene glycol solution in the jacket water cooling system is monitored during maintenance on the EDGs to ensure proper performance.

D. Detection of Aging Effects

DGMA are not intended to directly detect loss of material or cracking within EDG components or loss of preload in EDG bolting. The DGMA can detect loss of heat

exchanger performance in the heat exchangers through pressure and temperature instrumentation monitoring during performance of periodic surveillance tests.

E. Monitoring and Trending

Inspection and test results and chemical analysis data are maintained in plant records as specified in DGMA implementing procedures. Engineering personnel track and trend results in accordance with DGMA implementing procedures.

F. Acceptance Criteria

For performance tests, the acceptance criteria are listed in the specific plant procedures and are intended to ensure that system operating temperatures, pressures, and expansion tank levels are within the acceptable operating ranges. For preventive maintenance activities, the acceptance criteria are also contained within the maintenance procedures and are commensurate with the safety significance of the component inspected. After maintenance, the performance of the components must be such that the performance test criteria are satisfied.

18.3 PROGRAMS/ACTIVITIES - GROUP II

18.3.1 FIRE PROTECTION ACTIVITIES

Fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. Fire protection activities provide assurance that loss of material, cracking, flow blockage, and changes in material properties will not prevent the performance of necessary safe shutdown functions.

A. Program Scope

The Plant Hatch fire protection activities credited for license renewal include those portions of fire protection systems identified in the Fire Hazards Analysis (FHA) as forming part of the CLB. These include passive long-lived components in water based and gaseous fire suppression systems, the fire pump diesel fuel oil supply system (tanks and piping), fire doors, fire penetration seals, fire dampers, and cable tray enclosures. All of these components are part of the fire protection system.

The current term fire protection activities have been enhanced for the period of extended operation to include periodic inspection of water suppression system strainers and sprinkler heads.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

B. Preventive or Mitigative Actions

Flushing of loop headers removes corrosion product buildup and ensures adequate flow through the system. Other than flushes, there are no preventive or mitigative attributes associated with the condition and performance monitoring elements of this program.

C. Parameters Inspected or Monitored

Surveillance and inspection of in-scope fire protection system components are performed in accordance with the frequencies and requirements the applicable portions of both Appendix B of the FHA and plant procedures that cover in-scope components. The activities performed to manage the effects of aging for these systems are listed in Table 18.3.1 - 1.

An inspection, called “Sprinkler Head Inspections,” will be performed periodically for closed sprinkler heads in the scope of license renewal. The first inspection will take place after 50 years of service and subsequent inspections at 10-year intervals thereafter. Consistent with the guidance in NFPA-25[57], a random sampling of each type of closed sprinkler head in the scope of license renewal will be submitted to a recognized laboratory for testing. Based on the results,

corrective actions will be accomplished, if required, to assure continued sprinkler head function during the period of extended operation.

D. Detection of Aging Effects

Detection of flow blockage, loss of material, cracking, and changes in material properties are accomplished directly by visual examinations of component surfaces and laboratory testing and indirectly through the use of flow or functional testing.

E. Monitoring and Trending

Inspection and performance testing results are maintained in plant records. Engineering track and trend results in accordance with site procedures.

F. Acceptance Criteria

Any significant degradation of fire protection system components that is observed during visual inspections or performance testing activities is noted and corrective actions are implemented in accordance with the corrective actions program. Acceptance criteria are specifically stated in the plant procedures that govern each test or inspection.

18.3.2 FLOW ACCELERATED CORROSION PROGRAM

The FAC program is a condition monitoring program designed to monitor pipe component wear in those systems that have been determined to be susceptible to FAC related loss of material. The objective of the program is to ensure that the damage caused by flow-accelerated corrosion will not cause components failures. This objective is accomplished by predicting the rate of degradation of components and taking corrective actions once the degradation is detected.

FAC is different from many other corrosion processes in that corrosion rates may be generally predicted.

Components identified by the plant predictive FAC model are periodically examined based on the recommendations of the EPRI NSAC-202L[41] since they meet all of the screening criteria contained within EPRI NSAC 202L for systems potentially susceptible to FAC.

The current term FAC program has been enhanced for the period of extended operation to include some components that do not meet all of the FAC criteria within EPRI NSAC 202L or component that are excluded from the plant predictive FAC model due to size.

The basis for the FAC program is EPRI NSAC-202L and the associated CHECWORKS™[42] computer code, which is used to create a plant predictive CHECWORKS™ FAC model. This plant predictive FAC model accounts for system conditions relevant to FAC such as pH, dissolved oxygen content, fluid (steam) quality, temperature, pipeline velocity, component geometry, and material of construction.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

A. Program Scope

The FAC program will examine portions of the following systems within the scope of license renewal.

- Nuclear Boiler
- High Pressure Coolant Injection Steam Supply Drains
- Reactor Core Injection Coolant Steam Supply Drains
- Radioactive decay holdup volume (main steam, main steam line drains, condensate drains, and condenser shell)

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The FAC program provides for visual and volumetric inspections intended to detect loss of material by monitoring component wall thickness. Smaller than two inch piping shall be inspected based on industry and plant specific operating experience as opposed to computer modeling.

D. Detection of Aging Effects

FAC program inspections are implemented to detect loss of material via radiographic (RT), ultrasonic (UT), and visual inspections.

E. Monitoring and Trending

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with FAC program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the FAC program is noted and corrective actions will be implemented in accordance with the corrective action program.

18.3.3 PROTECTIVE COATINGS PROGRAM

The Plant Hatch protective coatings program (PCP) provides a means of preventing or minimizing loss of material that would otherwise result from contact of the base material with a corrosive environment. The PCP is a mitigation and condition monitoring program designed to provide base metal aging management through surface application, maintenance, and inspection of protective coatings on selected components and structures.

Coating Service Level I are those coating systems applied inside the primary containment where coating failure could adversely affect the operation of post-accident fluid systems and, thereby, impair safe shutdown of the plant.

Coating Service Level II are those coating systems, which are applied to systems, structures and components whose operation is essential to the attainment of the intended normal operating performance. The function of service level II coatings is to provide corrosion protection and the ability to decontaminate the pipe.

Coating Service Level III are those coating systems applied outside of primary containment, but which in the event of failure could adversely affect the orderly and safe shutdown of the plant.

A. Program Scope

The PCP provides specifications for coatings applied to structures and components within the scope of license renewal. The PCP includes specific inspection techniques and frequencies for Service Level I coatings (which include non-immersion coatings applied to the suppression chamber and drywell airspace and immersion coatings applied to the suppression chamber interior below the normal water level). The current term PCP has been enhanced for the renewal term to provide inspection techniques and frequencies for certain accessible non-service level I coatings. These requirements apply to external surfaces of carbon steel commodities outside of primary containment and within the scope of license renewal that are expected to experience significant atmospheric corrosion.

The PCP has also been enhanced to provide for inspection and documentation of the condition of normally inaccessible (underground, submerged, or embedded) carbon steel components within the scope of license renewal, whenever these components are exposed or uncovered.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

B. Preventive or Mitigative Actions

Proper application of coatings limits, loss of material by preventing direct contact between susceptible base materials and environmental conditions conducive to corrosion.

Prior to coating application surfaces will meet the requirements of SSPC-SP11 or equivalent. In addition, thick edge paint shall be feathered. During coating application, ambient conditions and surface temperatures are monitored periodically to ensure suitable conditions for mixing and applying coatings exist.

C. Parameters Inspected or Monitored

Periodic visual inspection (per industry guidance) of components is conducted in order to identify areas of degraded coatings and associated corrosion of base metals, which may indicate a loss of material

Underground pipe lines are covered with coal tar enamel wrapping. Whenever underground sections of pipe are uncovered they will be cleaned, primed, coated, and wrapped. A special instruction will be placed in the site procedure used to manage excavation activities to assure that buried commodities are examined by protective coating personnel.

Visual inspections will be performed on newly applied coatings. Dry film testing will be performed on finished surfaces, and where needed, continuity testing will be performed. If required, profile measurements will be taken on prepared surfaces.

D. Detection of Aging Effects

Detection of degraded coatings and associated corrosion of base metals is accomplished primarily through visual inspection techniques. For surfaces determined to be suspect, dry film thickness, adhesion, and continuity tests may also be performed.

E. Monitoring and Trending

Service level I coatings will be inspected once per cycle. A baseline inspection of non-service level I coated components within the scope of license renewal will be performed. Subsequent inspection frequencies will be determined on the basis of the results of the baseline inspection, trends, and plant specific operating experience. Coated components are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with site procedures.

F. Acceptance Criteria

Any significant degradation of structural components that is observed during the visual inspection activities is noted and corrective actions implemented in accordance with the corrective actions program. Acceptance criteria are specifically stated in the PCP and the implementing procedures.

Specific acceptance criteria for the protective coatings program are based on multiple codes and standards. These include but are not limited to ANSI N5.12 - 1972[43], ANSI N101.2 – 1972[44], ASTM, Section 6, Volume 06.02[45], AWWA C203 - 1966[46], AWWA C209 -1995[47].

Coatings application is performed in accordance with vendor recommendations and industry practices.

18.3.4 EQUIPMENT AND PIPING INSULATION PROGRAM

Equipment and piping insulation performance may be degraded if the insulation or jacketing is damaged. The equipment and piping insulation monitoring program (EPIM) is a condition monitoring program designed to detect cracking, loss of material, and changes in material properties in insulation through periodic inspection of specific passive component insulation. The current term program has been enhanced for the period of extended operation to include insulation on selected systems located inside buildings.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

A. Program Scope

The equipment and piping insulation monitoring program inspects insulation on portions of systems within the scope of license renewal. These systems are:

- standby liquid control
- residual heat removal (RHR) and RHR service water
- core spray
- high pressure coolant injection
- reactor core isolation cooling
- condensate transfer and storage (exposed piping at CST)
- plant service water
- fire protection (exposed piping at fire pump house)

B. Preventive or Mitigative Actions

EPIM program implementing procedures contain precautions that mitigate insulation damage by limiting climbing on pipe insulation. Damage is further

mitigated by implementing procedures that provide specific instructions for removal, storage and installation of thermal and reflective insulation. Preventing the damage assures that changes in material properties, cracking, and loss of material are also prevented.

C. Parameters Inspected or Monitored

The equipment and piping insulation monitoring program provides for periodic visual inspection. The visual inspection identifies changes in material properties of the insulation. Aluminum and galvanized steel insulation jackets and their binders are inspected for cracking and loss of material.

D. Detection of Aging Effects

Visual inspection of the insulation and insulation jackets is performed to identify degradation which may indicate the aging effects of changes in material properties, loss of material, or cracking.

E. Monitoring and Trending

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with EPIM program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of a change in material properties, cracking, or loss of material will be evaluated by engineering. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the EPIM program is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.3.5 STRUCTURAL MONITORING PROGRAM

The structural monitoring program (SMP)[48] provides a condition monitoring and appraisal process for structures and components within the scope of the Maintenance Rule (10 CFR 50.65)[49] and the License Renewal Rule (10 CFR 54)[25]. The SMP inspection process assesses the overall conditions of the buildings and structures, and identifies any ongoing degradation. The SMP manages loss of material, cracking and changes in material properties (including loss of adhesion).

A. Program Scope

The enhanced SMP monitors those portions of the following structures, components and commodities that are within the scope of license renewal. The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program[50].

- switchyard
- reactor buildings
- turbine buildings
- intake structure
- off gas stack
- EDG building
- control building
- condensate storage tank foundations and concrete walls surrounding the tanks
- PSW valve pits
- diesel generator fuel oil storage tanks
- nitrogen storage tank foundations
- foundations for the two fire protection water storage tanks
- foundations for the two fire protection diesel pump fuel tanks
- foundation for the fire pump house
- underground concrete duct runs and pull boxes between Class I structures
- Category I and II/I piping supports and tube tray supports
- Category I HVAC duct supports
- Category I and II/I cable trays and supports
- Category I and II/I conduits and supports
- Category I control room panels, racks and supports
- Category I auxiliary panels, racks and supports
- sealants in the joints between the reactor building exterior precast siding panels
- reactor building tornado vents

- reactor building penetrations

In addition, the SMP monitors secondary containment leakage characteristics.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The SMP is a condition monitoring program that utilizes visual inspections to identify aging effects prior to any loss of intended function. Concrete structures are inspected for cracks, leaching, spalling and corrosion staining, as evidence of loss of material and cracking. Steel components are inspected for general and localized corrosion as evidence of loss of material. Panel joints and seals are inspected for evidence of loss of adhesion and changes in material properties. The acrylic domes of the tornado vents are inspected for cracks. Block walls are inspected for cracks. Piping is inspected for leakage. Secondary containment leakage characteristics are verified per SR 3.6.4.1.4 of the Plant Hatch Technical Specifications.[51]

Structures monitored under 10CFR50.65(a)(2) will be inspected at least every five operating cycles unless a greater frequency is warranted.

D. Detection of Aging Effects

Structural condition is assessed through a visual inspection. Inspections include those structures normally accessible, as well as those below ground or embedded. When inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Qualified personnel, using detailed checklists, inspection tools and preparations perform the inspections. Noted degradation may be documented utilizing digital photography.

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. The frequencies of the inspections are defined in the SMP document[48] and the implementing procedures.

As an additional measure of detection, the standby gas treatment system flow test can detect gross changes in in-leakage that may be indicative of age-related degradation and identification and correction of leakage from piping systems can prevent age-related degradation of components affected by that leakage.[51]

E. Monitoring and Trending

Initial inspections (baseline) were conducted to facilitate condition trending. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with SMP implementing procedures.

F. Acceptance Criteria

Acceptance criteria for the inspection and criteria for categorizing the overall structure and component conditions (i.e., acceptable, acceptable with deficiency, or unacceptable) are provided in the procedure. The acceptance criteria are consistent with the recommended criteria in ACI-349.3R-1996[52], but also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The results of the inspections are evaluated in accordance with the guidance given in ACI-349.3R-1996[52] and NRC Regulatory Guide 1.160[53].

The structures will be inspected for the following conditions based on the acceptance criteria stated in the SMP document[48]. Any significant degradation of structural components, including leakage from piping, observed during the visual inspections is noted and corrective actions implemented in accordance with corrective actions program. Acceptance criteria are specifically stated in the SMP and the implementing procedures. The acceptance criteria for the secondary containment draw-down tests are specified in Ref. 51.

Table 18.3.1-1

Activities Performed to Manage Aging Effects for Fire Protection System Components

Activity	Method	Parameter
Cable tray enclosure inspection	Visual inspection	Condition - degradation
CO2 systems component inspection	Visual inspection	Condition - corrosion / degradation
CO2 systems performance test	Performance test	Flow
Exterior coatings inspection	Visual inspection	See Protective Coatings Program
Fire damper functional test	Performance test / Visual inspection	Observe full closure and no visible openings
Fire damper inspection	Visual inspection	Condition - corrosion / degradation
Fire diesel fuel oil tank level	Visual inspection	Fuel oil level
Fire hydrant flow check	Performance testing	Flow
Fire penetration seal inspection	Visual inspection	Condition - degradation
Fire Water Tank internal and external inspection	Visual inspection	Condition – corrosion, size and depth of pits
Fire Water Tank volume	Visual inspection	Water level
Flow test of water mains	Performance test	Pressure drop
Fuel oil storage tank sampling	Visual inspection / lab analysis	Presence of water, sediment, and other contaminants
Fuel oil system leak inspection	Visual inspection	Fuel oil leaks
Fuel oil tank internal inspection	Visual inspection	Condition - corrosion / degradation
Hose station inspection	Visual inspection	Condition - corrosion / degradation
Hose station valve cycling	Performance testing	Flow
Open head/deluge spray nozzle air flow test	Performance test	Flow
Sprinkler heads and nozzles inspection	Visual inspection	Condition – corrosion / degradation
Sprinkler system header flow activity	Performance test	Flow
Sprinkler system trip test	Performance test	Flow
Start and run each fire pump	Performance test	Flow, developed head
Start and run fire diesels	Performance test	Fuel oil leaks
Strainer inspection	Visual inspection	Condition - corrosion / degradation
System isolation valve cycling	Performance test / Visual inspection	Observe full valve position change

18.4 PROGRAMS/ACTIVITIES - GROUP III

18.4.1 GALVANIC SUSCEPTIBILITY INSPECTIONS

The galvanic susceptibility inspections will provide for condition monitoring via one-time inspections that will provide objective evidence that loss of material due to galvanic corrosion is being managed for specific components within the scope of license renewal.

A. Program Scope

Galvanic susceptibility inspections will examine an initial sample set of raw water carbon to stainless steel connections that are within the scope of license renewal. The inspected points will be the locations that are expected to have the greatest potential for galvanic coupling. Based on the results of the sample inspections, the sample set may be expanded to include galvanic couples associated with components in other environments. Systems include:

- nuclear boiler
- control rod drive
- residual heat removal and residual heat removal service water
- core spray
- high pressure coolant injection
- reactor core isolation cooling
- main condenser system
- plant service water
- emergency diesel generator
- primary containment
- containment atmospheric control
- traveling water screens

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The galvanic susceptibility inspections provide for visual and volumetric inspections intended to detect loss of material due to galvanic corrosion. Inspection locations will be based on engineering judgment and will include areas predicted to be most susceptible.

The sample size of each examination method will be a function of the sample locations and component geometry.

D. Detection of Aging Effects

Inspections will be performed using one or more methods. These may include visual inspections, ultrasonic thickness determinations, radiographic testing, depth gauges, and pipe removal and analysis. Visual inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the GSI is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.2 TREATED WATER SYSTEMS PIPING INSPECTIONS

The treated water systems piping inspections will be one time condition monitoring examinations intended to prove that existing chemistry control is managing loss of material and cracking in piping that is not examined under another inspection program.

A. Program Scope

Scope of the program includes the specific structure, component, or commodity for the identified aging effect. Specific commodities include, but are not limited to, carbon and stainless steel piping, tubing, valve bodies, pump casings, tanks, accumulators and strainer bodies.

Treated water systems piping inspections will examine a sample population of carbon and stainless steel tubing and piping (including both large-bore pipe and small-bore butt-welded stainless steel pipe) in the treated water systems within the scope of license renewal. The results of the sample population examinations will be evaluated, and subsequent examinations will be conducted where evaluation results warrant.

Systems included are:

- nuclear boiler
- reactor recirculation
- control rod drive
- standby liquid control
- residual heat removal
- core spray
- high pressure coolant injection
- reactor core injection coolant
- main turbine auxiliaries
- portions of the radioactive decay holdup volume (main steam, main steam lines condensate drains and condenser shell)
- condensate storage and transfer
- reactor building component cooling water
- plant component cooling water (Unit 2 only)
- emergency diesel generator auxiliaries
- primary containment
- containment atmospheric control system

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The treated water systems piping inspection provide for visual and volumetric inspections intended to detect loss of material and cracking.

These one-time inspections will focus Class 1 and Non-Class 1 carbon and stainless steel components within the reactor water, torus water, demineralized water, closed cooling water, and borated water environments.

Inspection locations will be based on engineering judgment and will include areas predicted to be most susceptible.

D. Detection of Aging Effects

Inspections of the sample set will be conducted using the best available examination method for the inspected component. Visual inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210. Alternately, volumetric inspections may be used.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of corrosion will be evaluated by further engineering. When appropriate, engineering evaluations will be based upon the design code record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by treated water systems piping inspections is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.3 GAS SYSTEMS COMPONENTS INSPECTIONS

The gas systems component inspections (GSCI) will be a set of one-time condition monitoring inspections that provide objective evidence that age-related degradation is not inhibiting component function in gas-bearing in-scope systems and components. The aging effects that GSCI are intended to manage are loss of material, cracking, and material property changes.

A. Program Scope

The GSCI are applied to a sample set drawn from a population of components exposed to humid and wetted gas in the following systems:

- nuclear boiler (safety relief valve tailpipes to the torus)
- control rod drive
- residual heat removal
- high pressure coolant injection
- reactor core isolation cooling
- sampling
- starting air and engine exhaust subsystems of the emergency diesel generators
- primary containment (including the drain lines for the drywell sump discharge)
- reactor building HVAC
- standby gas treatment
- primary containment purge and inerting
- outside structure HVAC
- fuel oil (fuel oil storage tank vapor spaces)
- control building HVAC (including gaskets)
- turbine building HVAC

The sample population will focus on those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation.

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The GSCI provide for visual and volumetric inspections intended to detect loss of material, cracking, and material property changes.

D. Detection of Aging Effects

The GSCI use visual inspection techniques (similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210). Alternatively, volumetric inspections may be used.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with these inspections.

F. Acceptance Criteria

Any unacceptable indication of loss of material or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the GSCI is noted and corrective actions will be implemented in accordance with the existing corrective actions program.

18.4.4 CONDENSATE STORAGE TANK INSPECTIONS

The CST Inspection will be a one-time condition monitoring inspection of the internal surfaces of each CST designed to provide objective evidence that no loss of material is occurring. This inspection is intended to validate the adequacy of current demineralized water chemistry controls to manage corrosion.

A. Program Scope

The CST inspection activities will inspect only those CST components, within the scope of license renewal, required to assure the availability of approximately 100,000 gallons of water for the high pressure coolant injection and reactor core injection coolant systems.

The Unit 1 inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The condensate storage tank inspection provides for visual inspection intended to detect loss of material. These inspections will focus on selected areas associated with the standpipes, associated supports and nozzles.

Inspection locations will be based on engineering judgment and will include areas predicted to be most susceptible.

D. Detection of Aging Effects

The CST Inspection will utilize visual inspection techniques similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the condensate storage tank inspection is noted and corrective actions will be implemented in accordance with the corrective action program.

18.4.5 PASSIVE COMPONENTS INSPECTION ACTIVITIES

The passive components inspection activities (PCIA) are a set of on-going condition monitoring inspections designed to confirm that age-related degradation is not inhibiting the component functions of systems and components within the scope of license renewal. The PCIA manages the aging effects of loss of material, cracking, and change in material properties.

A. Program Scope

The PCIA are applied to a sample set of components drawn from a population of components, in the scope of license renewal, in the following systems:

- nuclear boiler (safety relief valve tailpipes to the torus)
- control rod drive
- residual heat removal
- high pressure coolant injection

- reactor core isolation cooling
- starting air and engine exhaust subsystems of the emergency diesel generators
- primary containment (including the drain lines for the drywell sump discharge)
- reactor building HVAC
- standby gas treatment
- primary containment purge and inerting
- outside structure HVAC
- fire protection
- fuel oil (fuel oil storage tank vapor spaces)
- control building HVAC (including gaskets)
- turbine building HVAC

PCIA is based on availability, not population. As such, population, frequency, and sample size are not pre-determined. The preferred inspection sites will be those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with these activities.

C. Parameters Inspected or Monitored

Visual inspections in the PCIA verify material condition by checking for the presence of corrosion and cracking, so that engineering can make an evaluation of the impact of loss of material and cracking. For gaskets, the PCIA will visually inspect for the presence of cracks or material degradation to determine if a change in material properties of a loss of material has occurred.

D. Detection of Aging Effects

The PCIA are condition monitoring activities that utilize visual inspections and volumetric inspections to identify aging effects prior to any loss of intended function. The PCIA will develop a baseline examination of a sample population of the in-scope components, as they become available due to normal maintenance activities. The PCIA will use visual inspection techniques (similar to that described

for VT-1 in ASME Section XI[6], paragraph IWA-2210). Where possible and practical, accessible components may be inspected for stress corrosion cracking using surface or volumetric examination.

E. Monitoring and Trending

The PCIA collects, reports, and trends age-related data. Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with PCIA implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material, change in material properties, or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the PCIA is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.6 RHR HEAT EXCHANGER AUGMENTED INSPECTION AND TESTING PROGRAM

The RHR heat exchanger augmented inspection and testing program is a condition monitoring program that manages aging of the RHR heat exchangers. The aging effects managed are loss of material, flow blockage, cracking, and loss of thermal performance.

The program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13[18]. SNC used the guidance of SAND 93-7070[54], as supplemented by reviews of current industry experience and practice, as the basis for this program.

A. Program Scope

The subject program will inspect, test, and maintain passive components of the RHR heat exchangers that are within the scope of the license renewal.

B. Preventive or Mitigative Actions

The RHR heat exchanger augmented inspection and testing program requires that heat exchanger tubes and channel interior be cleaned on a periodic basis. This cleaning of the heat exchanger tubes and channel head mitigates flow blockage and loss of thermal performance.

C. Parameters Inspected or Monitored

The RHR heat exchanger augmented inspection and testing program provides for visual inspections, pressure testing, and eddy current testing intended to detect loss of material and flow blockage. Parameters inspected or monitored are the following: loss of material, flow area reduction due to fouling, and cracking.

This program also includes the pit and diving inspection activities of the structural monitoring program. These activities provide for inspection and removal of sediment in the pump suction pit to prevent or minimize flow blockage and loss of material.

D. Detection of Aging Effects

RHR heat exchanger augmented inspection and testing program is performed at prescribed frequencies in the implementing procedures (once every 10 year cycle) to detect the identified aging effects of the heat exchanger passive components.

Visual inspection of channel side (including partition plate and tube sheet) and tube interior is performed. This activity detects loss of material, flow blockage, and cracking.

The current term activities have been augmented for the period of extended operation by addition of the following tests and inspections:

Eddy Current Testing is performed periodically (at least once every 10 year cycle) and whenever leaks are suspected. Testing will be performed by qualified personnel and include accessible portions of the straight tube sections and U-bends of the test sample (at least 10% of the operational tubes). This activity detects loss of material and cracking.

The shell side of the tube sheets, shell internals, and impingement plates are visually inspected periodically, where accessible. The inspection focuses on tube interfaces, tie rods or fasteners, and accessible welds. This activity detects loss of material, flow blockage (fouling), and cracking.

Tube and tube sheet leak testing is performed whenever leaks are suspected. This activity detects leaks due to cracking and loss of material.

These augmentations will be fully implemented no later than midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

E. Monitoring and Trending

Inspection and testing results are maintained in plant records. Engineering personnel track and trend results in accordance with implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material is evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections are performed. Any significant degradation of components inspected by the RHR heat exchanger augmented inspection and testing program is noted and corrective actions are implemented in accordance with the existing corrective actions program.

18.4.7 TORUS SUBMERGED COMPONENTS INSPECTION PROGRAM

The torus submerged components inspection program (TSCIP) is a condition monitoring activity designed to monitor torus submerged components for loss of material and cracking. The objective of the program is to assure that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of suppression pool chemistry controls to manage aging effects for a variety of uncoated structures and components that are exposed to the suppression pool environment.

A. Program Scope

The TSCIP will initially examine a sample set of 10 percent of the uncoated components within the scope of license renewal and located in the torus. This sample will be biased towards the areas most likely to exhibit corrosion related degradation.

Portions of the following systems are within the scope of the TSCIP:

- safety relief valve tailpipe
- residual heat removal strainers
- core spray strainers
- high pressure coolant injection suction strainers and turbine exhaust
- reactor core isolation cooling suction strainers and turbine exhaust
- primary containment purge and inerting (vacuum relief piping)

The TSCIP will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The TSCIP provides for visual inspections intended to detect loss of material and cracking in uncoated components and structures submerged within the suppression pool and in the vapor space directly above the suppression pool.

D. Detection of Aging Effects

The TSCIP will utilize visual inspection techniques similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted based upon the results of the initial inspections, inspections of additional locations within the torus will be performed. Corrective actions will be implemented in accordance with the corrective actions program.

18.4.8 INSULATED CABLES AND CONNECTIONS PROGRAM

The insulated cables and connections program is a condition monitoring program designed to confirm that age-related degradation (change in material properties) is not inhibiting component function of insulated cables and connectors.

A. Program Scope

The insulated cables and connections program is a sampling program and includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the primary containment structure, reactor building, radwaste building, diesel generator building, turbine building, control building, intake structure, low voltage switchyard, high voltage switchyard, and main stack, which could be subject to applicable aging effects from heat or radiation. This program does not include cables and connections that are in the Environmental Qualification program. Based on the results of the sample inspections, the sample set may be expanded to include additional components. The initial Unit 1 and common inspections will be performed by midnight August 6, 2014. The initial Unit 2 inspections will be performed by midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The insulated cables and connections program provides for visual inspections and testing intended to detect aging degradation. Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat or radiation.

D. Detection of Aging Effects

Accessible insulated cables and connections in adverse localized equipment environments (ALEEs) will be visually inspected at least once every 10 years for jacket surface anomalies such as embrittlement, discoloration, cracking, or surface contamination. Inaccessible cables and connections in adverse localized equipment environments (ALEEs) will be tested at least once every 10 years.

Sampling is acceptable, and if used the same size will be determined prior to the inspection or test.

E. Monitoring and Trending

Inspection and test results are maintained in plant records. Engineering personnel track and trend results in accordance with insulated cables and connections program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of change in material properties will be evaluated by engineering. If warranted, additional inspections or tests will be performed. Any significant degradation of components inspected by the insulated cables and connections program is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.5 TIME LIMITED AGING ANALYSES CREDITED FOR LICENSE RENEWAL

18.5.1 TIME LIMITED AGING ANALYSES

Title 10 CFR Part 54 (the License Renewal Rule, or the Rule) requires that time limited aging analyses (TLAA) be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40 year operating life of the plant. In addition, the Rule requires that any exemptions based on TLAAs be identified and analyzed to justify extension of those exemptions through the renewal term.

TLAA evaluations for Plant Hatch included those calculations and analyses that met all six criteria of the Rule, specifically, those calculations or analyses that:

- involved systems, structures and components (SSC) within the scope of license renewal;
- considered the effects of aging;
- involved time-limited assumptions defined by the licensed operating term at the time of the license renewal application;
- were determined to be relevant in making a safety determination;
- involved conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated by the Rule; and
- were contained or incorporated by reference in the licensing basis at the time of application for renewal.[55]

Given those six criteria, many calculations and analyses qualified as TLAAs. A summary listing of those calculations and analyses is shown in Table 18.5-1.

Once a TLAA has been identified, the Rule requires it be dispositioned by one of the following three specific criteria:

1. the analyses remain valid for the license renewal term; or
2. the analyses have been acceptably projected to the end of the renewal term; or
3. programs are in place to manage the effect of aging in the analyzed systems, structures or components.[56]

With the exceptions of two areas further discussed below, all of the items in Table 18.5-1 were entirely dispositioned by criterion 1 and/or 2 above. As such, these TLAAs were entirely dispositioned through an update of the existing calculations. The two areas dispositioned in part by Criterion 3 are further discussed below.

18.5.1.1 Stress Analysis Calculations

The stress analysis calculations for the RPV, Class 1 piping, and the torus will be monitored to assure that the cumulative usage factor stays less than or equal to 1.0 (see Section 18.2.12). Additional details of this program are described in sections 4.2.5 and 5.4.6 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

18.5.1.2 Equipment Qualification Report Evaluations

Aging of electrical equipment falling within the scope of 10 CFR 50.49, that has less than a 60-year qualified life, are managed by the Environmental Qualification (EQ) Program. The EQ Program is described in section 7.16 and section 3.11 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

Table 18.5-1

Summary Listing of Calculations and Analyses Meeting the Six Time Limited Aging Analyses Criteria

1. Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant.
2. Fatigue/stress analyses for the torus structure and nozzle connections.
3. Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant.
4. Calculation of the corrosion allowance assumed for the reactor vessel.
5. Environmental equipment qualification calculations that qualify electrical components for 40 years.
6. A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant.
7. Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR 50 Appendix G).
8. Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR 50 Appendix G) due to the extended operating term.
9. Analyses performed to demonstrate the acceptability of a technical alternative to the ASME code requirement inspection of reactor pressure vessel circumferential welds.

18.6 REFERENCES

1. BWRVIP-190, “BWR Water Chemistry Guidelines.”

2. EPRI Report 1007820, “Closed Cooling Water Chemistry Guideline: Revision 1 to TR-107396, Closed Cooling Water Chemistry Guideline.”

3. Generic Letter 89-13 with Supplement 1 “Service Water System Problems Affecting Safety-Related Equipment,” 1990.

4. State of GA Department of Natural Resources Environmental Protection Division Permit No. GA0004120, “Plant Hatch NPDES Permit”, Effective September 15, 1997.

5. 10 CFR 50, Appendix B “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”

6. ASME Boiler and Pressure Vessel Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.”

7. 10 CFR 50.55a, Codes and Standards

8. ANSI B30.2-1976, Overhead and Gantry Cranes.

9. NUREG-0612, Control of Heavy Loads of Nuclear Power Plants.

10. ANSI B30.9-1971, Slings.

11. ANSI/ASME B 30.10-1982, Hooks (Revision of ANSI B30.10-1975).

12. ANSI N14.6-1978, Special Lifting devices for shipping containers weighing 10,000 lbs. (4500 kg) or more for nuclear materials.

13. ASME Boiler and Pressure Vessel Code, Section VIII, “Pressure Vessel.”

14. ASME Boiler and Pressure Vessel Code, Section II, “Specification for Carbon Steel Externally Threaded Standard Fasteners.”

15. ASTM Standards, Section 15, Volume 15.08, “Fasteners.”

16. ASME B31.1, “Power Piping.”

17. ASME Boiler and Pressure Vessel Code, Section III, “Rules of Construction for Nuclear Power Plant Components.”

18. NRC Generic Letter 89-13, “Service Water System Problems Affecting Safety Related Equipment,” July 18, 1989.

19. 10 CFR 50, Appendix J "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors".

20. Regulatory Guide 1.163 "Performance-based Containment Leak-Test Program".

21. NEI 94-01 "Industry Guideline for Implementing Performance-based Option of 10 CFR Part 50, Appendix J".

22. ANSI/ANS 56.8-1994 "American National Standard for Containment System Leakage Testing Requirements".

23. Bechtel Topical Report BN-TOP-1 "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants".

24. Edwin I. Hatch Nuclear Plant Technical Specifications, Units 1 and 2, Section 3.6.

25. 10 CFR 54, License Renewal Rule.

26. NUREG 0619 – “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking”, U.S. NRC, November 1980.

27. BWRVIP-18 – BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines.

28. BWRVIP-26 – BWR Top Guide Inspection and Flaw Evaluation Guidelines.

29. BWRVIP-27 – BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines.

30. BWRVIP-38 – BWR Shroud Support Inspection and Flaw Evaluation Guidelines.

31. BWRVIP-41 – BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines.

32. BWRVIP-47 – BWRVIP Lower Plenum Inspection and Flaw Evaluation Guidelines.

33. BWRVIP-48 – Vessel ID Attachment Weld Inspection and Evaluation Guidelines.

34. BWRVIP-74 – BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines.

35. BWRVIP-76 – Core Shroud Inspection and Evaluation Guidelines.

36. 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements.

37. BWRVIP-86, Revision 1-A, BWRVIP Updated BWR Integrated Surveillance Program (ISP) Implementation Plan.

38. ASTM E185, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels.”

39. Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials”

40. 10 CFR 50, Appendix G, Fracture Toughness Requirements.

41. EPRI NSAC-202L “Recommendations for an Effective Flow-Accelerated Corrosion Program.”

42. EPRI CHECWORKS Computer Program.

43. ANSI N5.12 – 1972 “Protective Coatings (Paints) for the Nuclear Industry.”

44. ANSI N101.2 – 1972 “Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities.”

45. ASTM Section 6, Vol. 6.02 “Paints-Products and Applications; Protective Coatings; Pipeline Coatings.”

46. American Water Works Association (AWWA) C203 – 1966 “Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines – Enamel and Tape – Hot Applied.”

47. AWWA C209 – 1995 “Cold Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines,” 2nd Ed.

48. A-44985, Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant, Units 1 and 2.

49. 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

50. Westinghouse Owner’s Group Life Cycle Management / License Renewal Program, Altran Corporation / Altran Materials Engineering.

51. Unit 1 and Unit 2 Plant Hatch Technical Specifications, SR 3.6.4.1.3 and SR 3.6.4.1.4.

52. ACI Committee 349, Report ACI 349.3R-96, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.”

53. NRC Regulatory Guide 1.160, Rev 2 “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

54. SAND 93-7070. UC-523, “Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers,” July 1994.

55. 10 CFR 54.3, “Definitions.”

56. 10 CFR 54.21.(c).1, “Contents of the Application – Technical Information.”
57. NFPA 25, National Fire Protection Association Standard.

58. NEI 08-05, Industry Initiative on Control of Heavy Loads.

59. EPRI NP-5769, Degradation and Failure of Bolting in Nuclear Power Plants, Volumes 1 and 2.

60. A-47039, E. I. Hatch Nuclear Plant – Unit No. 1/2 License Renewal Aging Management Review Summary.

61. BWRVIP-139-A: BWR Vessel and Internals Project, Steam Dryer Inspection and Flaw Evaluation Guidelines, Electric Power Research Institute, Palo Alto, CA, July 2009, Technical Report 1018794.

62. BWRVIP-183: BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines, Electric Power Research Institute, Palo Alto, CA, December 2007, Technical Report 1013401.

APPENDIX A

CONFORMANCE WITH NUCLEAR REGULATORY COMMISSION (NRC) REGULATORY GUIDES

This appendix addresses the conformance of the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) with the guidelines presented in Division 1 of the NRC Regulatory Guides listed in the Table of Contents.

Since the HNP-2 construction permit was issued in December of 1972, many of these guides were not available for incorporation into the design bases. This appendix discusses or makes reference to the appropriate section in the text of the FSAR where the subject of the guide is discussed.

A.1 REGULATORY GUIDE 1.1 - NET POSITIVE SUCTION HEAD FOR ECCS AND CONTAINMENT HEAT REMOVAL SYSTEM PUMPS (SAFETY GUIDE 1, NOVEMBER 2, 1970)

Conformance

HNP-2 is in conformance with this guide in that all core spray and residual heat removal pumps for this unit conform to the regulatory position. Net positive suction head evaluation is discussed in paragraph 6.3.3.9.

A.2 REGULATORY GUIDE 1.2 - THERMAL SHOCK TO REACTOR PRESSURE VESSELS (SAFETY GUIDE 2, NOVEMBER 2, 1970)

Conformance

HNP-2 is in conformance with this guide. Specific investigations are as follows:

A. The position stated in Regulatory Guide 1.2 is incorporated as follows:

An investigation of boiling water reactor (BWR) pressure vessels structural integrity during a design basis accident (DBA) has been conducted. (Refer to NEDO-10029, "An Analytical Study on Brittle Fracture of GE BWR Vessel Subject to the Design Basis Accident.") It has been determined that no failure of the vessel by brittle fracture as a result of a DBA will occur based upon the methods of fracture mechanics.

B. The investigation included:

- A comprehensive thermal analysis considering the effect of blowdown and the low-pressure coolant injection system reflooding.
- A stress analysis considering the effects of pressure, temperature, seismic load, jet load, dead weight, and residual stresses.
- The radiation effect on material toughness (nil ductility transition temperature shift) and critical stress intensity.
- Methods for calculating crack tip stress intensity associated with a nonuniform stress field following the DBA.

This analysis incorporated very conservative assumptions in all areas (particularly in the areas of heat transfer, stress analysis, effects of radiation on material toughness, and crack tip stress intensity). Therefore, the results reported therein provide an upper bound limit on brittle fracture failure mode studies. Because of the upper bound approach, it is concluded that catastrophic failure of the pressure vessel due to the DBA is shown to be impossible from a fracture mechanics point of view. In the case studied, even if an acute flaw does form on the vessel inner wall, it does not propagate as the result of the DBA.

A.3 REGULATORY GUIDE 1.3 - ASSUMPTIONS USED FOR EVALUATION OF THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF THE LOCA FOR BWRs (REVISION 2, JUNE 1974)

Conformance

Superseded by Regulatory Guide 1.183. See section A.183.

A.4 REGULATORY GUIDE 1.4 - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT FOR PRESSURIZED WATER REACTORS (REVISION 2, JUNE 1974)

Conformance

Since HNP-2 utilizes a boiling water reactor, this guide is not applicable.

A.5 REGULATORY GUIDE 1.5 - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAK ACCIDENT FOR BWRs (SAFETY GUIDE 5, MARCH 10, 1971)

Conformance

Superseded by Regulatory Guide 1.183. See section A.183.

A.6 REGULATORY GUIDE 1.6 - INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS (SAFETY GUIDE 6, MARCH 10, 1971)

Conformance

The conformance to this regulatory guide is discussed in chapter 8, paragraphs 8.3.1.2.1 and 8.3.2.2.1.

A.7 REGULATORY GUIDE 1.7 - CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS-OF-COOLANT ACCIDENT (MARCH 10, 1971)

Conformance

The design of the original post loss-of-coolant accident, primary containment combustible gas control system for HNP-2, was in accordance with Nuclear Regulatory Commission (NRC) Regulatory Standard Review Plan 6.2.5 and Branch Technical Position CSB 6-2, “Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident,” March 1975.

Branch Technical Position CSB 6-2 superseded Regulatory Guide 1.7, and Draft Regulatory Guide DG-1117 will supersede Branch Technical Position CSB 6-2 to conform to the new rule under 10 CFR 50.44, which no longer defines a design basis hydrogen release and eliminates requirements for hydrogen control systems to mitigate such a release. HNP-2 is currently in conformance with the 10 CFR 50.44, January 1, 2006 revision. HNP will review the new Regulatory Guidance upon its completion for conformance.

A.8 REGULATORY GUIDE 1.8 - PERSONNEL SELECTION AND TRAINING (MARCH 10, 1971)

Conformance

The Southern Nuclear Operating Company (SNC) program for the selection and training of nuclear power plant personnel complies with this guide. Qualification requirements for nuclear plant personnel are given in subsection 13.1.3. The nuclear training program is described in section 13.2.

A.9 REGULATORY GUIDE 1.9 - SELECTION OF DIESEL GENERATOR SET CAPACITY FOR STANDBY POWER SUPPLIES (MARCH 10, 1971)

Conformance

Conformance with this guide is discussed in chapter 8, paragraph 8.3.1.2.1.

A.10 REGULATORY GUIDE 1.10 - MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CATEGORY I CONCRETE STRUCTURES (REVISION 1, JANUARY 2, 1973)

Conformance

The requirements for mechanical (Cadweld) splices in rebar for Category I concrete structures are provided in supplement 3.8.A to section 3.8. The requirements of the regulatory guide for visual inspection, tensile testing, and tensile test frequency are met by the HNP-2 construction program. The deviations from the regulatory guide are summarized by paragraph reference to this guide as follows:

A. Paragraph C.1.- Crew Qualification - Only one joint for each position was actually prepared and tested as opposed to the two required by this paragraph. Crew requalification was not performed in accordance with this paragraph. SNC follows the Erico Products, Inc. Cadweld procedure for rebar splicing without exception. Crew qualification is handled by Erico Products, Inc. specialists. Requalification is under the supervision of the SNC Cadweld inspector and the welding contractor. This procedure satisfies the intent of this guide.

B. Paragraph C.5.- Procedure for Substandard Tensile Test Results - When any of the tested specimens failed, two additional random splices from the same lot were tested and if both passed the test, the lot was accepted; if one or both splices failed, the entire lot was rejected. Although this procedure is not in conformance with this paragraph, it does provide substantial assurance of quality and, thus, meets the intent of the requirement.

A.11 REGULATORY GUIDE 1.11 - INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT (SAFETY GUIDE 11, MARCH 10, 1971, SUPPLEMENT TO SAFETY GUIDE 11, BACKFITTING CONSIDERATIONS, FEBRUARY 10, 1972)

Conformance

Conformance with this guide is discussed in chapter 6, paragraph 6.2.5.3.

A.12 <u>REGULATORY GUIDE 1.12 - INSTRUMENTATION FOR EARTHQUAKES (REVISION 1, APRIL 1974)</u>

Conformance

Conformance to this guide is discussed in chapter 3, subsection 3.7.A.4.

A.13 REGULATORY GUIDE 1.13 - FUEL STORAGE FACILITY DESIGN BASIS (MARCH 10, 1971)

Conformance

Conformance to this guide is discussed in chapter 9, paragraph 9.1.3.4.

A.14 REGULATORY GUIDE 1.14 - REACTOR COOLANT PUMP FLYWHEEL INTEGRITY (OCTOBER 27, 1971)

Conformance

Since HNP-2 does not utilize pumps with flywheels, this guide is not applicable.

A.15 REGULATORY GUIDE 1.15 - TESTING OF REINFORCING BARS FOR CATEGORY I CONCRETE STRUCTURES (REVISION 1, DECEMBER 28, 1972)

Conformance

The yield and tensile strength tests and deformation inspections for the rebar used in all Category I concrete structures are described in paragraph 3.8.4.6.2. HNP-2 is in conformance with this guide.

A.16 REGULATORY GUIDE 1.16 - REPORTING OF OPERATING INFORMATION - APPENDIX A TECHNICAL SPECIFICATIONS (JANUARY 1975)

Conformance

In addition to the applicable reporting requirements of Title 10 Code of Federal Regulations, the program for reporting HNP-2 operating information is in accordance with Generic Letter 97-02, "Revised Contents of the Monthly Operating Report," dated May 15, 1997.

A.17 REGULATORY GUIDE 1.17 - PROTECTION OF NUCLEAR POWER PLANTS AGAINST INDUSTRIAL SABOTAGE (JUNE 1973)

Conformance

SNC's security program, established for the protection of HNP-2 from industrial sabotage, complies with this guide. The Plant Hatch Security Plan was prepared as a proprietary document, and discusses specific measures for the physical protection of the plant. A general discussion of the Security Plan is contained in section 13.7.

A.18 REGULATORY GUIDE 1.18 - STRUCTURAL ACCEPTANCE TEST FOR CONCRETE PRIMARY REACTOR CONTAINMENTS (REVISION 1, DECEMBER 28, 1972)

Conformance

Since HNP-2 utilizes a steel containment as discussed in section 3.8, this guide is not applicable.

A.19 REGULATORY GUIDE 1.19 - NONDESTRUCTIVE EXAMINATION OF PRIMARY CONTAINMENT LINER WELDS (SAFETY GUIDE 19, AUGUST 11, 1972)

Conformance

Since HNP-2 utilizes a steel containment which does not require a liner, as discussed in section 3.8, this guide is not applicable.

A.20 REGULATORY GUIDE 1.20 - VIBRATION MEASUREMENTS ON REACTOR INTERNALS (DECEMBER 29, 1971)

Conformance

HNP-2 reactor internals vibration startup measuring program includes provision for both prototype and confirmatory tests as referenced in this guide. The Fitzpatrick Nuclear Plant is the prototype plant for HNP-2.

A.21 REGULATORY GUIDE 1.21 - MEASURING, EVALUATING, AND REPORTING RADIOACTIVITY IN SOLID WASTES AND RELEASES OF RADIOACTIVE MATERIALS IN LIQUID AND GASEOUS EFFLUENTS FROM LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1, JUNE 1974)

Conformance

The measurement and evaluation of the radioactivity in solid wastes and the release of radioactive materials in liquid and gaseous effluents are discussed in chapter 11 and are more fully covered in the HNP-2 procedure manuals. The periodic environmental surveillance reports which are filed with the Region II Directorate of Regulatory Operations will comply with this guide for reporting the results of measurements and evaluations.

A.22 REGULATORY GUIDE 1.22 - PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS (SAFETY GUIDE 22, FEBRUARY 17, 1972)

Conformance

HNP-2 conforms to the intent of this guide as discussed in sections 7.2, 7.3, 7.4, 7.6, and 7.7.

In addition, conformance with branch technical position E1CSB-22 is discussed below.

Conformance of the protection system to the requirements of IEEE 279-1971 is presented in chapter 7. Actuated equipment which is not tested during reactor operation is as follows:

A. Reactor Building Closed Cooling Water System Containment Penetration Inlet and Outlet Isolation Valves

These valves are not closed during reactor operation since their closure would interrupt cooling water flow to the reactor recirculation pump seals.

B. Main Feedwater Check Valves

These valves are not testable during reactor operation; however, the operators are testable.

C. Control Rod Drive Scram Discharge Valves

These valves are not tested during reactor operation since operation of individual valves introduces undesirable reactivity transients.

D. Standby Liquid Control System (SLCS) Explosive Valves

The SLCS explosive valves are not tested during normal plant operation.

The actuated equipment, which is not tested during reactor operation, consists of valve designs that are widely used in operating nuclear power stations and for which there is a significant operating experience that demonstrates a low probability of failure in the interval between periodic tests. These valves, which are not tested during reactor operation, are tested at each refueling.

A.23 REGULATORY GUIDE 1.23 - ONSITE METEOROLOGICAL PROGRAMS (SAFETY GUIDE 23, FEBRUARY 17, 1972)

Conformance

The onsite meteorological program is discussed in subsection 2.3.3. The discussion includes a description of the meteorological parameters being monitored, the siting of meteorological instruments, the data recorders, instrument accuracy, instrument maintenance, and data reduction and compilation. The onsite meteorological program conforms with this guide with the exception of the location of the lower windspeed and direction indicator on the meteorological tower. The locations of the weather instrumentation are given in table 2.3-7.

A.24 REGULATORY GUIDE 1.24 - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A PRESSURIZED WATER REACTOR GAS STORAGE TANK FAILURE (SAFETY GUIDE 24, MARCH 23, 1972)

Conformance

Since HNP-2 utilizes a boiling water reactor, this guide is not applicable.

A.25 REGULATORY GUIDE 1.25 - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT IN THE FUEL HANDLING AND STORAGE FACILITY FOR BOILING AND PRESSURIZED WATER REACTORS (SAFETY GUIDE 25, MARCH 23, 1972)

Conformance

Superseded by Regulatory Guide 1.183. See section A.183.

A.26 <u>REGULATORY GUIDE 1.26 - QUALITY GROUP CLASSIFICATIONS AND STANDARDS (SEPTEMBER 1974)</u>

Conformance

Quality Group Classifications and code requirements for components of process systems, as discussed in subsection 3.2.2 and as provided on all system piping and instrumentation diagrams, meet the intent of this guide. Clarifications and exceptions are as follows:

A. Paragraph C.1.c - Although the main steam piping to the turbine stop and bypass valves is Quality Group B, an exception is taken for branch lines to the steam jet air ejector, steam seal piping, and lines 2 in. and under; these lines have a manual isolation valve (as opposed to an automatic isolation valve) downstream of which the Quality Group is D. The alternate criterion of a third isolation valve applies to the feedwater piping.

B. Paragraph C.2.a - Cooling water to the shell side of the fuel pool cooling and cleanup system heat exchanger is from the reactor building closed cooling water system which is a Quality Group D system. The fuel pool can be cooled by the residual heat removal heat exchangers which are included in a Quality Group C loop serving the fuel pool.

C. Paragraph C.2.b - Seal and cooling water for the recirculation pumps are Quality Group D since the recirculation pumps are not required for safety.

D. Paragraph C.2.d - Certain components of the radwaste system are not Quality Group C as indicated in sections 11.2 and 11.5. The postulated rupture of any of the components will not yield a conservatively calculated potential offsite dose in excess of 0.5 rem to the whole body or its equivalent to any part of the body. Calculations which confirm this conclusion are provided in chapter 15.

A.27 REGULATORY GUIDE 1.27 - ULTIMATE HEAT SINK FOR NUCLEAR POWER PLANTS (REVISION 1, MARCH 1974)

Conformance

The conformance of HNP-2 with this guide is discussed in subsection 9.2.5.

A.28 REGULATORY GUIDE 1.28 - QUALITY ASSURANCE PROGRAM REQUIREMENTS (DESIGN AND CONSTRUCTION) (REVISION 2, FEBRUARY 1979)

Conformance

The SNC Quality Assurance (QA) Program complies with this guide. The QA Program is described in chapter 17.

A.29 REGULATORY GUIDE 1.29 - SEISMIC DESIGN CLASSIFICATION (REVISION 1, AUGUST 1973)

Conformance

The requirements of this guide are met with the following exceptions or clarifications:

A. The spent-fuel pool cooling and cleanup system is not completely designed to Seismic Category I requirements. In order to maintain the function of cooling spent fuel, the portions of the spent-fuel pool cooling and cleaning system connected to the residual heat removal (RHR) system up to and including the boundary isolation valves meet Seismic Category I requirements. Cooling by the RHR system is used in the event of a failure of the spent-fuel pool cooling and cleanup system or in the event of storage of a large load of spent fuel. These situations are discussed in subsection 9.1.3.

B. Radioactive liquid and gaseous waste treatment, handling, and disposal systems are not Seismic Category I; however, the postulated failure of these systems does not yield a conservatively calculated potential offsite dose in excess of 0.5 rem to the whole body or its equivalent to any part of the body. Discussions of the calculations made to verify this are presented in section 15.4 for the liquid radwaste and off-gas systems.

The seismic design criteria for HNP-2 were established and implemented prior to the issuance of this guide.

A.30 REGULATORY GUIDE 1.30 - QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION AND TESTING OF INSTRUMENTATION AND ELECTRIC EQUIPMENT (SAFETY GUIDE 30, AUGUST 11, 1972)

Conformance

HNP-2 conforms to this guide as discussed in chapter 8, paragraph 8.3.1.3.

Regulatory Guide 1.30 provided NRC endorsement of ANSI N45.2.4 (IEEE 336-1971). The SNC Quality Assurance Topical Report (QATR) is based on NQA-1-1994 which incorporates IEEE 336-1985. Accordingly, the quality assurance requirements for the installation, inspection, and testing in instrumentation and electric equipment are described in the QATR.

A.31 REGULATORY GUIDE 1.31 - CONTROL OF STAINLESS STEEL WELDING (JUNE 1973)

Conformance

This guide is met with the following exceptions or clarifications for components other than those supplied by the nuclear steam supply system vendor.

Paragraphs C.1.a, C.1.b, C.3 - The stainless steel procedure qualifications do not contain any delta ferrite requirements; however, the approved weld procedures state that filler metal used in stainless steel welds shall be capable of producing a minimum of 8 to 25% ferrite. Ferrite content of weld rods is specified to be within the range of 8 to 25% as measured by plotting on the Schaeffler diagram.

Type 309 and 309L welding filler materials are controlled to deposit 5 to 15% delta ferrite. Use of type 309 and 309L welding materials is limited to welding carbon or low-alloy steels to austenitic stainless steel.

The heat analysis of bare wires for use with gas metal arc welding or gas tungsten arc welding processes is used for establishing ferrite content.

A. Paragraph C.1.c - Magnetic measurement devices are not used to determine delta ferrite content.

B. Paragraph C.1.d - With the exception of speed of travel, the requirements of this paragraph are included in the approved weld procedures.

C. Paragraph C.1.e - The qualification procedures do not contain requirements for visual inspection but give acceptance requirements.

D. Paragraph C.2 - Recommended form Q-1 from American Society of Mechanical Engineers Section IX is used.

E. Paragraph C.4 - Individual welds are not necessarily made of single heats of filler wire and single lots of fluxes since filler materials are controlled as discussed above for Paragraph C.1.a.

F. Paragraph C.5 - No production welds are examined to verify delta ferrite levels since welding experience has shown that by maintaining a minimum of 8% ferrite content in the weld rod a minimum of 3% delta ferrite in the weld can be maintained. This experience is based on a previous examination of randomly selected stainless steel welds in which the ferrite content was found to be well within the acceptance range of this guide.

G. Paragraph C.6 - Metallographic examinations are not performed on weld metal samples cut in a plant transverse to the weld location; magnetic measuring devices are not required because the delta ferrite content is controlled as discussed above for Paragraph C.1.a.

H. Paragraph C.7 - Production welding is monitored by welding inspectors and by SNC mechanical inspectors for compliance with all essential variables.

A.32 REGULATORY GUIDE 1.32 - USE OF IEEE STANDARD 308-1971, CRITERIA FOR CLASS 1E ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS (AUGUST 11, 1972)

Conformance

The application of IEEE 308-1971 is discussed in chapter 8, paragraphs 8.3.1.2.1 and 8.3.2.2.1.

A.33 REGULATORY GUIDE 1.33 - QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION) CONFORMANCE (REVISION 2, FEBRUARY 1978)

Conformance

Georgia Power Company chose to use American National Standards Institute (ANSI) N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," instead of ANSI N18.7-1972. With one exception, the Quality Assurance Program complies with this regulatory guide as addressed in section 17.2. As the exclusive operating licensee, SNC adopts that conclusion.

Exception is taken to Paragraph 5.2.16, "Measuring and Test Equipment," of ANSI N18.7-1976 which requires "equipment be suitably marked to indicate calibration status." Installed process instruments at Plant Hatch are identified by unique instrument numbers. These instrument numbers are traceable to calibration schedules and calibration records. These instruments are not tagged or labeled with the date due to next calibration.

During original plant licensing, a 2-year review process for plant procedures was developed to meet the requirement of Regulatory Guide 1.33 and ANSI 18.7-1976. Since the procedural process has now matured and adequate programs to assure procedural revisions consistent with plant design, operational, and regulatory requirements are in place, this original commitment has been modified to require biennial quality assurance (QA) audits of the procedural development and maintenance program utilizing a representative sampling process. Therefore, the 2-year review process is no longer required.

In place of the biennial review, the following provisions have been implemented. In addition, programmatic procedural controls will continue to be in place to update plant procedures as new design information or other factors warrant.

1. *Applicable plant procedures will be reviewed following an unusual incident (such as an accident, an unexpected transient, significant operator error, or equipment malfunction) and following any modification to a system.*

2. *The periodic review of security procedures will be performed in accordance with the Security Plan.*

3. *The periodic review of emergency implementing procedures will be performed in accordance with the Emergency Plan.*

4. *Nonroutine procedures (such as emergency operating procedures and abnormal operating procedures) shall continue to be reviewed at least every 2 years and revised as appropriate.*

5. *At least once every 2 years, the QA organization shall review a representative sample of the routine plant procedures that are used more frequently than 2 years.*

Regulatory Guide 1.33, Section 4 provides that the following program elements be audited at the indicated frequencies; the results of actions taken to correct deficiencies that affect nuclear safety and occur in facility equipment, structures, systems, or method of operation–at least once per 6 months; the conformance of facility operation to provisions contained within the Technical Specifications and applicable licensing conditions–at least once per 12 months; and the performance, training, and qualifications of the facility staff–at least once per 12 months. Audit frequencies for each of these program elements are now established as at least once per 24 months.

The SNC QATR is based on ASME NQA-1-1994 and incorporates the applicable requirements of ANSI N18.7-1976. Accordingly, SNC complies with the applicable requirements of ANSI N18.7-1976 via compliance with the QATR without an explicit (or implied) commitment to ANSI N18.7-1976.

A.34 REGULATORY GUIDE 1.34 - CONTROL OF ELECTROSLAG WELD PROPERTIES (DECEMBER 28, 1972)

Conformance

Electroslag welding is not done at HNP-2; therefore, this guide is not applicable.

A.35 REGULATORY GUIDE 1.35 - INSERVICE INSPECTION OF UNGROUTED TENDONS IN PRESTRESSED CONCRETE CONTAINMENT STRUCTURES (REVISION 1, JUNE 1974)

Conformance

Since HNP-2 utilizes a steel containment as discussed in section 3.8, this guide is not applicable.

A.36 REGULATORY GUIDE 1.36 - NONMETALLIC THERMAL INSULATION FOR AUSTENITIC STAINLESS STEEL (FEBRUARY 23, 1973)

Conformance

This guide was used as a requirement for purchase and installation of insulation in HNP-2; thus, HNP-2 is in conformance with this guide.

HNP-2 is in conformance with this guide for systems in contact with the reactor coolant pressure boundary. For applications which may not be addressed by the regulatory guide, an engineering evaluation will be performed to limit the possibility of stress corrosion cracking.

A.37 <u>REGULATORY GUIDE 1.37 - QUALITY ASSURANCE REQUIREMENTS FOR CLEANING OF FLUID SYSTEMS AND ASSOCIATED COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS (MARCH 16, 1973)</u>

Conformance

The quality assurance requirements of this guide and of its basic reference, American National Standards Institute N45.2.1-1973, are being followed; thus, HNP-2 is in conformance with this guide.

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.1. Accordingly, quality assurance requirements for cleaning of fluid systems and associated components are described in the SNC QATR.

A.38 <u>REGULATORY GUIDE 1.38 - QUALITY ASSURANCE REQUIREMENTS FOR PACKAGING, SHIPPING, RECEIVING, STORAGE, AND HANDLING OF ITEMS FOR WATER-COOLED NUCLEAR POWER PLANTS (MARCH 16, 1973)</u>

Conformance

For maintenance and modification activities during the operations phase that are comparable to construction phase activities, SNC meets the regulatory position of this regulatory guide with the following exceptions or clarifications. This regulatory guide states that ANSI N45.2.2-1972 requirements and guidelines provide an acceptable method of meeting the intent of this guide.

Exceptions

None.

Clarifications

1. *ANSI N45.2.2-1972, paragraph 6.4.2, Care of Items, subpart (7): Motors rated 15 horsepower or above may be evaluated by engineering personnel, as appropriate, to determine if in-storage maintenance is required; the results of the evaluation shall be documented. If in-storage maintenance is required, it shall be performed in accordance with plant procedures providing such guidance. Motors rated less than 15 horsepower do not require in-storage maintenance.*

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.2. Accordingly, quality assurance requirements for packaging, shipping, receiving, storage, and handling are described in the SNC QATR.

A.39 REGULATORY GUIDE 1.39 - HOUSEKEEPING REQUIREMENTS FOR WATER-COOLED NUCLEAR POWER PLANTS (MARCH 16, 1973)

Conformance

For maintenance and modification activities during the operations phase that are comparable to construction phase activities, SNC meets the regulatory position of this Regulatory Guide with one exception. Cleanliness zones were not established at Plant Hatch. Instead, radiation protection and security procedures provide housekeeping controls commensurate with the requirements of Paragraph 5.2.10 of ANSI N18.7-1976.

Regulatory Guide 1.39, dated March 16, 1973, provides NRC endorsement of ANSI N45.2.3. The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.3. Accordingly, housekeeping requirements are described in the SNC QATR.

A.40 REGULATORY GUIDE 1.40 - QUALIFICATION TESTS OF CONTINUOUS-DUTY MOTORS INSTALLED INSIDE THE CONTAINMENT OF WATER-COOLED NUCLEAR POWER PLANTS (MARCH 16, 1973)

Conformance

There are no Class 1E continuous-duty motors located inside the primary containment of HNP-2; thus, this guide is not applicable. However, the recommendations of this guide have been implemented in the qualification of the continuous-duty motors for the fan coil units of the drywell cooling system, which is not a safety design system.

A.41 <u>REGULATORY GUIDE 1.41 - PREOPERATIONAL TESTING OF REDUNDANT ONSITE ELECTRIC POWER SYSTEMS TO VERIFY PROPER LOAD GROUP ASSIGNMENTS (MARCH 16, 1973)</u>

Conformance

Compliance with Regulatory Guide 1.41 is discussed in chapter 8, paragraphs 8.3.1.2.1 and 8.3.2.2.1.

A.42 <u>REGULATORY GUIDE 1.42 - INTERIM LICENSING POLICY ON AS LOW-AS-PRACTICAL FOR GASEOUS RADIOIODINE RELEASES FROM LIGHT-WATER-COOLED NUCLEAR POWER REACTORS (REVISION 1, MARCH 1974)</u>

Conformance

This guide was withdrawn by the NRC in March 1976. The development of Appendix I to 10 CFR 50 eliminated the need for this guideline. The design bases for the gaseous effluent treatment systems are given in chapter 11, subsection 11.3.1.

A.43 REGULATORY GUIDE 1.43 - CONTROL OF STAINLESS STEEL WELD CLADDING OF LOW-ALLOY STEEL COMPONENTS (MAY 1973)

Conformance

Since HNP-2 does not use SA-508 material made to coarse grain practice, this guide is not applicable.

A.44 REGULATORY GUIDE 1.44 - CONTROL OF THE USE OF SENSITIZED STAINLESS STEEL (MAY 1973)

Conformance

Control of the use of sensitized stainless steel is discussed in subsection 5.2.5. In addition, procedures used for fabrication of piping systems include requirements which prevent subjecting materials to sensitizing conditions.

A.45 REGULATORY GUIDE 1.45 - REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS (MAY 1973)

Conformance

The design of the reactor coolant pressure boundary leak detection system (LDS) meets the intent of this guide. The HNP-2 construction permit review was conducted well in advance of the issuance of this guide. Conformance to specific regulatory positions is described below except for the seismic requirements of Paragraph C.6. The LDS sumps, i.e., primary containment equipment and floor drain sumps, are designed to meet the requirements of the Seismic Category I primary containment structure; however, the sump pumps are not specifically designed to Seismic Category I requirements. LDSs are discussed in subsection 5.2.7.

Post-accident monitoring capability exists for measuring temperature, pressure, relative humidity, and gross radioactivity. The post-accident gamma monitors, which are designed to withstand a design basis earthquake, are located so as to provide a continuous readout of the gross gamma radioactivity in the primary containment in the main control room. This monitoring system is discussed in detail in subsection 7.6.4, Process Radiation Monitoring System.

Regulatory Position C.2

Leakage into the primary containment from unidentified sources is collected in the drywell floor drain sump. Most of the parameters listed in table 5.2-6 for detection of leakage cannot be correlated to a leakage rate. The sump is capable, however, of measuring the unidentified leakage rate within the limits specified in the Technical Specifications. This system uses timing devices for monitoring the frequency and duration of sump pump operation. This information, together with the known sump capacity of 13 gal/in. and sump pump flow totalizer data, is used to determine the leakage rate.

As stated in paragraph 3.7A.4.4, the plant will be shut down following any earthquake that exceeds the operating basis earthquake and will not be restarted without permission from the Nuclear Regulatory Commission.

Regulatory Position C.4

System	Leakage Detection Available
Core spray	Pressure and temperature indication
High-pressure coolant injection	Pressure and temperature indication
Residual heat removal	Pressure and temperature indication
Reactor core isolation cooling	Pressure and temperature indication
Standby liquid control	Pressure and tank level indicator
Reactor water cleanup	Pressure indication
Main steam isolation valve leakage control	Temperature and flow indication

Regulatory Position C.5

As previously noted, additional level monitoring instrumentation is being provided for the drywell floor drain sump. This instrumentation is capable of detecting an unidentified leakage rate of 5 gal/min in $<$ 1 h.

Regulatory Position C.8

Surveillance test requirements for the LDS are provided in Technical Specification 3.4.5.

A.46 REGULATORY GUIDE 1.46 - PROTECTION AGAINST PIPE WHIP INSIDE CONTAINMENT (MAY 1973)

Conformance

The design for protection against pipewhip inside containment is discussed in detail in section 3.6 and meets the requirements of this guide. Since the design for HNP-2 was completed prior to the issuance of this guide, the guide did not form the basis for design, particularly in the reactor recirculation piping restraints; however, the design is sufficiently conservative so that the intent of applicable regulatory positions of this guide is satisfied.

A.47 REGULATORY GUIDE 1.47 - BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS (MAY 1973)

Even though this regulatory guide was not available for consideration during the original design of the HNP safety systems, status indication of bypassed and inoperable safety systems was considered. Therefore, the plant is designed so that sufficient status information, in conjunction with operating procedures, provide adequate control over equipment operation. In order to provide status indication, a manually operated light display board will be located in the main control room on the console front in clear view of the operator to warn the operator of an engineered safety feature (ESF) system or auxiliary support system that is inoperable because of previous failure, repair work in progress, or routine maintenance. The systems to be displayed are the following:

- High-pressure coolant injection.
- Automatic depressurization.
- Core spray I.
- Core spray II.
- Low-pressure coolant injection (LPCI), Div I.
- LPCI, Div II.
- Standby gas treatment (SGT) I.
- SGT II.
- Hydrogen control.
- Main steam line sealing.
- Plant service water (PSW), Div I.
- PSW system, Div II.
- Residual heat removal service water (RHRSW), Div I.
- RHRSW, Div II.
- Main control room environmental control (MCREC).
- Diesel generator 2A.
- Diesel generator 1B.

- Diesel generator 2C.
- Recirculation pump trip (RPT).

All of these systems are governed by the Technical Specifications which prescribe actions (up to and including plant shutdown) to be taken when systems are found or made to be inoperable. The plant operator is required to maintain a record of systems that are made or become inoperable. The system that is inoperable and the time at which it was declared inoperable is recorded in the operator's log. The operator is also required to record the time at which the system is again declared operable. The status board is manually operated in accordance with the operator's entries in his log.

The Technical Specifications dictate operator action, including plant shutdown, to be taken if systems are inoperable. ESFs that are shared with HNP-1 (diesel generator 1B, MCREC system), are indicated on the status board. Since the system is manually operated, erroneous bypass indications can only occur by administrative failure and can only be eliminated by the operator canceling the erroneous indication. The indication system is not used to perform any functions essential to safety and no administrative procedures require operator action based on bypass indications. Since it is a manually initiated system, the possibility of adverse effects on plant safety systems is precluded, and its operable status can be verified at any time.

A.48 REGULATORY GUIDE 1.48 - DESIGN LIMITS AND LOADING COMBINATIONS FOR SEISMIC CATEGORY I FLUID SYSTEM COMPONENTS (MAY 1973)

Conformance

HNP-2 does not fully conform to this guide. Category I pressure-retaining components are designed pursuant to 10 CFR 50.55a, which invokes compliance with American Society of Mechanical Engineers (ASME) Code, Section III. Specific exceptions or clarifications to the regulatory positions of the guide are indicated below:

A. Paragraph C.2 - The Class 1 valves were not designed by analysis. There are no Class 1 pumps in HNP-2.

B. Paragraph C.4 - The Class 1 valves were not designed by analysis. There are no Class 1 pumps in HNP-2.

C. Paragraph C.5 - The pressure requirements are met. Operability assurance requirements under Note 6 to this paragraph are discussed in paragraph 3.9.2.4 and meet the intent of this paragraph.

D. Paragraph C.7 - The Code Class 2 vessels are not designed to Division 2 of Section VIII of the Code; thus, this paragraph is not applicable.

E. Paragraph C.8.b - ASME Code Case 1606 is used in lieu of this loading combination.

F. Paragraph C.10. - The active Class 3 pumps are in the service water and residual heat removal service water system pumps which were ordered in June 1972 and May 1973, respectively. The specifications for these pumps required that the total stresses resulting from horizontal and vertical seismic loads from the operating basis earthquake, plus operating loads, be within normal Code allowable stresses and that the total stresses resulting from horizontal and vertical seismic loads from the design basis earthquake (DBE), plus operating loads, be within 90% of the material yield stress. It was further required that the deflections resulting from the seismic inputs not interfere with the operation of the pumps or cause permanent damage. Furthermore, calculations were made of the stress levels for all conditions of operation, and when combined with the seismic stresses the results are within the limits set forth in the specifications and the code. The calculated deflections resulting from the combination of operating and seismic loads are of such magnitude that no loss of function of these pumps will occur.

G. Paragraph C.12. - The pressure requirements are met. Operability assurance requirements under Note 6 to this paragraph are discussed in paragraph 3.9.2.4 and meet the intent of this paragraph.

H. Dynamic system loadings associated with the faulted plant condition are not combined with the DBE. A summary of an independent evaluation of combining all

loss-of-coolant and DBE loads directly for the Class 1 components in the reactor coolant pressure boundary is provided in paragraph 3.9.1.5.

A.49 REGULATORY GUIDE 1.49 - POWER LEVELS OF WATER-COOLED NUCLEAR POWER PLANTS (DECEMBER 1973)

Conformance

HNP-2 is in conformance with this guide.

A.50 REGULATORY GUIDE 1.50 - CONTROL OF PREHEAT TEMPERATURE FOR WELDING OF LOW-ALLOY STEEL (MAY 1973)

Conformance

Minimum preheat and maximum interpass temperatures are required by piping specifications. Qualification sheets for each weld procedure specify minimum preheat temperatures. The piping specification and welding procedures require a check on the preheat temperature and require delaying a welding pass if the interpass temperature reaches the maximum allowed temperature. These requirements satisfy the intent of this guide.

A.51 REGULATORY GUIDE 1.51 - INSERVICE INSPECTION OF ASME CODE CLASSES 2 AND 3 NUCLEAR POWER PLANT COMPONENTS (MAY 1973)

Conformance

Class 2 Systems

This guide was withdrawn by the NRC in July 1975. The guidance was incorporated into the 1974 edition of Section XI of the ASME Boiler and Pressure Vessel Code. Plant Hatch's program adheres to the 1980 edition of Section XI with addenda through winter 1981. The description of the inservice inspection program for HNP-2 is presented in subsection 5.2.8 and includes the program for Code Class 2 and 3 components.

A.52 REGULATORY GUIDE 1.52 - DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR ATMOSPHERE CLEANUP SYSTEM AIR FILTRATION AND ADSORPTION UNITS OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS [JUNE 1973 (REV 0), MARCH 1978 (REV 2)]

Conformance

The design of the standby gas treatment system (SGTS) and the main control room environmental control (MCREC) system is in accordance with the intent and major portions of this regulatory guide; clarifications and exceptions are discussed below. The HNP-2 construction permit review was conducted well in advance of the issuance of this guide; however, the significant criteria of the guide were considered in the design of the SGTS and MCREC system.

Although the system design was in accordance with Revision 0 of the Regulatory Guide, system testing will be performed in accordance with applicable sections of Revision 2 of the Regulatory Guide.

The SGTS, as discussed in subsection 6.2.4, is an engineered safety feature (ESF) system provided to ensure reduction in radioactivity release through filtration and elevation of release following design basis loss-of-coolant accidents or fuel-handling accidents. The MCREC system, discussed in sections 6.4 and 15.4, and subsection 9.4.1, is designed to ensure continued occupancy for plant operators in the MCR following a postulated design basis accident (DBA). These systems are designed in accordance with applicable portions of Regulatory Guides 1.26 and 1.29 (Seismic Category I). They are designed to withstand the single failure of an active component; they obtain power from the essential ac power system upon loss of normal ac power. They have the capability for periodic testing and inspection of principal components; and quality assurance requirements are followed. They are designed to perform their intended functions under the most severe environmental conditions postulated following DBAs and other abnormal occurrences.

The following regulatory positions are those for which the design conformance of the SGTS and MCREC system requires clarification and/or exception: (NOTE: The exceptions are made in reference to Revision 0 of the Regulatory Guide.)

A. Paragraphs C.2.a and C.3.a - The MCREC system contains no heater or demister since the filter units are not expected to encounter entrained moisture and since the internal control room atmosphere is air-conditioned (section 6.4 and subsection 9.4.1).

B. Paragraph C.2.h - The design of the SGTS and MCREC system complies with the Institute of Electrical and Electronic Engineers (IEEE) Standards of this paragraph to the extent applicable except for IEEE 334, which does not apply since there are no motors for these systems inside containment.

C. Paragraph C.2.j - Overall design considerations include reduction of radiation exposures during routine maintenance and testing insofar as possible. It is envisioned, however, that workers will not handle filter units immediately after a

DBA and will thereby avoid exposures associated with immediate post-accident filter handling. Accordingly, no specific provisions have been made for removal of the train following an accident. All filter components and the fan are enclosed in unitized housing.

D. Paragraph C.2.k - No outside air supply is provided for the SGTS since outside air is provided through building inleakage.

E. Paragraph C.3.a - Although standard mines safety appliance research 71-45 was not included in the purchase specification of the demister for the SGTS, the demister design does conform to the standard; thus the intent of this paragraph is satisfied.

F. Paragraph C.3.b - The SGTS meets this requirement. The MCREC system does not have a heater for the reasons stated in item A.

G. Paragraph C.3.c - For both the SGTS and MCREC system, the prefilters are specified to be tested in accordance with ASHRAE Standard 52-76.

H. Paragraph C.3.d - Since none of the high-efficiency particulate air (HEPA) filter separators are exposed to potential iodine removal spray, the units are not designed for contact with this type of spray.

I. Paragraph C.3.e - For the MCREC system, the frame material for the HEPA filters is of chromized steel with aluminum as a separator material. For the carbon adsorbers, tray material is stainless steel 300 series and frame material is mild steel. These materials satisfy the intent of this paragraph.

J. Paragraph C.3.f - For the MCREC system, a galvanized steel, 10 Ga (138), per American Society of Testing Materials-A-526 is used. This material satisfies the intent of this paragraph.

K. Paragraph C.3.h - No containment sprays will contact the SGTS or MCREC system.

L. Paragraph C.3.i - For the SGTS carbon adsorbers, the residence time was calculated to be ~ 0.46 s for 4 in. of bed depth. This is slightly lower than the 0.25 s per 2 in. of bed depth as specified in this paragraph; however, the effect on efficiency was verified to be negligible.

M. Paragraph C.4.c - The use of vacuum breakers on a large filter housing is not practical for door opening. There are few occasions which require entrance into the housing while the fan is running. The addition of vacuum breakers would increase the probability of leakage and contamination due to potential failure of the valve to fully close; thus no vacuum breakers are provided.

N. Paragraph C.4.d - For the MCREC system the spacing required by this paragraph does not exist at the ends of the housing; however, the tapered ends provide

additional elbow room for sufficient access. For the SGTS, the carbon adsorber is filled and emptied externally, and the specified access spacing is not required.

O. Paragraph C.4.h - The length of piping associated with manifolding would promote plateout of the constituents of the sampled gas stream and would thereby result in erroneous test results. The test probes are located in readily accessible locations; a minimum run of piping is used and manifolding is not employed.

P. Paragraph C.4.k - No permanent lighting is installed within the units. Temporary portable lighting will be used when required.

Q. Paragraph C.5.b - No provision for bypassing the carbon adsorbers during dioctyl phtalate (DOP) testing is installed. The DOP, which is adsorbed during such testing has, at most, a negligible effect on the carbon adsorbent. Moreover, installation of a bypass provision would present a potential for both leakage and accidental bypass of the adsorbent during nontest operation. Since the HEPA filters do not deteriorate during periods of nonuse, testing of these units once per operating cycle (so as to include a refueling outage) provides sufficient confidence in their filtration capability.

R. Paragraphs C.5 and C.6 - Testing acceptance criteria and frequency requirements are provided in the Technical Specifications. Testing is performed in accordance with the version of Regulatory Guide 1.52 listed in the Technical Specifications.

Regulatory Guide 1.52, Revision 2 recommends an 18-month surveillance interval for ventilation filter testing. It states that certain factors, including “industrial contaminants, pollutants, temperature, and relative humidity contribute to the tagging and weathering of filters and adsorbers, and reduce their capability to perform their intended functions.” Periodic testing is specified as a means of ensuring reliability recommended in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in Table 2, which is associated with Sections C.6.a and C.6.b. The regulatory guide does not discuss any specific failure mechanisms or degradation factors that were the bases for specifying 18 months. ASME N510-1989 specifies a recommended frequency of once per operating cycle, with no specific time value given for an operating cycle. Therefore, the 18-month surveillance interval recommendation within Regulatory Guide 1.52 is interpreted as once per operating cycle.

A.53 REGULATORY GUIDE 1.53 - APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS (JUNE 1973)

Conformance

HNP-2 has met the intent of this guide by specifying, designing, and constructing the engineer safeguards systems and reactor protection system to meet the single failure criterion, Section 4.2 of Institute of Electrical and Electronics Engineering (IEEE) 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," and IEEE 379, "IEEE Trail-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems." Redundant sensors are used and the logic is arranged to ensure that a failure in an instrument channel, or the division logic, or an actuator will not prevent or initiate protective action. Separated instrument channels are employed so that a fault affecting one channel does not prevent the other channels from operating properly.

Facilities for testing are provided so that the equipment can be operated in various test modes to confirm that it operates properly when called upon. Testing incorporates all elements of the system under one test mode or another, including sensors, logic, actuators, and actuated equipment. The testing is performed at intervals so that there is an extremely low probability of failure in the periods between tests. During testing there is always enough equipment available for operation to provide proper protection.

A.54 REGULATORY GUIDE 1.54 - QUALITY ASSURANCE REQUIREMENTS FOR PROTECTIVE COATINGS APPLIED TO WATER-COOLED NUCLEAR POWER PLANTS (JUNE 1973)

Conformance

The quality assurance requirements for protective coatings used in the primary containment, as discussed in paragraph 3.8.2.7, meet the requirements of this guide except that American National Standards Institute (ANSI) N45.2-1971 listed in Regulatory Position C.1 was not used in conjunction with ANSI N101.4-1972.

During major modifications or additions since receipt of the operating license, this regulatory guide has been used for protective coatings applied inside the primary containment.

A.55 REGULATORY GUIDE 1.55 - CONCRETE PLACEMENT IN CATEGORY I STRUCTURES (JUNE 1973)

Conformance

HNP-2 conforms to the requirements of this guide as discussed in section 3.8.

A.56 REGULATORY GUIDE 1.56 - MAINTENANCE OF WATER PURITY IN BOILING WATER REACTORS (JUNE 1973)

Conformance

HNP-2 conforms with the intent of this guide although determinations of concern in Positions 2, 3, and 4 are not made on a routine basis as part of normal operating procedures; such determinations are made during occasional tests of the filter-demineralizer units. Alarms at increasing levels of conductivity, as discussed in position 5, are not used. One alarm with a setpoint consistent with Position C.5.a of this guide is provided in the MCR. Plant procedures, in conjunction with the alarm and results of Technical Specifications required water samples, provide for actions which meet the intent of the multiple alarm levels of position 5. Paragraph 10.4.6.5 describes the instrumentation available for determination of the ion-exchange capacity and effluent conductivity of each filter-demineralizer unit. Water chemistry limits were included in the Technical Specifications and are discussed in paragraph 5.2.3.4. As part of the Technical Specifications Improvement Program implemented according to NUREG-1433, chemistry limits were removed from the Technical Specifications and relocated to the Technical Requirements Manual and plant procedures. These limits are consistent with the requirements of this guide.

Reactor water chemistry controls are based upon BWRVIP-190, “BWR Water Chemistry Guidelines” or the latest approved industry guidance.

A.57 REGULATORY GUIDE 1.57 - DESIGN LIMITS AND LOADING COMBINATIONS FOR METAL PRIMARY REACTOR CONTAINMENT SYSTEM COMPONENTS (JUNE 1973)

Conformance

The design limits and loading combinations for metal primary reactor containment system components, including all penetrations and attachments that form part of the primary containment, are in accordance with Subsection NE, Class MC, of Section III of the American Society of Mechanical Engineers Code, 1971 Edition including 1971 Summer Addenda, which meets the intent of this guide. See also paragraph 3.8.2.6. The service limits and associated load combinations relating to the Mark I Containment Long-Term Program given in NUREG 0661 are incorporated in supplement 3.8B.

A.58 REGULATORY GUIDE 1.58 - QUALIFICATIONS OF NUCLEAR POWER PLANT INSPECTION, EXAMINATION, AND TESTING PERSONNEL (AUGUST 1973)

Conformance

Inspection, examination, and testing personnel used onsite at HNP-2 for safety-related systems and equipment meet the requirements of American National Standards Institute N45.2.6-1973. HNP-2 is also in compliance with Regulatory Positions C.1, 5, 6, 7, 8, and 10 of Regulatory Guide 1.58, Revision 1.

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.6. Accordingly, the requirements for qualification of inspection, examination, and testing personnel are described in the QATR.

A.59 REGULATORY GUIDE 1.59 - DESIGN BASIS FLOODS FOR NUCLEAR POWER PLANTS (AUGUST 1973)

Conformance

The conditions resulting from the worst site-related flood probable at HNP-2, with attendant wind-generated wave activity, were considered in the design of safety-related structures, systems, and components to ensure that they would remain functional during such an event, in accordance with the Regulatory Position of this guide. Subsection 2.4.3 describes the probable maximum flood that was used in the design of the plant and the technique used to determine its magnitude.

A.60 REGULATORY GUIDE 1.60 - DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS (REVISION 1, DECEMBER 1973)

Conformance

The design response spectra for seismic design of HNP-2 are discussed and provided in section 3.7. The seismic design criteria for HNP-2 were established well before the advent of this guide and, thus, the requirements of this guide were not utilized in the design of HNP-2.

A.61 REGULATORY GUIDE 1.61 - DAMPING VALUES FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS (OCTOBER 1973)

Conformance

The design damping values used for the seismic design of HNP-2 are discussed and provided in section 3.7. The seismic design criteria for HNP-2 were established well before the advent of this guide; thus, the requirements of this guide were not utilized in the design of HNP-2.

A.62 REGULATORY GUIDE 1.62 - MANUAL INITIATION OF PROTECTIVE ACTIONS (OCTOBER 1973)

Conformance

The manual initiation requirements of Institute of Electrical and Electronics Engineers (IEEE) 279-1971, Section 4.17 were satisfied in the design bases for manual initiation requirements.

The HNP-2 design was completed before IEEE 279-1971 and Regulatory Guide 1.62 were effective. The degree of conformance for each system is as described below:

A. Reactor Protection System (RPS)

The manual scram pushbuttons comply with this design requirement. Failure of an automatic RPS function affects the automatic portions of the system, but the manual trip logics will still be able to initiate protective action. A modification to the RPS manual scram was made in accordance with NRC directions, to meet Section 4.17 of IEEE standard 279-1971. This modification is described below.

All K15 A-D relay contacts are deleted from the scram solenoid valve circuits and from the backup scram valve circuits. General Electric (GE)-type CR 105 relays K15 A-D are exchanged for GE-type HFA relays. Contacts from the HFA-type K15 A-D relays are used in the auto scram logic circuit to deenergize the scram contactor relays K14 A-H. Two manual scram pushbutton switches are added to the manual logic and wiring changes made such that each individual manual scram pushbutton deenergizes only its corresponding K15 relay; i.e., 2C71-S3A manual scram pushbutton deenergizes the 2C71-K15A relay only.

This modification resolved the problem where a single relay failure (K15 A-D or K19 A, B, E, H) could have prevented insertion of half of the control rods on a manual scram.

B. Nuclear Steam Supply System Isolation

All isolation valves are capable of manual actuation independent of active components of the automatic actuation circuitry, with the exception of the motor starters for the motor-operated valves. Individual motor-operated valves do not have redundant starters. Manual action requires the operation of a switch for each valve. The motor generator sets may be manually tripped from the main control room (MCR), also initiating system level isolation.

C. Reactor Core Isolation Cooling (RCIC)

Each piece of RCIC actuation equipment required to operate (pumps and valves) is capable of manual initiation electrically from the control panel in the MCR.

Failure of logic circuitry to initiate the RCIC system does not affect the manual control of equipment.

D. Core Spray/Low-Pressure Coolant Injection/High-Pressure Coolant Injection

Each piece of actuation equipment (pumps, valve, breaker, and starter) is capable of individual manual initiation, electrically from the control panel in the MCR and locally, if desired, by use of physical mechanisms. The valves have handwheels overriding the motor operators, and the switchgear is capable of having closing springs charged manually and the breaker closed by mechanical linkages on the switchgear. In addition, each system may be manually initiated through the use of test jacks, located on relay panels, provided for each one-out-of-two-twice initiation logic arrangement. By inserting the test fixture and manually turning the test switch (part of the test fixture) to the appropriate position, the system can be manually initiated.

E. Automatic Depressurization System (ADS)

Each ADS valve is provided with a manual control switch located in the MCR with which the operator can manually open each ADS valve.

F. Plant Service Water

Means for system level manual initiation are not provided since both divisions of the system are continuously running during plant operation.

A.63 <u>REGULATORY GUIDE 1.63 - ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR WATER-COOLED NUCLEAR POWER PLANTS (OCTOBER 1973)</u>

Conformance

Conformance with this guide is discussed in chapter 8, paragraph 8.3.1.2.1.

A.64 REGULATORY GUIDE 1.64 - QUALITY ASSURANCE REQUIREMENTS FOR THE DESIGN OF NUCLEAR POWER PLANTS (REVISION 2, JUNE 1976)

Conformance

SNC complies with this Regulatory Guide with one exception. Paragraph C.2. of Revision 2 (June 1976) in effect, eliminates the allowance for a designer's immediate supervisor performing design verification even subject to the conditions and controls provided in Section 6.1 of ANSI N45.2.11-1974 and Section 3E4a. of NUREG 0800 (Revision 2, July 1981). SNC allows reviews by immediate supervisors subject to these controls, which are:

- *The supervisor is the only individual technically qualified to perform the verification.*
- *The supervisor did not specify a singular design approach, rule out certain design considerations, or establish the design inputs.*
- *The need for verification by the supervisor is individually documented and approved in advance by the supervisor's management.*
- *Quality Assurance (QA) audits cover the frequency and effectiveness of use of supervisors as design verifiers to guard against abuse.*

The QA Program for design is implemented through the requirements of the Edwin I. Hatch Nuclear Plant QA Manual, and the architect-engineer QA manual and associated detailed procedures of the architect-engineer.

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.11. Accordingly, quality assurance requirements applicable to design activities are described in the QATR.

A.65 REGULATORY GUIDE 1.65 - MATERIALS AND INSPECTIONS FOR REACTOR VESSEL CLOSURE STUDS (OCTOBER 1973)

Conformance

The HNP-2 design and inspection procedures are in conformance with the requirements of this guide except those in Regulatory Positions 2b, 2e, and 3.

Studs were examined in accordance with the requirements of American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, N-235 (1968 Edition plus 1970 Summer Addendum in effect at time of contract). Bored blank nuts were ultrasonically examined by both the longitudinal and shear wave methods. Shear wave examination on the nuts was performed in both the axial and circumferential directions.

Regulatory Position 3 recommends provision for adequate corrosion protection during venting and filling of the vessel, and while the head is removed. General Electric supplies thread protectors which prevent stud damage, but stud holes are not plugged, and neither stud nor flange threads are protected from exposure to water. In practice this has been found to be adequate, as exposure to applied loads and operating and servicing environments has not required the replacement of any boiling water reactor studs or flange threads. No corrosion protection for studs is proposed.

A.66 REGULATORY GUIDE 1.66 - NONDESTRUCTIVE EXAMINATION OF TUBULAR PRODUCTS (OCTOBER 1973)

Conformance

This guide was withdrawn by the NRC in September 1977. All applicable portions of the guide are included in ASME Code, Section III.

A.67 REGULATORY GUIDE 1.67 - INSTALLATION OVERPRESSURE PROTECTION DEVICES (OCTOBER 1973)

Conformance

The scope of this guide does not include closed discharge systems as used with boiling water reactors. All safety relief valves are piped to the suppression pool, and Code Case 1569 is not applicable to closed discharge systems; therefore, this guide is not applicable to HNP-2.

A.68 REGULATORY GUIDE 1.68 - PREOPERATIONAL AND INITIAL STARTUP TEST PROGRAMS FOR WATER-COOLED POWER REACTORS (NOVEMBER 1973)

Conformance

The HNP-2 preoperational and initial startup test programs complied with the intent of this guide but did not include all of the details of this guide. The programs are described in detail in subsections 14.1.3 and 14.1.4, and paragraph 14.1.1.5.

Georgia Power Company conducted the preoperational and startup test program in conformance with Regulatory Guide 1.68 (November 1973) as discussed below, and as presented in chapter 14. The following discussion is intended to clarify the applicability of specific sections of the Regulatory Guide to HNP-2.

A.1.b Those items not applicable to boiling water reactors (BWRs) (pressurizer, steam generator) were not tested.

A.2.a Was not tested as part of the HNP-2 program; the system is not applicable to HNP.

A.2.f HNP-2 complied with this requirement through the functional testing of auxiliary startup instrumentation in the fuel loading startup test (STI-3) and startup procedure HNP-2-10203. This requirement is not covered in a preoperational test procedure.

A.4.b Was not tested as part of the HNP-2 program; the system is not applicable to HNP.

A.4.c Was not tested as part of the HNP-2 program, the system is not applicable to HNP.

A.4.h Was not tested as part of the HNP-2 program; this system is with HNP-1.

A.5.h Was not tested as part of the HNP-2 program; the system is not applicable to HNP.

A.5.1 Was not tested as part of the HNP-2 program; the system is not applicable to HNP.

A.5.d See section 14A.39.

A.5.q See sections 14A.2 and 14B.24.

A.11 See section 14A.28.

A.12.b Was not tested as part of the HNP-2 program; this system is shared with HNP-1.

A.12.c Was not tested as part of the HNP-2 program; this system is shared with HNP-1.

B.1 Was not tested as part of the HNP-2 program; this section is not applicable to HNP.

C.1 Was not tested as part of the HNP-2 program; this section is not applicable to HNP.

C.2.f See section 14A.29. The calibration program was not a part of preoperational or startup tests but rather was covered in plant operating procedures. No releases were planned for calibration of the effluent radiation monitors.

D.1 Was not tested as part of the HNP-2 program; the section is not applicable to HNP.

D.2 Was not tested as part of the HNP-2 program; the system is not applicable to HNP.

D.2.f A recirculation system two-pump trip was not planned from 100% power.

Recirculation pump trips (RPTs) are no longer of significant interest from a thermal limit standpoint; therefore, fewer pump trips are performed as a part of the startup test program. A recirculation system two-pump trip was conducted from 50% power to demonstrate plant equipment response and pump capabilities at power.

A recirculation system two-pump trip was not planned at 100% power. This trip was conducted on the 75% flow line and analyzed for plant response at higher power levels.

D.2.j & D.2.o Demonstration of plant response to load swings was made along the 50% load line and extrapolated to the 100% load line. The rod sequence exchange demonstration was included in the startup test program.

D.2.s & D.2.t Both trips were not planned because the response of the nuclear steam supply system (NSSS) to one of these tests can easily be inferred from the results of the other; thereby eliminating the need to do both.

Both a turbine trip and a generator trip at 100% power are not desired due to the extreme transients involved. It was concluded that the reactor system's response to these two trips is essentially similar and need not be conducted twice. See additional discussion below.

D.2.f This test was performed from ~ 50% power. Since the two-pump trip is not a limiting transient from the standpoint of the minimum critical power ratio (MCPR), there is no need for conducting the more extensive tests. The two-pump trip from test condition 3 will be sufficient to demonstrate plant response to simultaneous loss of both pumps. Test condition 4 (natural circulation), is the point of minimum control stability. Arriving at this condition from 100% power by tripping both pumps offers no additional information.

D.2.j Plant response to changes in recirculation flow was demonstrated at each major test condition and along each major load line, i.e., midpower and rated load line. In addition, plant response to a larger load swing was demonstrated along a midpower load line.

D.2.o This rod sequence exchange demonstration was included in the startup test program as STI-8.

D.2.s The turbine trip and generator load rejection transients are similar from the standpoint of the NSSS. However, the load rejection is considered to be slightly more severe and was, therefore, tested at the maximum allowable power. The results of either transient can be extrapolated to the results of the other. A turbine trip was also performed at test condition 3 (60 to 80% power), from which plant response to turbine trip (especially electrical response) could be determined.

D.2.v Sampling of the effluent monitoring system was accomplished at major power levels in the implementation of chemical and radiochemical tests as part of the chemical and radiochemical startup test (STI-1) and startup test procedure HNP-2-10080.

D.2.aa Process computer checkout by means of completion of the dynamic system test case was accomplished during the testing at test conditions 1, 2, and 3. This testing was completed and all NSSS software operational prior to power ascent above 50%.

Items identified above by A.4.h, A.12.b, and A.12.c were not tested as part of the preoperational and startup testing programs. These functions are shared with and are operational on HNP-1, and, thus, functional capability was proven to be adequate.

Justification for not performing the two RPTs and both turbine and generator trips at 100% power is given below.

More recent analytical information shows that the simultaneous trip of both recirculation pumps from very high initial power levels is no longer a significant fuel thermal transient. Previous calculations of minimum critical heat flux rates showed this event to be important; but now the more accurate MCPR method shows wide fuel thermal margins; hence, this test was deleted as unnecessary from our initial startup test programs since it causes a significant plant transient, power loss, and possible additional scram.

The reactor core power-void mode of dynamic response is known to be the least stable at a combination of low-core-flow rate and higher power levels. This mode has behavior characteristics that are predictable from linear system analytical methods (NEDO-21506, Stability and Dynamic Performance of the GE-BWR, January 1977). Either small, medium, or large-disturbance inputs can be used to test for its characteristics such as decay ratio and frequency. The only requirement is to make the test disturbance of a size sufficient to make the response observable on the transient recorder. At test condition 4, several different types of reactor transient tests are performed. In particular, the pressure-control backup regulator test and the control rod notch test are adequately sized to make the core power-void more observable. Pressure setpoint steps and feedwater level setpoint step tests are also performed at test condition 4 to show the reactor and its control systems to be acceptably stable.

The recirculation two-pump trip event, using the 100% control rod line, does yield a larger neutron flux transient, but most of that occurs while the reactor core flow rate is still high. By the time the core flow is nearing its minimum value, the relative rates of response have converged and stabilized to near steady state. They are smaller than some of those transient tests already initiated from test condition 4 in each startup test program. Thus, the data to analyze for core stability has not been improved, but the plant has suffered a large power loss (100% power to

50% power). There is even a small possibility of a reactor scram and its attendant operational delay and power loss.

It is our judgment, with respect to observing reactor stability, and from the hydraulic consideration, that an RPT test on the 100% control rod line yields no added useful data, and it burdens the plant with an added large power loss. For this reason, we recommend that this test be performed from test condition 3, where its flow coastdown data more efficiently fits in with other startup test objectives.

It may also be noted that when the Hench/Levy thermal hydraulic correlation was used as the analysis basis for boiling water reactors (BWRs), the large flow transients were the limiting transients of concern. With the change to the GEXL thermal-hydraulic correlation, the flow transients are no longer limiting, as may be seen from the HNP-2 plant transient analysis. Consequently, the need to examine plant performance for wide flow reductions is no longer regarded as a startup test requirement.

A two-pump trip test was added for mid-power levels. This was performed to verify proper RPT system performance prior to the plant's ascension to very high-power levels.

Several years ago, both turbine and generator trip tests were performed from high-power at General Electric (GE) direction to provide more data on variations from nominal conditions. For the last few years, the trip scram test matrix has been made more efficient. For BWR plants with partial turbine bypass valve flow capacity, the transient experienced by the reactor in the turbine trip case is virtually identical to that in the generator trip case. The only important difference is the turbine valve closure times, which differ only by 1/10 s or less. After considering the great cost and transient impact of such trip scram events, when compared to the relatively small value of the data-gathering advantage, the need for both tests could not be justified.

At this time, GE requires choosing one or the other of a turbine or a generator trip at rated conditions in the startup program. Most plants decide in favor of the generator trip to simultaneously obtain main turbine speed and acceleration data while they are verifying the protective aspects of the fast control valve closure. They must have already performed a main turbine trip at between 60 and 80% where protective-related data can be obtained prior to the ascension to very high-power levels. Thus, one of each kind of transient test is performed. This differs from Regulatory Guide 1.68 only in specified initial power levels.

Note also that another generator trip test is required of every plant early in its startup program at a power level just within the partial bypass valve flow capacity rating. With regard to the main turbine control and stop valves, the evidence to date indicates consistent operation in terms of characteristic and operating time. During a turbine trip, the turbine stop valves, turbine control valves, reheat stop valves, and intercept valves are all required to close from the initiating signal. For the load-rejection transient, only the control valves and intercept valves are called upon to close. For this latter case, the turbine overspeed protection performs in such a manner that the turbine stop valves and reheat valves do not close. Thus, performance of the load-rejection test provides additional performance data. As stated above, the operating characteristics of all the valves involved are so well known that the performance of an additional turbine trip at 100% power is not justified on the basis of obtaining new information. There has

been no evidence from previous tests of this type of turbine stop valve showing any sensitivity to flow with respect to an effect on closing time.

Plant load changes result from controlled maneuvers of the recirculation system. The optimized recirculation flow control system adjustments are determined after stability and response performance transients are performed. Stability testing is done first and yields faster load changes of from 2 to 7% of rated power. Core flow and power response transients follow with magnitudes of 18 to 35% of rated power along constant control rod pattern lines. In general, the size of midpower load maneuvers is about half of those performed along the rated power rod line. The load changes are accomplished by an increase in recirculation flow from about 65 to 100% over a period of $\leq$ 1 min.

The test abstract for the rod pattern exchange demonstration was included in the startup test specifications.

In order to yield a clearer and more efficient test program, the objective of STI 29 - Recirculation Flow Control and STI 32 - Recirculation MG Set Speed Control were combined into one test. There has been no deletion of system adjustment testing, but rather a reorganization and addition of test content to yield a more thoroughly adjusted control system.

The vibration measurements were eliminated from startup testing since they were replaced by cold flow vibration testing during the preoperational phase of testing.

The safety analysis included parametric information for the prediction of performance criteria for a 75% power turbine trip, a full-power isolation, a full-power load rejection, and a loss of feedwater heating.

The input for the test predictions is consistent with that used throughout this report. Briefly, the analysis basis can be expressed as follows:

A. Nuclear parameters are based on beginning-of-cycle core performance.

B. All plant hardware is assumed to operate properly, including bypass valves, relief valves, scram and trip functions, etc. (Should a significant hardware failure occur, such as bypass valve failure, the criteria may be violated and reanalysis might be required. This reanalysis could identify hardware or modeling errors or could use available sensitivity studies to correct discrepancies between actual plant conditions and the conditions assumed in the original analysis.) The operation of this equipment is recorded during the test.

C. Plant hardware is assumed to perform within the nominal expected limits required by Technical Specifications and design specifications. In some cases, performances were assumed to be at a particular value in this range; measured values were used with parametric studies to make appropriate corrections to the acceptance criteria. Sensitivity studies have been performed for many parameters such as power level, relief valve set points, capacity and opening delay, bypass valve capacity and delay, reactivity insertion rate, and main steam isolation valve (MSIV) closure times. The studies demonstrate the relative sensitivity of the

transient results to these parameters and permit adjustments to the analytical results for actual test conditions for these effects. Performance of this plant hardware is recorded during the test.

For the pressurization transients, i.e., the turbine trip, load rejection, and MSIV closure, there are two key predicted parameters:

A. The positive change in reactor pressure that occurs within the first 30 s following the initiation of the transient. This represents the highest pressure experienced by the system and has the highest rate of increases; thus, it provides the best measure of the plant performance compared to expectations in the area of overpressure protection. The pressure response of the reactor is recorded throughout the test.

B. The positive change in reactor-simulated heat flux that occurs within the first 30 s following the initiation of the transient provides information representative of the thermal output and performance of the system. In the case of these transients, a reactor scram is initiated and turns power before steam flow is significantly decreased; therefore, no increase in heat flux is expected. The reactor-simulated heat flux is also recorded during the test as well as steam flow.

The loss of turbine-generator and offsite power test is not amenable to the preceding approach because it is largely a test of balance-of-plant equipment and predicted performance would be of little value. It should also be noted that this test is not as good an indicator of reactor performance as the aforementioned tests. This test is used to verify that the diesels start and power their assigned loads. Parameters such as emergency core cooling system (ECCS) equipment and diesel generator automatic actuation are recorded as well as the reactor responses.

A.68.1 REGULATORY GUIDE 1.68.1 - PREOPERATIONAL AND INITIAL STARTUP TESTING OF FEEDWATER AND CONDENSATE SYSTEMS FOR BOILING WATER REACTOR POWER PLANTS

HNP-2 complied with the intent of this guide except that steam-driven pumps were not flow tested in the preoperational test program due to the limited amount of steam available. Electric-driven pumps were also exempted from full flow testing during the preoperational testing because of the limited capacity of test lines.

A.69 REGULATORY GUIDE 1.69 - CONCRETE RADIATION SHIELDS FOR NUCLEAR POWER PLANTS (DECEMBER 1973)

Conformance

Concrete radiation shields as discussed in paragraph 3.8.4.6 meet the intent of this guide.

A.70 REGULATORY GUIDE 1.70 - STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS (REVISION 1, OCTOBER 1972)

Conformance

The format of the HNP-2 FSAR follows that suggested by this guide and the following additional Regulatory Guides:

1.70.1 Additional Information -- Hydrological Considerations for Nuclear Power Plants (December 1973)

1.70.2 Additional Information -- Air Filtration Systems and Containment Sumps for Nuclear Power Plants (December 1973)

1.70.3 Additional Information -- Radioactive Materials Safety for Nuclear Power Plants (February 1974)

1.70.4 Additional Information -- Fire Protection Considerations for Nuclear Power Plants (February 1974)

1.70.5 Additional Information -- Water Level (Flood) Design for Nuclear Power Plants (May 1974)

A.71 REGULATORY GUIDE 1.71 - WELDER QUALIFICATION FOR AREAS OF LIMITED ACCESSIBILITY (DECEMBER 1973)

Conformance

All welder qualification at HNP-2 is done in compliance with American Society of Mechanical Engineers Section IX, and, thus, satisfies the intent of this guide. Very few welds of limited accessibility are encountered.

A.72 REGULATORY GUIDE 1.72 - SPRAY POND PLASTIC PIPING (DECEMBER 1973)

Conformance

Since HNP-2 does not utilize a spray pond, this guide is not applicable.

A.73 REGULATORY GUIDE 1.73 - QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS (JANUARY 1974)

Conformance

Prototype tests on valve operators (with Reliance motor) were carried out by the manufacturer in accordance with this guide and Institute of Electrical and Electronics Engineering Standard 382-1972. Test reports show that the valve operators remain functional during and after exposure to environmental conditions set forth in IEEE Standard 382-1972.

A.74 REGULATORY GUIDE 1.74 - QUALITY ASSURANCE TERMS AND DEFINITIONS (FEBRUARY 1974)

Conformance

Quality assurance terms and definitions used in the SNC, Southern Company Services, Inc., General Electric Company, and Bechtel Power Corporation quality assurance programs are generally in agreement with American National Standards Institute N45.2.10-1973 and, therefore, satisfy the intent of this guide.

The quality assurance program for plant operations complies with this guide.

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.10. Accordingly, terms and definitions used in the quality assurance program are provided in the SNC QATR.

A.75 REGULATORY GUIDE 1.75 - PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS (FEBRUARY 1974)

Conformance

Conformance to this guide is discussed in chapter 8, paragraph 8.3.1.2.1.

A.76 REGULATORY GUIDE 1.76 - DESIGN BASIS TORNADO FOR NUCLEAR POWER PLANTS (APRIL 1974)

Conformance

The design basis tornado for HNP-2 is discussed in subsection 3.3.2. The deviations from this guide are as follows:

A. While a rotational speed of 300 mph and a translational speed of 60 mph were used for HNP-2 design, a minimum translational speed was not considered; however, low travel speeds (maximum transit time) were not limiting factors in the design of the ultimate heat sink.

B. A calm period of 3 s and a rate of pressure drop of 1 psi/s were used in design.

Although the HNP-2 design basis tornado was established well before the advent of this guide, the above deviations from the guide are not considered significant.

A.77 REGULATORY GUIDE 1.77 - ASSUMPTIONS USED FOR EVALUATING A CONTROL ROD EJECTION ACCIDENT FOR PRESSURIZED WATER REACTORS (MAY 1974)

Conformance

Since HNP-2 utilizes a boiling water reactor, this guide is not applicable.

A.78 <u>REGULATORY GUIDE 1.78 - ASSUMPTIONS FOR EVALUATING THE HABITABILITY OF A NUCLEAR POWER PLANT CONTROL ROOM DURING A POSTULATED HAZARDOUS CHEMICAL RELEASE (JUNE 1974)</u>

Conformance

The design assumptions for the main control room environmental control (MCREC) system are in accordance with the intent of this guide; clarifications and exceptions are discussed below. The HNP-2 construction permit review was conducted well in advance of the issuance of this guide; however, the significant criteria of the guide were considered in the design of the MCREC system.

The MCREC system, discussed in sections 6.4 and 15.4, and subsection 9.4.1 (corresponding design basis accidents) is designed to ensure continued occupancy for plant operators in the main control room (MCR) following a postulated hazardous chemical release.

The following regulatory positions are those for which the design conformance of the MCREC system requires clarification and/or exception:

A. Paragraph C.1 - No major depots or storage tanks of hazardous chemicals such as the chemicals listed in Table C-1 of the guide are within a 5-mile radius of the plant site, with the exception of onsite nitrogen, and carbon dioxide storage.

B. Paragraph C.2 - No hazardous chemicals, such as those indicated in Table C-1, are projected to be frequently shipped by rail, water, or road routes within a 5-mile radius of the plant site, with the exception of nitrogen, or carbon dioxide deliveries to the site. Nitrogen and carbon dioxide are expected to be delivered at infrequent intervals as required.

C. Paragraph C.3 - Since no gaseous chlorine will be used or stored on site, no toxic hazard to MCR personnel will occur due to an accidental release of site stored chlorine. Therefore, no instrumentation is provided to detect chlorine escape, set off an alarm, or provide a readout in the control room.

D. Paragraph C.7 - Since no gaseous chlorine will be used or stored on site, no credit need be taken in the chlorine accident analysis for closing of the MCREC system air intake. Thus, isolating the MCR as a result of a chlorine accident is not required.

E. Paragraph C.11 - No credit has been taken for the removal of hazardous chemicals by filtration.

The liquid nitrogen storage tanks are located outside the plant structures on the east side of the HNP-1 reactor building. Since the control room fresh air intake is located on the west side of the control building, a threat to the operators is not considered possible. The carbon dioxide storage tank is inside the HNP-1 portion of the control building; its relationship to the MCR and its potential effects on operators are discussed in section 15.4.

With the exceptions and clarifications stated above, the assumptions used for the evaluation of the HNP-2 MCR habitability, given that a postulated hazardous chemical release occurs, are in conformance with this guide.

A.79 REGULATORY GUIDE 1.79 - PREOPERATIONAL TESTING OF EMERGENCY CORE COOLING SYSTEMS FOR PRESSURIZED WATER REACTORS (JUNE 1974

Conformance

Since HNP-2 utilizes a boiling water reactor, this guide is not applicable.

A.80 REGULATORY GUIDE 1.80 - PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS (JUNE 1974)

Conformance

The HNP-2 preoperational test for the instrument air system met the intent of this guide. Some of the testing required by this guide was performed with the preoperational tests for the systems which utilize instrument air. The instrument air system is discussed in subsection 9.3.1.

A.81 REGULATORY GUIDE 1.81 - SHARED EMERGENCY AND SHUTDOWN ELECTRIC SYSTEMS FOR MULTI-UNIT NUCLEAR POWER PLANTS (JUNE 1974)

Conformance

Conformance with this guide is discussed in chapter 8, paragraphs 8.3.1.2.1 and 8.3.2.2.1.

A.82 REGULATORY GUIDE 1.82 - SUMPS FOR EMERGENCY CORE COOLING AND CONTAINMENT SPRAY SYSTEM (JUNE 1974)

Conformance

This guide is not applicable to HNP-2 since emergency core cooling system sumps are not used.

A.83 REGULATORY GUIDE 1.83 - INSERVICE INSPECTION OF PRESSURIZED WATER REACTOR STEAM GENERATOR TUBES (JUNE 1974)

Conformance

Since HNP-2 utilizes a boiling water reactor, this guide is not applicable.

A.84 REGULATORY GUIDE 1.84 - CODE CASE ACCEPTABILITY ASME SECTION III, DESIGN AND FABRICATION (JUNE 1974)

Conformance

A. All American Society of Mechanical Engineers (ASME) Code, Section III components for HNP-2 were either procured prior to July 1, 1974, the effective date of this guide, or code cases were not allowed for equipment procured after this date, with the exception of a valve order placed in August 1976, wherein the following code cases were authorized:

- 1516-2.
- 1535-2.
- 1635-1.
- 1662.
- 1672.
- 1677.

Thus, HNP-2 conforms to this guide.

B. All ASME Code, Section III components for HNP-2, which were replaced during the 1984 recirculation pipe replacement project (i.e., recirculation piping, stainless steel portion of RHR piping between the tee connection to the recirculation loop piping and the first RHR isolation valve and the portion of the RWC piping from the 20-in. RHR suction to the isolation valve, and that section between the piping penetration and the outboard isolation valve) were fabricated in accordance with ASME Code, Section III, Class 1, 1980 Edition including Winter 1980 Addenda with no code cases. Code case N.122 was used only for analysis of hanger lugs. The one-piece piping penetration was retained.

A.85 REGULATORY GUIDE 1.85 - CODE CASE ACCEPTABILITY ASME III MATERIAL (JUNE 1974)

Conformance

A. All American Society of Mechanical Engineers (ASME) Code, Section III components for HNP-2 were either procured prior to July 1, 1974, the effective date of this guide, or code cases were not allowed for equipment procured after this date, with the exception of a valve order placed in August 1976, wherein code case 1335-9 was authorized. Thus, HNP-2 conforms to this guide.

B. All ASME Code, Section III materials for the HNP-2 1984 recirculation piping replacement were procured in accordance with the 1980 Edition including Winter 1980 Addenda with no code cases authorized.

A.86 REGULATORY GUIDE 1.86 - TERMINATION OF OPERATING LICENSES FOR NUCLEAR REACTORS (JUNE 1974)

Conformance

At the present time, Georgia Power Company's (GPC) plans for decommissioning and dismantling HNP have not been developed. It is anticipated that technology relating to decommissioning and dismantling of nuclear power stations will be advanced considerably during the life of HNP. GPC and SNC will evaluate these advances and utilize the most feasible alternatives.

Tentative plans for decommissioning or "mothballing" HNP include the following activities:

- Removing spent-fuel from the site.
- Decontaminating auxiliary systems.
- Disposing of chemical cleaning and flushing water and other radioactive waste water.
- Disposing of resins and filters by offsite burial.
- Sealing containment and other buildings containing contaminated process piping and components.
- Performing a radiation survey to determine the level of decontamination achieved.
- Isolating the area with a security fence and alarms.

Additionally, in the State of Georgia, the plant would be subject to periodic fire and security inspections and radiological monitoring.

A.87 REGULATORY GUIDE 1.87 - CONSTRUCTION CRITERIA FOR CLASS 1 COMPONENTS IN ELEVATED TEMPERATURE REACTORS (SUPPLEMENT TO ASME SECTION III CODE CASES 1592, 1593, 1594, 1595, AND 1596) (JUNE 1974)

Conformance

Since the HNP-2 boiling water reactor is not considered an elevated temperature reactor in the context of this guide, this guide is not applicable.

A.88 REGULATORY GUIDE 1.88 - COLLECTION, STORAGE, AND MAINTENANCE OF NUCLEAR POWER PLANT QUALITY ASSURANCE RECORDS (AUGUST 1974)

Conformance

HNP-2 conforms to the requirements of this guide.

Regulatory Guide 1.88, dated August 1974, provides NRC endorsement of ANSI N45.2.9. The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.9. Accordingly, the requirements for collection, storage, and maintenance of quality assurance records are described in the QATR.

A.89 REGULATORY GUIDE 1.89, REVISION 1 - ENVIRONMENTAL QUALIFICATION OF CERTAIN ELECTRIC EQUIPMENT IMPORTANT TO SAFETY FOR NUCLEAR PLANTS (JUNE 1984)

Conformance

Plant Hatch conforms to this guide as it pertains to rulemaking 10 CFR 50.49.

A.90 REGULATORY GUIDE 1.90 - INSERVICE INSPECTION OF PRESTRESSED CONCRETE CONTAINMENT STRUCTURES WITH GROUTED TENDONS (NOVEMBER 1974)

Conformance

Since HNP-2 utilizes a steel containment, this guide is not applicable.

A.94 REGULATORY GUIDE 1.94 - QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS (REVISION 1, APRIL 1976)

Conformance

HNP-2 conforms to the requirements of this guide.

Regulatory Guide 1.94, revision 1, dated April 1976, provides NRC endorsement of ANSI N45.2.5-1974. The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.5. Accordingly, the quality assurance requirements for installation, inspection, and the testing of structural concrete and structural steel during the construction phase are described in the QATR.

A.97 REGULATORY GUIDE 1.97 - INSTRUMENTATION FOR LIGHT WATER COOLED NUCLEAR POWER PLANT TO ASSESS PLANT AND ENVIRONS CONDITIONS DURING AND FOLLOWING AN ACCIDENT (REVISION 2, DECEMBER 1980)

Conformance

HNP-2 conformance is described in FSAR subsections 7.5.3 and 7.6.11.

A.105 REGULATORY GUIDE 1.105 - INSTRUMENT SETPOINTS (REVISION 1, JULY 1976)

Conformance

The trip setpoints for the instruments within the scope of the analog trip system were developed using the criteria of this Regulatory Guide. Since this Regulatory Guide was not available, it was not used in the original plant design.

A.116 <u>REGULATORY GUIDE 1.116 - QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF MECHANICAL EQUIPMENT AND SYSTEMS (REVISION O THROUGH R, MAY 1977)</u>

Conformance

HNP-2 conforms to the requirements of this guide.

Regulatory guide 1.116, dated May 1977, provides NRC endorsement of ANSI N45.2.8. The SNC QATR based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.8. Accordingly, the quality assurance requirements for installation, inspection, and testing of mechanical equipment and systems are described in the QATR.

A.123 REGULATORY GUIDE 1.123 - QUALITY ASSURANCE REQUIREMENTS FOR CONTROL OF PROCUREMENT OF ITEMS AND SERVICES FOR NUCLEAR POWER PLANTS (REVISION 1, JULY 1977)

Conformance

HNP-2 conforms with the requirements of ANSI N45.2.13-1976, as it is endorsed by this guide with the following clarification:

> *Paragraph 3.3 requires procurement documents to be reviewed prior to bid or award of contract. The quality assurance review of procurement documents is satisfied through review of the applicable technical and quality procurement requirements prior to bid or award of contract.*

The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.13. Accordingly, quality assurance requirements for control of procurement of items and services are described in the QATR.

A.143 <u>REGULATORY GUIDE 1.143 - DESIGN GUIDANCE FOR RADIOACTIVE WASTE MANAGEMENT SYSTEMS, STRUCTURES, AND COMPONENTS INSTALLED IN LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1, OCTOBER 1979)</u>

Conformance

HNP-2 is in conformance with this guide in that the seismic evaluation of the radwaste facilities buildings (Units 1 and 2) conforms to the regulatory position. The seismic evaluation is discussed in subsection 3.8.7.

A.144 REGULATORY GUIDE 1.144 - AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS (REVISION 1, SEPTEMBER 1980)

Conformance

HNP-2 conforms to the requirements of this guide.

Regulatory Guide 1.144, dated September 1990, provides NRC endorsement of ANSI N45.2.12. The SNC QATR is based on ASME NQA-1-1994 which incorporates the requirements of ANSI N45.2.12. Accordingly, requirements for auditing quality assurance programs are described in the QATR.

A.146 <u>REGULATORY GUIDE 1.146 - QUALIFICATION OF QUALITY ASSURANCE PROGRAM AUDIT PERSONNEL FOR NUCLEAR POWER PLANTS (AUGUST 1980)</u>

Conform except as discussed below.

ANSI N45.2.23-1978, Section 2.3.4, states that the prospective Lead Auditor shall have participated in a minimum of five quality assurance audits within a period of time not to exceed 3 years prior to the date of qualification, one audit of which shall be a nuclear quality assurance audit within the year prior to his qualification.

In lieu of the requirements of Section 2.3.4 of ANSI N45.2.23-1978, the prospective Lead Auditor shall demonstrate his ability to effectively implement the audit process and effectively lead an audit team. The demonstration process will be described in written procedures and shall evaluate and document the results of the demonstration. Regardless of the methods used for the demonstration, the prospective Lead Auditor shall have participated in at least one nuclear quality assurance audit within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Section 2.3 of ANSI N45.2.23-1978, the individual may be certified as being qualified to lead audits.

The SNC QATR contains qualification requirements applicable to quality assurance audit personnel in NQA-1-1994 Basic Requirement 2 and Supplement 2S-3. Accordingly, requirements for qualification of quality assurance program audit personnel are described in the QATR.

A.155 REGULATORY GUIDE 1.155 - STATION BLACKOUT (AUGUST 1988)

Conformance

HNP-2 conforms to the requirements of this guide, and its conformance is discussed in chapter 8, section 8.4.

A.183 REGULATORY GUIDE 1.183 - ALTERNATIVE RADIOLOGICAL SOURCE TERMS FOR EVALUATING DESIGN BASIS ACCIDENTS AT NUCLEAR POWER REACTORS (JULY 2000)

HNP-1 and HNP-2 conform to the requirements of this guide with the following exceptions:

A. Main Section 5.1.2 of the regulatory guide allows credit to be taken for accident mitigation features that are classified as safety related, are required to be operable by Technical Specifications, are powered by emergency power sources, and are either automatically actuated or, in limited cases, have actuation requirements explicitly addressed in emergency operating procedures. The single active component failure that results in the most limiting radiological consequences should be assumed. Assumptions regarding the occurrence and timing of a loss of offsite power should be selected with the objective of maximizing the postulated radiological consequences.

   Selected nonsafety-related systems are credited as accident mitigation features. These systems are the alternate leakage treatment pathway via the main condenser, the standby liquid control system (a safe shutdown system, not an engineered safety feature), and turbine building ventilation system. Each of these systems has been thoroughly analyzed to ensure that they would be able to perform their designated accident mitigation function when required.

B. The following Regulatory Guide 1.183 sections are not applicable to the analyses of the HNP-1 and HNP-2 design basis accidents (DBAs): Appendix A (LOCA) sections 3.4, 3.8, 5.4, and 7; Appendix B (FHA) section 4; and Appendix C (CRDA) section 3.5.

C. Regulatory Guide 1.183 Appendix D (MSLB) section 4.3 states that all the radioactivity in the released coolant should be assumed to be released to the atmosphere instantaneously as a ground-level release. No credit should be assumed for plateout, holdup, or dilution within facility buildings.

   For offsite doses the MSLB analysis conforms to this section 4.3. For doses to the main control room, which is located in the HNP-1 and HNP-2 turbine buildings, it is conservatively assumed that activity is released directly into the turbine buildings, thereby providing a direct pathway to the main control room.

The analyses of the DBAs are discussed in section 15.3.