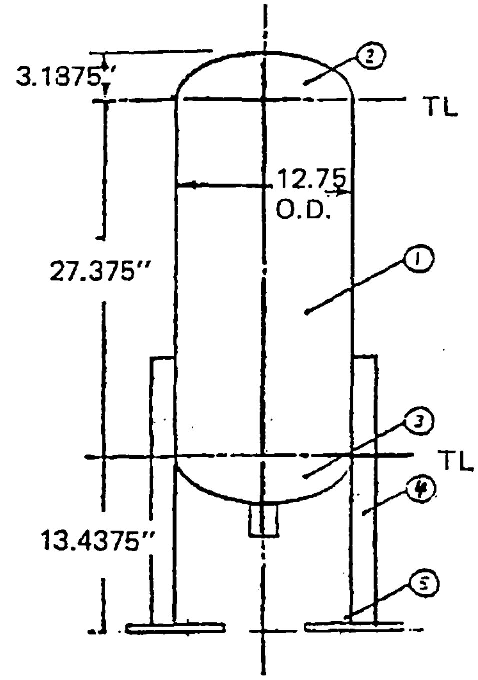
Item	Name	Material
1	Shell-Cylin.	304L S.S.
2	Head—Ellip.	304L S.S.
3	Head-Ellip w/Nozzle	304L S.S.
4	Leg- L 2½X2½X3/8	304 S.S.
5	Anchor Bolt	N/A



A. Seismic Analysis Summary

1. Predicted Fundamental Frequency: 87.8 Hz
2. Fundamental Mode: Lateral motion of the tank causing cantilever flexing of the support legs.

B. Stress Analysis Summary

1. Status of Stress Levels for Original Design: Satisfactory, no reinforcing pads required
2. Overstressed Items in Original Design: None
3. Plant Condition During Overstressing: N/A
4. Modifications to Overstressed Items: None
5. Final Status of Stress Levels for Modified Design: Satisfactory

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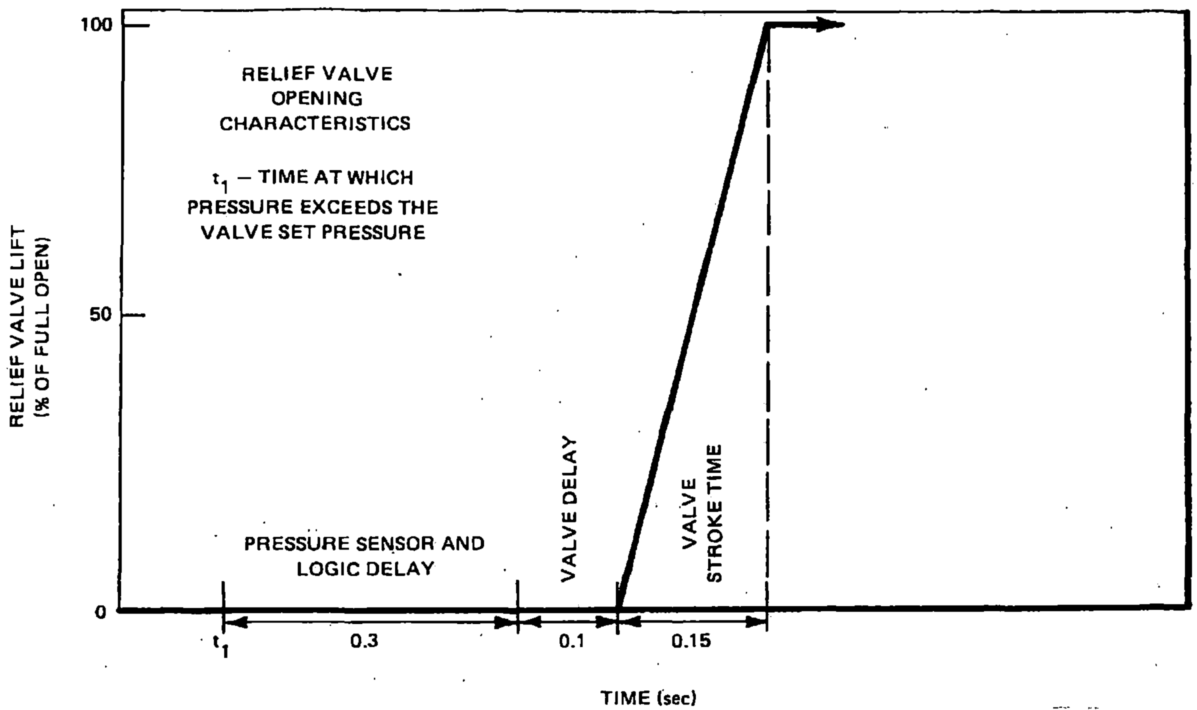
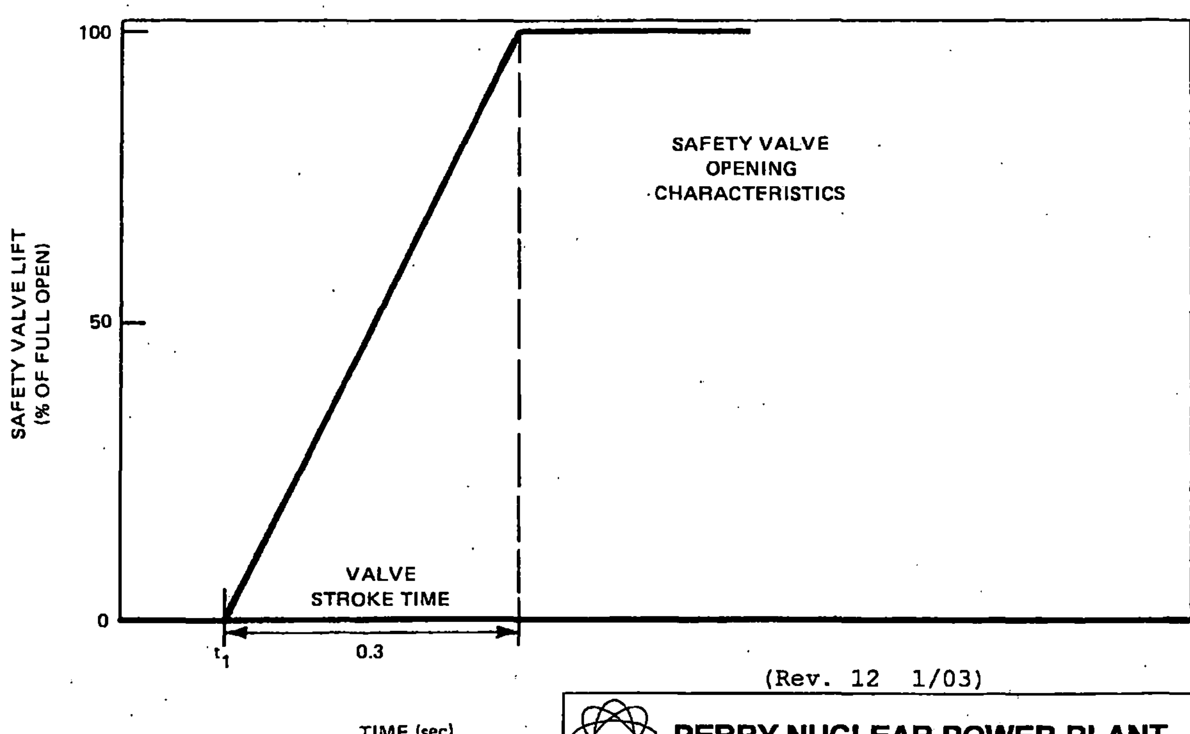
PERRY NUCLEAR POWER PLANT

Analysis Summary for Safety Relief Valve Accumulator Tank-
Tank No. 10, 1B21-A004A, etc.

Figure 3.9-14





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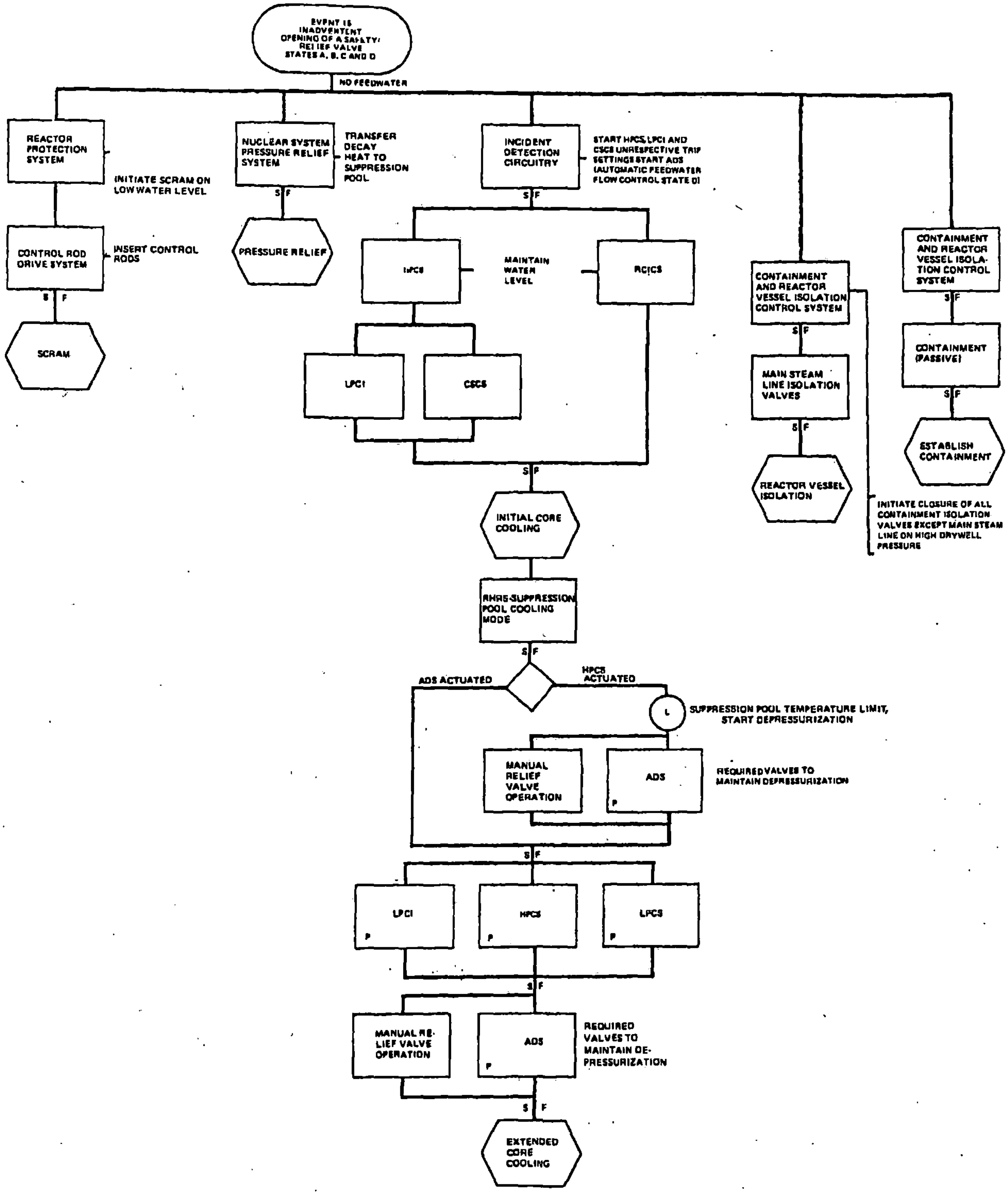
PERRY NUCLEAR POWER PLANT

Power Actuated & Safety Action
Valve Lift Characterisitics

Figure 5.2-6a



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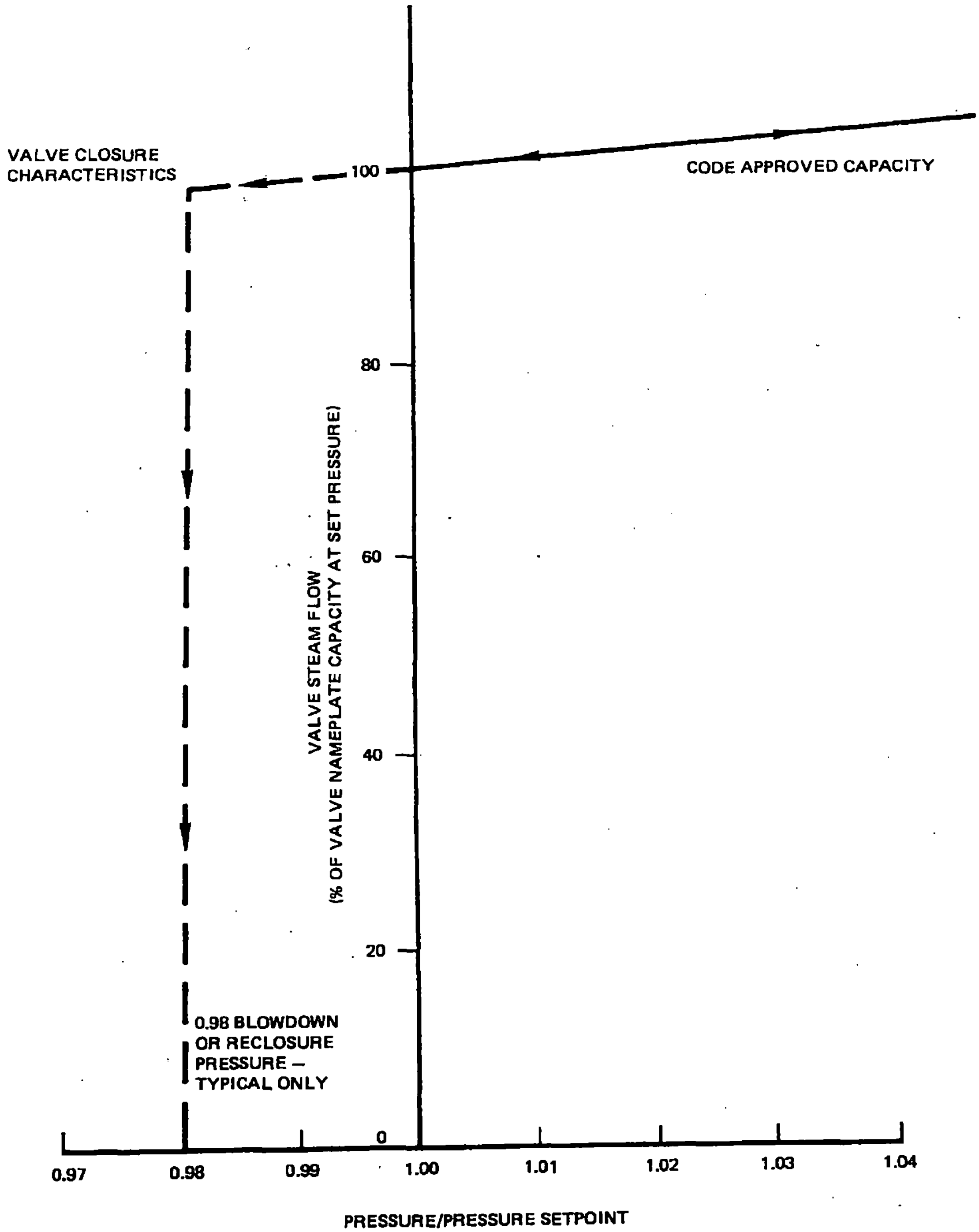
PERRY NUCLEAR POWER PLANT

Protective Sequences for Inadvertent Opening of a Safety/ Relief Valve

Figure 15A.6-15



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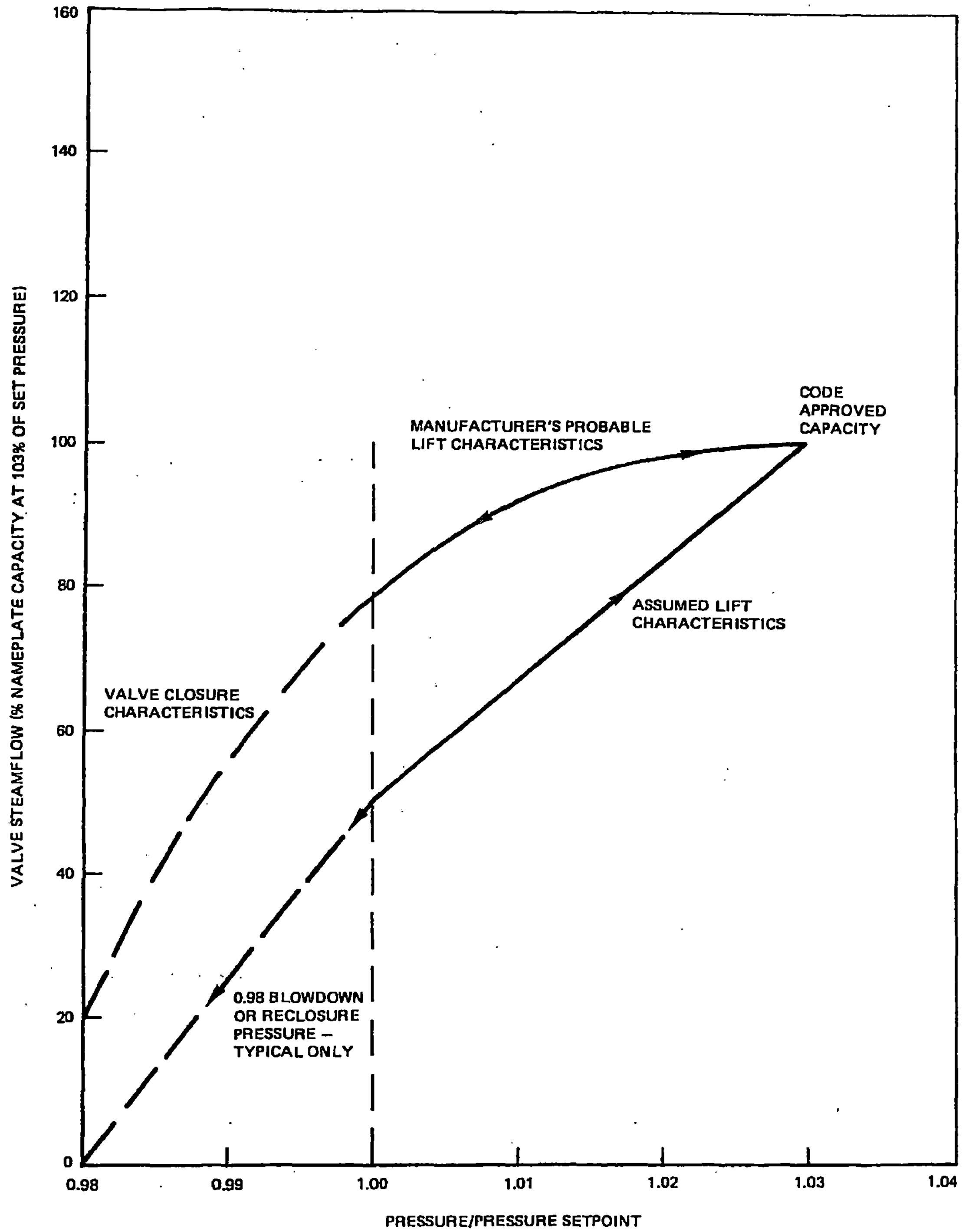
PERRY NUCLEAR POWER PLANT

Typical Dual Safety/Relief Valve Capacity Characteristics Power - Actuated Relief Mode

Figure 5.2-1



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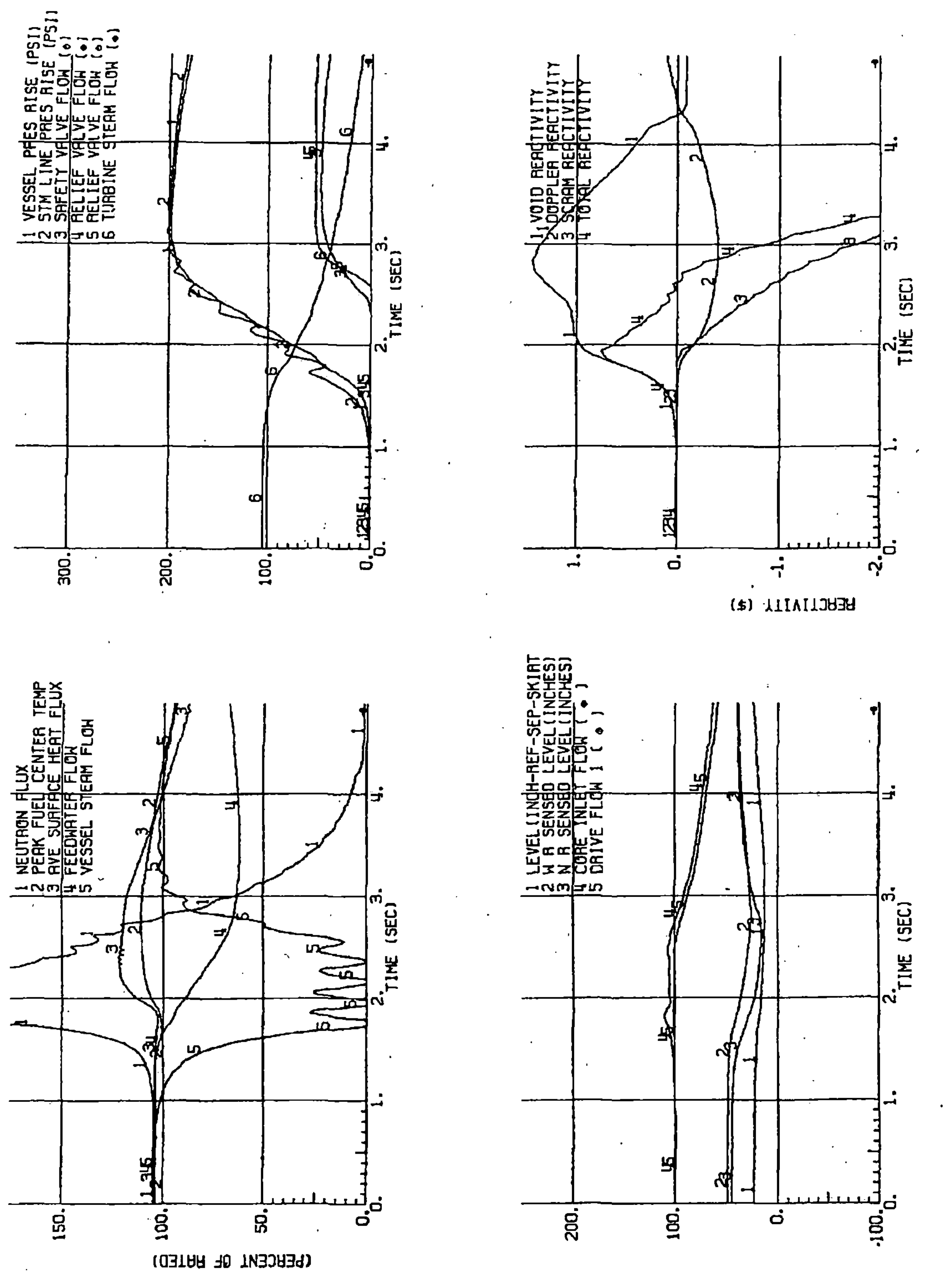
PERRY NUCLEAR POWER PLANT

Typical Dual Safety/Relief Valve Capacity Characteristics - Spring Action Safety Mode

Figure 5.2-2



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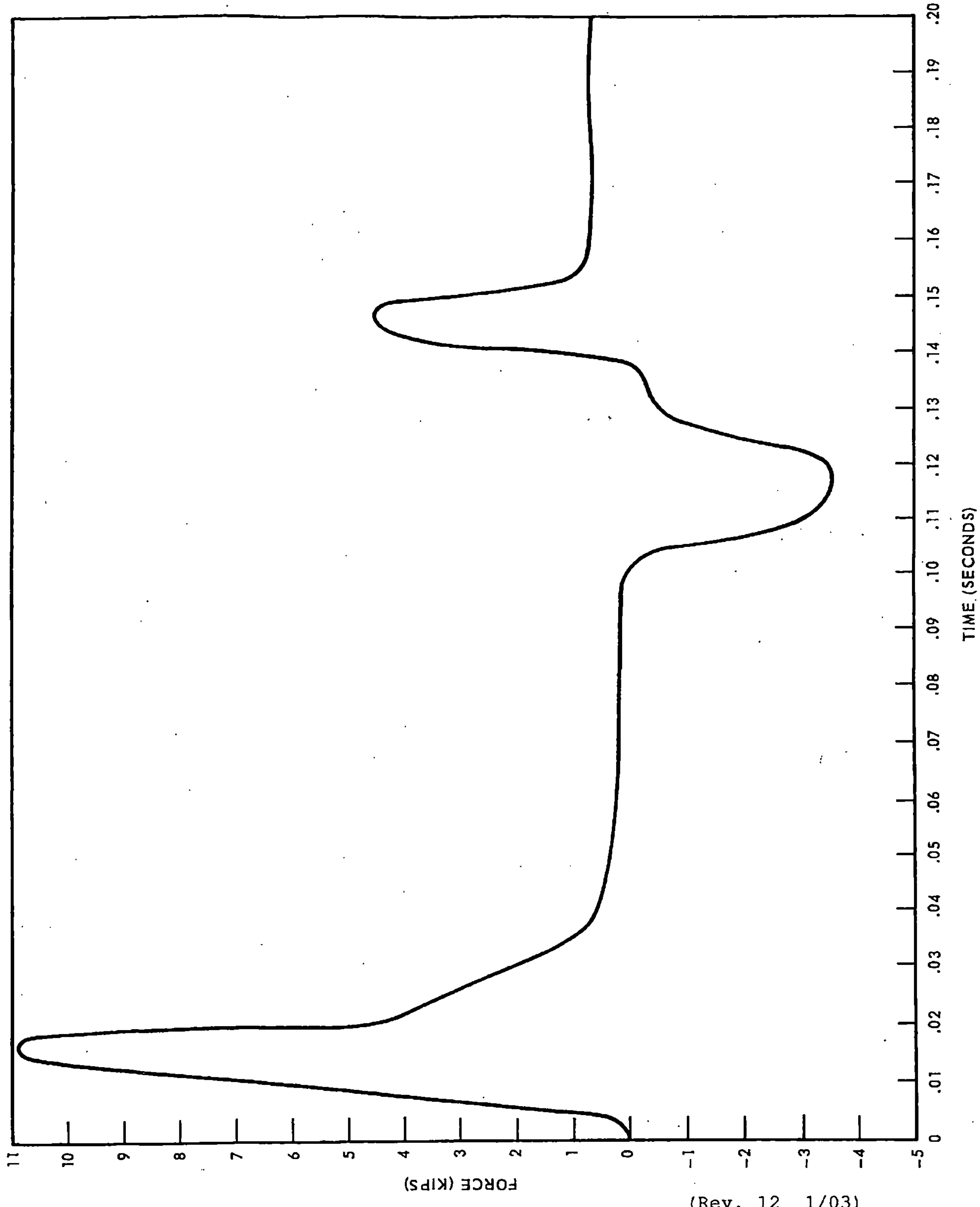
PERRY NUCLEAR POWER PLANT

Initial Cycle MSIV Closure with Flux Scram and Installed Safety/Relief Valve Capacity (Overpressurization Protection Analysis)

Figure 5.2-3



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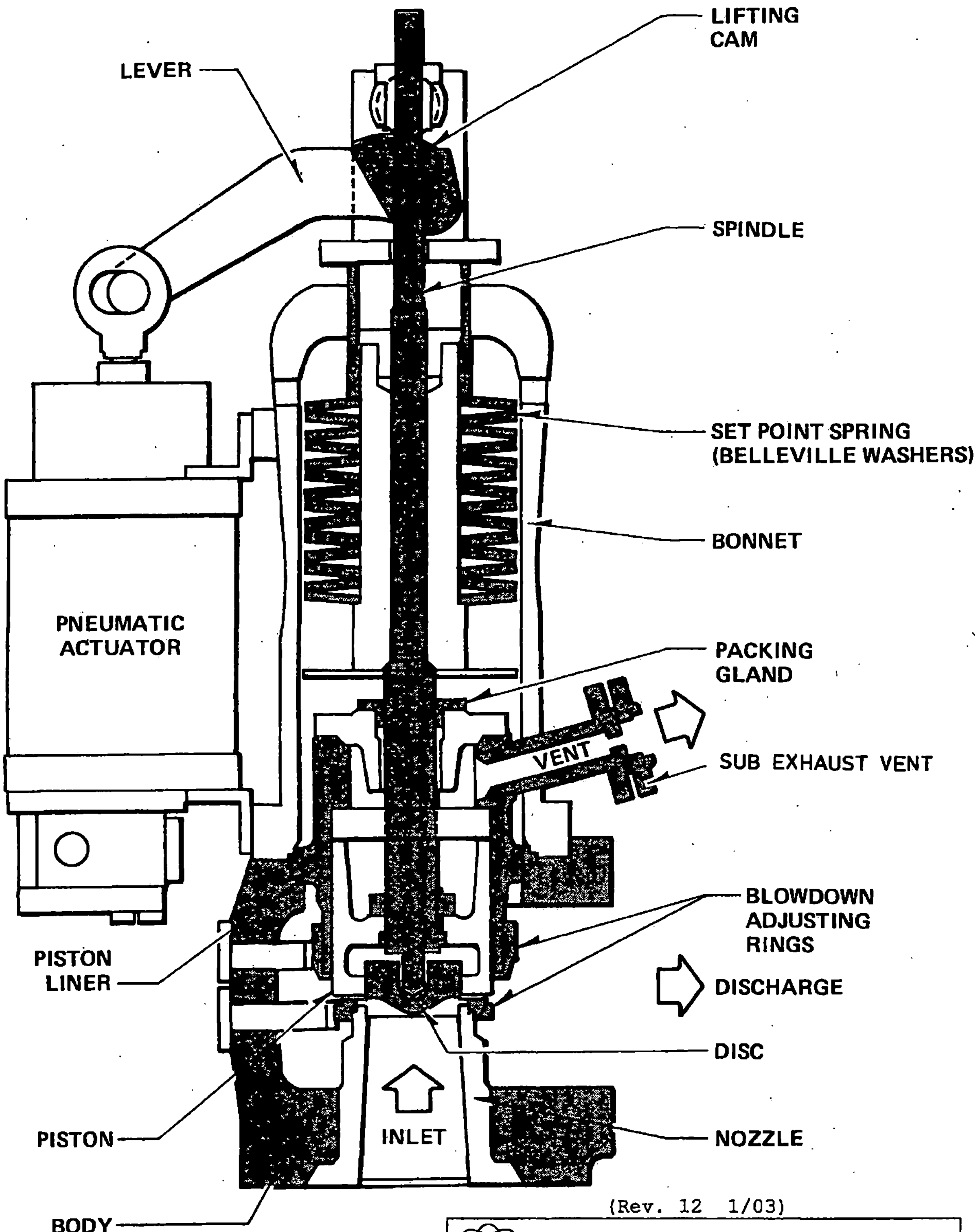
PERRY NUCLEAR POWER PLANT

Typical Relief Valve Opening
Transient Forcing Function

Figure 3.9-18



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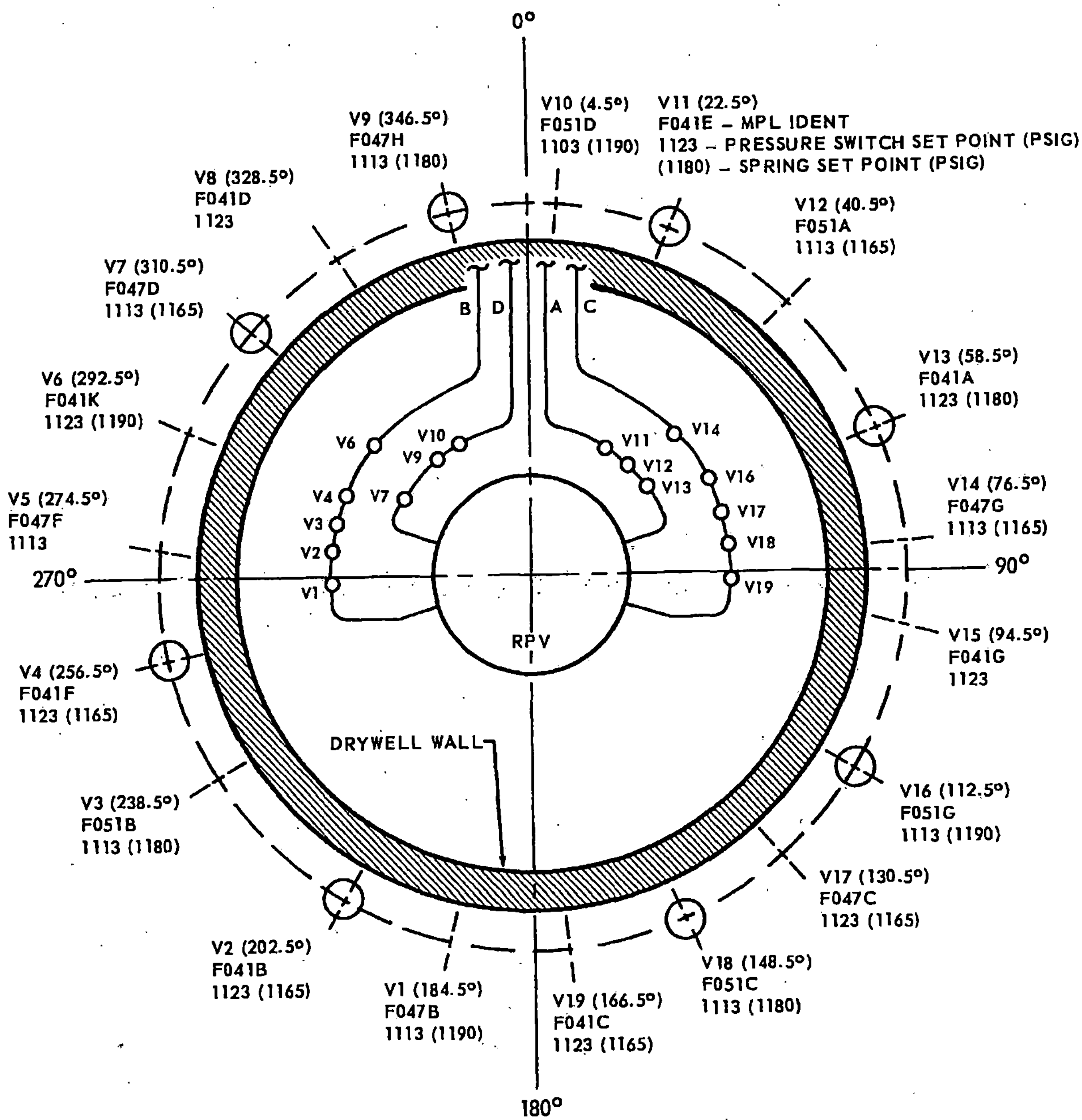
PERRY NUCLEAR POWER PLANT

Schematic of Safety Valve with Auxiliary Activating Device

Figure 5.2-12



LEGEND: ADS = ○

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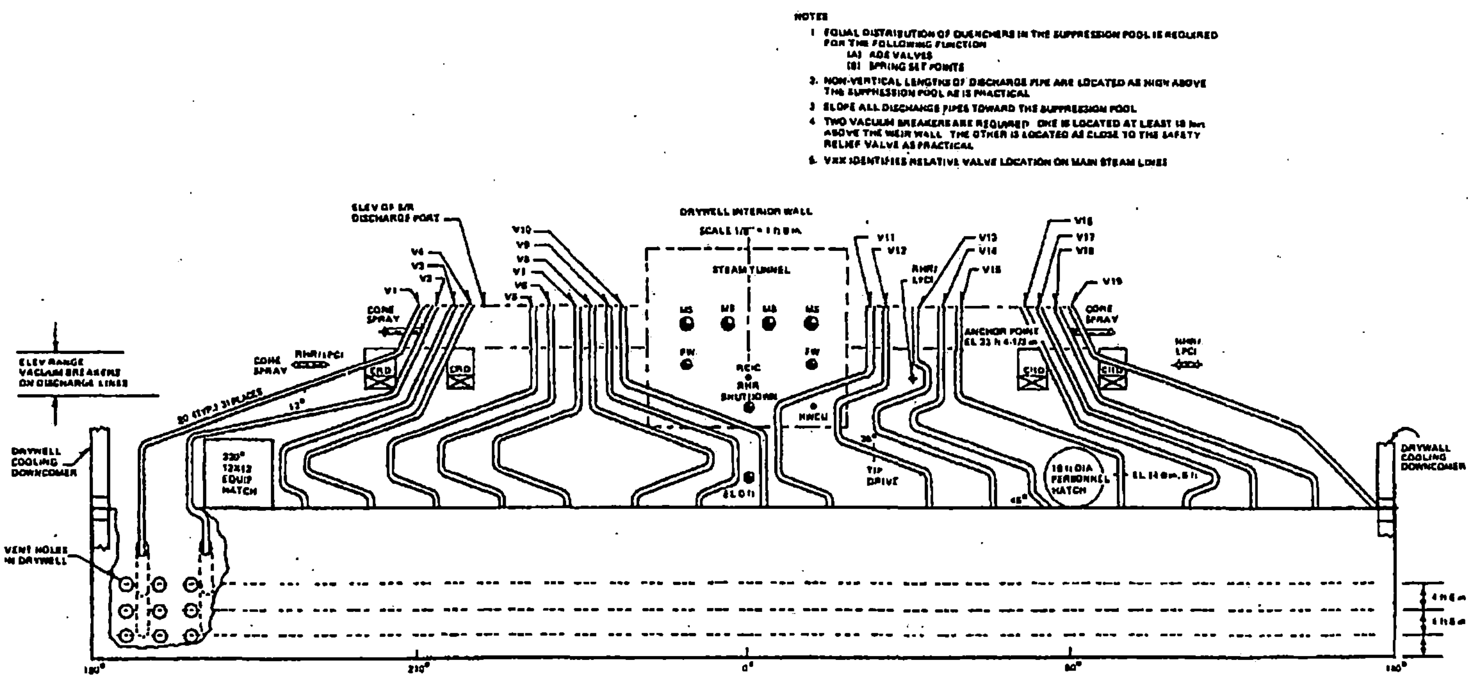
PERRY NUCLEAR POWER PLANT

Safety/Relief Valve
Discharge Locations

Figure 3BA-3



PERRY NUCLEAR POWER PLANT

Safety/Relief Valve Discharge
Piping Arrangement

Figure 3BA-4

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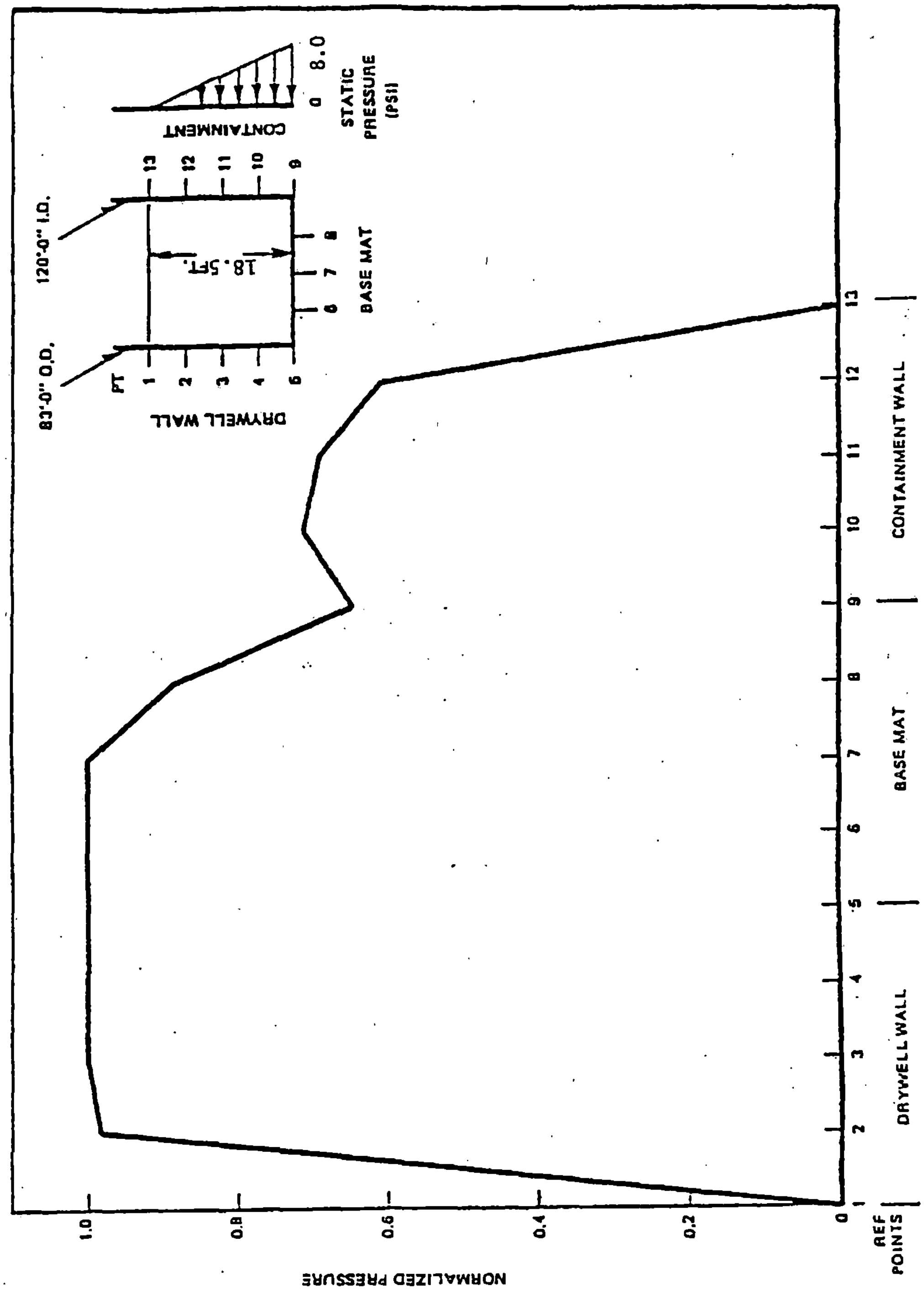

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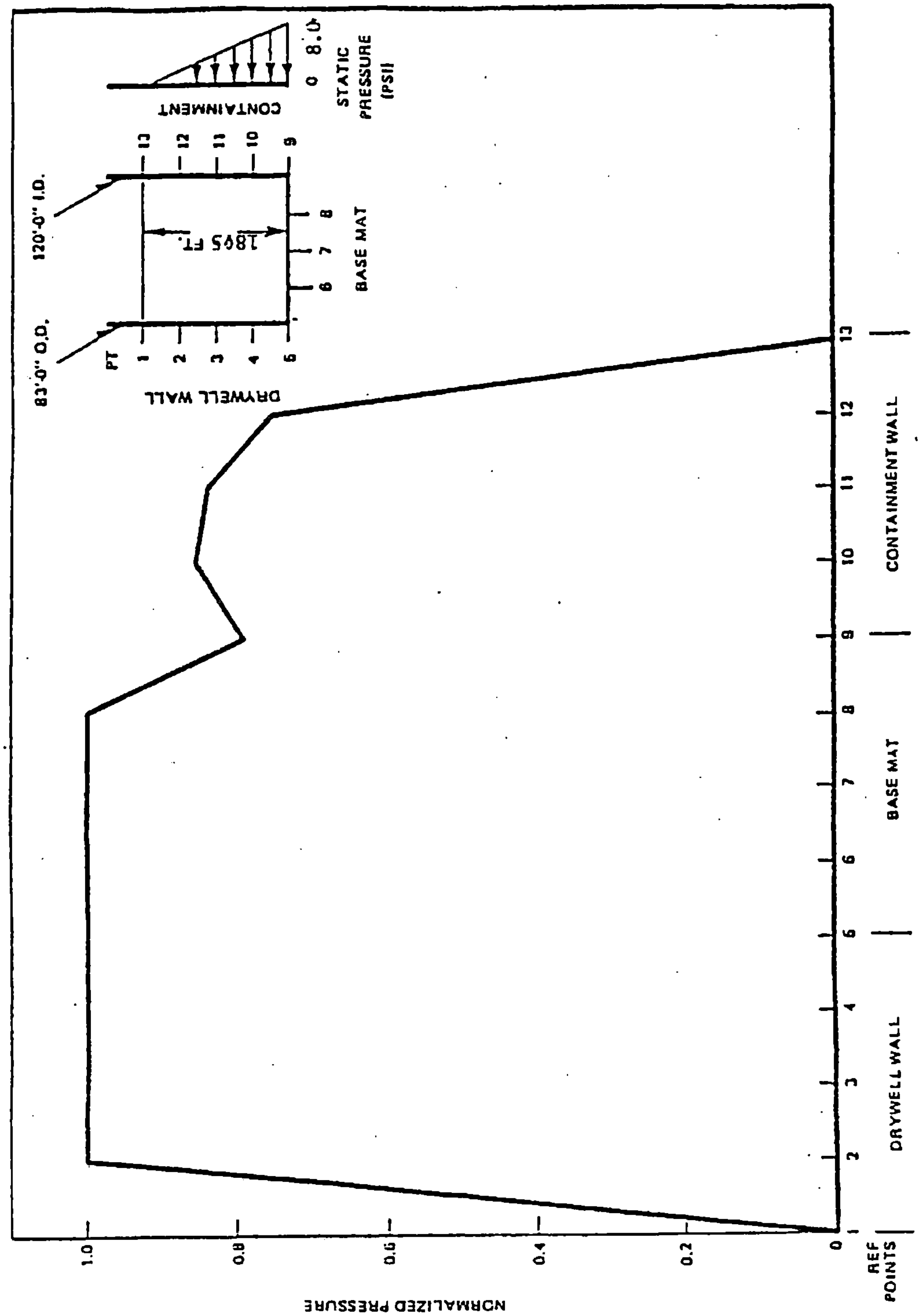
PERRY NUCLEAR POWER PLANT

One Safety/Relief Valve Normalized
Wall Pressure at 4.5°

Figure 3BA-5



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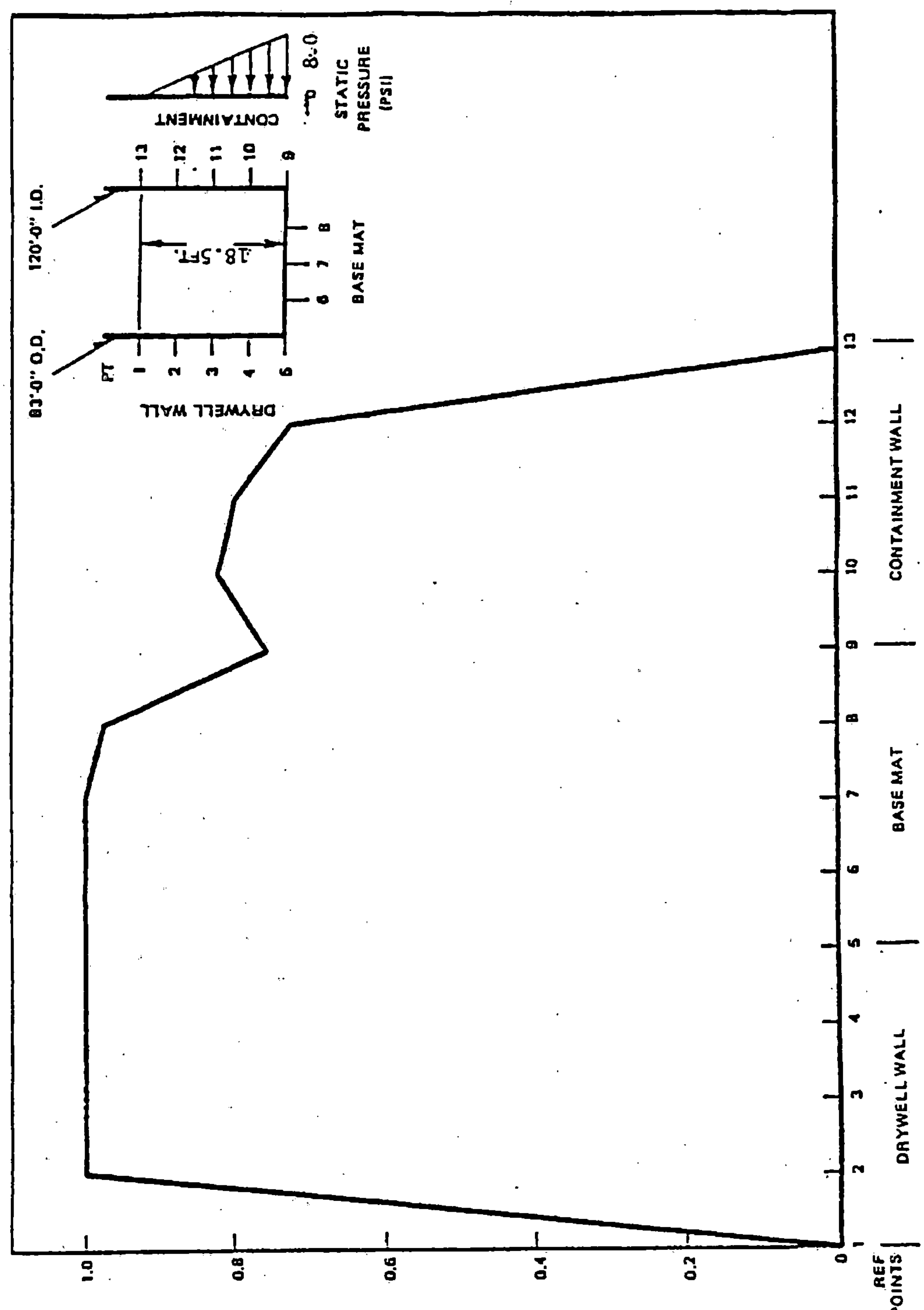
PERRY NUCLEAR POWER PLANT

Two Safety/Relief Valves Normalized
Wall Pressure at 355.5°

Figure 3BA-6



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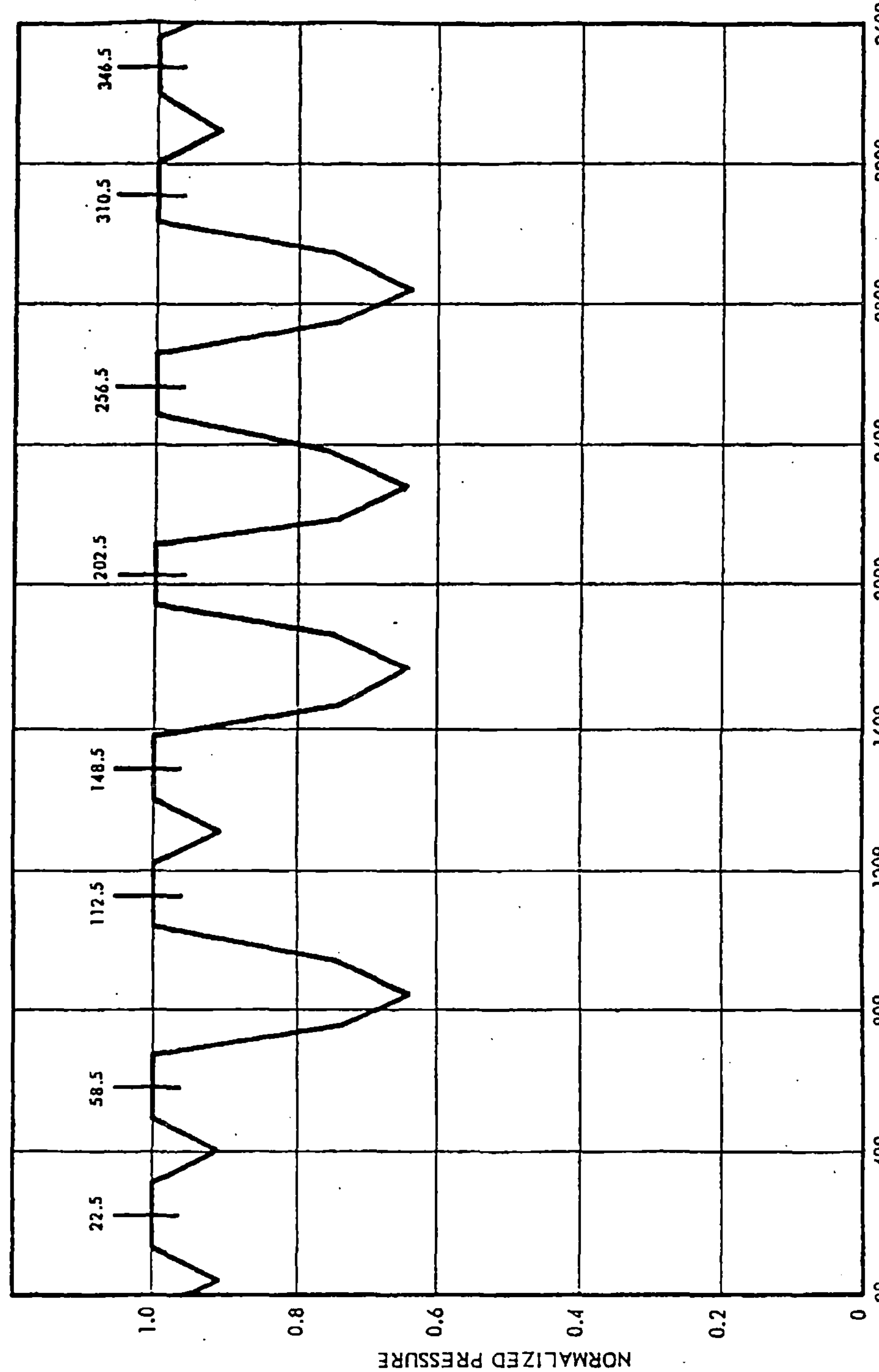
PERRY NUCLEAR POWER PLANT

Eight Safety/Relief Valves Normalized
Wall Pressure at
346.5° Azimuth

Figure 3BA-7



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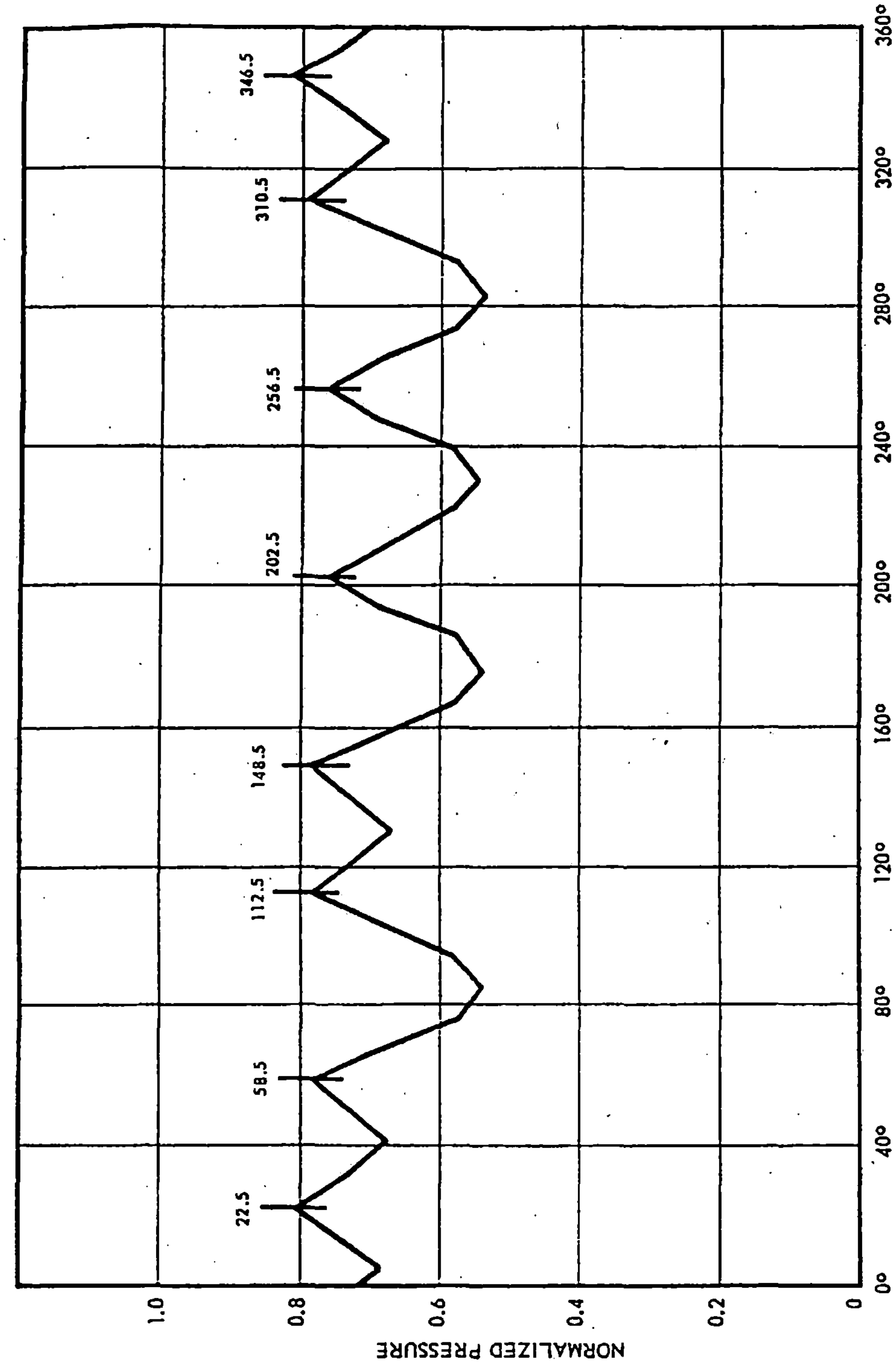
PERRY NUCLEAR POWER PLANT

Eight Safety/Relief Valves
Reference Point 4
(Circumferential Distribution)

Figure 3BA-8



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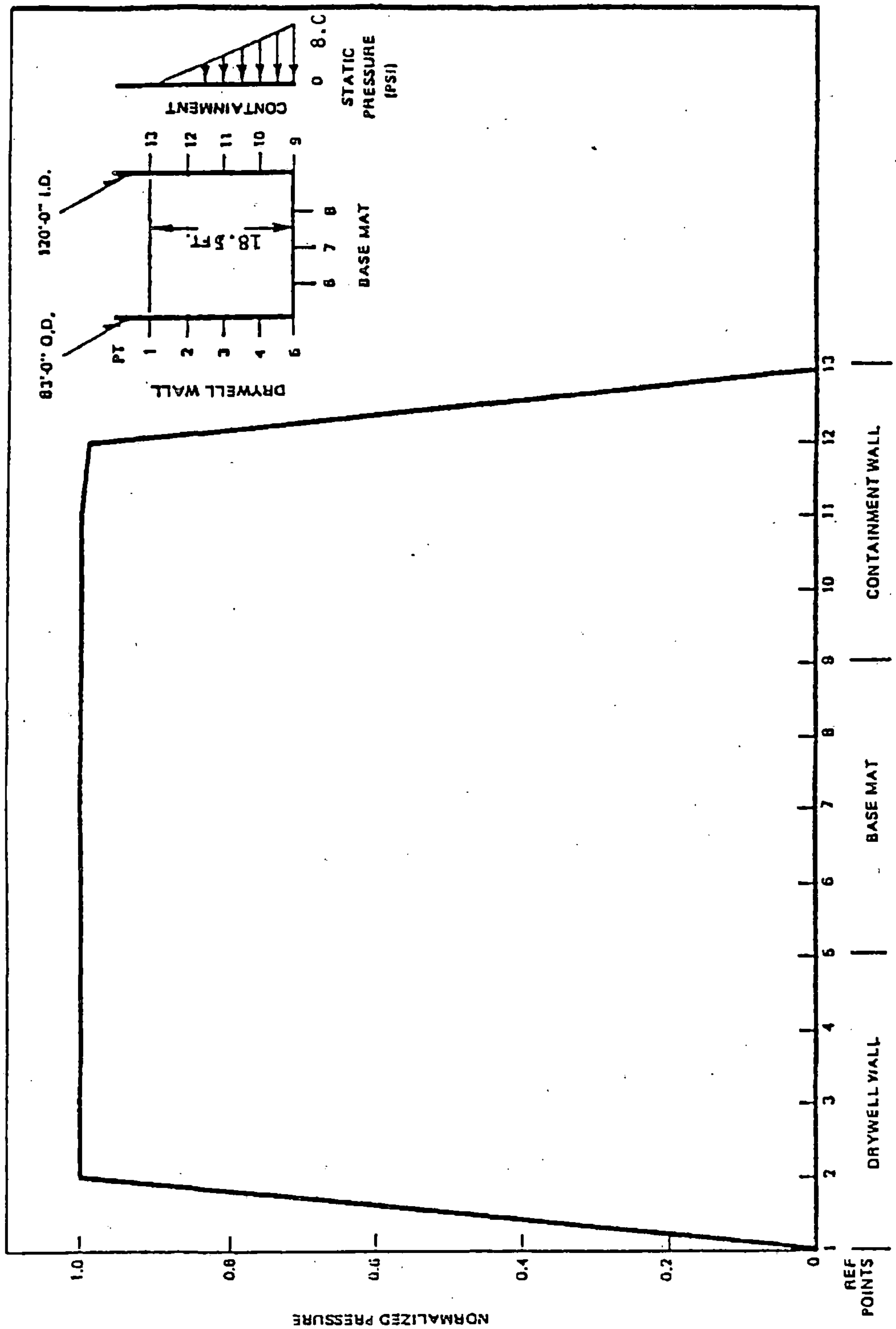
PERRY NUCLEAR POWER PLANT

Eight Safety/Relief Valves
Reference Point 10
(Circumferential Distribution)

Figure 3BA-9



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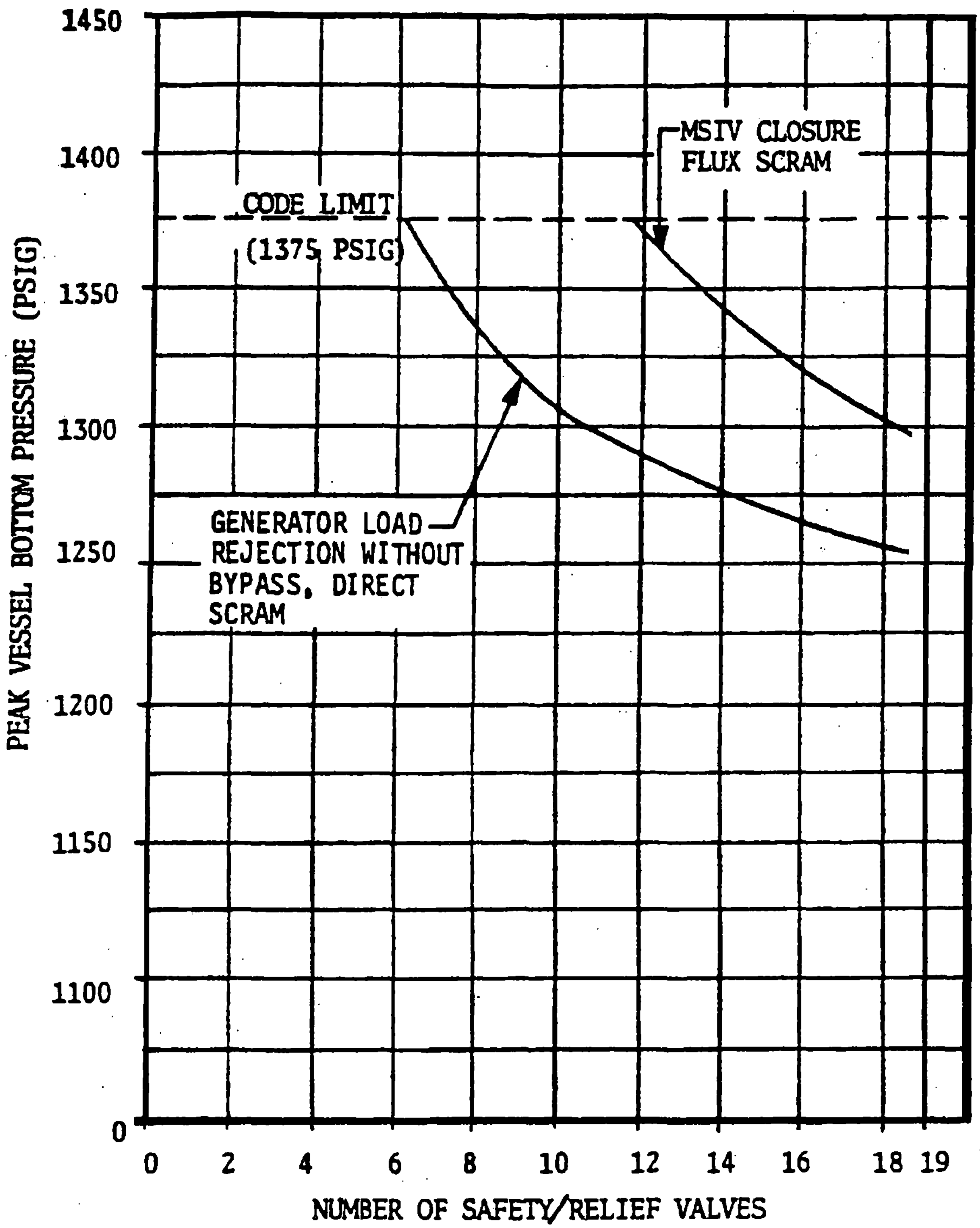
PERRY NUCLEAR POWER PLANT

Nineteen Safety/Relief Valves
Normalized Wall Pressure
At 130.5° Azimuth

Figure 3BA-10



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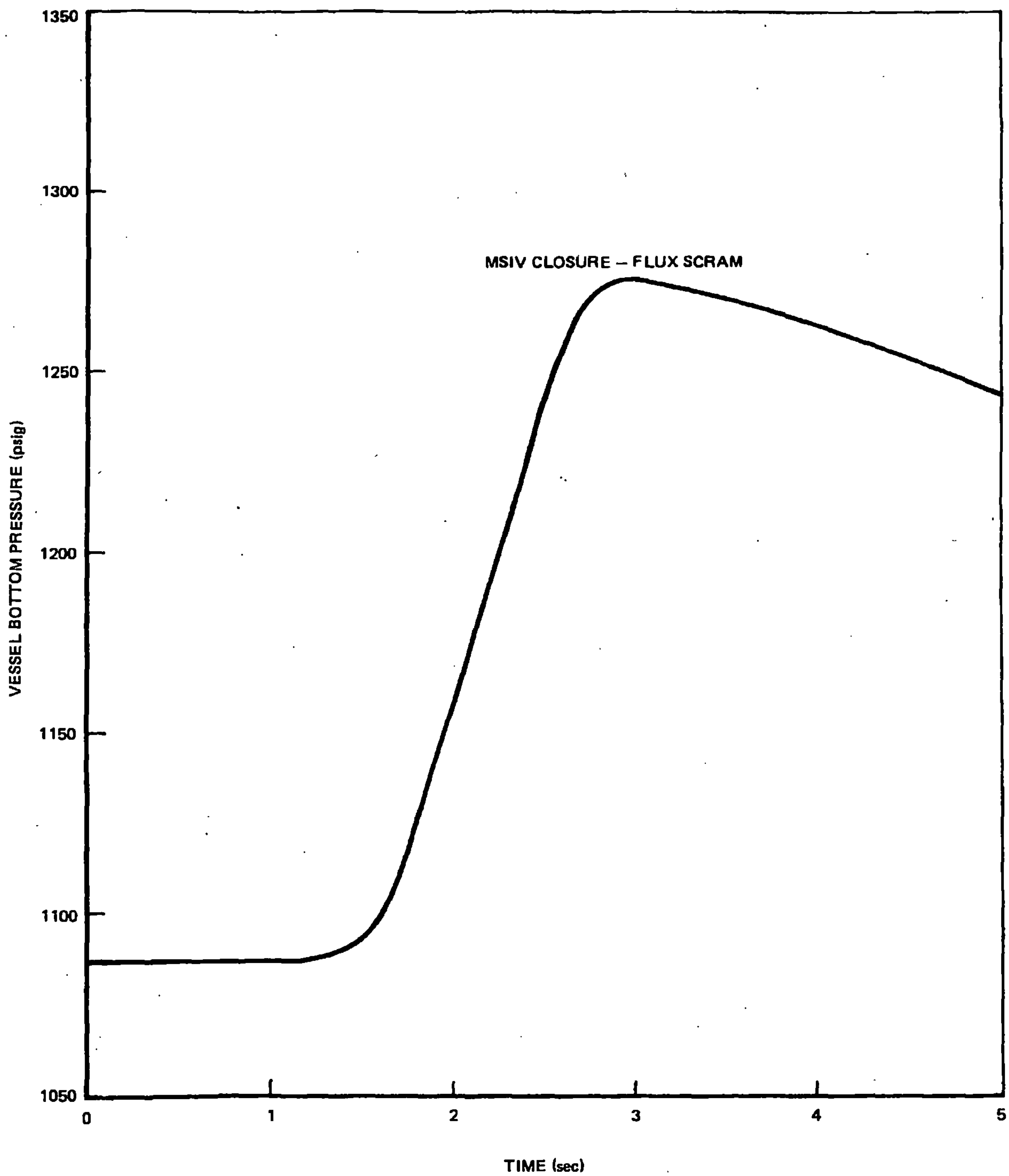
PERRY NUCLEAR POWER PLANT

Peak Vessel Pressure
Versus Safety/Relief Capacity

Figure 5.2-7



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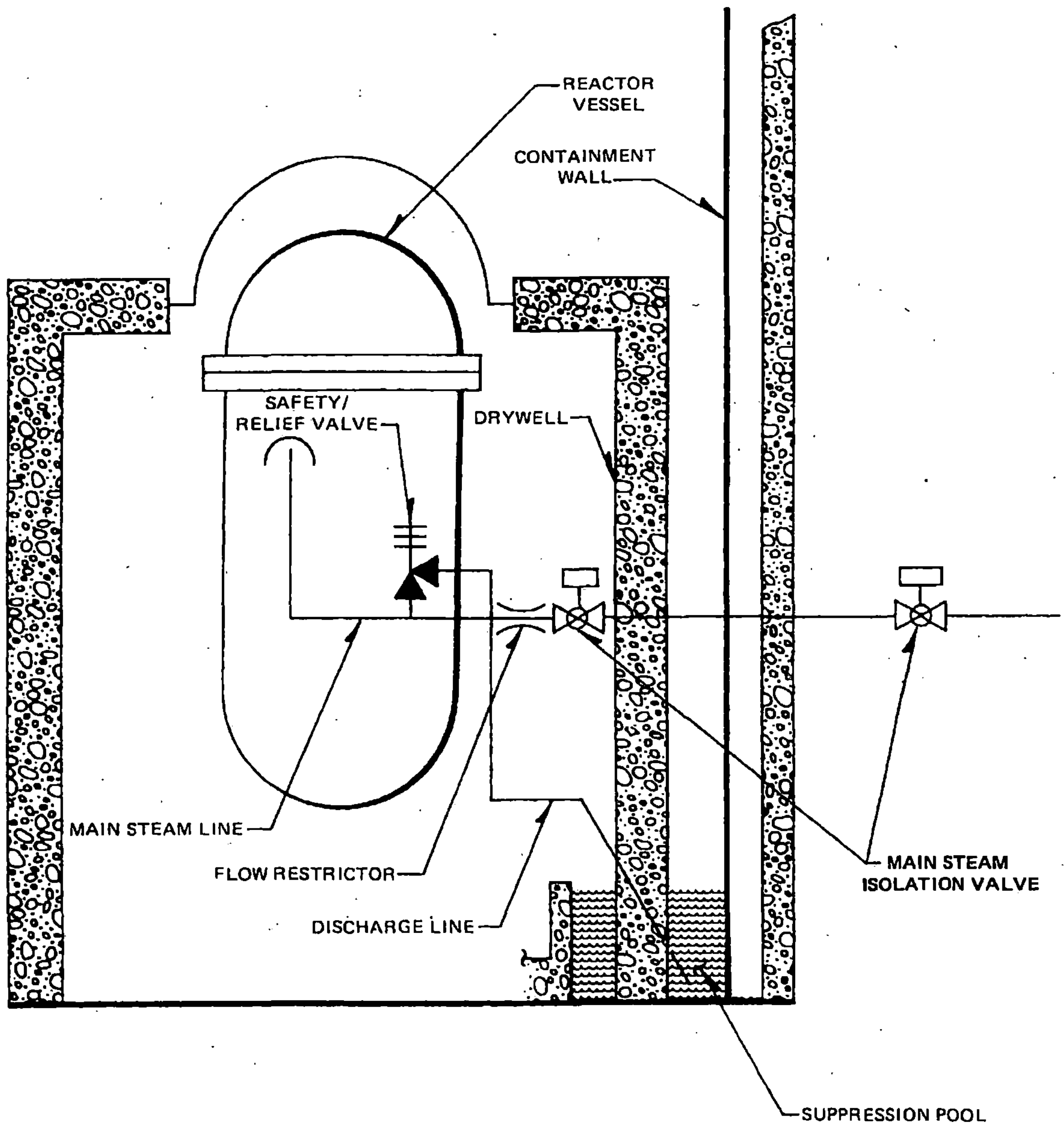
PERRY NUCLEAR POWER PLANT

Initial Cycle
Time Response for Pressurization

Figure 5.2-8



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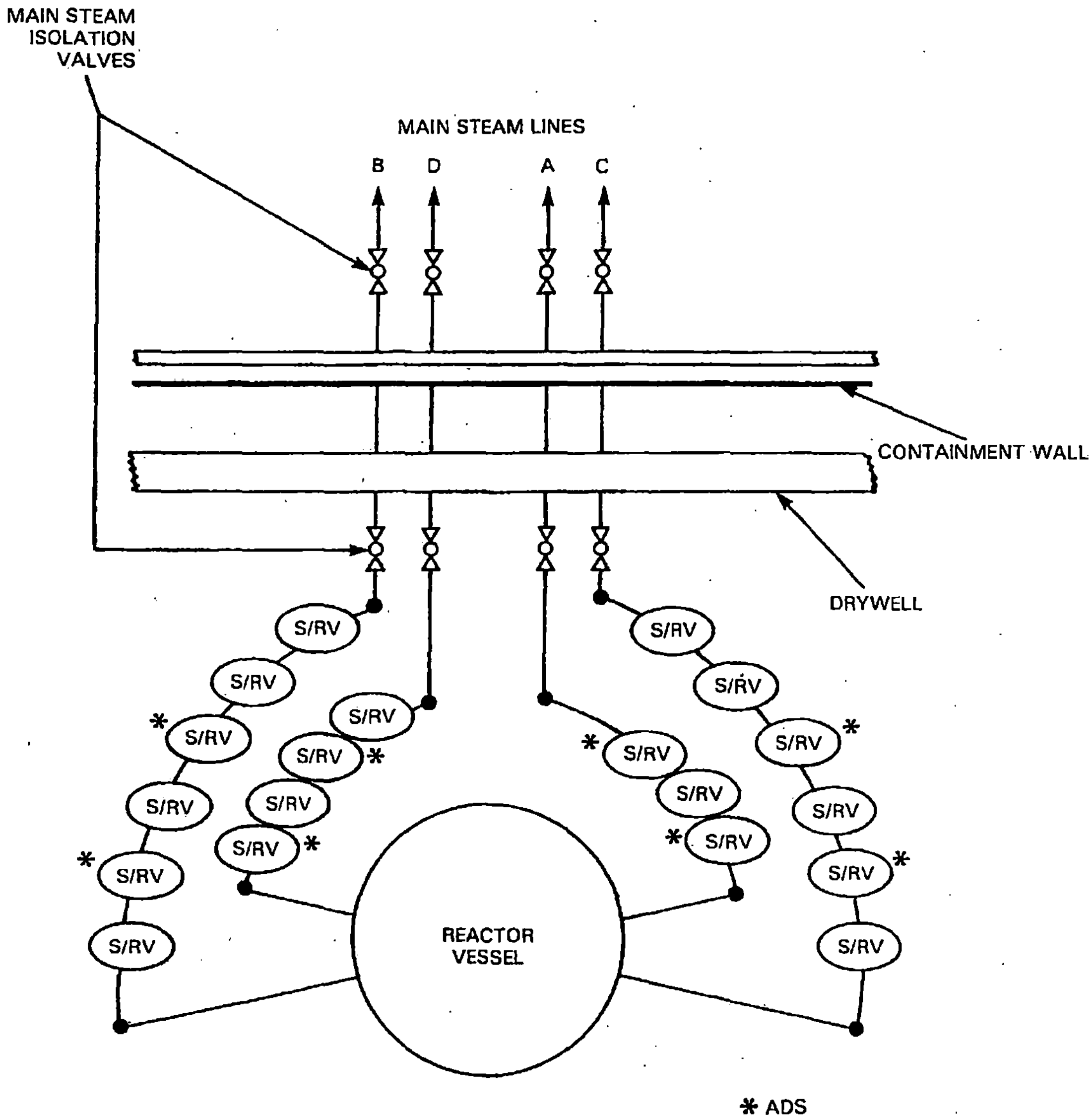
PERRY NUCLEAR POWER PLANT

Safety/Relief Valve Schematic
Elevation

Figure 5.2-9



SCHEMATIC PLAN

(Rev. 12 1/03)

PERRY NUCLEAR POWER PLANT

Safety/Relief Valve and
Steamline Schematic

Figure 5.2-10

d. This Code Case is not appropriate for analyzing the dynamic response of piping systems using supports designed to dissipate energy by yielding (i.e., the design of which is covered by Code Case N420).

e. This Code Case is not applicable to piping in which stress corrosion cracking has occurred unless a case-specific evaluation is made and is reviewed by the NRC staff.

5.2.2 OVERPRESSURIZATION PROTECTION

This section provides evaluation of the systems that protect the RCPB from overpressurization.

The analysis for the initial cycle, documented in this section, was performed at a core power of 3,729 MWt. This analysis resulted in a peak pressure at the bottom of the vessel of 1,276 psig. An updated analysis, discussed in <Section 15.2.4>, was performed for the uprated power case. This analysis resulted in a peak pressure at the bottom of the vessel of 1,295 psig. In both cases, the peak pressure is below the 1,375 psig ASME limit.

The overpressurization protection analysis for the current cycle reload core is discussed in <Appendix 15B>, Reload Safety Analysis.

5.2.2.1 <u>Design Bases</u>

Overpressure protection is provided in conformance with General Design Criteria 15 <Section 3.1>. Preoperational and startup instructions are discussed in <Chapter 14>.

5.2.2.1.1 Safety Design Bases

The nuclear pressure relief system has been designed to:

a. Prevent overpressurization of the nuclear system that could lead to the failure of the reactor coolant pressure boundary.

b. Provide automatic depressurization if small breaks in the nuclear system should occur with subsequent failure/improper operation of the high pressure core spray (HPCS) system, requiring operation of the low pressure coolant injection (LPCI) mode of residual heat removal (RHR) and the low pressure core spray (LPCS) systems to protect the fuel barrier.

c. Permit verification of its operability.

d. Withstand adverse combinations of loadings and forces resulting from normal, upset, emergency, or faulted conditions.

5.2.2.1.2 Power Generation Design Bases

The nuclear pressure relief system safety/relief valves have been designed to meet the following operating bases:

a. Discharge to the containment suppression pool.

b. Correctly reclose following operation so that maximum operational continuity is maintained.

5.2.2.1.3 Discussion

The ASME Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from overpressure due to upset conditions. The code allows a peak allowable pressure of 110 percent of

vessel design pressure under upset conditions. The code specifications for safety/relief valves require that the lowest set pressure is at or below vessel design pressure and that the highest set pressure is such that total accumulated pressure does not exceed 110 percent of the design pressure for upset conditions. The safety/relief valves are designed to open by either of two modes of operation: automatically using a pneumatic power actuator or by self-actuation in the spring lift mode.

The safety/relief valve setpoints are listed in <Table 5.2-2>. These setpoints satisfy the ASME Code, Section III, specifications for safety/relief valves.

The automatic depressurization capability of the nuclear system pressure relief system is evaluated in <Section 6.3> and <Section 7.3>.

The following detailed criteria are used in selection of the safety grade relief valves:

a. Must meet requirements of ASME Code, Section III.

b. Must qualify for 100 percent of nameplate capacity credit for the overpressure protection function.

c. Must meet other performance requirements such as response time, etc., as necessary to provide relief functions.

The safety/relief valve discharge piping is designed, installed and tested in accordance with the ASME Code, Section III.

5.2.2.1.4 Safety/Relief Valve Capacity

The safety/relief valve capacity of this plant is adequate to limit the primary system pressure, including transients, to the requirements of

the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels up to and including the Winter Addenda, 1972. The essential ASME requirements are all met by this analysis.

It is recognized that the protection of vessels in a nuclear power plant is dependent upon many protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices will not independently provide complete protection. The safety valve sizing evaluation assumes credit for operation of the scram protective system which may be tripped by either one of two sources (a direct or flux trip signal). The direct scram trip signal is derived from position switches mounted on the main steamline isolation valves or the turbine stop valves or from pressure switches mounted on the dump valve of the turbine control valve hydraulic actuation system. The position switches are actuated when the respective valves are closing and following 10 percent travel of full stroke. The pressure switches are actuated when a fast closure of the turbine control valves is initiated. Credit is taken for 50 percent of the total installed safety/relief valve capacity operating by the power operated mode as permitted by ASME Code, Section III.

Credit is also taken for the remaining safety/relief valve capacity which opens by the spring mode of operation direct from inlet pressure. The valve flow capacity and discharge coefficient were established through full scale and full flow tests.

The rated capacity of the safety/relief valves is sufficient to prevent a rise in pressure within the pressure vessel not exceeding 110 percent of the design pressure (1.10 x 1,250 psig = 1,375 psig) for the events defined in <Section 15.2> - Increase in Reactor Pressure.

Full account is taken of the pressure drop on both the inlet and discharge sides of the valves. All combination safety/relief valves discharge into the suppression pool through a discharge pipe from each

valve which is designed to achieve sonic flow conditions through the valve, thus precluding sonic conditions occurring in the discharge piping.

<Table 5.2-3> lists the systems which could initiate during the design basis overpressure event.

5.2.2.2 Design Evaluation

5.2.2.2.1 Method of Analysis

To design the pressure protection for the nuclear boiler system, extensive analytical models representing all essential dynamic characteristics of the system are simulated on a large computing facility. These models include the hydrodynamics of the flow loop, the reactor kinetics, the thermal characteristics of the fuel and its transfer of heat to the coolant, and all the principal controller features, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand. These are represented with all their principal nonlinear features in models that have evolved through extensive experience and favorable comparison of analysis with actual BWR test data.

A detailed description of this model is documented in licensing topical report NEDO-24154, "Qualification of the One Dimensional Core Transient Model for BWR" (Reference 1). Safety/relief valves are simulated in a nonlinear representation, and the model thereby allows full investigation of the various valve response times, valve capacities and actuation setpoints that are available in applicable hardware systems.

Typical valve characteristics as modeled are shown in <Figure 5.2-1> and <Figure 5.2-2> for the pneumatically activated relief and spring action safety modes of the dual purpose safety/relief valves. The associated bypass, turbine control valve, main steam isolation valve and reactor

recirculation pump trip due to high reactor pressure characteristics are also simulated in the model.

5.2.2.2.2 System Design

A parametric study was conducted to determine the required steam flow capacity of the safety/relief valves based on the assumptions that follow.

5.2.2.2.2.1 Operating Conditions

Operating conditions for the initial cycle performance were as follows:

a. Operating power is 3,729 MW_t (104.2 percent of nuclear boiler rated power).

b. Vessel dome pressure ≤1,045 psig.

c. Steam flow is 16.16 x 10^6 lb/hr (105 percent of nuclear boiler rated steam flow).

d. Nuclear characteristics: End-of-Cycle.

These conditions are the most severe because maximum stored energy exists at these conditions. At lower power conditions the transients would be less severe.

The operating conditions for reload cycle performance of the overpressurization analysis are specified in <Appendix 15B>, Reload Safety Analysis.

5.2.2.2.2.2 Transients

The overpressure protection system must accommodate the most severe pressurization transient. There are two major transients, the closure of all main steam line isolation valves and turbine generator trip with a coincident closure of the turbine steam bypass system valves that represent the most severe abnormal operational transients resulting in a nuclear system pressure rise. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirect derived scrams; therefore, it is used as the overpressure protection basis event and the results for the initial cycle are shown in <Figure 5.2-3>. <Table 5.2-4> lists the sequence of events for the main steam line isolation valve closure event with flux scram (performed for the initial cycle) with the installed safety/relief valve capacity.

The transient response and sequence of events for the current reload cycle are provided within <Appendix 15B>, Reload Safety Analysis.

5.2.2.2.2.3 Scram

The scram reactivity curve and control rod drive scram motion are illustrated by <Figure 5.2-4> and <Figure 5.2-5>, respectively. The initial cycle analysis used the second safety grade scram signal with initial reactor pressure at 1,045 psig. The ATWS recirculation pump trip on high reactor pressure was also included.

5.2.2.2.2.4 Safety/Relief Valve Transient Analysis Specification

These assumptions are:

a. Simulated valve groups

Pneumatically actuated relief mode - 4 groups

Spring action safety mode - 5 groups

b. Opening pressure setpoint (maximum safety limit)

Power actuated relief mode -	Group 1:	1,145 psig
	Group 2:	1,155 psig
	Group 3:	1,165 psig
	Group 4:	1,175 psig

Spring action safety mode -	Group 1:	1,175 psig
	Group 2:	1,185 psig
	Group 3:	1,195 psig
	Group 4:	1,205 psig
	Group 5:	1,215 psig

The valve groups used in the reload analyses are based upon the three groups specified in the Technical Specifications for each mode.

The above analyses input setpoints are assumed at a conservatively higher level above the nominal setpoints. This is to account for initial setpoint errors and any instrument setpoint drift that might occur during operation. Typically the assumed setpoints in the analysis are 2 to 4 percent above the nominal setpoints. Highly conservative safety/relief valve response characteristics are also assumed. Therefore, the analysis conservatively bounds all safety/relief operating conditions.

5.2.2.2.2.5 Safety/Relief Valve Capacity

Sizing of the safety/relief valve capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1,375 psig) in response to the reference transients.

Whenever system pressure increases to the relief pressure setpoint of a group of valves having the same setpoint, half of those valves are assumed to operate in the relief mode, opened by the pneumatic power actuation. When the system pressure increases to the valve spring set pressure of a group of valves, those valves not already considered open are assumed to begin opening and to reach full open at 103 percent of the valve spring set pressure. By this method, the total valve capacity can be determined.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety/Relief Valve Capacity

The required safety/relief valve capacity is determined by analyzing the pressure rise from a MSIV closure with flux scram transient. The plant is assumed to be operating at the turbine generator design conditions at a maximum vessel dome pressure of 1,045 psig which is the maximum steady-state operating pressure allowed by the Technical Specification. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. For the initial cycle analysis, the power actuated relief setpoints of the safety/relief valve are assumed to be in the range of 1,145 to 1,175 psig and the spring action setpoints to be in the range of 1,175 to 1,215 psig. The resulting peak pressure at the bottom of the vessel for the initial cycle is 1,276 psig. Therefore, the analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME code allowable pressure in the nuclear system (1,375 psig). <Figure 5.2-3>

shows curves produced by this analysis for the initial cycle. The sequence of events in <Table 5.2-4> assumed in this initial cycle analysis was investigated to meet code requirements and to evaluate the pressure relief system exclusively. The results of the overpressurization analysis for the current reload cycle are presented in <Appendix 15B>, Reload Safety Analysis. A curve showing vessel pressure versus valve capacity (number of valves) is shown in <Figure 5.2-7>. This curve is based on a sensitivity study for the BWR/6 design with a 231 inch vessel and shows the relationship between valves out-of-service and margin to the peak allowable ASME code pressure.

Under the General Requirements for Protection Against Overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, credit can be allowed for a scram from the reactor protection system. In addition, credit is also taken for the protective circuits which are indirectly derived when determining the required safety/relief valve capacity. The backup reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving dual purpose safety/relief valves. Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety/relief valve capacity of nuclear vessels under the provisions of the ASME code. The safety/relief valves are operated in a relief mode (pneumatically) at setpoints lower than those specified for the safety function. This ensures sufficient margin between anticipated relief mode closing pressures and valve spring forces for proper seating of the valves.

The time response of the vessel pressure to the MSIV transient with flux scram for the initial cycle is illustrated in <Figure 5.2-8>. This shows that the pressure at the vessel bottom exceeds 1,250 psig for less than five seconds. This is not long enough to transfer any appreciable

amount of heat into the vessel metal which was at a temperature well below 550°F at the start of the transient.

The peak pressure results in this overpressure analysis (and the overpressure analysis for the current reload cycle see <Appendix 15B>) bound all moderate frequency transients in <Chapter 15>.

5.2.2.2.3.2 Low-Low Set Relief Function

To assure that no more than one relief valve reopens following a reactor isolation event, two safety/relief valves are provided with lower opening and closing setpoints and four valves are provided with lower closing setpoints. These setpoints override the normal setpoints following the initial opening of the relief valves and act to hold open these valves longer, thus preventing more than a single valve from reopening subsequently. This system logic is referred to as the low-low set relief logic and functions to ensure that the containment design basis of one safety/relief valve operating on subsequent actuations is met.

The low-low set relief function is armed whenever any safety/relief valves are called upon to open in the relief mode by pressure instruments. Thus, the low-low set valves will not actuate during normal plant operation even though the reopening setpoints of one of the valves is in the normal operating pressure range. This arming method results in the low-low set safety/relief valves opening initially during an overpressure transient at the normal relief opening setpoint.

The lowest setpoint low-low set valve will cycle to remove decay heat. Since this valve will have a larger differential between its opening and closing set pressures than assumed for the normal relief function, the number of single safety/relief valve actuations during isolation events will be reduced. <Table 5.2-2> shows the opening and closing setpoints for the low-low set safety/relief valves.

The assumptions used in the calculation of the pressure transient after the initial opening of the relief valves are:

a. The transient event is a three-second closure of all MSIV's with position scram.

b. Nominal relief valve setpoints are used.

c. The maximum expected relief capacity is used.

d. Relief valve opening and closing response times shown in <Figure 5.2-6a> are used.

e. The closing setpoint of the relief valves is 100 psi below the opening setpoint.

f. ANS + 20 percent decay heat at infinite exposure is used.

The results using the above assumptions are shown in the reactor vessel pressure transient curve shown in <Figure 5.2-6b>. Despite the conservative input assumptions which tend to maximize the pressure peaks on subsequent actuations, there is a 65 psi margin for avoiding the second opening of more than one valve. The system is single failure proof since a failure of one of the low-low set valves still gives a 42 psi margin for avoiding multiple valve actuations.

The safety/relief valves are balanced type, spring loaded safety valves provided with an auxiliary pneumatically actuated device which allows opening of the valve even when pressure is less than the safety-set pressure of the valve. Previous undesirable performance on operating BWRs was associated principally with multiple stage pilot operated safety/relief valves. These newer, pneumatically operated safety valves employ significantly fewer moving parts wetted by the steam and are, therefore, considered an improvement of the previously used valves.

5.2.2.2.3.3 Pressure Drop in Inlet and Discharge

Pressure drop in the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures. Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent backpressure on each safety/relief valve from exceeding 40 percent of the valve inlet pressure; this assures choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each safety/relief valve has its own separate discharge line.

5.2.2.3 Piping and Instrument Diagrams

<Figure 5.2-9> shows the schematic location of safety/relief valves for:

a. The reactor coolant system.

b. The primary side of the auxiliary or emergency systems interconnected with the primary system.

c. Any blowdown or heat dissipation system connected to the discharge side of the safety/relief valves.

The schematic arrangements of the safety/relief valves are shown in <Figure 5.2-10>.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The nuclear pressure relief system consists of safety/relief valves located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system.

The safety/relief valves provides the following protection functions:

a. Overpressure relief operation. The valves open automatically to limit a pressure rise.

b. Overpressure safety operation. The valves function as safety valves and open (self-actuated operation if not already automatically opened for relief operation) to prevent nuclear system overpressurization.

c. Depressurization operation. The ADS valves open automatically as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from <Figure 5.2-10>.

<Chapter 15> discusses the events which are expected to activate the primary system safety/relief valves. The section also summarizes the number of valves expected to operate during the initial blowdown of the valves and the expected duration of this first blowdown. For several of the events it is expected that the lowest set safety/relief (pressure or power set) valve will reopen and reclose as generated heat drops into the decay heat characteristics. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the decay heat drops off, and until such time as the RHR system can dissipate this heat. Remote-manual actuation of the valves from the control room is recommended to minimize the total number of these discharges, with the intent of achieving extended valve seat life.

A schematic of the safety/relief valve is shown in <Figure 5.2-12>. It is opened by either of two modes of operation:

a. The spring mode which consists of direct action of the steam pressure against a spring loaded disk that will pop open when the valve inlet pressure force exceeds the spring force.

b. The power actuated mode which consists of using an auxiliary actuating device consisting of a pneumatic piston/cylinder and mechanical linkage assembly which opens the valve by overcoming the spring force (even with valve inlet pressure equal to zero psig).

The pneumatic operator is arranged so that a malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressure.

For overpressure safety/relief valve operation (self-actuated or spring lift mode), the spring load establishes the safety valve opening setpoint pressure and is set to open at setpoints designated in <Table 5.2-2>. In accordance with the ASME code, the full lift of this mode of operation is attained at a pressure no greater than 3 percent above the setpoint.

The safety function of the safety/relief valve is a backup to the relief function described below. The spring-loaded valves are designed and constructed in accordance with ASME III, NB 7640 as safety valves with auxiliary actuating devices.

For overpressure relief valve operation (power actuated mode), each valve is provided with a pressure sensing device which operates at the setpoints designated in <Table 5.2-2>. When the set pressure is reached, it operates a solenoid air valve which in turn actuates the pneumatic piston/cylinder and linkage assembly to open the valve.

When the piston is actuated, the delay time, maximum elapsed time between receiving the overpressure signal at the valve actuator and the actual start of valve motion, will not exceed 0.1 seconds. The maximum elapsed time between signal to actuator and full open position of valve will not exceed 0.25 seconds.

The safety/relief valves can be operated in the pneumatically actuated mode by remote-manual controls from the main control room.

Actuation of either solenoid A or solenoid B on the safety/relief valve will cause the safety/relief valve to open; hence, there is no single failure of a logic component or safety/relief valve solenoid valve which would result in failure of the safety/relief valve to open. The trip units for each safety/relief valve within each division are in series, and failure of one of the transmitters will not cause the safety/relief valves to open. Each safety/relief valve is provided with its own pneumatic accumulator and inlet check valve. The accumulator capacity is sufficient to provide one safety/relief valve actuation, all that is required for overpressure protection. Subsequent actuations for an overpressure event can be spring actuations to limit reactor pressure to acceptable levels.

The safety/relief valves are designed to operate to the extent required for overpressure protection in the following accident environments:

a. A temperature of 330°F for three hours at a drywell pressure ≤30 psig.

b. A temperature of 310°F for an additional three hour period at a drywell pressure ≤15 psig.

c. A temperature of 250°F for an additional 18 hour period at 15 psig.

d. A temperature drop of 250°F to 100°F at 15 psig from one day to 100 days. The valve must remain operable for the initial two days and be held either open or closed for the remaining 98 of the 100 days.

The automatic depressurization system (ADS) uses selected safety/relief valves for depressurization of the reactor as described in <Section 6.3>. Each of the safety/relief valves used for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators assure that the valves can be held open following failure of the air supply to the accumulators. They are sized to be capable of opening the valves and holding them open against the maximum drywell pressure of 30 psig. The accumulator capacity is sufficient for each ADS valve to provide two actuations against 70 percent of maximum drywell pressure. The ADS accumulators are recharged as described in <Section 6.8.1>.

Each safety/relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The safety/relief valve discharge lines are classified as Quality Group C and Seismic Category I. Safety/relief valve discharge line piping from the safety/relief valve to the suppression pool consists of two parts: the first is attached at one end to the safety/relief valve and attached at its other end to a pipe anchor. The main steam piping, including this portion of the safety/relief valve discharge piping, is analyzed as a complete system. The second part extends from the anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system.

As a part of the startup testing of the main steam lines, movement of the safety/relief valve discharge lines was monitored.

The safety/relief valve discharge piping is designed to limit valve outlet pressure to 40 percent of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, two vacuum relief valves are provided on each safety/relief valve discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. The safety/relief valves are located on the main steam line piping rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steam lines are more accessible during a shutdown for valve maintenance.

The nuclear pressure relief system automatically depressurizes the nuclear system sufficiently to permit the RHR and LPCS systems to operate as a backup for the high pressure core spray (HPCS) system. Further descriptions of the operation of the automatic depressurization feature are found in <Section 6.3> and <Section 7.3.1>.

5.2.2.4.2 Design Parameters

The specified operating transients for components within the RCPB are given in <Section 3.9>. Refer to <Section 3.7> for discussion of the input criteria for design of Seismic Category I structures, systems and components.

The design requirements established to protect the principal components of the reactor coolant system against environmental effects are discussed in <Section 3.11>.

5.2.2.4.2.1 Safety/Relief Valve

The discharge area of the valve is 18.429 sq inches and the coefficient of discharge K_D is equal to 0.873 ($K = 0.9\ K_D$).

The design pressure and temperature of the valve inlet and outlet are 1,375 psig at 585°F and 625 psig at 500°F, respectively.

The valves have been designed to achieve the maximum practical number of actuations consistent with state-of-the-art technology.

5.2.2.5 Mounting of Pressure Relief Devices

The pressure relief devices are located on the main steam piping header. The mounting consists of a special, contour nozzle and an over-sized flange connection. This provides a high integrity connection that withstands the thrust, bending and torsional loadings which the main steam pipe and relief valve discharge pipe are subjected to. This includes:

a. Thermal expansion effects of the connecting piping.

b. Dynamic effects of the piping due to SSE.

c. Reactions due to transient unbalanced wave forces exerted on the safety/relief valves during the first few seconds after the valve is opened and prior to the time steady-state flow has been established; with steady-state flow, the dynamic flow reaction forces will be self-equilibrated by the valve discharge piping.

d. Dynamic effects of the piping and branch connection due to the turbine stop valve closure.

In no case are allowable valve flange loads exceeded nor does the stress at any point in the piping exceed code allowables for any specified combination of loads. The design criteria and analysis methods for considering loads due to SRV discharge are contained in <Section 3.9.3>.

5.2.2.6 Applicable Codes and Classification

The vessel overpressure protection system is designed to satisfy the requirements of Section III of the ASME Boiler and Pressure Vessel Code. The general requirements of Section III of the code for protection against overpressure recognize that reactor vessel overpressure protection is one function of the reactor protective systems and allow the integration of pressure relief devices with the protective systems of the nuclear reactor. Hence, credit is taken for the scram protective system as a complementary pressure protection device. The NRC has also adopted the ASME codes as part of their requirements in <10 CFR 50.55a>.

5.2.2.7 Material Specification

Material specifications of pressure retaining components of safety/relief valves are reported in <Table 5.2-5>.

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is listed in Table 1 of <Figure 5.1-3 (3)>.

5.2.2.9 System Reliability

The system is designed to satisfy the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Therefore, it has high reliability. The consequences of failure are discussed in <Section 15.1.4> and <Section 15.6.1>.

5.2.2.10 Testing and Inspection

The safety/relief valves are tested at vendor's shop in accordance with quality control procedures to detect defects and to prove operability prior to installation. The following tests are conducted:

a. Hydrostatic test at specified test conditions.

b. Pneumatic seat leakage test at 90 percent of set pressure with maximum permitted leakage of 30 bubbles per minute emitting from a 0.250-in. diameter hole submerged 1/2 inch below a water surface or an equivalent test using an approved test medium.

c. Set pressure test: valve pressurized with saturated steam, with the pressure rising to the valve set pressure. Valve must open at nameplate set pressure ±3 percent. As left, tolerance is ±1 percent of set pressure.

d. Response time test: each safety/relief valve tested to demonstrate acceptable response time.

The valves are installed as received from the factory. The GE equipment specification requires certification from the valve manufacturer that design and performance requirements have been met. This includes capacity and blowdown requirements. The setpoints are adjusted, verified, and indicated on the valves by the vendor. Specified manual actuation relief mode of each safety/relief valve is verified during the startup test program.

A minimum of 20 percent of the installed valves shall be removed for testing every refueling outage, with the maximum number of years for the testing of all valves not to exceed that specified in the PNPP ASME Code of record. Removed valves shall be inspected and tested as follows:

a. Set pressure test: Verify set pressure of the removed valves during refueling outages. Verify opening and closing times by using the pneumatic power actuator unless relief has been granted. Verify that valve mainseat leakage is within acceptable limits.

b. Inspection: Inspect all external surfaces and parts; disassemble and inspect internal surfaces and parts for wear/damage/erosion. Replace all damaged or worn parts and gaskets/seals as necessary due to inspections results. Lubricate valves and relap valve seats if inspection or testing necessitates. Retest all valves disassembled and make appropriate adjustments prior to use.

Valve operability is verified during the preoperational test program as discussed in <Chapter 14>. See <Figure 5.2-12> for a schematic cross section of the valve.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

<Table 5.2-5> lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 PWR Reactor Coolant Chemistry

This section is not applicable to PNPP.

The MOV limit switch settings are determined and set as required per maintenance and diagnostic test instructions to assure proper open and closing operations, torque switch bypass features, and stroke times consistent with the Tech Spec requirements.

Inservice inspection of the RCPB is discussed in <Section 5.2.4>.

5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Safety Design Bases

a. Overpressure protection has been provided at isolatable portions of RCPB systems in accordance with the requirements set forth in the ASME Code, Section III for Class 1, 2 and 3 components. <Section 5.2.2> discusses RCPB safety/relief valves.

b. The valves are designed in accordance with the requirements listed in <Table 3.2-1>.

c. The design loading, design procedure and acceptability criteria are described in <Section 3.9>.

d. The design and installation details for the mounting of pressure relief devices are described in <Section 3.9>.

5.4.13.2 Description

Safety or pressure relief valves are designed and constructed in accordance with the same code class as that of the line valves in the system.

5.4.13.3 Safety Evaluation

The use of pressure relieving devices will assure that overpressure will not exceed 10 percent above the design pressure of the system. The number of pressure relieving devices on a system or portion of a system has been determined on this basis.

In accordance with ASME code requirements, all safety valves are constructed so that failure of any part cannot obstruct the free discharge of steam or water from the valve.

5.4.13.4 Inspection and Testing

The valves are inspected and tested in accordance with the requirements of the applicable ASME code. In addition, shop performance tests are performed on the valves to ensure their operability in accordance with specification requirements.

No provisions are to be made for inline testing of spring loaded safety/relief valves. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer and further examinations would necessitate removal of the component. Leakage past seating surfaces during normal plant operation is detected by visual examinations or by measuring an increase in discharge line temperature.

5.4.14 COMPONENT SUPPORTS

Support elements are provided for those components included in the RCPB and the connected systems.

15.6 DECREASE IN REACTOR COOLANT INVENTORY

15.6.1 INADVERTENT SAFETY/RELIEF VALVE OPENING

This event is discussed and analyzed in <Section 15.1.4>.

15.6.2 INSTRUMENT LINE PIPE BREAK

This event involves the postulation of a small steam or liquid line pipe break inside containment. In order to bound the event, it is assumed that a small instrument line, instantaneously and circumferentially, breaks at a location where it may not be isolated and where immediate detection is not automatic or apparent.

Obviously, this event is far less limiting than the postulated events in <Section 15.6.4> "Steam System Piping Break Outside Containment", <Section 15.6.5> "Loss-of-Coolant Accidents - Inside Containment, and <Section 15.6.6> "Feedwater Line Break - Outside Containment". Accordingly, this accident was not reanalyzed for the current reload as it has been determined to be less limiting and bounded by the analyzed accidents described in the previously listed sections.

This postulated event represents the envelope evaluation for small line failure inside containment, relative to sensitivity to detection.

15.6.2.1 Identification of Causes and Frequency Classification

15.6.2.1.1 Identification of Causes

There is no specific event or circumstance identified which results in the failure of an instrument line. These lines are designed to high quality, engineering standards, seismic, and environmental requirements. However, for the purpose of evaluating the consequences of a small line rupture, the failure of an instrument line is assumed to occur.

TABLE 15.1-5

SEQUENCE OF EVENTS FOR INADVERTENT SAFETY/RELIEF VALVE OPENING

Time-sec	Event
0	Initiate opening of 1 safety/relief valve.
0.5 (est.)	Relief flow reaches full flow.
15 (est.)	System establishes new steady-state operation.

In this region, examination of 100% of the accessible circumferential and longitudinal pipe welds, or a number of these piping welds as determined using the Risk-Informed process outlined in EPRI Topical Report 1006937, will be performed during each inspection interval. Additionally, examination of the accessible welds attaching penetration head fittings to main steam and feedwater process piping will be performed during each inspection interval.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

5.2.5.1 Leakage Detection Methods

The nuclear boiler leak detection system consists of temperature, pressure, flow, airborne gaseous and particulate fission product sensors, and process radiation sensors with associated instrumentation used to indicate leakage from the reactor coolant pressure boundary and, in certain cases, to provide alarms or to initiate signals used for automatic closure of isolation valves to shut off leakage external to the primary containment. The system is designed to be in conformance with NRC <Regulatory Guide 1.45> and reference IEEE Standard 279.

Abnormal leakage from the following systems within the primary containment and within selected areas of the plant outside the primary containment is detected, indicated, and in certain cases alarmed or isolated:

a. Main steam lines.

b. Reactor Water Cleanup (RWCU) System.

c. Residual Heat Removal (RHR) System.

d. Reactor Core Isolation Cooling (RCIC) System.

e. Feedwater System.

f. High Pressure Core Spray (HPCS).

g. Coolant Systems within the primary containment.

h. Low Pressure Core Spray (LPCS).

i. Reactor pressure vessel.

j. Miscellaneous systems.

Leak detection methods used to obtain conformance with <Regulatory Guide 1.45> differ for plant areas inside the drywell as compared to these areas located outside the drywell. These areas are considered separately.

5.2.5.1.1 Detection of Leakage within the Drywell

The detection methods for small unidentified leaks within the drywell include monitoring of floor drain sump inleakage, upper cooler condensate flow rate, and airborne gaseous and particulate radioactivity. The sensitivity of the floor drain sump level and upper cooler condensate flow rate monitors for unidentified leakage within the drywell is 1 gpm within 1 hour. These variables are continuously indicated and/or recorded in the control room. If the unidentified leakage increases to a total of 5 gpm, floor drain sump level and upper cooler condensate flow rate instruments will trip and activate an alarm in the control room. No isolation trip will occur.
Fixed-measurement-interval methods are also available, which can provide indication of floor drain sump inleakage. If airborne particulate or gaseous radioactivity levels increase to their monitor alarm setpoints, an alarm will be activated in the control room.

The additional detection methods, of drywell atmosphere pressure and temperature are used to detect gross unidentified leakage. High drywell pressure will alarm and trip the isolation logic which will result in closure of the containment isolation valves.

The detection of small identified leakage within the drywell is accomplished by monitoring of drywell equipment drain sump level inflow rate (gpm). The detection channel will activate an alarm in the control room when the total leak rate reaches 25 gpm. This measurement has a sensitivity for detection of leakage increases of 1 gpm over normal background leakage.

The determination of the source of identified leakage within the drywell is accomplished by monitoring the drain lines to the drywell equipment drain sumps from various potential leakage sources. These include upper containment pool seal drain flow, reactor recirculation pump seal drain flow, valve stem leakoff drain line temperatures, and reactor vessel head seal drain line pressure. Additionally, temperature is monitored in the safety/relief valve discharge lines to the suppression pool to detect leakage through each of the safety/relief valves. All of these monitors, except the reactor recirculation seal drain flow monitor, continuously indicate and/or record in the control room. All of these monitors will trip and activate an alarm in the control room on detection of leakage from monitored components.

Any possible leakage from the reactor vessel head flange is retained in the flange drain line to prevent the leaking steam from scoring the head surface. A pressure transmitter provides an alarm in the control room on high pressure in this line.

Each line that is used to route valve packing leakage to the drain sump is equipped with a temperature transmitter which provides an alarm in the control room on high temperature in the line. Leakage of such a

magnitude that it was not being condensed would be indicated by this high temperature alarm. A manually operated solenoid valve provided in each line can then be closed by the operator to isolate the line.

In addition, the drains of the upper two coolers of the drywell air cooling system are equipped with a common flow transmitter which provides an alarm in the control room on high condensate drain flow. High drain flow is indicative of possible reactor coolant pressure boundary leakage.

To minimize the potential for drain system blockage, drywell floor and equipment drain sumps are monitored continuously for level or rate to indicate normal sump operation. Also, pressure switches located downstream of sump pumps, trip the pumps on high discharge pressure (line blockage). An inspection of the drywell and the drain sump areas will be performed prior to closing out the drywell after maintenance.

Excessive leakage inside the drywell (e.g., process line break or loss-of-coolant accident within primary containment) is detected by high drywell pressure, low reactor water level or steam line flow (for breaks downstream of the flow elements). The instrumentation channels for these variables will trip when the monitored variable exceeds a predetermined limit to activate an alarm and trip the isolation logic which will close appropriate isolation valves <Table 5.2-8>.

The alarms, indication and isolation trip functions initiated by the leak detection systems are summarized in <Table 5.2-8> and <Table 5.2-9>.

5.2.5.1.2 Detection of Leakage External to the Drywell (Within Reactor Building)

The detection of leakage within the reactor building but outside the drywell is accomplished by detection of increases in reactor building floor drain sump and reactor building equipment drain sump fillup time and pumpout time. The reactor building floor drain sump monitors detect unidentified leakage increases with a sensitivity of 50 percent of normal background and activate an alarm in the control room when total leakage reaches 5 gpm. The reactor building equipment drain sump monitors detect identified leakage increase with a sensitivity of 50 percent normal background leakage and activate an alarm in the control room when total leakage reaches 25 gpm.

The determination of the source of identified leakage to the reactor building equipment drain sump is accomplished by monitoring flow in the upper containment pool liner drain lines. High flow in a drain line activates an alarm in the control room.

5.2.5.1.3 Detection of Leakage External to Reactor Building

The areas outside the reactor building which are monitored for primary coolant leakage are: equipment areas in the auxiliary building, the main steam tunnel and the turbine building. The process piping for each system to be monitored for leakage is located in compartments or rooms separate from other systems where feasible so that leakage may be detected by area temperature indications. Each leakage detection system will detect leak rates that are less than the established leakage limits.

a. The main steam tunnel is monitored by dual element thermocouples for sensing high ambient temperature in the areas and high differential temperature between the inlet and outlet ventilation ducts which service the individual areas. The temperature elements

are located or shielded so that they are sensitive to air temperatures only and not radiated heat from hot piping or equipment. Increases in ambient and/or differential temperature will indicate leakage of reactor coolant into the area. These monitors have sensitivities suitable for detection of reactor coolant leakage into the monitored areas. The temperature trip setpoints are a function of room size and the type of ventilation provided. These monitors provide alarm and indication and recording in the control room and will trip the isolation logic to close selected isolation valves.

b. Leakage detection in the turbine building is accomplished by the use of thermocouples for sensing high ambient temperature in the MSL areas. These monitors also alarm and indicate in the control room and trip the isolation logic to close the main steam line isolation and MSL drain isolation valves before leakage exceeds 280 gpm (32.9 lbm/sec).

c. Leakage detection in each ECCS system compartment is accomplished by monitoring increases in floor drain sump level. These monitors also alarm in the control room.

d. Excess leakage external to the containment (e.g., process line break outside containment) is detected by low reactor water level, high process line flow, high ambient and differential temperature in the piping or equipment areas, high differential flow and low main condenser vacuum. These monitors provide alarm and indication in the control room and trip the isolation logic to cause closure of appropriate system isolation valves on indication of excess leakage <Table 5.2-8>. Differential temperature provides alarm and indication only.

5.2.5.1.4 Intersystem Leakage Monitoring

Radiation monitors are used to detect reactor coolant leakage into cooling water systems supplying the RHR heat exchangers and the reactor water cleanup system (RWCS) heat exchangers. These monitoring channels are part of the process radiation monitoring system. Coolant leakage into the cooling water systems of the RHR systems is monitored using two channels: one for monitoring downstream of equipment in the emergency service water system Loop A and the other for Loop B. Coolant leakage into the cooling water systems supplying the RWCS heat exchangers is monitored by one channel in the nuclear closed cooling water system. Each channel will alarm on high radiation conditions indicating process leakage into the cooling water. No isolation trip functions are performed by this monitor.

Radioactive releases from the ADHR system to the service water system are monitored by the ADHR heat exchanger service water outlet radiation monitor. This channel will alarm on high radiation conditions indicating ADHR leakage into the service water. If a high radiation level is detected, the ADHR system can be manually isolated.

5.2.5.2 Leakage Detection Instrumentation and Monitoring

5.2.5.2.1 Leak Detection Instrumentation and Monitoring Inside Drywell

Leak detection instrumentation and monitoring inside drywell is as follows:

a. Floor Drain Sump Measurement

The normal design leakage collected in the floor drain sump includes unidentified leakage from the control rod drives, valve flange leakage, component cooling water, air cooler drains, and any

leakage not connected to the equipment drain sump. The floor drain sump instrumentation monitors and records sump level in terms of flow rate (gpm). Abnormal leakage rates are alarmed in the main control room. Collection in excess of background leakage would indicate an increase in reactor coolant leakage from an unidentified source.

Two fixed-measurement interval methods exist for determining unidentified drywell leakage rates. First, the leakage rate can be calculated using the change in the drywell floor drain sump level as indicated in the control room. By monitoring the level change over a period of time, the leakage rate can be calculated.

The second fixed-measurement method involves monitoring the drywell floor sump drain pump run time. By determining pump run time over a given period, the leakage rate can be determined if the pump rate is known or can be conservatively estimated.

b. Equipment Drain Sump

The equipment drain sump collects only identified leakage. This sump receives piped drainage from pump seal leakoff, reactor vessel head flange vent drain, and valve stem packing leakoff. Collection in excess of background leakage would indicate an increase in reactor coolant from an identified source. The equipment drain sump instrumentation is similar to that of the floor drain sump and, in addition, monitors sump drain pump fillup time and pumpout time.

c. Cooler Condensate Drain

Condensate from the upper two drywell coolers is routed to the floor drain sump and is monitored by use of a flow transmitter which measures flow in the condensate drain line and sends signals for indication and alarm instrumentation in the control room. An adjustable alarm is set to annunciate on the condensate high flow rate at a level exceeding normal flow rate conditions.

d. Temperature Measurement

The ambient temperature within the drywell is monitored by six single element RTD'S located equally spaced in the vertical direction within the drywell. An abnormal increase in drywell temperature could indicate a leak within the drywell. In addition, the drywell exit end of the containment penetration guard pipe for the main steam line is also monitored for abnormal temperature rise caused by leakage from the main steam line. Ambient temperatures within the drywell are recorded and high average temperatures are alarmed on the leakage detection and isolation system (LD&IS) control room panel.

e. Fission Product Monitoring

This drywell air sampling system is used along with the temperature, pressure, and flow variation method described above to detect leaks in the nuclear system process barrier. The system continuously monitors the drywell and drywell atmosphere for airborne radioactivity (iodine, noble gases and particulates). The sample is drawn directly from the drywell. A sudden increase of activity, which may be attributed to steam or reactor water leakage, is annunciated in the control room. The power supply for the atmospheric monitor is from a vital stub bus which receives power from a divisional bus through an isolation breaker located in Class 1E switchgear. This breaker is tripped upon receipt of a LOCA signal. The operator has the ability to restore power to the bus when required after the LOCA signal has reset <Section 12.3.4>.

f. Drywell Pressure Measurement

The drywell pressure varies slightly during reactor operation and is monitored by pressure sensors. The pressure fluctuates slightly as result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values will indicate a possible leak within the drywell. Pressure exceeding the preset values will be annunciated in the main control room and safety action will be automatically initiated.

g. Reactor Vessel Head Seal

The reactor vessel head closure is provided with double seals with a leakoff connection between seals that is piped through a normally closed manual valve to the equipment drain sump. When leakage through the first seal is detected by an increase in pressure between the seals an alarm in the control room is actuated. The second seal then operates to contain the vessel pressure.

h. Reactor Water Recirculation Pump Seal

Reactor water recirculation pump seal leaks are detected by monitoring flow in the seal drain line. Leakage, indicated by high flow rate, alarms in the control room. The leakage is piped to the equipment drain sump.

i. Safety/Relief Valves

Temperature sensors connected to a multipoint recorder are provided to detect safety/relief valve leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the safety/relief valve discharge piping several feet downstream from the valve body. Temperature rise above the alarm setpoint is annunciated in the main control room. The

nuclear boiler system piping and instrumentation diagram is shown on <Figure 5.1-3>.

j. Valve Stem Packing Leakage

Valve stem packing leaks of power-operated valves 2 inches or larger in the nuclear boiler system, reactor water cleanup system, high pressure core spray, low pressure core spray, reactor core isolation cooling system, residual heat removal system, and recirculation system are detected by monitoring packing leakoff. High temperature is recorded and annunciated by an alarm in the main control room.

k. High Flow in Main Steam Lines (for leaks downstream of flow elements)

High flow in each main steam line is monitored by differential pressure sensors that sense the pressure difference across a flow element in the line. Steam flow exceeding preset values for any of the four main steam lines results in annunciation and isolation closure of all the main steam and steam drain lines.

l. Reactor Water Low Level

The loss of water in the reactor vessel (in excess of makeup) as the result of a major leak from the reactor coolant pressure boundary is detected by using the same nuclear boiler system low reactor water level signals that alarm and isolate selected primary system isolation valves.

m. RCIC Steam Supply Line Flow (for leaks downstream of flow element)

The RCIC steam supply line provides motive power for the operation of the RCIC steam turbine. The line is monitored for abnormal flows. Steam flows exceeding preset values will initiate annunciation and isolation of the RCIC steam supply line.

n. High Differential Pressure Between ECCS Injection Lines (for leakage internal to reactor vessel only)

A break between ECCS injection nozzles and vessel shroud is detected by monitoring the differential pressure between RHR "A" and LPCS, RHR "B" and "C," and HPCS and reactor vessel plenum. Indicator and alarm are located in the main control room.

o. Upper Pool Leakage

Upper pool liner and bellows seal is monitored for leakage by means of a flow transmitter locally mounted on the upper pool drain line. Indicator and alarm are located in the control room.

As the primary method for detecting identified and unidentified leakage, the drywell floor drain sump level and the drywell equipment drain sump pump level will be used to monitor flow rate (gpm) into the sump. Other fixed-measurement-interval methods are also available utilizing sump level changes or pump out times.

Airborne particulate and gaseous radioactivity are monitored in the drywell as a qualitative method for determining high gross unidentified leakage. Correlating particulate and gaseous radioactivity readings with reactor coolant leakage rate is considered impractical in detecting increases in leakage rates of 1 gpm to 3 gpm and also for the maximum allowed sump leakage limit of 5 gpm.

Condensate flow rate from the upper two drywell coolers (Elevation 630'-1") is also monitored as a method of leak detection. Readout units are in gallons per minute.

<Table 5.2-8> and <Table 5.2-9> summarize the actions taken by each leakage detection function. The tables show that those systems which detect gross leakage initiate immediate automatic isolation. The systems which are capable of detecting small leaks initiate an alarm in the control room or/are monitored at appropriate intervals. The operator may manually isolate the leakage source or take other appropriate action. A record of background leakage shall be maintained in the control room. This record shall be kept by the control room operators and will be periodically reviewed to determine if any trends have developed.

Leakage monitoring for drywell equipment drain sump level and drywell floor drain sump level is contained in the ERIS computer. However, this is not the primary display method.

5.2.5.2.2 Leak Detection Instrumentation and Monitoring External to Drywell

The leak detection instrumentation and monitoring external to drywell is as follows:

a. Containment Sump Flow Measurement

Instrumentation monitors and indicates the amount of unidentified leakage into the reactor building floor drainage system outside the drywell. Background leakage is identified during startup tests. Identified leakage within the reactor building outside the drywell includes the upper containment pool, transfer pool liner and separator liner leakage, which is piped to the containment equipment drain sump. The containment floor and equipment

drain sump instrumentation monitors sump drain pump fillup time and pumpout time.

b. Visual and Audible Inspection

Accessible areas are inspected periodically and the temperature and flow indicators discussed above are monitored regularly. Any instrument indication of abnormal leakage will be investigated.

c. Differential Flow Measurement (reactor water cleanup system only)

Because of its arrangement, the reactor water cleanup system uses the differential flow measurement method to detect leakage. The flow into the cleanup system is compared with the flow from the system. An alarm in the control room and an isolation signal are initiated when high differential flow exists between flow into the system and flow back to the reactor vessel indicating that a leak equal to the established leak rate limit may exist.

d. Main Steam Line Area Temperature Monitors

High temperature in the main steam line tunnel areas is detected by dual element thermocouples. Some of the dual element thermocouples are used for measuring main steam tunnel ambient temperatures and are located in the area of the main steam and RCIC steam lines. The remaining dual elements are used in pairs to provide measurement of differential temperature across (inlet to outlet) the tunnel area vent system. All temperature elements are located or shielded so as to be sensitive to air temperatures and not to the radiated heat from hot equipment. One thermocouple of each differential temperature pair is located so as to be unaffected by tunnel temperature. High ambient or high differential temperature will alarm in the control room. High ambient will also provide a signal to close the main steam line and drain line isolation valves, RCIC steam line

isolation valves, and the reactor water cleanup system isolation valves. A high temperature or differential temperature alarm may also indicate leakage in the reactor feedwater line which passes through the main steam tunnel. Leak detection in the main steam line area in the turbine building is accomplished by the use of thermocouples for sensing high ambient temperatures.

e. Temperature Monitors in Equipment Areas

Dual element thermocouples are installed in the equipment areas and in the inlet and outlet ventilation ducts to the RCIC, RHR and RWCU equipment rooms for sensing high ambient or high differential temperature. These elements are located or shielded so that they are sensitive to air temperature only and not radiated heat from hot equipment. High ambient and high differential temperature are alarmed in the control room.

f. Intersystem Leakage Monitoring

The intersystem leakage monitoring is included in the process radiation monitoring system to satisfy the requirements of that system.

g. Large Leaks External to the Primary Containment

The main steam line high flow, RCIC steam supply line high flow and reactor vessel low water level monitoring discussed in <Section 5.2.5.2.1>, Items k, l and m, can also indicate large leaks from the reactor coolant piping external to the primary containment.

5.2.5.2.3 Summary

<Table 5.2-8> and <Table 5.2-9> summarize the actions taken by each leakage detection function. The table shows that those systems which detect gross leakage initiate immediate automatic isolation. The systems which are capable of detecting small leaks initiate an alarm in the control room or are monitored at appropriate intervals. The operator can manually isolate the violated system or take other appropriate action. A time delay is provided before automatic isolation of the reactor core isolation cooling system on a high ambient temperature in the main steam tunnel so that the MSIV's and RWCU can be isolated first and thereby preserve the operation of the RCIC system for core cooling. A time delay is also provided for the RWCU differential flow to prevent normal system surges from isolating the system.

The leak detection system is a multi-dimensional system which is redundantly designed so that failure of any single element will not interfere with a required detection of leakage or isolation. In the four division portion of the LD&IS, applied where inadvertent isolation could impair plant performance (e.g., main steamline isolation valves), any single channel or divisional component malfunction will not cause a false indication of leakage or false isolation trip because it will only trip one of four channels. It thus combines a very high probability of operating when needed with a very low probability of operating falsely. The system is testable during plant operation.

5.2.5.3 <u>Indication in Control Room</u>

Leak detection methods are discussed in <Section 5.2.5.1>. Details of the leakage detection system indications are included in <Section 7.6.1>.

5.2.5.4 Limits for Reactor Coolant Leakage

5.2.5.4.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the floor drain and equipment drain sumps. The total leakage rate limit is well within the makeup capability of the RCIC system. The total leakage rate limit is established at 30 gpm averaged over the previous 24 hours. The unidentified leakage rate limit is established at 5 gpm.

The total leakage rate limit is low enough to prevent overflow of the sumps. The equipment sump and the floor drain sump, which collect all leakage, are each pumped out by two 50 gpm pumps.

5.2.5.4.2 Identified Leakage Inside Drywell

The pump packing glands, valve stems and other seals in systems that are part of the reactor coolant pressure boundary, and from which normal design identified source leakage is expected, are provided with leakoff drains. Large nuclear system valves inside the primary containment and recirculation pumps are equipped with double seals. Leakage from the primary recirculation pump seals is monitored for flow in the drain line and pipe to the equipment drain sump as described in <Section 5.4.1.3>. Leakage from the main steam safety/relief valves discharging to the suppression pool is monitored by temperature sensors that transmit to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage.

Thus, the leakage rates from recirculation pumps, valve stem packings and the reactor vessel head seal, which all discharge to the equipment drain sump, are measured during plant operation.

5.2.5.5 Unidentified Leakage Inside Drywell

5.2.5.5.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the sumps that is not identified as previously described. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack that is large enough to propagate rapidly (critical crack length). The unidentified leakage rate limit must be low because of the possibility that most of the unidentified leakage rate might be emitted from a single crack in the nuclear system process barrier.

An allowance for leakage that does not compromise barrier integrity and is not identifiable is made for normal plant operation.

The unidentified leakage rate limit is established at 5 gpm rate to allow time for corrective action before the process barrier could be significantly compromised. This 5 gpm unidentified leakage rate is a small fraction of the calculated flow from a critical crack in a primary system pipe <Figure 5.2-15>. Leakage limits are discussed in Technical Specifications.

5.2.5.5.2 Sensitivity and Response Times

Sensitivity, including sensitivity tests and response time of the leak detection system are covered in <Section 7.6.1>.

5.2.5.5.3 Length of Through-Wall Flaw

Experiments conducted by GE and Battelle Memorial Institute, (BMI), permit an analysis of critical crack size and crack opening displacement (Reference 4). This analysis relates to axially oriented through-wall cracks.

a. Critical Crack Length

Satisfactory empirical expressions to predict critical crack length have been developed to fit test results. A simple equation which fits the data in the range of normal design stresses (for carbon steel pipe) is:

$$L_c = \frac{15{,}000D}{\sigma_h}$$ (see data correlation on <Figure 5.2-16>)

where:

L_c = critical crack length (in.)

D = mean pipe diameter (in.)

σ_h = nominal hoop stress (psi).

b. Crack Opening Displacement

The theory of elasticity predicts a crack opening displacement of

$$\omega = \frac{2\ L\sigma}{E}$$

where:

L = crack length

σ = applied nominal stress

E = Young's modulus

Measurements of crack opening displacement made by BMI show that local yielding greatly increases the crack opening displacement as the applied stress, σ_s, approaches the failure stress, σ_f. A suitable correction factor for plasticity effects is:

$$C = \sec\left(\frac{\pi}{2}\frac{\sigma_s}{\sigma_f}\right)$$

The crack opening area is given by

$$A = \frac{C\pi\omega L}{4} = \frac{\pi}{2}\left(\frac{L^2\sigma}{E}\right)\ \sec\left(\frac{\pi}{2}\frac{\sigma_s}{\sigma_f}\right)$$

For a given crack length L, σ_f = 15,000 D/L.

c. Leakage Flow Rate

The maximum flow rate for blowdown of saturated water at 1,000 psi is 55 lb/sec-in.^{2}, and for saturated steam the rate is 14.6 lb/sec-in.^{2} (Reference 5). Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec) the effect of friction is small. The required leak size for 5 gpm flow is:

A = 0.0126 in.^{2} (saturated water)
A = 0.0475 in.^{2} (saturated steam)

From this mathematical model, the critical crack length and the 5 gpm crack length have been calculated for representative BWR pipe size (Schedule 80) and pressure (1,050 psi).

The lengths of through-wall cracks that would leak at the rate of 5 gpm given as a function of wall thickness and nominal pipe size are:

Nominal Pipe Size (Sch. 80), in.	Average Wall Thickness, in.	Crack Length L, in.	
		Steam Line	Water Line
4	0.337	7.2	4.9
12	0.687	8.5	4.8
24	1.218	8.6	4.6

The ratios of crack length, L, to the critical crack length, L_c as a function of nominal pipe size are:

Nominal Pipe Size (Sch. 80), in.	Ratio L/L_c	
	Steam Line	Water Line
4	0.745	0.510
12	0.432	0.243
24	0.247	0.132

It is important to recognize that the failure of ductile piping with a long, through-wall crack is characterized by large crack opening displacements which precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs, involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gallons per minute will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1 to 0.2 inch at the time of incipient rupture, corresponding to a leakage area on the order of 1 sq in. for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there are insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550°F yield stress, assuming high thermal expansion stresses exist. It is assumed that the longitudinal

crack, subject to a stress as high as 30,000 psi, constitutes a "worst case" with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

<Figure 5.2-15> shows general relationships between crack length, leak rate, stress, and line size, using the mathematical model described previously. The asterisks denote conditions at which the crack opening displacement is 0.1 in., at which time instability is imminent as noted previously under Item c. This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is significantly greater than the 5 gpm criterion.

If either the identified or unidentified leak rate limits are exceeded, an orderly shutdown can be initiated and the reactor can be placed in a cold shutdown condition within 24 hours.

5.2.5.5.4 Margins of Safety

The margins of safety for a detectable flaw to reach critical size are presented in <Section 5.2.5.5.3>. <Figure 5.2-15> shows general relationships between crack length, leak rate, stress and line size using the mathematical model.

5.2.5.5.5 Criteria to Evaluate the Adequacy and Margin of the Leak Detection System.

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier located in the primary containment, reactor building and auxiliary building as shown in <Table 5.2-8> and <Table 5.2-9>. The instrumentation is designed so it can be set to

provide alarms at established leakage rate limits and isolate the affected system, if necessary, or it is monitored at appropriate intervals. The alarm points are determined analytically or based on measurements of appropriate parameters made during startup and preoperational tests.

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that, even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier would be threatened.

The leak detection system will satisfactorily detect unidentified leakage of 5 gpm.

5.2.5.6 Differentiation Between Identified and Unidentified Leaks

<Section 5.2.5.1> describes the systems that are monitored by the leak detection system. The ability of the leak detection system to differentiate between identified and unidentified leakage is discussed in <Section 5.2.5.4>, <Section 5.2.5.5>, and <Section 7.6>.

5.2.5.7 Sensitivity and Operability Tests

Sensitivity, including sensitivity testing and response time of the leak detection system, and the criteria for shutdown if leakage limits are exceeded, are covered in <Section 7.6>.

Testability of the leakage detection system is contained in <Section 7.6>.

5.2.5.8 Safety Interfaces

The Balance of Plant/GE Nuclear Steam Supply System safety interfaces for the leak detection system are the signals from the monitored balance of plant equipment and systems which are part of the nuclear system process barrier, and associated wiring and cable lying outside the nuclear steam supply system equipment.

5.2.5.9 Testing and Calibration

Provisions for testing and calibration of the leak detection system are covered in <Chapter 14>.

5.2.5.10 Regulatory Guide 1.45 Compliance

The detection of leakage through the reactor coolant pressure boundary, described in the preceding sections, meets the intent of the <Regulatory Guide 1.45>. Details of compliance are discussed in the following.

a. Leakage is separated into identified and unidentified categories and total flow rate for each is independently monitored, thus meeting Position C.1 of <Regulatory Guide 1.45>.

b. Small unidentified leaks (5 gpm and less) inside the drywell are detected by temperature changes, pressure changes, sump fill rate activities, fission product monitoring, and upper drywell cooler condensate flow monitoring. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

   The 5 gpm leakage rate is the plant Technical Specification limit on unidentified leakage inside the drywell. The leak detection

system is fully capable of monitoring the flow rates of 1 gpm and is thus in compliance with Position C.2 of <Regulatory Guide 1.45>.

c. By monitoring floor drain sump level (flow rate), airborne particulate radioactivity, cooler condensate flow rate and airborne gaseous radioactivity, Position C.3 is satisfied.

   Isolation and/or alarm of affected systems and the detection methods used are summarized in <Table 5.2-8> and <Table 5.2-9>.

d. Monitoring of coolant for radiation in the RHR and RWCU heat exchangers satisfies Position C.4. For system details, see <Section 7.6>.

e. The floor drain sump monitoring, and the upper air cooler condensate monitoring systems are designed to detect leakage rates of 1 gpm within 1 hour, thus meeting Position C.5. The fission products monitoring subsystem is not designed to detect leakage rates of 1 gpm within 1 hour.

f. The fission products monitoring subsystem is qualified for SSE. The drywell floor drain sump level, equipment drain sump level and air cooler drain rate instrumentation are capable of performing their functions following seismic events that do not require plant shutdown, thus meeting Position C.6.

g. Leakage detection indicators and alarms for the drain sump, cooler condensate flow rate monitoring and radioactivity monitoring systems are provided in the main control room. Procedures for the fixed-measurement methods of determining drywell unidentified leakage rates will be available to the operators for converting the sump level changes and/or pump run times to a leakage rate. Procedures for converting the drywell floor drain sump rate monitoring instrumentation and cooler condensate flow rate

monitoring instrumentation are not necessary since these indicators are expressed as gallons per minute. There is no attempt to correlate radioactivity monitoring indication to leakage flow rate due to the uncertainties involved. This satisfies the procedural requirements of Position C.7 of this guide.

h. The leakage detection system is equipped with provisions to permit testing for operability and calibration during plant operation using the following methods:

1. Simulation of signals into trip units

2. Comparing channel "A" to channel "B" of the same leak detection method (drywell temperature and pressure monitoring)

3. Checking operability by comparing one method versus another (air cooler condensate flow versus floor drain sump level (flow rate)).

4. Comparing one method versus another (sump fill up versus pump out and particulate monitoring, air cooler condensate flow versus sump fill up rate)

5. Continuous monitoring of floor drain sump level is provided.

These methods satisfy Position C.8.

i. Technical Specifications limit unidentified leakage to 5 gpm and total leakage (identified plus unidentified) to 30 gpm. This satisfies Position C.9.

15.1.4 INADVERTENT SAFETY/RELIEF VALVE OPENING

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent opening is attributed to malfunction of the valve or an operator initiated opening. Opening and closing circuitry at the individual valve level (as opposed to groups of valves) is subject to a single failure. It is therefore simply postulated that a failure occurs and the event is analyzed accordingly. Detailed discussion of the valve design is provided in <Chapter 5>.

This transient is similar to the incident of a safety/relief valve sticking open. This is the only operational transient that requires operator action to attempt to reclose the valve or shut down the plant when suppression pool temperature exceeds the technical specification limit.

15.1.4.1.2 Frequency Classification

This transient disturbance is categorized as an infrequent incident but due to a lack of a comprehensive data basis, it is being analyzed as an incident of moderate frequency.

15.1.4.2 Sequence of Events and Systems Operation

15.1.4.2.1 Sequence of Events

<Table 15.1-5> lists the sequence of events for this event.

15.1.4.2.1.1 Identification of Operator Actions

Control room alarms from the safety/relief valve open/close monitor, or from the suppression pool temperature monitor, will provide the operator pertinent information for his action. The plant operator must reclose the valve as soon as possible and check that reactor and T-G output return to normal. If the valve cannot be closed, plant shutdown should be initiated. The elapsed time the operator has depends on the temperature of the suppression pool water at the onset of the event. However, the operator is required to scram the reactor when the suppression pool temperature reaches the technical specification limit.

15.1.4.2.2 Systems Operation

This event assumes normal functioning of normal plant instrumentation and controls, specifically the operation of the pressure regulator and level control systems.

15.1.4.2.3 The Effect of Single Failures and Operator Errors

Failure of additional components (e.g., pressure regulator, feedwater flow controller) is discussed elsewhere in <Chapter 15>. In addition, a detailed discussion of such effects is given in <Appendix 15A>.

15.1.4.3 <u>Core and System Performance</u>

15.1.4.3.1 Mathematical Model

The reactor model briefly described in <Section 15.1.1.3.1> was previously used to simulate this event in earlier FSARs. This model is discussed in detail in (Reference 2). It was determined that this event is not limiting from a core performance standpoint. Therefore, a qualitative presentation of results is described below.

15.1.4.3.2 Input Parameters and Initial Conditions

It is assumed that the reactor is operating at an initial power level corresponding to 102 percent of rated core power conditions when a safety/relief valve is inadvertently opened. Manual recirculation flow control is assumed. Flow through the relief valve at normal plant operating conditions stated above is approximately 7 percent of rated steam flow.

15.1.4.3.3 Qualitative Results

The opening of a safety/relief valve allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

The pressure regulator senses the nuclear system pressure decrease and within a few seconds closes the turbine control valve far enough to stabilize reactor vessel pressure at a slightly lower value and reactor power settles at nearly the initial power level. Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. MCPR is essentially unchanged and therefore, the safety limit margin is unaffected.

15.1.4.4 <u>Barrier Performance</u>

As discussed above, the transient resulting from a stuck open relief valve is a mild depressurization which is within the range of normal load following and therefore, has no significant effect on RCPB and containment design pressure limits.

15.1.4.5 <u>Radiological Consequences</u>

While the consequence of this event does not result in fuel failure it does result in the discharge of normal coolant activity to the

suppression pool via SRV operation. Since this activity is contained in the primary containment there will be no exposures to operating personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen the release will be in accordance with technical specifications; therefore, this event, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.1.5 SPECTRUM OF STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE OF CONTAINMENT IN A PWR

This event is not applicable to BWR plants.

15.1.6 INADVERTENT RHR SHUTDOWN COOLING OPERATION

15.1.6.1 Identification of Causes and Frequency Classification

15.1.6.1.1 Identification of Causes

At design power conditions no conceivable malfunction in the shutdown cooling system could cause temperature reduction.

In startup or cooldown operation, if the reactor were critical or near critical, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for the RHR heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without violating fuel thermal limits and without any measurable increase in nuclear system pressure.

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

7.3.1 DESCRIPTION

Section 7.3 describes the instrumentation and controls of the following plant Engineered Safety Features (ESF) systems:

a. Emergency Core Cooling Systems (ECCS)

b. Containment and Reactor Vessel Isolation Control Systems (CRVICS)

c. (Deleted)

d. RHRS-Containment Spray Cooling Mode (RHRS-CSCM)

e. RHRS-Suppression Pool Cooling Mode (RHRS-SPCM)

f. Emergency Water Systems (EWS)[1]

g. Control Complex HVAC System[1]

h. ESF Building and Area HVAC System[1]

i. Annulus Exhaust Gas Treatment System (AEGTS)

j. Pump Room Cooling System[1]

k. Containment Combustible Gas Control System

l. Suppression Pool Makeup System

m. Containment Vacuum Relief

n. Standby Power Support Systems[1]

o. Fuel Handling Area Exhaust Subsystem[2]

NOTE:

1. The following systems are considered to be ESF support systems not ESF systems in accordance with the guidance provided in <NUREG-0800>, Section 7.3. These systems will continue to be treated as safety-related for design, construction, maintenance, testing, and other operational purposes. Independent actuation of any one of these systems will not be reported per <10 CFR 50.73(a)(2)(iv)>.

   a. Emergency Closed Cooling Water (ECC) (P42)

   b. Control Complex Chilled Water (CCCW) (P47)

   c. ESF Building and Area HVAC Systems (M23)(M24)(M43)

   d. Pump Room Cooling Systems (M28)(M32)(M39)

   e. Standby Power Support Systems (R44)(R45)(R46)(R47)(R48)

2. Only the exhaust subsystem of the fuel handling area ventilation system is ESF.

The sources which supply power to the engineered safety feature systems originate from onsite ac and/or dc safety-related busses or, as in the case of the CRVICS failsafe logic, from the nonsafety-related RPS MG sets. Refer to <Chapter 8> for a complete discussion of the ESF systems power sources.

7.3.1.1 System Description

7.3.1.1.1 Emergency Core Cooling Systems (ECCS) - Instrumentation and Controls

The Emergency Core Cooling System is a network of the following subsystems <Section 6.3.1> and <Section 6.3.2>.

a. High Pressure Core Spray System (HPCS).

b. Automatic Depressurization System (ADS).

c. Low Pressure Core Spray System (LPCS).

d. Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal System (RHRS).

The purpose of ECCS instrumentation and control is to initiate appropriate responses from the system to ensure that the fuel is adequately cooled in the event of a design basis accident (DBA). The cooling provided by the system restricts the release of radioactive materials from the fuel by preventing or limiting the extent of fuel damage following situations in which coolant is lost from the reactor coolant pressure boundary.

The ECCS instrumentation detects a need for core cooling systems operation, and the trip systems initiate the appropriate response.

Included in this section is a discussion of protective considerations which are taken between the high pressure reactor coolant system and the low pressure ECCS system. The high pressure/low pressure interlocks are examined in <Section 7.6.1.2>.

The following plant variables are monitored and provide automatic initiation of the ECCS when these variables exceed predetermined limits:

a. Reactor Vessel Water Level

A low water level in the reactor vessel could indicate that reactor coolant is being lost through a breach in the reactor coolant pressure boundary and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. Refer to <Figure 5.1-3> for a schematic arrangement of reactor vessel instrumentation.

b. Drywell Pressure

High pressure in the drywell could indicate a breach of the reactor coolant pressure boundary inside the drywell and that the core is in danger of becoming overheated as reactor coolant inventory diminishes.

7.3.1.1.1.1 High Pressure Core Spray (HPCS) System - Instrumentation and Controls

a. HPCS Function

The HPCS system supplies sufficient coolant flow following a reactor scram in the event of a loss-of-coolant accident. The HPCS system supplies makeup water to the reactor vessel in the event of reactor isolation and failure of the reactor core isolation cooling (RCIC) system <Section 6.3.2.2.1>.

b. HPCS Operation

Schematic arrangements of system mechanical equipment are shown in <Figure 6.3-7>. HPCS system component control logic is shown in

<Figure 7.3-1>. Elementary diagrams are listed in <Section 1.7.1>. Plant layout drawings are shown in <Section 1.2>. Operator information displays are shown in <Figure 6.3-7> and <Figure 7.3-1>.

The HPCS is initiated automatically by either reactor vessel low water level (Trip Level 2) or drywell high pressure. The system is designed to operate automatically for at least 10 minutes without any actions required by the control room operator. Once initiated, the HPCS logic seals-in and can be reset by the operator if reactor water level has been restored even if the high drywell pressure condition exists. Refer to <Figure 7.3-1> for a schematic representation of the HPCS system initiation logic.

Reactor vessel water level (Trip Level 2) is monitored by four redundant level transmitters. Each transmitter provides an input to a trip unit. The trip unit relay contacts are arranged in a one-out-of-two twice logic arrangement to assure that no single event can prevent the initiation of the HPCS.

Initiation diversity is provided by drywell pressure which is monitored by four redundant pressure transmitters. The trip unit relay contacts are electrically connected in a one-out-of-two twice logic arrangement to assure that no single instrument failure can prevent the initiation of the HPCS.

The HPCS components respond to an automatic initiation signal as follows (actions are simultaneous unless stated otherwise):

1. The HPCS diesel generator is signaled to start.

2. Following an initiation signal and if no loss of offsite power has occurred, the HPCS pump is automatically started after a time delay. If a loss of offsite power occurs concurrent with

an initiation signal, the HPCS pump is automatically started immediately, once power is available at the bus.

3. The pump suction from the condensate storage tank valve E22F001, is signaled to open, provided the suppression pool suction valve E22F015 is not full open.

4. The test return valves E22F010, E22F011 and E22F023 are signaled closed.

5. The HPCS injection valve E22F004 is signaled to open.

The HPCS pump discharge flow and pressure are monitored by pressure transmitters. If pump discharge pressure is normal but discharge flow is low enough that pump overheating may occur the minimum flow return line valve E22F012 is signaled open. The valve is automatically closed if flow is normal. The HPCS reaches its rated flow in 27 seconds.

If the water level in the condensate storage tank falls below a predetermined level, the suppression pool suction valve E22F015 automatically opens. When E22F015 is fully open, the condensate storage tank suction valve E22F001 automatically closes. Two level transmitters are used to detect low water level in the condensate storage tank. Either transmitter can cause automatic suction transfer. The suppression pool suction valve also automatically opens if high water level is detected in the suppression pool. Two level transmitters monitor suppression pool water level and either transmitter can initiate opening of the suppression pool suction valve. During the automatic CST to suppression pool suction transfer, to prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes.

The HPCS provides makeup water to the reactor until the vessel water level reaches the high level trip (Trip Level 8) at which time the injection valve E22F004 is automatically closed even if a high drywell pressure signal still exists. The pump will continue to run on minimum flow recirculation. The injection valve will automatically reopen if vessel level again drops to the low level (Trip Level 2) initiation point.

The HPCS pump motor and injection valve are provided with manual override controls. These controls permit the reactor operator to manually control the system following automatic initiation.

7.3.1.1.1.2 Automatic Depressurization System (ADS) - Instrumentation and Controls

a. ADS System Function

The automatic depressurization system is designed to provide automatic depressurization of the reactor vessel by activating eight safety/relief valves. These valves vent steam to the suppression pool in the event that the HPCS cannot maintain the reactor water level following a LOCA. ADS reduces the reactor pressure so that flow from the RHRS-LPCI mode and LPCS, can inject into the reactor vessel in time to cool the core and limit fuel barrier temperature. Refer also to <Section 6.3.2>. Refer to <Section 7.6.1.11> for the relief function of the safety/relief valves.

b. ADS Operation

Schematic arrangements of system mechanical equipment are shown in <Figure 5.1-3>. ADS component control logic is shown in <Figure 7.3-3>. Elementary diagrams are listed in <Section 1.7.1>.

Plant layout drawings are shown in <Section 1.2>. Operator information displays are shown in <Figure 5.1-3> and <Figure 7.3-3>.

The ADS consists of two redundant and independent trip systems, trip systems A and B. The ADS trip system A actuates the "A" solenoid air pilot valve on each ADS safety/relief valve. Similarly, the ADS trip system B actuates the "B" solenoid air pilot valve on each ADS safety/relief valve. Actuation of either solenoid pilot valve causes the ADS safety/relief valve to open and provide depressurization. To prevent inadvertent actuation of the ADS, two channels of logic for each ADS trip system (A & B) are used. Both channels must be activated to actuate an ADS trip system.

One channel of each trip system includes two differential pressure transmitter inputs monitoring reactor vessel low water level (Trip Level 3 and Trip Level 1). The low water Level 3 trip provides confirmation of a reactor vessel low water level condition. The second channel is redundant except the low water level confirmation signal is omitted. A manual inhibit switch is provided to allow the operator to prevent automatic ADS initiation.

To assure that adequate makeup water is available after the vessel has been depressurized, each trip channel includes a pump discharge pressure permissive signal indicating LPCI or LPCS system availability for vessel water makeup. Any one of the three LPCI pumps or the LPCS pump available for reactor coolant makeup is sufficient to permit automatic depressurization.

After receipt of the initiation signals and after a delay provided by timers, each of the two solenoid air pilot valves are energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. Each ADS trip system has a time delay that

can be reset manually to delay system initiation. The time delay is selected to be within a period that allows the HPCS to perform its function prior to ADS initiation. In the event of HPCS failure, the time delay period is selected to allow initiation of ADS, LPCI and LPCS in time to maintain the fuel barrier temperature within acceptable limits. If reactor vessel water level is restored by HPCS prior to the end of the time delay, ADS initiation will be prevented.

Once initiated, the ADS logic seals-in and can be reset by the control room operator only when vessel water level returns to normal.

Two control switches (one for each trip system solenoid) are located in the control room for each safety/relief valve associated with the ADS. Each switch controls one of the two solenoid pilot valves.

7.3.1.1.1.3 Low Pressure Core Spray (LPCS) - Instrumentation and Controls

a. LPCS Function

The purpose of the LPCS is to provide low pressure reactor vessel core spray following a loss-of-coolant accident when the vessel has been depressurized and vessel water level has not been restored by the HPCS. The LPCS is functionally diverse to the LPCI mode of the residual heat removal system <Section 6.3.2>.

b. LPCS Operation

Schematic arrangements of system mechanical equipment are shown in <Figure 6.3-8>. LPCS component control logic is shown in <Figure 7.3-4>. Elementary diagrams are listed in <Section 1.7.1>.

Plant layout drawings are shown in <Figure 1.2>. Operator information displays are shown in <Figure 6.3-8> and <Figure 7.3-4>.

The LPCS is initiated automatically by either reactor vessel low water level (Trip Level 1) and/or drywell high pressure. The system is designed to operate automatically for at least 10 minutes without any actions required by the control room operator. Once initiated, the LPCS logic seals-in and can be reset by the control room operator only when the initial conditions return to normal. Refer to <Figure 7.3-4> for a schematic representation of the LPCS system initiation logic.

Reactor vessel water level (Trip Level 1) is monitored by two redundant level transmitters. Drywell pressure is monitored by two redundant pressure transmitters. The vessel level trip unit relay contacts and the drywell pressure trip unit relay contacts are connected in a one-out-of-two twice logic arrangement so that no single instrument failure can prevent initiation of LPCS (i.e., LPCS will be initiated when either both level channels, both pressure channels, or one level channel and one pressure channel are tripped).

The LPCS components respond to an automatic initiation signal simultaneously (or sequentially as noted) as follows:

1. The Division 1 diesel generator is signaled to start.

2. The normally closed test return line to the suppression pool valve E21F012 is signaled closed.

3. Following a LOCA initiation signal and if no loss of offsite power has occurred, the LPCS pump is automatically started after a time delay. If a loss of offsite power occurs concurrent with a LOCA initiation signal, the LPCS pump is automatically started immediately, once power is available at the bus.

4. Reactor pressure is monitored by a pressure transmitter which senses pressure on the vessel side of the LPCS injection valve E21F005. When the pressure is low enough to protect the LPCS from overpressure and power is available to the pump motor bus, the injection valve is signaled to open. A blue indicating lamp, labeled "Pressure Permissive," is installed above the LPCS injection valve manual control switch which will illuminate to inform the operator that the injection pressure is low enough to prevent over pressurization of the LPCS piping.

   The LPCS pump discharge flow is monitored by a differential pressure transmitter. When the pump is running and discharge flow is low enough to cause pump overheating to occur, the minimum flow return line valve E21F011 is opened. The valve is automatically closed if flow is normal.

   The LPCS pump suction from the suppression pool valve E21F001 is normally open, the control switch is keylocked in the open position, and thus requires no automatic open signal for system initiation.

   The LPCS pump and injection valve are provided with manual override controls. These controls permit the operator to manually control the system subsequent to automatic initiation.

7.3.1.1.1.4 RHRS - Low Pressure Coolant Injection (LPCI) Mode - Instrumentation and Controls

a. LPCI Function

Low pressure coolant injection (LPCI) is an operating mode of the residual heat removal system (RHRS) <Section 5.4.7>. The purpose

of the LPCI system is to provide low pressure reactor vessel coolant makeup following a loss-of-coolant accident when the vessel has been depressurized and vessel water level is not restored by the HPCS <Section 6.3.2>.

b. LPCI Operation

Schematic arrangements of system mechanical equipment is shown in <Figure 5.4-13>. LPCI component control logic is shown in <Figure 7.3-5>. Elementary diagrams are listed in <Section 1.7.1>. Plant layout drawings are shown in <Section 1.2>. Operator information displays are shown in <Figure 5.4-13> and <Figure 7.3-5>.

The LPCI system is initiated automatically by either reactor vessel low water level and/or by drywell high pressure. The system is designed to operate automatically for at least 10 minutes without any actions required by the control room operator. Once initiated, the LPCI logic seals-in and can be reset by the control room operator only when initial conditions return to normal.

Reactor vessel water level (Trip Level 1) is monitored by two redundant differential pressure transmitters. Drywell pressure is monitored by two redundant pressure transmitters.

To initiate the Division 2 LPCI (Loops B and C), the vessel level trip unit relay contacts and the two drywell pressure trip unit relay contacts are connected in a one-out-of-two-twice arrangement so that no single instrument failure can prevent initiation of LPCI (i.e., LPCI will be initiated when either both level channels, both pressure channels, or one level channel and one pressure channel are tripped).

The Division 1 LPCI (Loop A) receives its initiation signal from the LPCS logic.

The LPCI system components respond to an automatic initiation signal simultaneously (or sequentially as noted) as follows (the loop A components are controlled from the Division 1 logic; the loop B and C components are controlled from the Division 2 logic):

1. The Division 2 diesel generator is signaled to start from the loop B and C initiation logic.

2. When the offsite power or the diesel generators are providing power to the pump motor buses, sequential loading is provided. This is accomplished by delaying the start of LPCI pumps A and B by 5 seconds while allowing the LPCI pump C to start immediately. The LPCS pump start is delayed when offsite power is providing power to the bus. If power is supplied by the diesel generators, the LPCS pump will start immediately.

3. The following normally closed valves are signaled closed to ensure proper system lineup:

    (a) (Deleted)

    (b) The RHR heat exchanger flush to suppression pool valves E12F011 A, B.

    (c) (Deleted)

    (d) (Deleted)

    (e) The test return line to the suppression pool valves E12F024 A, B and E12F021.

    (f) The containment spray valves E12F028 A, B.

4. Reactor pressure is monitored by pressure transmitters which sense pressure on the vessel side of LPCI injection valves. When the pressure is low enough to protect the LPCI lines from overpressure and power is available to the pump motor buses, the injection valves are signaled to open. A blue indicating lamp, labeled "Pressure Permissive," is installed above the LPCI injection valve manual control switch which will illuminate to inform the operator that the injection pressure is low enough to prevent over pressurization of the LPCI piping.

The heat exchanger bypass throttle valves E12F048 A, B and the heat exchanger outlet throttle valves E12F003 A, B are signaled to fully open after 110 second time delay. The open signal is automatically removed 10 minutes after system initiation to allow the operator to manually control these valves. This automatic opening function is designed to operate whenever these valves are controlled from the control room. The automatic opening function does not operate when control of these valves is transferred to the remote shutdown station.

Each LPCI pump discharge flow is monitored by a differential pressure transmitter which, when the pump is running and following an 8 second time delay, opens the minimum flow return line valve E12F064 A, B, C if flow is low enough that pump overheating may occur. The valve is automatically closed if flow is normal.

The three RHR pump suction valves from the suppression pool valves E12F004 A and B and F105 have their control switches keylocked in the open position, and thus require no automatic open signal for system initiation. The RHR heat exchanger

inlet valves E12F047 A and B are administratively controlled to ensure that they are open and therefore do not require an automatic signal.

The upper pool shutdown cooling valves E12F037 A, B, the two series RHR heat exchanger vent valves E12F073 A and F074 A, B and the RHR shutdown cooling mode suction valves E12F006A, B are all normally closed and thus require no automatic close signal for system initiation. RHR heat exchanger vent valve 1E12F073B is normally open and thus requires an automatic signal to close.

The LPCI pump motors and injection valves are provided with manual override controls. These controls permit the operator to manually control the system subsequent to automatic initiation.

7.3.1.1.2 Containment and Reactor Vessel Isolation Control System (CRVICS) - Instrumentation and Controls

a. CRVICS Function

The CRVICS, also known as nuclear steam supply shutoff system (NSSSS), includes the instrument channels, trip logics and actuation circuits that automatically initiate valve closure providing isolation of the containment and/or reactor vessel, and initiation of systems provided to limit the release of radioactive materials.

See <Section 6.2.4> and <Table 6.2-32> for a complete description of primary containment and reactor vessel process lines and isolation signals applied to each. The Technical Specifications require that several CRVICS Instrumentation channels for the Main

Steam Line Isolation Valves meet response time criteria. <Table 7.3-1> provides the acceptable response for these channels along with any clarifying information.

b. CRVICS Operation

Schematic mechanical arrangements of containment isolation valves and other components initiated by CRVICS are shown in <Figure 5.4-13>, <Figure 5.1-3>, <Figure 5.4-16>, and <Figure 5.4-2>. CRVICS component control logic is shown in <Figure 7.3-3>, <Figure 7.3-5> and <Figure 7.3-6>. Elementary diagrams are listed in <Section 1.7.1>. Plant layout drawings are shown in <Section 1.2>. Operator information displays are shown in <Figure 5.1-3> and <Figure 7.3-3>.

During normal plant operation, the isolation control system sensors and trip logic that are essential to safety are energized. When abnormal conditions are sensed, instrument contacts open, de-energize the trip logic and initiate an isolation. Once initiated, the CRVICS trip logics seal-in and may be reset by the operator only when the initial conditions return to normal.

Each main steam line isolation valve (MSIV) has two control solenoids. Each solenoid receives inputs from two redundant logics. A signal from either can de-energize the solenoid. For any one valve to close automatically, both of its solenoids must be de-energized.

The main steam line isolation valve logic has a minimum of four redundant instrument channels for each measured variable. One channel of each variable is connected to one trip logic. One group of redundant logics (A, C) is used to control one solenoid of both inboard and outboard valves of all four main steam lines and the other group of redundant logics (B, D) is used to control the other

solenoid of both inboard and outboard valves. The four CRVICS trip logics are arranged in a one-out-of-two twice logic combination (Trip Logic A or C and B or D).

Except for the main steam line drain valves and RHR isolation valves (reactor vessel pressure) the remaining containment and vessel isolation valves also operate in pairs. The remaining inboard isolation valves close if both of the Division 2 and Division 3 logics (B and C) are tripped, and the outboard valves close if the Division 1 and Division 4 logics (A and D) are tripped.

Main steam line drain outboard valves close if Channels A and D isolation logic is tripped, while an inboard valve closes if Channels B and C logic is tripped. The RHR outboard valves close if Channel A or D isolation logic is tripped, while the inboard valves close if Channel B or C logic is tripped.

The following variables provide inputs to the CRVICS logics for initiation of reactor vessel and containment isolation, as well as the initiation or trip of other plant functions when predetermined limits are exceeded. Combinations of these variables, as necessary, provide initiation of various isolating and initiating functions as described in <Table 6.2-32> and below:

1. Reactor Vessel Low Water Level

   A low water level in the reactor vessel could indicate that reactor coolant is being lost through a breach in the reactor coolant pressure boundary and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes.

Reactor vessel low water level initiates closure of various valves. The closure of these valves is intended to isolate a breach of the pipelines, conserve reactor coolant by closing off process lines, and limit the escape of radioactive materials from the containment through process lines that communicate with the primary coolant boundary or containment.

Reactor vessel water level is monitored by four redundant level transmitters. Each instrument provides a low water level input to one of the four CRVICS trip channels.

Three reactor vessel low water level isolation trip settings are used to complete the isolation of the containment and the reactor vessels. The first (and highest) Level 3 reactor vessel low water level isolation trip setting initiates closure of RHR isolation valves, the second reactor vessel low water level (Level 2) initiates closure of all valves in major process pipeline except the main steam lines and associated drains, the nuclear closed cooling system isolation valves and the instrument air system isolation valves for the MSIV's air supply. The main steam lines are left open to allow the removal of heat from the reactor core. The third, and lowest (Level 1) reactor vessel low water level, completes the isolation of the containment and pressure vessel by initiating closure of the main steam line isolation valves, main steam line drain valves, nuclear closed cooling system isolation valves, and the instrument air system isolation valves for the MSIV's air supply.

The instrument air containment isolation valve 1P52-F200 and drywell isolation valve 1P52-F646 are provided with manual override control. This control permits the operator to override the RHR LOCA isolation signal to open the valves as directed by the Emergency Operating Procedures (EOPs). The reactor

vessel low water level (Level 1) MSIV isolation signal can be bypassed manually in accordance with the Emergency Operating Procedures (EOPs) from the control room by actuating four keylocked switches.

Diversity of trip initiation for low reactor vessel water level from pipe breaks inside the drywell is provided by drywell high pressure.

2. Drywell High Pressure

High pressure in the drywell could indicate a breach of the reactor coolant pressure boundary inside the drywell and that the core is in danger of becoming overheated as reactor coolant inventory diminishes.

Drywell pressure is monitored by four redundant pressure transmitters. Each transmitter trip unit provides an input to one of the four trip channels.

3. Main Steam Line-High Radiation

The main steam line radiation monitoring senses the gross release of fission products from the fuel and initiates alarms and automatic actions to contain the released fission products. Monitor input to isolate MSIV's and associated drain valves has been deleted based on analysis presented in NEDO-31400A.

Four redundant detectors monitor the gross gamma radiation from the main steam lines. Each provides an input to one of the four CRVICS trip channels.

Each radiation monitoring channel consists of a gamma-sensitive ion chamber and a log radiation monitor. Each log radiation monitor has four alarm/trip circuits. One upscale trip circuit is used to initiate an alarm and a trip signal to the associated CRVICS trip logic. The second circuit is used for an alarm and is set at a level below that of the first circuit. The third circuit is a downscale trip that actuates an instrument trouble alarm. The fourth circuit is the instrument inoperative trip which produces an alarm and a trip signal to the associated CRVICS trip logic. Annunciator indicating lights are located in the control room.

When the main steam line radiation level exceeds a predetermined value, CRVICS initiates closure of the reactor water sample valves. The high radiation or instrument inoperative trip signals from main steam line radiation monitors A or C also trip the offgas system mechanical vacuum pump(s) and isolate the mechanical vacuum pump lines.

4. Main Steam Line-Tunnel and Pipe Routing in Turbine Building High Ambient Temperature and Differential Temperature

High ambient temperature in the tunnel and pipe routing areas in the turbine building in which the main steam lines are located outside of the primary containment could indicate a leak in a main steam line. Such a leak may also be indicated by high differential temperature between the outlet and inlet ventilation air for the MSL tunnel. The automatic closure of valves prevent the excessive loss of reactor coolant and the release of a significant amount of radioactive material from the reactor coolant pressure boundary.

Four redundant main steam line high ambient temperature sensors are provided in the main steam tunnel and four in the

steam line area of the turbine building. Four redundant differential temperature sensors monitor the outlet and inlet ventilation air ducts of the main steam line tunnel. Each main steam line trip isolation logic is de-energized by high ambient temperature in the main steam tunnel or the steam line area of the turbine building. Four other ambient temperature sensors are located in the turbine power complex and provide alarm capability.

When a predetermined increase in main steam line tunnel ambient temperature, or the steam line area of the turbine building temperature is detected, trip signals initiate closure of all main steam line isolation and drain valves. In addition, MSL tunnel high ambient temperature will cause RWCU and RCIC system isolation initiations.

Diversity of trip initiation signals for main steam line tunnel ambient temperature is provided by main steam line high flow, and steam line low pressure instrumentation.

5. Main Steam Line-High Flow

Main steam line high flow could indicate a breach in a main steam line. Automatic closure of isolation valves prevents excessive loss of reactor coolant and release of significant amounts of radioactive material from the reactor coolant pressure boundary.

Sixteen redundant differential pressure transmitters, four for each main steam line, monitor the main steam line flow. Four differential pressure transmitter trip units for each main

steam line provide inputs to each of the four trip channels. When a significant increase in main steam line flow is detected, trip signals initiate closure of all main steam line isolation and drain valves.

6. Main Turbine Inlet - Low Steam Pressure

Low steam pressure at the turbine inlet while the reactor is operating could indicate a malfunction of the nuclear system pressure regulator in which the turbine control valves or turbine bypass valves become fully open, and causes rapid depressurization of the reactor vessel.

Four redundant pressure transmitters, one for each main steam line, monitor main steam line pressure and each provides an input to one of the four trip channels.

When a decrease in main steam line pressure below a preselected value is detected, the CRVICS initiates closure of all main steam line isolation and drain valves.

The main steam line low pressure trip is bypassed by the reactor mode switch in the Shutdown, Refuel and Startup modes of reactor operation. In the Run mode, the low pressure trip function is operative.

7. Containment and Drywell Purge and Vent Exhaust Radiation Monitor

The containment and drywell purge and vent exhaust radiation monitor consists of four sensor and trip units. Each channel has two trips. The upscale trip indicates high radiation and the downscale trip indicates instrument trouble.

The containment and drywell purge and vent exhaust radiation monitor senses reactor building exhaust to the release point. In the event that radiation levels exceed predetermined limits, the containment and drywell purge system inboard and outboard isolation valves are closed.

8. Reactor Water Cleanup (RWCU) System-High Differential Flow

High differential flow in the reactor water cleanup system could indicate a breach of the system pressure boundary of the cleanup system. The flow at the inlet to the system (suction from recirculation lines) is compared with the flow at the outlets of the system (flow return to feedwater or flow to the main condenser and/or radwaste).

Two redundant differential flow sensors compare the reactor water cleanup system inlet-outlet flow. Each of the flow monitoring sensors provides an input to one of the two (inboard or outboard) logic trip channels.

When an increase in reactor water cleanup system differential flow is detected, the CRVICS initiates closure of all reactor water cleanup system isolation valves.

Diversity of trip initiation signals for reactor water cleanup system line break is provided by instrumentation for reactor water level, differential flow, and ambient or differential temperature in RWCU equipment areas.

The reactor water cleanup system high differential flow trip is bypassed by an automatic timing circuit during normal reactor water cleanup system surges. This time delay bypass prevents inadvertent system isolations during system operational changes.

9. Reactor Water Cleanup (RWCU) System-Area High Ambient Temperature and Differential Temperature

High temperature in the equipment room areas of the reactor water cleanup system could indicate a breach in the reactor coolant pressure boundary in the cleanup system.

Sixteen ambient temperature and sixteen differential temperature instruments monitor the RWCU system area temperatures. Eight ambient and eight differential temperature switches are associated with the same logic channel. The remaining instrument channels are associated with a different logic channel. Two ambient temperature elements are located as shown in <Figure 7.6-1>. Two pairs of differential temperature elements are appropriately located to measure inlet and outlet temperatures of the above locations.

When a significant increase in reactor water cleanup system area ambient temperature is detected the CRVICS initiates closure of all reactor water cleanup system isolation valves.

The output trip signal of each sensor initiates a channel trip and closure of either the inboard or outboard reactor water cleanup system isolation valve.

Diversity of trip initiation signals for temperature is provided by two ambient temperature elements for each reactor water cleanup system area. One differential temperature element and its differential temperature switch and an ambient temperature element and its temperature switch in an RWCU area are associated with one of two logic channels.

14. Main Condenser Vacuum Trip

The main turbine condenser low vacuum signal could indicate a leak in the condenser. Initiation of automatic closure of various valves will prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material.

Four redundant pressure transmitters monitor the main condenser vacuum. The output trip signal of each instrument channel initiates a channel trip. The output trip signal of the channel logics are combined in one-out-of-two twice logic for MSIV's and two-out-of-two logic for drain valves.

When a significant decrease in main condenser vacuum is detected, the CRVICS initiates closure of all main steam line isolation and drain valves.

Main condenser low vacuum trip can be bypassed manually from the control room by actuating a keylocked switch.

7.3.1.1.3 (Deleted)

7.3.1.1.4 RHRS-Containment Spray Cooling Mode (RCSCM) - Instrumentation and Controls

a. Containment Spray Cooling Mode Function

The containment spray cooling mode is an operating mode of the RHR system. It is designed to provide the capability of condensing steam in the containment atmosphere, removing fission products

Manual initiation is provided at the system level by separate armed push button switches. High drywell pressure sensors in a one out of two configuration provide a permissive for the manual initiation. Manual bypass of the high drywell pressure permissive is provided by keylocked bypass switches in the control room. Bypass operation is also annunciated in the control room.

The start of the "B" loop is delayed by 90 seconds after initiation, while the "A" loop starts immediately after initiation.

7.3.1.1.5 RHRS Suppression Pool Cooling Mode (RSPCM) - Instrumentation and Controls

a. RHRS-SPCM Function

The suppression pool cooling mode is an operating mode of the residual heat removal system. It is designed to prevent suppression pool temperature from exceeding predetermined limits following a reactor blowdown of the ADS or safety/relief valves.

b. SPCM Operation

Schematic arrangements of system mechanical equipment is shown in <Figure 5.4-13>. Component control logic is shown in <Figure 7.3-5>. Plant layout drawings and elementary diagrams are identified in <Section 1.7.1>. Operator information displays are shown in <Figure 5.4-13> and <Figure 7.3-5>.

The suppression pool cooling mode is initiated by the control room operator either during normal plant operation or following a LOCA, when the containment atmosphere monitoring system <Section 7.6.1.8> indicates that suppression pool temperature may exceed a predetermined limit.

During normal plant operation, the operator initiates the SPCM as follows:

1. The RHR Pump (A or B) is started. The emergency service water pump is started and the RHR heat exchanger service water discharge valve is opened.

2. The RHR test return line valve E12F024 A, B is opened.

3. The RHR heat exchanger inlet and outlet valves E12F047 A, B and E12F003A, B are open. The heat exchanger bypass valve E12F048 A, B and valve E12F003 A, B are throttled as necessary.

Subsequent to a LOCA, the operator initiates the SPCM as follows:

1. Once reactor vessel water level has been restored, the LPCI flow must be terminated by closing the LPCI injection valve E12F042 A, B. Closing the injection valve causes the LOCA initiation logic to be overridden and allows operator control of the valve.

2. The RHR test return line valve E12F024 A, B control logic also has LOCA signal override provisions. This allows the operator to open the valve. The valves have provisions for throttling capability in order to support the operation of the M51 combustible gas mixing compressors. The After Coolers for these compressors are cooled using the RHR system.

3. The RHR heat exchanger inlet and outlet valves E12F047 A, B and E12F003 A, B are open. The heat exchanger bypass valve E12F048 A, B, can be closed after a time delay (a ten minute timer keeps this valve open following a LOCA).
   Valves E12F003 A, B are throttled as necessary (the same ten minute timer keeps this valve open following a LOCA).

7.3.1.1.6 Emergency Water System (EWS) Instrumentation and Controls

a. EWS Function

The purpose of the emergency water systems instrumentation and controls is to initiate appropriate responses from the systems to ensure the ECCS system receives adequate cooling water in the event of a design basis accident. The emergency water systems consists of two subsystems:

1. Emergency Service Water (ESW) System

2. Emergency Closed Cooling (ECC) System

Emergency water systems are also used during plant shutdown, hot standby condition and when running the RHR pumps and diesel generators.

b. ESW System Operation

The control and instrumentation equipment for the emergency service water system is located in the auxiliary building, diesel-generator building, service water pumphouse, and the intermediate building <Figure 9.2-1>. The emergency service water system consists of three independent loops A, B and C, each with one pump and strainer. Loop A and loop B are automatically initiated with the automatic initiation of the RHR or LPCS systems. Loop A is also automatically initiated with automatic initiation of RCIC system. Loop A supports the RCIC, RHR and LPCS, while loop B supports the RHR only (LPCI mode). Loop C is automatically initiated with the automatic initiation of HPCS. When shutting down loop operation, the initiation signal is remote-manually initiated.

The motor-operated isolation valves from the RHR heat exchangers are operated remote-manually by a selector switch in the control room (loop A valves can also be controlled at the remote reactor shutdown panel) and open automatically upon receipt of a signal from ECCS or ESW pump start. The pump discharge isolation valves operate from the same remote-manual signal or the automatic signal used to initiate pump operation. Motor-operated sluice gates are automatically opened upon receipt of a signal from level switches in the emergency service water pumphouse forebay. When elevated lake temperatures may cause the ESW forebay temperature to approach its maximum allowable design limit of 85°F, the sluice gate seals are inflated and the automatic opening feature is disabled. Differential pressure switches across the emergency service water strainers start the strainer backwash operation on high differential pressure.

The flow, temperature and pressure transmitters are used to provide flow, temperature and pressure indication in the control room. Flow, temperature and pressure switches are provided to give alarms in the control room. Radiation monitors provide alarm signals in the event there is a leak of radioactive water into the emergency service water system (loop A and loop B) from the RHR heat exchangers.

c. ECC System Operation

The ECC system provides the required cooling water for the emergency core cooling support components, i.e., RHR pump and room coolers, LPCS room cooler, RCIC room cooler, control complex chillers and the hydrogen analyzers. The system is designed to provide the required cooling without compromising the independence of the redundant core cooling systems.

The control and instrumentation equipment for the emergency closed cooling system is located in the intermediate building, auxiliary building, control complex building, and the control room <Figure 9.2-3>.

The ECC system automatic initiation circuits (ESF) are interlocked with the ECCS automatic initiation circuit (ESF). Whenever an automatic signal (ESF signal) is provided to initiate the ECCS, the emergency closed cooling system is initiated. When shutting down loop operation, the signal is remote-manually initiated. The level in each ECC system surge tank is maintained automatically by an air operated makeup valve. The solenoid valve that supplies air to the water makeup valve is actuated by high and low level switches on each ECC system surge tank.

An electro-hydraulic operator positions a three-way valve at the inlet of each ECC heat exchanger. The electro-hydraulic operator controls this valve based on the ECC system water temperature downstream of the heat exchangers so as to maintain the ECC water temperature within acceptable limits.

The outlet of each control complex chiller contains a flow element that supplies a differential pressure signal to a flow switch. Each flow switch trips the individual chiller when the ECC system flow rate to that particular chiller reaches a predetermined low value.

The bypass provided around the control complex chillers is employed only during maintenance and testing conditions. At all other times, both trains of the ECCW system are aligned in their post

accident configuration. The following events occur automatically after a LOOP or LOCA signal:

1. Emergency service water pumps start to supply cooling water to ECC system heat exchangers.

2. ECC system pumps start.

3. Motor-operated valves on nuclear closed cooling system supply and return lines to the fuel pool coolers are closed (0P42-F380A, B, 0P42-F440, 0P42-F390A, B, and 0P42-F445).

The valves associated with the fuel pool heat exchangers have isolation functions only. Stroke times associated with these valves are not dependent upon other interactions.

No operator action is required on the ECC system for 10 minutes following initiation of a LOOP or LOCA signal. At the end of the 10 minute period, the system continues to run. Manual control of the ECC pumps may be assumed at any time by operating their control switch. The operator cannot change the position of any motor operated valve that receives a LOCA or a LOOP signal until after the signal has been cleared.

7.3.1.1.7 Control Complex HVAC System

a. System Function

The purpose of the control complex HVAC system instrumentation and controls is to monitor the control complex atmosphere and to initiate appropriate responses from the system to ensure the continued habitability of the control complex. The instrumentation and controls for this system are shown on <Figure 6.4-1>, <Figure 9.4-1> and <Figure 9.4-20>.

The Control Complex HVAC System consists of two subsystems:

1. Control room HVAC system

2. Control complex chilled water system

b. System Operation

The control room HVAC system consists of two independent control loops; the power for each loop is supplied from the Class 1E electrical system.

The control room HVAC system is normally manually initiated. Change over to the emergency recirculation mode is manually or automatically initiated by high drywell pressure, low reactor water

level, high radiation signal from the system radiation monitor, or as a result of a LOOP condition. Change over to the smoke clear mode is manually initiated.

Status lights on the control panel indicate that the motor driven fans are energized. All dampers are provided with limit switches to provide indication of their opened or closed position on the control panel. During emergency recirculation mode of operation, one or both of the fans operate continuously.

The instrumentation and controls for the control complex chilled water system are shown in <Figure 9.4-20>.

The control complex chilled water system has two loops. Loop A provides chilled water to the control room cooling coil A, and motor control center area and miscellaneous areas cooling coil A. Loop B provides chilled water to the control room cooling coil B, and the motor control center area and miscellaneous areas cooling coil B. The two loops (A and B) are served by three 100 percent capacity circulating pumps and three 100 percent capacity chillers (A, B and C).

The circulating pumps and associated chillers are powered from the Class 1E electrical system.

A control complex chilled water chiller is automatically shut down upon loss of chilled water or cooling water flow through the chiller.

The Control Complex Chilled Water C chiller which is not diesel backed can be operated as a front line chiller, and chiller A and B can be used as standby chillers. During a LOOP/LOCA event, the

Control Complex Chilled Water C chiller and its associated pump are tripped. The A and B chiller and pumps are automatically started upon receiving a LOOP/LOCA signal.

The system valve lineup and operation will be the same for normal and post-LOOP or LOCA conditions.

The operation of the system, with the exception of the automatic chiller shutdowns, is remote-manual.

Separation within the control complex chilled water system is such that no single failure will cause the complete loss of the chilled water system. The circulating pumps and associated chiller and control equipment have the following power division arrangements:

Division 1 (Unit 1)	Division 2 (Unit 1)	Division 1 (Unit 2)
Circulating Pump A	Circulating Pump B	Circulating Pump C
Chiller A	Chiller B	Chiller C
Controls & Instr. A	Controls & Instr. B	Controls & Instr. C

7.3.1.1.8 ESF Building and Area HVAC System - Instrumentation and Control

a. System Function

The ESF building and area HVAC systems provide and maintain suitable environmental conditions for ESF or ESF supporting

equipment building compartments. The ESF Building and Area HVAC system consist of:

1. Motor control center (MCC), switchgear and miscellaneous electrical equipment area HVAC System.

2. Battery room exhaust system.

3. Diesel generator building ventilation system.

b. System Operation

The MCC, switchgear and miscellaneous electrical equipment area HVAC system consists of two redundant trains of fans, filters, plenums, and ductwork Refer to <Figure 9.4-1>.

The MCC, switchgear and miscellaneous electrical equipment area HVAC system is normally manually initiated from a local panel. During normal operation, one of the two trains of redundant components operate continuously. A LOOP or combined LOCA signal consisting of low reactor water level or high drywell pressure will automatically initiate the standby train. In addition, automatic switch over to the standby train on low flow is provided as an operator convenience during normal operation.

Smoke detectors are installed in each supply and return fan discharge duct to give alarm indication on the local panel and to alarm in the control room upon detection of smoke.

Each room (total of 21 rooms) is provided with a temperature element which alarms and indicates on a temperature monitoring system in the control room. In addition, all fan motors are provided with status indicating lights in the control room.

The battery room exhaust system consists of two redundant subsystems or trains <Figure 9.4-1>.

The battery room exhaust system is normally manually initiated from a local panel. During normal operation, one of the two trains of redundant components operate continuously. A LOOP or a combined LOCA signal consisting of low reactor water level or high drywell pressure will automatically initiate the standby train. In addition, automatic switchover to the standby train on low flow is provided as an operator convenience during normal operation.

Smoke detector in the outlet duct of each fan to give alarm indication on the local panel and to alarm in the control room upon detection of smoke.

All components are controlled from a local panel. All fan motors are provided with indicating or status lights in the control room.

The diesel generator building ventilation system has two 100 percent capacity redundant supply fans for each division diesel generator room <Figure 9.4-14>.

The diesel generator building ventilation system is normally idle, except for the auxiliary exhaust fan, which operates automatically when the diesel is not operating to promote further cooling in the diesel generator room. The system is automatically initiated when the respective diesel generator is started. See <Chapter 8> for diesel generator initiation signals. The supply fans can be started and stopped remote-manually from the control room. All of the DGBVS fans are interlocked to prevent their operation when the fire protection CO_2 system is activated.

Each diesel generator room is provided with two 100 percent capacity redundant supply fans. Each system is supplied power from the diesel generator it serves. Because cooling is not required, unless the diesel generator is operating, redundant power supplies are not required.

The diesel generator building ventilation system supply fans are remote-manually controlled from the control room. The mixing and exhaust louvers are interlocked with their respective fans. The mixing louvers are modulated by a temperature controller when the corresponding fan is running and assume their failed positions when the fan is stopped. When both fans are stopped, the mixing louvers modulate to promote natural ventilation. The exhaust louvers open when either supply fan is running and close when both supply fans stop. However, the exhaust louver closest to the auxiliary exhaust fan is maintained open during exhaust fan operation. The supply fans and exhaust louvers are provided with status lights. Control room switches permit operation of the ventilation systems independently of the diesel generators for testing or other purposes. The auxiliary exhaust fans operate automatically when the diesel generator is not operating to promote further cooling in the associated diesel room, and can be started and stopped manually from their local control panels.

The indications and alarms provided in the control room allow the operator to monitor and control the operation of each system. The redundant supply fans in each diesel generator room permit maintenance and testing without affecting diesel generator availability.

7.3.1.1.9 Annulus Exhaust Gas Treatment System (AEGTS)

a. System Function

The AEGTS maintains a negative pressure differential between the containment vessel annulus and the outside so that leakage from the containment vessel will be detained in the annular space, mixed with the annulus space air, diluted with air leakage into the annular space, and filtered before release to the unit vent <Section 6.5.3>.

b. System Operation

The AEGTS consist of two independent and redundant systems. One system operates during normal plant operation and the standby system is automatically initiated by a LOCA signal or abnormal low air flow.

During normal operation, the system creates a small negative pressure in the annular region, exhausting gases which may leak from the containment through the filter system to the plant vent thereby eliminating the possibility of uncontrolled ground level releases of radioactive gases through containment leaks. Each system is powered from a separate Class 1E power supply.

Two pressure differential transmitters, spaced 180° apart, transmit signals to record in the control room the pressure differential between the annulus and the outdoor air. The differential pressure transmitters also transmit signals to a differential pressure signal modifier which is wired to a controller located in the control room. The differential pressure signal modifier selects the least pressure differential signal and transmits a signal to the controller which sequentially modulates the discharge damper and the recirculation damper in order to maintain a (negative)

pressure differential in the annulus of 0.66 inch w.g. The 0.66 inches of water gauge pressure differential is provided to maintain the 0.25 inches of water gauge minimum pressure differential required due to instrument location, to meet plant post-LOCA conditions, and to adjust for all environmental conditions. The controller, located in the control room, has an AUTO/MANUAL switch to allow manual operation of the motor-operated dampers in case of controller malfunction.

The AEGTS operation will be under administrative control so that the units may be maintained as required by the maintenance schedule and procedures. Low flow alarms, pressure drop indicators, temperature indicators, and radiation monitor indicators are located in the control room and will give indication of the performance of the operational unit.

The AEGTS can be controlled remote-manually from the control room. All dampers and fan motors are provided with status indicating lights in the control room.

7.3.1.1.10 Pump Room Cooling System - Instrumentation and Controls

a. System Function

The purpose of the pump room cooling systems instrumentation and controls is to provide indication of proper cooling operation and to provide controls to put the cooling system into operation.

The instrumentation for the following systems is shown on <Figure 9.4-11>, <Figure 9.4-12>, and <Figure 9.4-13>.

b. System Identification

The pump rooms cooling system consists of the following subsystems:

1. The emergency core cooling system pump room cooling systems (ECCSCS)

   (a) High pressure core spray pump room cooling system.

   (b) Low pressure core spray pump room cooling system.

   (c) Residual heat removal C pump room cooling system.

   (d) Residual heat removal pump A room and residual heat removal pump A heat exchanger room cooling system.

   (e) Residual heat removal pump room B and residual heat removal pump B heat exchanger room cooling system.

   (f) Reactor core isolation cooling pump room cooling system.

2. The emergency service water pumphouse ventilation system (ESWVS).

3. The emergency closed cooling pump area cooling system (ECPCS).

The power supplied to each system instrumentation and controls is the same as the associated pump.

c. System Operation

1. ECCSCS

The fan cooling unit for the reactor core isolation cooling pump room will run in conjunction with the RCIC pump because it is interlocked with the RCIC turbine steam admission valve. The other ECCS pump room fan cooling units are interlocked with their respective pump motor circuits and will run whenever their associated pump runs.

A temperature element in each ECCS pump room and heat exchanger room alarms and gives readout in the control room when a preset high temperature is exceeded.

A differential pressure switch across each fan alarms in the control room and indicates locally on low air flow with the fan in operation.

2. ESWVS

The electric motor-operated outside and return air dampers in each fan mixing box are controlled by a temperature controller. The outside air dampers fail closed and the return air dampers fail open on loss of control signal. When the corresponding fan is stopped, the dampers are in their fail position. When the corresponding fan is started, the dampers are permitted to modulate.

A differential pressure switch across each fan alarms in the control room on low air flow as a result of high or low differential pressure with fan in operation.

Temperature elements in the pump area alarm in the control room when the room temperature falls below or rises above a preset low and high temperature set points.

The fan cooling units are interlocked with the corresponding pump motor circuits and will run whenever their associated pump runs.

The power for the instrumentation and controls on each fan cooling unit is provided from the same ESF division as the corresponding ESW pump.

3. ECPCS

The fan cooling units are interlocked with the associated pump motor circuits and will run whenever their associated pump runs.

Temperature elements in the pump area alarm and give readout in the control room when a preset high temperature is exceeded.

A differential pressure switch across each air handling unit fan alarms in the control room and indicates low air flow on local panel with the fan or associated pump in operation.

The power supply to the instrumentation and controls for each fan cooling unit is from the same ESF division as the corresponding pump.

7.3.1.1.11 Containment Combustible Gas Control System

a. Containment Combustible Gas Control System Function

The purpose of the combustible gas control in containment system is to monitor for the presence of free hydrogen gas within the drywell and containment following the unlikely event of a LOCA and to provide a means of controlling the buildup of this gas in the containment. Upon the detection of predetermined concentrations of hydrogen, the mixing system, and recombiner system will be manually started to mix the atmosphere within the drywell and containment, and to reduce the concentration of hydrogen within the drywell and containment. The combustible gas purge system can also be manually placed in operation from the control room to vent the drywell <Figure 6.2-62> and <Figure 7.3-8>.

The CCGCS consists of four subsystems:

1. Hydrogen Analysis System

2. Hydrogen Mixing System

3. Hydrogen Recombination System

4. Combustible Gas Purge System

b. System Operation

The hydrogen analysis system consists of two completely redundant hydrogen analyzers each with control room recorders and switch stations. One is located in the auxiliary building at Elevation 620′-6″ and the other in the intermediate building at Elevation 654′-6″ <Figure 1.2-5> and <Figure 1.2-7>. One is supplied by Division 1, the other by Division 2. Each analyzer

samples from four redundant sample lines: one from above the suppression pool, one from the space between the reactor vessel head and the drywell dome, one from the top of the drywell area, and one from the top of the dome of the containment vessel <Figure 7.3-8>.

Each sample point is manually selected for continuous sampling. After passing through the analyzers, the gas samples and any associated moisture are returned to the containment in an area above the suppression pool <Figure 7.3-8>. Each analyzer has the capability to measure a range of 0-10% hydrogen concentration and is provided with reference and calibration gases as required. Each analyzer has alarms to annunciate in the control room for the following conditions; high and high-high hydrogen concentration, low sample flow, and system failure. The sample isolation valves are closed during normal plant operation. They are opened by an administratively controlled key operated switch prior to starting the hydrogen analyzers following a LOCA.

The hydrogen mixing system consists of two completely independent redundant systems located in adjacent quadrants of the containment building. Each system consists of one air compressor and related ductwork.

Low discharge pressure for the compressor will be annunciated in the control room. Isolation valves between the drywell and containment vessel are motor-operated and have position indication in the control room. The compressor discharge control valve is interlocked to open when the compressor is started and closed when the compressor is stopped. Selector switches in the control room are provided for remote-manual control of these valves.

The system is normally idle except for periodic testing. Following a LOCA, each mixing system is started manually on high hydrogen concentration in the drywell. Manual initiation is acceptable because high hydrogen concentration will not be reached for at least a number of hours after the LOCA.

The hydrogen recombination system consists of two completely redundant systems located in the containment. Each system consists of a recombiner unit, a power supply cabinet and control panel which are separately mounted. The power supply cabinet and control panel are located outside containment. A wattmeter and thermocouple readout are provided on the control panel to monitor performance.

The hydrogen recombiners are remote-manually initiated from the control complex. Except for periodic testing, the recombiners are idle during normal operation.

The combustible gas purge system is designed to aid in the cleanup of hydrogen. This purge system is manually operated from the control room. The system is designed to utilize the annulus gas treatment unit to exhaust the hydrogen laden air from the drywell/containment. The system is provided with two containment isolation valves and a flow control valve failed in the open position which allows straight through flow to the AEGTS filters. The AEGTS is normally in service. The combustible gas purge system is normally used for drywell pressure control during plant startup and operation. For additional hydrogen control, refer to <Section 7.6.1.9>, Hydrogen Control System.

7.3.1.1.12 Suppression Pool Makeup (SPMU) System - Instrumentation and Controls

a. System Function

The suppression pool makeup (SPMU) system instrumentation and controls are designed to allow transfer of a portion of the water from the upper pool to the suppression pool. It will ensure long term drywell vent water coverage for all conceivable postaccident entrapment volumes, by gravity flow from the upper pool in accordance with the design basis described in <Section 6.2.7>.

b. System Operation

Four motor operated valves are furnished, two for each line, along with appropriate piping to route water from the upper pool to the suppression pool when the occasion demands it. Four narrow range (16-19 ft) suppression pool level measuring sensors are provided which will signal the need for water when the "low-low" water level (LLWL) is reached following a LOCA. Additionally, automatic makeup occurs following a LOCA plus a time delay. System logic is shown in <Figure 7.3-9>. For system P&ID, see <Figure 6.2-67>. <Section 7.5.1.4.2.4.d> provides a further discussion of the suppression pool water level instrumentation.

One narrow range channel per division is indicated and recorded in the control room. In addition, the LLWL set point both annunciates and provides a signal to actuate the suppression pool makeup flow.

Level sensor actuation signals for suppression pool makeup in a single electrical division are parallel such that either level sensor provides a signal to open the series valves on only the suppression pool makeup line in the same electrical division as the level sensors.

Each level sensor is a differential pressure cell. The instrument water level sensing lines run from the suppression pool to the sensors located outside of containment with the sensor static reference lines returning to containment atmosphere.

The suppression pool makeup system is not required for normal operations. The suppression pool level instrumentation channels will provide the operator with suppression pool level information during normal operation, and will also be available for postaccident tracking of suppression pool level.

The suppression pool makeup system controls do not require operator action to initiate the correct responses. However, the control room operator can manually initiate the system in modes requiring use. Alarms and indications in the control room allow the operator to interpret any situation that requires the suppression pool makeup system and to verify the responses of the system.

7.3.1.1.13 Containment Vacuum Relief (CVR) System

a. System Function

The CVR system is provided to limit the buildup of negative pressure inside the containment vessel in the event that one or both of the containment spray loops are inadvertently actuated <Figure 7.3-10>.

b. System Operation

The check valves are normally closed while the motor operated isolation valves are normally open. Both valves can be operated from the control room. The motor-operated isolation valve is closed automatically by a containment isolation signal. If vacuum relief is required during containment isolation, differential

pressure devices provide an isolation override and automatically open the valve as required. The control logic for this system is shown in <Figure 7.3-11>. Isolation valve position indicating lights and system bypassed, inoperative alarms in the control room provide the operator sufficient information to monitor the status of the system and its devices.

7.3.1.1.14 Drywell Vacuum Relief (DVR) System

Refer to <Section 7.7.1.12>

7.3.1.1.15 Standby Power Support Systems - Instrumentation and Controls

The standby power support systems consist of the HPCS and standby diesel generator support systems <Section 8.3.2>.

a. System Function

The purpose of the diesel generator support system instrumentation and control is to ensure the availability of an adequate fuel oil supply and starting air pressure to start and operate the diesel generators and to ensure that the ventilation fans are available to carry away heat from the diesel generators and prevent heat buildup in the room. Additionally, lubricating oil level and temperature and coolant temperature are maintained and monitored to assure quick start capability. The diesel generator ventilation system is discussed in <Section 7.3.1.1.8>.

The diesel generator support systems for each of the standby and HPCS diesel generators include the following five subsystems:

1. Diesel generator fuel oil system.

2. Diesel generator starting air system.

3. Diesel generator ventilation system.

4. Lubricating oil system.

5. Cooling water system.

b. System Operation

1. Diesel Generator Fuel Oil System

The instrumentation and controls for the diesel generator fuel oil storage and transfer system are provided to ensure that fuel is always available in the day tank and to alert the plant operators to any conditions which might jeopardize that objective so that corrective action can be taken.

Level switches are provided to automatically start and stop the fuel transfer pumps to maintain the fuel oil level in the day tanks within predetermined limits. Abnormal level conditions within the fuel tanks are annunciated in the control room. Pressure and level indicators are provided locally at the equipment as shown on <Figure 9.5-8>.

The diesel generator fuel oil transfer system has two motor-driven fuel transfer pumps per day tank. These pumps are normally operated automatically, although manual operation is possible from the local control panel for functional checkout or instrumentation calibration. In the automatic mode, a "low" level switch on the day tank starts the primary online pump. A separate "low-low" level switch starts the standby pump and annunciates this condition on the standby diesel generator local control panel and in the control room

by actuating the general diesel generator trouble alarm. Both pumps are stopped by individual "high" level switches. Additional level switches on the day tanks annunciate alarms on the standby diesel generator local control panel and in the control room if the tank level should continue to rise past the high level pump cutoff point or drop below the standby pump start level. Overflow is diverted back to the main storage tank.

Level switches are provided on the main storage tank to annunciate when fuel oil inventory drops below minimum required levels. Separate alarms are provided, both on the standby diesel generator local control panel and in the main control room, for level corresponding to a seven day supply of fuel oil and for level corresponding to a 24 hour supply of fuel oil. Alarms are also provided for the standby diesel generators only on the local diesel generator control panel for fuel oil transfer pump strainer high pressure drop. Actuation of any of the alarms on the local control panel annunciate the diesel generator trouble alarm in the control room.

Control room indication is provided for the storage and day tank levels. Local indication is provided for transfer pump discharge pressure, fuel oil strainer pressure drop and standby diesel generator day tank level.

A discussion of diesel generator engine protection interlocks is contained in <Section 8.3>. The detailed description of the fuel oil day tanks, storage tank and fuel transfer system is provided in <Section 9.5.4> for the standby diesel generator, and <Section 9.5.9.1> for the HPCS diesel generators.

2. Diesel Generator Starting Air System

The diesel generator starting air system instrumentation and controls are provided to ensure that an adequate supply of compressed air is always available during plant operation. Alarms are provided to alert the plant operators to lack of adequate air pressure in either of each diesels redundant air start systems so that corrective action can be taken. The starting air system is completely described in <Section 9.5.6> for the standby diesel generators and <Section 9.5.9.3> for the HPCS diesel generators and is shown on <Figure 9.5-10>. Control of each engine's two independent air compressors is through controls mounted on a local panel. The compressor may be operated manually by use of a selector switch but the normal mode is automatic operation. The automatic controls cycle the compressor as required to maintain the required receiver tank pressure. A local pressure indicator is provided for each receiver tank.

To provide for monitoring of starting air availability and interfacing with the standby diesel generator engine controls, a pressure sensing line is routed from just upstream of each pair of air admission solenoid valves on the engine to the local diesel generator control panel. In the control panel these lines connect to the following instrumentation:

(a) Pressure switches, two pair of switches per air start system, one pair of switches will actuate common starting air pressure low alarms on the local diesel generator control panel and in the control room if either air start receiver reaches the low setpoint. Actuation of the local alarm also actuates the diesel generator trouble alarm in the control room. The second pair of switches

will actuate the diesel generator out of service alarm in the control room if either air start receiver reaches the low low setpoint.

(b) Pressure switches, one per air start system, which interlock with the diesel generator LOCA and bus under/degraded voltage start circuit. Inadequate starting air pressure will prevent the corresponding start air admission solenoid valves from opening. This condition is applicable to LOCA and bus under/degraded voltage starts.

(c) Pressure switches, one per air start system, which control each air compressor.

(d) Pressure gauges, one per air start system.

A discussion of engine generator protection interlocks is contained in <Section 8.3>.

3. Diesel Generator Lubrication System

The diesel engine lubrication oil system is provided with sensors, controls and alarms as required to ensure complete monitoring of satisfactory system performance, safe engine operation and to alert the plant operators to abnormal conditions requiring investigation and corrective action. For the standby diesel generators, this system is instrumented as shown on <Figure 9.5-11>. For the standby diesel generators, instrumentation and controls are provided to monitor system pressures at important points, lubrication oil temperatures in and out of the engine, sump tank level, and provide automatic operation of the keepwarm circulating pump and heater. The HPCS diesel generator lubricating oil system is detailed in <Section 9.5.9.4>.

To alert the plant operators of abnormal conditions which should be investigated for corrective action on the standby diesel generators, alarms are provided for the following parameters:

(a) Sump Tank Level Low

(b) Lube Oil Pressure Low

(c) Right Bank Turbocharger Oil Pressure Low

(d) Left Bank Turbocharger Oil Pressure Low

(e) Lube Oil Filter Pressure Drop High

(f) Lube Oil Strainer Pressure Drop High

(g) Lube Oil into Engine Temperature Low

(h) Lube Oil into Engine Temperature High

(i) Lube Oil from Engine Temperature Low

(j) Lube Oil from Engine Temperature High

(k) Keepwarm Oil Pump/Heater Control Switch not in "AUTO"

(l) Engine Trip due to Low Lube Oil Pressure

(m) Engine Trip due to Low Turbocharger Oil Pressure

(n) Engine Trip due to High Lube Oil Temperature

With the exception of the Control Switch not in Auto alarm (Item k.), each condition annunciates a separate alarm on the local diesel generator control panel. The local alarm for Item k. is shared with other control switches which are normally to be in an AUTO position. Actuation of any of the local alarms also annunciate a common diesel generator trouble alarm in the control room. Additionally, those parameters which cause an engine trip (Items l, m, n) are separately annunciated in the control room.

The three engine trip functions (low lube oil pressure, low turbocharger oil pressure, high lube oil temperature) are only available when the engine is started for non-emergency purposes, e.g., periodic surveillance testing, and serve to trip the engine during normal operation long before damage might occur. When the engine is started by a LOCA or a bus under/degraded voltage signal these three trips are de-activated but not their corresponding alarms. This allows the plant operators to evaluate the operating condition of the engine against overall plant requirements and then make a decision as to whether or not to shut down the diesel generator.

A bypass of the nonessential trips for the Division 1 diesel generator is provided by a keylock switch (1R43-S122SS) in the Division 1 Engine Control Panel (1H51P054A). This bypass switch will be positioned in the 'OFF' position during normal plant operation. This switch will have no effect on the plant when positioned in the 'OFF' position because this causes the switch contacts to be in an open condition. The switch will be placed in the 'ON' position in the event of a Control Room fire, or there is a need to restart the diesel generator following a high temperature trip.

On the standby diesel generator, the keepwarm oil pump is provided with controls permitting automatic or manual operation. Except for testing or maintenance situations the pump is operated in the AUTO mode and is interlocked with the diesel generator so that the pump runs whenever the diesel generator is not running. The keepwarm heater control is interlocked with the pump so that the heater can only be energized when the pump is running.

When the standby diesel generator keepwarm pump is running, the heater cycles on and off as demanded by a lubricating oil thermostat located on the engine.

Separate indicators are provided on the standby diesel generator local control panel for lubricating oil pressure, right bank and left bank turbocharger oil pressure and lubricating oil filter differential pressure. Thermocouples in the lubricating oil piping feed signals corresponding to lubricating oil temperature into and from the engine to the multiple position selector switch on the local control panel. Through the use of this switch, which also receives signals from the combustion air intake and exhaust system and the engine cooling water system, these temperatures may be displayed on the digital temperature indicator on the local control panel.

Another set of thermocouples in the lubricating oil piping feed oil temperature in and out of the engine signals to a slow speed temperature recorder in the local control panel. This recorder operates continuously and provides a continuous record of important engine temperature for performance monitoring, trending and engine diagnostics.

4. Diesel Generator Cooling Water System

The diesel engine cooling water system is designed to remove the heat loads of the engine air intercooler, oil cooler and water jacket. Additional information on this system is provided in <Section 9.5.5> for the standby diesel generators and <Section 9.5.9.2> for the HPCS diesel generators.

7.3.1.1.16 Fuel Handling Area Exhaust Subsystem

The Fuel Handling Area Exhaust Subsystem (FHAES) is a subsystem of the Fuel Handling Area Ventilation System (FHAVS). The FHAES is an ESF System.

a. FHAES Function

The purpose of the exhaust subsystem is to exhaust air from potentially contaminated areas. The air is filtered and passed through a charcoal filter train prior to discharge to atmosphere via the unit vent.

b. FHAES Operation

The exhaust subsystem consists of three-50 percent capacity exhaust fans and three-50 percent capacity charcoal filter trains. These filter trains include demisters, roughing filters, electric heating coils, HEPA prefilters, charcoal filters, and HEPA after-filters.

Schematic arrangements of mechanical equipment and instrumentation for the ESF and non-ESF portions of the Fuel Handling Area Ventilation System are shown on <Figure 9.4-4>.

Fuel Handling Area Exhaust Subsystem instrumentation is provided for indication in the control room of the following:

1. Indication of which exhaust fans are energized (status light).

2. Low air flow with exhaust fan in operation (alarm).

3. Smoke in exhaust fan common discharge ducts (alarm).

4. High radiation in the exhaust duct (alarm).

5. High and high-high temperature in the charcoal beds (alarm).

6. FHB HVAC system overload/power lost (alarm).

7. Continuous carbon bed temperature indication on panel H13-P904.

8. Exhaust air high moisture (alarm).

This system is manually initiated from the control room. During normal operation one supply fan and two exhaust fans operate. High radiation upstream of the charcoal exhaust units alarms in the control room and shuts down the supply fan. The exhaust units continue to run exhausting air through the charcoal filter units.

7.3.1.2 Design Basis

The ESF systems are designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the reactor coolant pressure boundary. <Chapter 15> identifies and evaluates events that jeopardize the fuel barrier and reactor coolant pressure boundary. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are identified, are presented in that chapter.

a. Variables Monitored to Provide Protective Action

The following variables are monitored in order to provide protective actions to the ESF systems:

1. HPCS

(a) Reactor Vessel Low Water Level (Trip Level 2)

(b) Drywell High Pressure

2. ADS

(a) Reactor Vessel Low Water Level (Trip Level 3)

(b) Reactor Vessel Low Water Level (Trip Level 1)

3. LPCS and LPCI

(a) Reactor Vessel Low Water Level (Trip Level 1)

(b) Drywell High Pressure

4. CRVICS

(a) Reactor Vessel Low Water Level (Trip Level 3)

(b) Reactor Vessel Low Water Level (Trip Level 2)

(c) Reactor Vessel Low Water Level (Trip Level 1)

(d) Main Steam Line High Radiation

(e) Main Steam Line Area High Ambient and Differential Temperature (MSL Tunnel), MSL Area High Ambient Temperature (Turbine Bldg).

(f) Main Steam Line High Flow

(g) Turbine Inlet Low Steam Pressure

(h) Containment and Drywell Purge and Vent Exhaust High Radiation

(i) RWCU High Differential Flow

(j) RWCU Area High Ambient Temperature and Differential Temperature

(k) RHR Area High Ambient Temperature and Differential Temperature

(l) Main Condenser Low Vacuum

(m) High Drywell Pressure

(n) RWCU Heat Exchanger Outlet High Temperature

(o) SLCS Actuation

(p) Reactor Vessel Pressure

5. (Deleted)

6. RHRS-CSCM

(a) Drywell High Pressure

(b) Reactor Vessel Water Level (Trip Level 1)

(c) Containment High Pressure

7. RHRS-SPCM

(a) Suppression Pool Temperature

(b) Drywell High Pressure

(c) Reactor Vessel Low Water Level (Trip Level 1)

8. Emergency Water Systems: ESW and ECC

(a) RHR, LPCS, RCIC, or Diesel Generator Start

(b) HPCS Start (just Loop "C" of ESW is needed)

9. Containment Combustible Gas Control System

(a) Containment hydrogen concentration

10. Standby Power Systems

(a) HPCS and Standard Diesel Generator Systems

(1) Refer to <Section 8.3.2>

(b) Diesel Generator Support Systems

(1) Fuel Oil Day Tank Level

(2) Fuel Oil Main Storage Tank Level

(3) Starting Air Receiver Pressure

(4) Standby or HPCS Diesel Start

11. Annulus Exhaust Gas Treatment System (AEGTS)

(a) Reactor Vessel Low Water Level (Trip Level 1)

(b) Drywell High Pressure

(c) Annulus to Outside Air Differential (AEGTS only)

(d) Low Flow (Fan Failure) on the Operating Train

12. Suppression Pool Makeup System

(a) Reactor Vessel Low Water Level (Trip Level 1)

(b) Drywell High Pressure

(c) Suppression Pool Low-Low Level

13. Containment Vacuum Relief System

(a) Reactor Vessel Low Water Level (Trip Level 2)

(b) High Drywell Pressure

(c) Low Containment to Outside Air Differential Pressure

14. ESF Building and Area HVAC System

(a) Reactor Vessel Low Water Level (Trip Level 1)

(b) High Drywell Pressure

(c) Diesel Generator Start Signals (Diesel Generator Building Ventilation System only)

15. Pump Room Cooling Systems

(a) ECCS Pump Motor Running

(b) RCIC Steam Admission valve Open. (RCIC Pump Room only)

16. Control Complex HVAC

    (a) Reactor Vessel Low Water Level (Trip Level 1)

    (b) Drywell High Pressure

    (c) High Radiation

    (d) Loss of Offsite Power

17. Fuel Handling Area Ventilation System

    (a) Charcoal Filter Inlet High Radiation

The plant conditions which require protective action involving the ESF systems are described in <Chapter 15> and <Appendix 15A>.

b. Location and Minimum Number of Sensors

Where applicable in Technical Specifications, the minimum number of sensors is specified to monitor safety-related variables. There are no sensors in the ESF systems which have a spatial dependence.

c. Prudent Operational Limits

Operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious ESF system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

d. Margin

The margin between operational limits and the limiting conditions of operation of ESF systems are accounted for in Technical Specifications.

e. Levels

Levels requiring protective action are established in Technical Specifications.

f. Range of Transient, Steady-State and Environmental Conditions

Environmental conditions for proper operation of the ESF components are discussed in <Section 3.11>.

g. Malfunctions, Accidents and Other Unusual Events Which Could Cause Damage to Safety System

<Chapter 15> describes the following credible accidents and events: floods, storms, tornadoes, earthquakes, fires, LOCA, pipe break outside containment. Each of these events is discussed below for the ESF systems.

1. Floods

   The buildings containing ESF systems components have been designed to meet the PMF (Probable Maximum Flood) at the site location. This ensures that the buildings will remain water-tight under PMF conditions including wind generated wave action and wave runup. For a discussion of internal flooding protection, refer to <Section 3.4.1> and <Section 3.6>.

2. Storms and Tornadoes

The buildings containing ESF systems components have been designed to withstand meteorological events described in <Section 3.3>.

3. Earthquakes

The structures containing ESF systems components have been seismically qualified as described in <Section 3.7> and <Section 3.8>, and will remain functional during and following a safe shutdown earthquake (SSE). Seismic qualification of instrumentation and electrical equipment is discussed in <Section 3.10>.

4. Fires

To protect the ESF systems in the event of a postulated fire, the redundant portions of the systems are separated by fire barriers. If a fire were to occur within one of the sections or in the area of one of the panels, the ESF systems functions would not be prevented by the fire. The use of separation and fire barriers ensures that even though some portion of the systems may be affected, the ESF systems will continue to provide the required protective action.

5. LOCA

The ESF systems components functionally required during and/or following a LOCA have been environmentally qualified to remain functional as discussed in <Section 3.11>.

6. Pipe Break Outside Secondary Containment

This condition will not affect the ESF systems. Refer to <Section 3.6>.

7. Missiles

Protection for safety-related components is described in <Section 3.5>.

h. Minimum Performance Requirements

Minimum performance requirements for ESF instrumentation and controls are provided in Technical Specifications.

7.3.1.3 Final System Drawings

The final system drawings, including piping and instrumentation diagrams, flow diagrams and functional control diagrams control logic diagrams, have been provided or referenced for the ESF systems in this section.

ESF systems elementary diagrams are listed in <Section 1.7.1>.

7.3.2 ANALYSIS

7.3.2.1 ESF Systems - Instrumentation and Controls

<Chapter 15> evaluates the individual and combined capabilities of the ESF systems.

The ESF systems are designed such that a loss of instrument air, a plant load rejection or a turbine trip will not prevent the completion of the safety function.

7.3.2.1.1 Conformance to <10 CFR 50 Appendix A>

The following is a discussion of conformance to those General Design Criteria which apply specifically to the ESF systems. Refer to <Section 7.1.2.2> for a discussion of General Design Criteria which apply equally to all safety-related systems.

a. Criterion 33

   See <Section 7.3.1.1.1> (HPCS).

b. Criterion 34

   See <Section 7.3.1.1.1> (ECCS) and <Section 7.3.1.1.6> (EWS).

c. Criterion 35

   See <Section 7.3.1.1.1> (ECCS) and <Section 7.3.1.1.6> (EWS).

d. Criterion 37, 46

   See <Section 7.3.2.1.3> <Regulatory Guide 1.22>.

e. Criterion 38

   See <Section 7.3.1.1.4> (RHRS-CSCM), <Section 7.3.1.1.5> (RHRS-SPCM) and <Section 7.3.1.1.6> (EWS).

f. Criterion 40

   See <Section 7.3.1.1.4> (RHR-CSCM) and <Section 7.3.1.1.5> (RHRS-SPCM).

g. Criterion 41

See <Section 7.3.1.1.11> (CCGC) and <Section 7.3.1.1.9> (AEGTS).

h. Criterion 44

See <Section 7.3.1.1.6> (EWS)

i. Criterion 64

See <Section 7.3.1.1.4> (CRVICS).

7.3.2.1.2 Conformance to IEEE Standards

The following is a discussion of conformance to those IEEE standards which apply specifically to the ESF systems. Refer to <Section 7.1.2.3> for a discussion of IEEE standards which apply equally to all safety-related systems.

a. IEEE Standard 279 Criteria for Protection Systems for Nuclear Power Generating Stations

1. General Functional Requirement (IEEE Standard 279, Paragraph 4.1)

   The ESF systems automatically initiates the appropriate protective actions, whenever the parameters described in <Section 7.3.1.2.a> reach predetermined limits, with precision and reliability, assuming the full range of conditions and performance discussed in <Section 7.3.1.2>.

2. Single Failure Criterion (IEEE Standard 279, Paragraph 4.2)

ESF systems are not required to meet single failure criteria on an individual system (division) basis. However, on a network basis, the single failure criteria does apply to assure the completion of a protective function. Redundant sensors, wiring, logic, and actuated devices are physically and electrically separated such that a single failure will not prevent the protective function. Refer to <Section 8.3.1.4> for additional discussion of the PNPP separation criteria.

3. Quality Components (IEEE Standard 279, Paragraph 4.3)

For a discussion of the quality of ESF system components and modules, refer to <Section 3.11>.

4. Equipment Qualification (IEEE Standard 279, Paragraph 4.4)

Qualification tests of the relay panels are conducted to confirm their adequacy for this service. In situ operational testing of these sensors, channels and other entire protection system will be performed during the preoperational test phase.

For a complete discussion of ESF equipment qualification, refer to <Section 3.2>, <Section 3.10> and <Section 3.11>.

5. Channel Integrity (IEEE Standard 279, Paragraph 4.5)

For a discussion of ESF systems channel integrity under all extremes of conditions described in <Section 7.3.1.2>, refer to <Section 3.10>, <Section 3.11>, <Section 8.2.1>, and <Section 8.3.1>.

6. Channel Independence (IEEE Standard 279, Paragraph 4.6)

ESF systems channel independence is maintained through the application of the PNPP separation criteria as described in <Section 8.3.1.4>.

7. Control and Protection Interaction (IEEE Standard 279, Paragraph 4.7)

There are no ESF system and control system interactions.

8. Derivation of System Inputs (IEEE Standard 279, Paragraph 4.8)

The ESF variables are direct measures of the desired variables requiring protective actions. Refer to <Section 7.3.1.1>.

9. Capability of Sensor Checks (IEEE Standard 279, Paragraph 4.9)

Refer to <Section 7.3.2.1.3>, <Regulatory Guide 1.22>.

10. Capability for Test and Calibration (IEEE Standard 279, Paragraph 4.10)

Refer to <Section 7.3.2.1.3>, <Regulatory Guide 1.22>.

11. Channel Bypass or Removal from Operation (IEEE Standard 279, Paragraph 4.11)

During periodic test of any one ESF system channel, a sensor or trip unit may be taken out-of-service and returned to service under the administrative control procedures. Since only one sensor or trip unit is taken out-of-service at any

given time during the test interval, protective action capability for ESF system automatic initiation is maintained through the remaining redundant instrument channels.

12. Operating Bypasses (IEEE Standard 279, Paragraph 4.12)

The ESF systems contain the following operating bypasses.

The CRVICS has four bypasses:

(a) Main steam line low pressure operating bypass which is imposed by means of the mode switch. In all modes except run, the mode switch cannot be left in this position above 10 percent of rated power without initiating a scram. Therefore, the bypass is removed by the normal reactor operating sequence.

(b) The low condenser vacuum bypass which is imposed by means of a manual bypass switch.

(c) The RWCU bypass which is imposed by means of a manual bypass switch. This bypass applies to the RWCU isolation signal originating from the leak detection system.

(d) The reactor vessel low water (Level 1) MSIV isolation bypass which is imposed by means of manual key locked bypass switches.

13. Indication of Bypasses (IEEE Standard 279, Paragraph 4.13)

For a discussion of bypass and inoperability indication, refer to <Section 7.1.2.4>, <Regulatory Guide 1.47>.

14. Access to Means for Bypassing (IEEE Standard 279, Paragraph 4.14)

Access to means of bypassing any safety action or function for the ESF systems is under the administrative control of the control room operator. The operator is alerted to bypasses as described in <Section 7.1.2.4>, <Regulatory Guide 1.47>.

Control switches which allow system bypasses are keylocked. All keylock switches in the control room are designed such that the key can only be removed when the switch is in the safe position. All keys will normally be removed from their respective switches during operation and maintained under the control of the Shift Manager.

15. Multiple Trip Settings (IEEE Standard 279, Paragraph 4.15)

There are no multiple set points within the ESF systems.

16. Completion of Protective Action Once Initiated (IEEE Standard 279, Paragraph 4.16)

Each of the automatically initiated ESF system control logics seal-in electrically and remain energized after initial conditions return to normal. Deliberate operator action is required to return (reset) an ESF system logic to normal.

17. Manual Initiation (IEEE Standard 279, Paragraph 4.17)

Refer to the discussion of <Regulatory Guide 1.62> in <Section 7.3.2.1.3>.

18. Access to Setpoint Adjustments (IEEE Standard 279, Paragraph 4.18)

All access to ESF system set point adjustments, calibration controls and test points are under the administrative control of the control room operator. Setpoint adjustments for all safety-related trip units are located in the control room behind keylocked tamper guards.

19. Identification of Protective Actions (IEEE Standard 279, Paragraph 4.19)

    ESF protective actions are directly indicated and identified by annunciators located in the control room and a typed record is available from the process computer.

20. Information Readout (IEEE Standard 279), Paragraph 4.20)

    The ESF systems are designed to provide the operator with accurate and timely information pertinent to their status. They do not introduce signals that could cause anomalous indications confusing to the operator.

21. System Repair (IEEE Standard 279, Paragraph 4.21)

    The ESF systems are designed to permit repair or replacement of components.

    Recognition and location of a failed component will be accomplished during periodic testing or by annunciation in the control room.

22. Identification of Protection Systems (IEEE Standard 279, Paragraph 4.22)

    The identification scheme for the ESF system is discussed in <Section 8.3.1>.

7.3.2.1.3 Conformance to Regulatory Guides

The following is a discussion of conformance to those regulatory guides which apply specifically to the ESF systems. Refer to <Section 7.1.2.4> for a discussion of regulatory guides which apply equally to all safety-related systems.

a. <Regulatory Guide 1.7>

For Control of Combustible Gas Concentrations in Containment following LOCA, refer to <Section 1.8>.

b. <Regulatory Guide 1.22>

The ESF systems instrumentation and controls are capable of being tested during normal plant operation, unless that testing is detrimental to plant availability, to verify the operability of each system component. Testing of safety-related sensors is accomplished by valving out each sensor, one at a time, and applying a test pressure source. The main steam line radiation sensors may be removed and test sources applied. The combustible gas control system sensors are tested by introducing sample gases of known analysis. This verifies the operability of the sensor and the associated logic components in the control room. Functional operability of temperature sensors may be verified by readout comparisons, applying a heat source to the locally mounted temperature sensing elements or by continuity testing.

For the HPCS, LPCS and LPCI, testing for functional operability of the control logic relays can be accomplished by use of plug-in test jacks and switches in conjunction with single sensor tests.

Four test jacks are provided to allow ADS logic testing one for each logic channel. During testing, only one logic should be

actuated at a time. However, when the test plug is plugged into one channel, the complement channel of that trip system is automatically rendered inoperative. Therefore, inadvertent ADS actuation cannot occur even if both channels are improperly placed in the test mode simultaneously. An alarm is provided if a test plug is inserted in either channel in a division. Operation of the test plug switch and the permissive contacts will close one of the two series relay contacts in the valve solenoid circuit. This will cause a panel light to come on indicating proper channel operation.

Annunciation is provided in the control room whenever a test plug is inserted in a jack to indicate to the operator that an ECCS is in a test status.

Operability of air operated, solenoid operated and motor-operated valves is verified by actuating the valve control switches and monitoring the position change by position indicating lights at the control switch.

The ESF systems are provided with indications, status displays, annunciation, and computer printouts which aid the control room operator during period system tests to verify component operability.

c. <Regulatory Guide 1.53>

Refer to IEEE Standard 279 Paragraph 4.2, <Section 7.3.2.1.2>.

d. <Regulatory Guide 1.62> - Manual Initiation of Protective Actions

The HPCS, LPCS and the Division 2 LPCI system are manually initiated at the system level from the control room by actuation of a switch. The LPCS switch also initiates the Division 1 LPCI system.

The ADS and the CRVICS are manually initiated at the system (division) level by actuation of two switches (one for each logic channel).

The RHRS containment spray cooling mode is manually initiated at the system (division) level by actuation of the RHR pump start control switch and by opening the Containment Spray or Suppression Chamber Spray valves.

The RHRS suppression pool cooling mode is manually initiated from the main control room by actuation of system pump and valve controls.

All ESF and ESF supporting systems are provided with manual actuation at the system and or component level. These actuations are discussed in the system operation section for each system.

The actuation of the system level manual initiation switches simulate all the actions of automatic or manual (individual equipment initiation) system actuation.

e. <Regulatory Guide 1.73> - Qualification Testing of Electric Motor Operators installed Inside the Containment of Nuclear Power Plants

See <Section 3.10> and <Section 3.11> for discussion of compliance.

f. <Regulatory Guide 1.95> - Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release

See <Section 1.8> for discussion of compliance.

g. <Regulatory Guide 1.96> - Design of Main Steam Isolation valve Leakage Control System for Boiling Water Reactor Nuclear Power Plants

MSIV-LCS has been eliminated and is abandoned in place.

TABLE 7.3-1

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME TABLE

Trip Function	Response Time (seconds)	Notes
MAIN STEAM LINE ISOLATION		
1. Reactor Vessel Water Level - Low, Level 1	≤1.0	See Note (1)(2)(3)
2. Main Steam Line Pressure - Low	≤1.0	See Note (1)(2)(3)
3. Main Steam Line Flow - High	≤0.5	See Note (1)(2)(3)

NOTES:

(1) Isolation system instrumentation response time specified for the Trip function actuating each containment isolation valve shall be added to the isolation time for each valve to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

(2) Isolation system instrumentation response time for MSIVs only. No diesel generator delays assumed.

(3) The sensor is not included in the response time testing for these circuits. Response time testing for the remaining channel including trip unit and relay logic is required.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

7.4.1 DESCRIPTION

This section discusses the instrumentation and controls of the following systems required for safe plant shutdown:

a. Reactor Core Isolation Cooling (RCIC) System

b. Standby Liquid Control System (SLCS)

c. RHRS Shutdown Cooling Mode (RSCM)

d. Remote Shutdown System (RSS)

The sources which supply power to the safe shutdown systems originate from onsite ac and/or dc safety-related buses. Refer to <Chapter 8> for a complete discussion of the safety-related power sources.

7.4.1.1 Reactor Core Isolation Cooling (RCIC) System

a. RCIC System Function

The reactor core isolation cooling system <Section 5.4.6> instrumentation is designed to maintain or supplement reactor vessel water inventory during the following conditions:

1. When the reactor vessel is isolated from its primary heat sink (the main condenser) and maintained in the hot standby condition.

2. When the reactor vessel is isolated and accompanied by a loss of normal coolant flow from the reactor feedwater system.

3. When the plant is being shutdown and normal coolant flow from the feedwater system is lost before the reactor is depressurized to a level where the reactor shutdown cooling mode of the RHR system can be placed into operation.

b. RCIC System Operation

Schematic arrangements of system mechanical equipment is shown in <Figure 5.4-9>. RCIC system component control logic is shown in <Figure 7.4-1>. Plant layout drawings are shown in <Section 1.2> and elementary diagrams are listed in <Section 1.7.1>. Operator information displays are shown in <Figure 5.4-9> and <Figure 7.4-1>.

The RCIC system can be initiated either manually or automatically. The control room operator can initiate RCIC by operating the manual initiation switch which simulates an automatic initiation or by activating each piece of equipment sequentially as required.

RCIC is automatically initiated by four redundant differential pressure transmitters/trip relay contacts, arranged in a one-out-of-two-twice logic configuration, which sense reactor vessel low water trip (trip Level 2).

The RCIC steam line isolation motor-operated (MO) inboard valve, the RCIC steam line isolation MO outboard valve, and the turbine exhaust to the suppression pool MO valve are in the open position and they require no change of position for automatic system initiation.

The RCIC system responds to an automatic initiation signal and reaches design flow rate within 30 seconds as follows (actions are simultaneous unless stated otherwise):

1. The pump suction from the condensate storage tanks valve E51F010 is signaled open.

2. To ensure that pump discharge flow is directed to the reactor vessel only, the test return line to the condensate storage tank valves E51F022 and E51F059 are signaled closed.

3. The turbine steam inlet valve 1E51F0045 is signaled to open.

4. When the turbine steam inlet valve E51F045 starts to open, the RCIC pump discharge to reactor vessel valve E51F013 is signaled open. Valve E51F013 is prohibited from opening or, if open, automatically closes when E51F045 or the turbine trip and throttle valve is closed.

5. The turbine gland seal compressor is signaled to start.

6. When valve E51F045 leaves the closed position, the RCIC turbine speed accelerates until the automatic flow controller set point is reached and the system discharge flow is controlled by the turbine electronic governor mechanism.

If water level in the condensate storage tanks becomes low, RCIC pump suction is automatically transferred from the condensate storage tank to the suppression pool by opening valve E51F031. When the Control Room is notified of the issuance of a tornado warning for the vicinity of the plant, or if a tornado is sighted in the immediate vicinity of the plant, administrative controls

require the RCIC suction to be aligned to the tornado missile protected suppression pool. Once valve F031 is fully open, the condensate storage tank valve E51F010 is automatically closed.

The RCIC system includes design features which provide system equipment protection or accomplish containment isolation if certain types of abnormal events occur. The turbine is either manually trip actuated by the control room operator or automatically shut down by closing the turbine trip and throttle valve if any of the following conditions are detected:

1. Turbine overspeed

2. High turbine exhaust pressure

3. RCIC isolation signal

4. Low pump suction pressure

To protect the RCIC pump from overheating during low flow conditions, the pump discharge flow and pressure are monitored. If the pump discharge pressure transmitter indicates that the pump is running and the pump discharge flow transmitter indicates low flow, the minimum flow return line valve E51F019 is automatically opened. The minimum flow valve is automatically closed when flow is normal or when either the turbine trip and throttle valve or the steam inlet valve E51F045 is closed.

High water level in the reactor vessel indicates that the RCIC system has performed satisfactorily in providing make up water to the reactor vessel. Further increase in level could result in RCIC system turbine damage caused by gross carry-over of moisture. To prevent this, a high water level trip is used to initiate closure

of steam supply valve E51F045, to shut off the steam to the turbine and halt RCIC operation. The system will automatically reinstate if the water level decreases to the reactor water low level trip point.

Air operated (AO) valves E51F025, F026, and F054, and a condensate drain pot are provided in a drain pipeline arrangement just upstream of the turbine supply valve. The water level in the steam line drain condensate pot is controlled by a level switch and valve E51F054 which energizes to allow condensate to flow out of the drain pot by bypassing the steam trap. The drainage path is isolated by closing E51F025 and E51F026 upon receipt of an RCIC initiation signal.

RCIC steam turbine exhaust line vacuum breaker valves E51F077, E51F078 and turbine exhaust to suppression pool MO E51F068 are normally open but close automatically following system trip on low steam line pressure if drywell pressure exceeds the setpoint.

Detection of abnormal conditions by redundant leak detection portions of the RCIC system will cause system isolation as follows:

1. Division 1 circuitry will override the manual control switches and signal the outboard steamline isolation valve F064 and pump suction to suppression pool valve F031 to close.

2. Division 2 circuitry will override the manual control switches and signal the inboard steamline isolation valve F063 and steamline warmup valve F076 to close.

The conditions that will initiate the isolation are:

1. RCIC low steamline pressure.

2. RCIC steam supply line high differential pressure.

3. Main steam tunnel high ambient or differential (inlet/outlet) ventilation air temperature.

4. RHR equipment area high ambient or differential (inlet/outlet) ventilation air temperature. Differential temperature instrumentation is required to provide the leak detection isolation signal only when the room coolers are running.

5. RCIC turbine exhaust diaphragm high pressure.

6. RCIC equipment area high ambient temperature.

For a complete description of the RCIC system leak detection isolation signals, see <Section 7.6.1>.

The RCIC system may be isolated after initiation by the control room operator by actuation of a switch which causes the outboard steamline isolation valve to close.

7.4.1.2 Standby Liquid Control System (SLCS)

a. SLCS Function

The standby liquid control system <Section 9.3.5> instrumentation is designed to manually initiate injection of a liquid neutron absorber into the reactor. Other instrumentation is provided to maintain this liquid chemical solution well above saturation temperature in readiness for injection.

The SLCS is a backup independent method of manually shutting down the reactor to cold shutdown conditions from normal operation or from anticipated transient conditions when control rod insertion capability is lost.

b. SLCS Operation

Schematic arrangements of system mechanical equipment is shown in <Figure 9.3-19>. SLCS component control logic is shown in <Figure 7.4-2>, with applicable drawings listed in <Section 1.7.1>. Operator information displays are shown in <Figure 9.3-19> and <Figure 7.4-2>.

The SLCS is initiated by the control room operator by turning a keylocked switch for system A, or a different keylocked switch for system B to the "ON" position. The key is removable in the "OFF" position. Should the selected pump fail to start, the other key switch may be used to select the alternate pump loop.

When the SLCS is initiated, the explosive-operated valve in the selected loop fires and the tank discharge valve starts to open immediately. The pump that has been selected for injection will not start until the tank discharge valve is fully open.

Pumps are interlocked so that either the storage tank discharge valve or the test tank discharge valve must be open for the pump to run unless the pumps are being tested using the momentary contact pump test switch. When SLCS system A is initiated the outboard RWCU isolation valve is automatically closed and when SLCS system B is initiated the inboard RWCU isolation valve is automatically closed.

7.4.1.3 RHRS/Reactor Shutdown Cooling Mode (RSCM)

a. RSCM Function

The Reactor Shutdown Cooling Mode <Section 5.4.7> of the RHR System is used during a normal reactor shutdown.

The RSCM consists of instrumentation designed to provide decay heat removal capability for the reactor core by accomplishing the following:

1. Reactor cooling during shutdown operation after the vessel pressure is reduced to approximately 130 psig.

2. Cooling the reactor water to a temperature at which reactor refueling and servicing can be accomplished.

3. Diverting part of the shutdown flow to the reactor vessel head to condense the steam generated from the hot walls of the vessel while it is being flooded.

b. RSCM Operation

The reactor shutdown cooling system contains two loops. Either loop is sufficient to satisfy the cooling requirements for shutdown cooling. However, both loops share a common suction line with two suction valves in series. In the event that one of the suction valves fails closed and normal shutdown cooling is not available, an alternate shutdown cooling loop may be established. The normal shutdown suction path may be bypassed by manually switching to take suction water from the suppression pool, returning through the LPCI line and manually opening the ADS valves to allow reactor water to flow back through the SRV discharge line to the suppression pool.

The ADS valves may be actuated by either Division 1 or Division 2 power, thus providing redundancy in the event of a divisional power failure.

See <Section 5.4.7> for a complete description of the RSCM operation.

7.4.1.4 Remote Shutdown System (RSS)

a. RSS Function

The RSS is designed to achieve a cold reactor shutdown from outside the control room following these postulated conditions:

1. The plant is at normal operating conditions and all plant personnel have been evacuated from the control room and it is inaccessible.

2. The initial event that causes the control room to become inaccessible is assumed to be such that the reactor operator can manually scram the reactor before leaving the control room. Two backup means of scramming the reactor from outside the control room are available. This can be accomplished by opening the output breakers at ATWS UPS distribution panels EVIA and EVIB or by opening the output breakers of the RPS MG sets.

3. Under normal conditions, the main turbine pressure regulators may be controlling reactor pressure via the bypass valves. It is assumed that this turbine generator control panel function is also lost. In the event of a pressure decrease to the MSIV isolation setpoint, the inboard MSIV's will be shut from the

Division 1 remote shutdown panel. Increases in reactor pressure will be relieved through the safety relief valves to the suppression pool.

4. The reactor feedwater system which is normally available is also assumed to be inoperable. Reactor vessel water inventory is provided by the RCIC system.

The RSS is required only during times of control room inaccessibility when normal plant operating conditions exist (i.e., no transients or accidents are occurring).

b. Remote Shutdown System Operation

Some of the existing systems used for normal reactor shutdown operation are also utilized in the remote shutdown capability to shut down the reactor from outside the control room. The Division 1 remote shutdown capability is designed to control the required shutdown systems from outside the control room irrespective of hot shorts, open circuits, or shorts to ground in the associated control room circuits that may have resulted from an event causing an evacuation (for example, a damaging fire in the control room). The functions needed for Division 1 remote shutdown control are provided with manual transfer switches at the remote shutdown panel which override controls from the control room, provide complete electrical isolation of the associated control room circuits, and transfer the controls to the Division 1 remote shutdown panel. Division 1 remote shutdown control is not possible without actuation of the transfer devices. All necessary power supplies and control logic are also transferred. Operation of the transfer devices used to transfer control of devices from the control room to the Division 1, remote shutdown panel, causes an alarm in the control room. Access to the Division 1 remote shutdown panel is administratively and procedurally controlled.

Most system equipment (i.e., valves and pumps) necessary for proper system lineup and complete system control are located on the Division 1

remote shutdown panel. Additional equipment required for remote shutdown capability are provided with combination transfer/control switches located on associated MCC doors (valves) and local panels (fans, chillers, pumps). Operation of these transfer/control switches causes an alarm in the control room by de-energizing voltage monitor relays. Equipment required for remote shutdown capability that has only voltage monitoring and/or indicating light circuits in the control room are provided with isolating fuses.

Redundant remote shutdown capability is provided using the Division 2 remote shutdown controls. These controls are designed to parallel the controls from the control room. All signals required for the Division 2 remote shutdown panel will be supplied from the ERIS data acquisition cabinet. An indicating panel for the Division 2 remote shutdown system is located in the Division 2 switchgear room. The Division 2 remote shutdown is controlled by pull-to-lock switches mounted on the switchgear and MCC panels. The pull-to-lock switches are used to control pumps and valves of associated essential safe shutdown systems.

Manual activation of safety relief valves and the initiation of the reactor core isolation cooling (RCIC) system will maintain reactor water inventory and bring the reactor to a hot shutdown condition after scram. In the case of the Division 2 remote shutdown system, assume that automatic initiation of HPCS has occurred, thereby providing for RCIC system backup. During this phase of shutdown, the suppression pool will be cooled by operating the residual heat removal (RHR) system in the suppression pool cooling mode. Reactor pressure will be controlled and core decay and sensible heat rejected to the suppression pool by relieving steam pressure through the relief valves.

This procedure will cool the reactor and reduce its pressure at a controlled rate until reactor pressure becomes so low that the RCIC

system is unable to sustain operation. The RHR system will then be operated in the shutdown cooling mode using the RHR system heat exchanger to cool reactor water and bring the reactor to the cold low pressure condition.

1. Reactor Core Isolation Cooling (RCIC) System

   The following RCIC System equipment/functions have transfer and control switches located on the Division 1 remote shutdown control panel:

   E51-F010: Motor-operated valve (pump suction from condensate storage)
   E51-F013: Motor-operated valve (RCIC injection shutoff)
   E51-F019: Motor-operated valve (minimum flow to suppression pool)
   E51-F022: Motor-operated valve (test bypass to condensate storage)
   E51-C004: Gland seal system air compressor
   E51-F031: Motor-operated valve (pump suction from suppression pool)
   E51-F045: Motor-operated valve (steam to turbine)
   E51-F059: Motor-operated valve (test bypass to condensate storage)
   E51-F063: Motor-operated valve (steam supply line isolation inboard)
   E51-F064: Motor-operated valve (steam supply line isolation, outboard)
   E51-F068: Motor-operated valve (turbine exhaust to suppression pool)
   E51-F076: Motor-operated valve (steam line warmup line isolation)

E51-F077: Motor-operated valve (vacuum breaker isolation outboard)

E51-F078: Motor-operated valve (vacuum breaker isolation inboard)

E51-F510: Motor-operated valve (turbine trip and throttle valve)

See <Figure 5.4-10>.

The following RCIC system instrumentation is provided on the Division 1 remote shutdown control panel:

C61-R001: RCIC flow controller and indicator

C61-R003: RCIC turbine speed indicator

Indicating lights are provided for conditions of turbine tripped, turbine bearing oil low pressure, turbine governor bearing oil temperature high, and turbine coupling end bearing oil temperature high.

Valve position and pump status indicators are also provided.

2. Residual Heat Removal (RHR) System

The following RHR system loop A equipment/functions have transfer and control switches located at the Division 1 remote shutdown control panel:

E12-C002A: Residual heat removal pump

E12-F003A: Motor-operated valve (heat exchanger shell side outlet)

E12-F004A: Motor-operated valve (RHR pump suction)

E12-F006A: Motor-operated valve (shutdown cooling)

E12-F006B: Motor-operated valve (shutdown cooling)

E12-F008: Motor-operated valve (outboard shutdown isolation)
E12-F009: Motor-operated valve (inboard suction isolation)
E12-F011A: Motor-operated valve (RHR heat exchanger flow to suppression pool)
E12-F023: Motor-operated valve (reactor head spray)
E12-F024A: Motor-operated valve (RHR test line)
E12-F027A: Motor-operated valve (injection shutoff)
E12-F028A: Motor-operated valve (containment spray)
E12-F037A: Motor-operated valve (shutoff upper pool cooling)
E12-F042A: Motor-operated valve (RHR injection)
E12-F047A: Motor-operated valve (heat exchanger shell side inlet)
E12-F048A: Motor-operated valve (heat exchanger shell side bypass)
E12-F040: Motor-operated valve (discharge to radwaste)
E12-F053A: Motor-operated valve (RHR injection)
E12-F064A: Motor-operated valve (RHR pump minimum flow)
E12-F609: Motor-operated valve (SPCU to RHR second outboard isolation)

The following RHR system loop B equipment/functions have control switches located at their respective motor control centers or switchgear panels:

E12-C002B: Residual heat removal pump
E12-F003B: Motor-operated valve (heat exchanger shell side outlet)
E12-F004B: Motor-operated valve (RHR pump suction)
E12-F011B: Motor-operated valve (RHR heat exchanger flow to suppression pool)
E12-F024B: Motor-operated valve (RHR test line)
E12-F027B: Motor-operated valve (injection shutoff)
E12-F028B: Motor-operated valve (containment spray)
E12-F037B: Motor-operated valve (shutoff upper pool cooling)

E12-F042B: Motor-operated valve (RHR injection)

E12-F047B: Motor-operated valve (heat exchanger shell side inlet)

E12-F048B: Motor-operated valve (heat exchanger shell side bypass)

E12-F053B: Motor-operated valve (RHR injection)

E12-F064B: Motor-operated valve (RHR pump minimum flow)

See <Figure 5.4-13>.

The following RHR instrumentation is located on the Division 1 remote shutdown control panel:

C61-R005: RHR flow indicator for loop A

The following RHR instrumentation is located on the Division 2 remote shutdown indicating panel:

C61-R025: RHR flow indicator for loop B.

Valve position status indication and pump status indication.

3. Nuclear Boiler System

The following functions have transfer and control switches located at the Division 1 remote shutdown control panel and control switches at the Division 2 remote shutdown control panel:

B21-F051C: Air operated safety relief valve

B21-F051G: Air operated safety relief valve

B21-F051D: Air operated safety relief valve

The following functions have transfer and control switches located at the Division 1 remote shutdown control panel:

B21-F022A: Inboard main steam line A isolation valve.
B21-F022B: Inboard main steam line B isolation valve.
B21-F022C: Inboard main steam line C isolation valve.
B21-F022D: Inboard main steam line D isolation valve.

The following function has transfer/control switches located on the associated MCC compartment door:

B21-F019: Motor-operated valve (main steam line drain isolation)

The following nuclear boiler instrumentation is provided on the Division 1 remote shutdown control panel:

C61-R012: Reactor pressure/level recorder
C61-R010: Reactor level indicator
C61-R011: Reactor pressure indicator

The following nuclear boiler instrumentation is provided on the Division 2 remote shutdown control panel:

C61-R030: Reactor level indicator
C61-R031: Reactor pressure indicator

Valve position status indicators.

See <Figure 5.1-3>

4. Reactor Water Cleanup System

The following function has transfer/control switches located on the associated MCC compartment door:

G33-F004: Motor-operated valve (reactor water cleanup discharge isolation).

5. Emergency Service Water System

The following loop A emergency service water system equipment/functions have transfer and control switches located at the remote shutdown control panel:

P45-F014A: Motor-operated valve (RHR heat exchanger isolation)
P45-F068A: Motor-operated valve (RHR heat exchanger isolation)
P45-F130A: Motor-operated valve (pump discharge shutoff)
P45-C001A: Emergency service water pump

The following loop B emergency service water system equipment/functions have control switches located on the associated motor control centers and switchgear panels:

P45-F014B: Motor-operated valve (RHR heat exchanger isolation)
P45-F068B: Motor-operated valve (RHR heat exchanger isolation)
P45-F130B: Motor-operated valve (pump discharge shutoff)
P45-C001B: Emergency service water pump

See <Figure 9.2-1>.

The following emergency service water system instrumentation is provided on the Division 1 remote shutdown control panel:

P45-R033A: Flow indicator (RHR heat exchanger A)

P45-R055A: Flow indicator (ECC system heat exchanger A)

The following emergency service water system instrumentation is provided on the Division 2 remote shutdown control panel:

P45-R033B: Flow indicator (RHR heat exchanger B)

P45-R055B: Flow indicator (ECC system heat exchanger B)

Valve position and pump status indicators.

6. Emergency Closed Cooling System

The following loop A emergency closed cooling system equipment has transfer and control switches located at the Division 1 remote shutdown control panel:

P42-C001A: Emergency closed cooling pump A

The following loop B emergency closed cooling system has control switches located on the associated switchgear panel in the Division 2 switchgear room:

P42-C001B: Emergency closed cooling pump B

Pump status indicators. See <Figure 9.2-3>.

The following emergency closed cooling system instrumentation is provided on the Division 1 remote shutdown control panel:

P42-R045A: Flow indicator (ECC system heat exchanger A)

The following emergency closed cooling system instrumentation is provided on the Division 2 remote shutdown control panel:

P42-R045B: Flow indicator (ECC system heat exchanger B)

7. Instrument Power

The following instrument 120 Vac power systems have a transfer switch located at the Division 1 remote shutdown panel:

R41-K050: 120 Vac instrument power

8. Containment Atmosphere Monitoring System

The following containment atmosphere monitoring system instrumentation is provided on the Division 1 remote shutdown control panel:

D23-R230: Recorder (drywell pressure/temperature)
D23-R240: Recorder (suppression pool level/temperature)

The following containment atmosphere monitoring system instrumentation is provided on the Division 2 remote shutdown panel:

D23-R260: Drywell temperature indicator
D23-R270: Suppression pool temperature indicator
D23-R280: Drywell pressure indicator
G43-R102: Suppression pool level indicator

9. MCC, Switchgear and Miscellaneous Electrical Equipment Area HVAC Systems/Battery Room Exhaust System

The following loop A MCC, switchgear, and miscellaneous electrical equipment area HVAC Systems, and battery room exhaust system equipment have a common transfer/control switch located on the 480V switchgear panel EF1A01

M23-C001A: MCC, switchgear and miscellaneous electrical equipment area HVAC supply fan A

M23-C002A: MCC, switchgear and miscellaneous electrical equipment area HVAC return fan A

M24-C001A: Battery room exhaust fan A

P47-F045A: MCC, SWGR and miscellaneous electrical equipment area train "A" chilled water temperature control MOV

10. Emergency Closed Cooling Pump Area Cooling System

The following loop A emergency closed cooling pump area cooling system equipment has fuse isolation provided for control room indication, voltage monitoring and annunciation circuits:

M28-B001A: Emergency closed cooling pump area cooling system ventilation fan "A".

11. Emergency Service Water Pumphouse Ventilation System

The following loop A emergency service water pumphouse ventilation system equipment have a common transfer/control switch and manual control units (for dampers) located in the emergency service water pumphouse ventilation system remote shutdown panel:

M32-C001A: Emergency service water pumphouse system ventilation Unit "A"

M32-F070A: Emergency service water pumphouse system pump house wall louver "A"

M32-F040A: Emergency service water pumphouse system fan inlet air damper "A"

M32-F050A: Emergency service water pumphouse system mixing air damper "A"

12. Emergency Core Cooling System Pump Room Cooling System

The following emergency core cooling system pump room cooling system equipment have fuse isolation provided for control room indication and voltage monitoring circuits:

M39-B001A: Emergency core cooling system pump room cooling system RHR pump "A" and heat exchanger cooler.

M39-B004: Emergency core cooling system pump room cooling system RCIC pump room cooler.

13. Diesel Generator Building Ventilation System

The following loop A diesel generator building ventilation system equipment is isolated from the control room by diesel generator A control transfer switch, located on the diesel generator A control panel, and actuated by an engine running interlock located in the diesel generator A engine control panel. The dampers are controlled by a setpoint station located on the Division 1 remote shutdown control panel which receives an input from a separate temperature transmitter used only for remote shutdown:

M43-C001A: Diesel generator building ventilation system ventilation fan A

M43-F020A: Diesel generator building ventilation system outside air damper

M43-F030A: Diesel generator building ventilation system return (recirculation) air damper

M43-F031A: Diesel generator building ventilation system return (recirculation) air damper

M43-F070A: Diesel generator building ventilation system exhaust damper

M43-F071A: Diesel generator building ventilation system exhaust damper

14. Control Complex Chilled Water System

The following loop A control complex chilled water system equipment have individual transfer/control switches located on the associated switchgear panels in the Division 1 switchgear room and local control panel at the chiller.

P47-B001A: Control complex chilled water system control complex chiller A

P47-C001A: Control complex chilled water system chilled water pump A

15. Emergency Service Water Screen Wash System

The following emergency service water screen wash system equipment has fuse isolation provide for control room auto start and voltage monitoring circuits:

P49-D001A: Emergency service water screen wash system screen control

16. Safety-related Instrument Air System

The following loop A safety-related instrument air system equipment have transfer/control switches located on the associated MCC compartment doors:

P57-F015A: Motor-operated valve (containment isolation)
P57-F020A: Motor-operated valve (drywell isolation)

17. Standby Diesel Generator System

The following Division 1 standby diesel generator (R43-S001A) components are provided with fuse and transfer switch isolation from the control room:

Voltage regulator control and indicating light
Generator field metering

18. Diesel Generator Fuel Oil System

The following diesel generator fuel oil system equipment is provided with fuse isolation for control room voltage monitoring circuit:

R45-C001A: Diesel generator fuel oil system fuel oil transfer pump A

7.4.1.5 Design Basis

The safe shutdown systems are designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the reactor coolant pressure boundary. <Chapter 15> identifies and evaluates events that jeopardize the fuel barrier and reactor coolant pressure boundary. The methods of assessing

barrier damage and radioactive material releases, along with the methods by which abnormal events are identified, are also presented in <Chapter 15>.

a. Variables monitored to provide protective actions

RCIC - Reactor vessel low water level (trip Level 2) is monitored in order to provide protective actions to the safe shutdown systems. All other safe shutdown systems are initiated by operator actions.

The plant conditions which require protective action involving safe shutdown are described in <Chapter 15> and <Appendix 15A>.

b. Location and Minimum Number of Sensors

Technical Specifications will discuss the minimum number of sensors required to monitor safety-related variables. There are no sensors in the safe shutdown systems which have a spatial dependence.

c. Prudent Operational Limits

Prudent operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious safe shutdown system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

d. Margin

The margin between operational limits and the limiting conditions of operation of safe shutdown systems are accounted for in Technical Specifications.

e. Levels

Levels requiring protective action are established in Technical Specifications.

f. Range of Transient, Steady-State and Environmental Conditions

Refer to <Section 3.11> for environmental conditions. Refer to <Section 8.2.1> and <Section 8.3.1> for the maximum and minimum range of energy supply to the safe shutdown systems instrumentation and controls. All safety-related instrumentation and controls are specified and purchased to withstand the effects of these energy supply ranges.

g. Malfunctions, Accidents and Other Unusual Events Which Could Cause Damage to Safety System

<Chapter 15> describes the following credible accidents and events: floods, storms, tornadoes, earthquakes, fires, LOCA, pipe break outside containment, and feedwater line break. Each of these events is discussed below for the safe shutdown systems.

1. Floods

The buildings containing safe shutdown system components have been designed to meet the PMF (Probable Maximum Flood) at the site location. This ensures that the buildings will remain water-tight under PMF conditions including wind generated wave action and wave runup. For a discussion of internal flooding protection, refer to <Section 3.4.1> and <Section 3.6>.